7a Point to point HVDC systems

HVDC LEARN
Modules for Maturing HVDC Electric Transmission Knowledge

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Prerequisite Competencies:	1. Motivating needs for high-capacity electric transmission 2. Introductory HVDC as found in Modules 1a, 1b, 1c.
Module Objectives:	1. Identify features of point-to-point HVDC transmission 2. Distinguish from multi-terminal HVDC systems. 3. Identify point-to-point applications and describe unique implementations

Abstract

In contrast to multi-terminal HVDC systems, point-to-point (PTP) HVDC transmission connects only two converter terminals via a direct current transmission path. They may connect two asynchronous AC systems, or they may provide a DC transmission path within a single AC system. PTP is the oldest HVDC design, having seen application since the early 1950s, and with over 200 implementations worldwide, it is by far the most common design. Many new PTP HVDC projects are being planned or built today. The objective of this module is to characterize PTP HVDC designs and applications.

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Acronyms

AAC	All aluminum conductor
AC	Alternating current
ACSR	Aluminum conductor steel reinforced
AGC	Automatic generation control
BPS	Bypass switch
BTB	Back-to-back
CSC	Current source converter
DC	Direct current
DS	Disconnect switch
ECC	Energy control center
EHVAC	Extra high voltage alternating current
ERTB	Earth return transfer breaker
HVAC	High voltage alternating current
HVDC	High voltage direct current
IFA	Interconnexion France Angleterre
IGBT	Insulated gate bipolar transistor
LCC	Line commutated converter
MI	Mass impregnated
MISO	Midcontinent Independent System Operator
MMC	Modular multilevel converter
MRTB	Metallic return transfer breaker
MVAR	Mega-volt-ampere-reactive
MW	Megawatt
NBS	Neutral bus switch
NESC	National Electric Safety Code
PI	Proportional integral
PLL	Phase locked loop
POI	Point of interconnection
PTP	Point to point
ROW	Right of way
SGRS	Sylmar ground return system
SVC	Static var compensator
VSC	Voltage source converter
XLPE	Crosslinked polyethylene

Nomenclature

$i(t)$	current as function of time
t	time
L	inductance
$v(t)$	voltage as function of time
V_{Rated}	Rated DC voltage of HVDC pole
I_{Rated}	Rated DC current of HVDC line or cable
V_{ab}, V_{bc} , V_{ca}	Line-to-line voltages
$\underline{/V_{AB}}$	Angle on a line-to-line voltage
I	Current phasor
ω	frequency in radians per second
P_{ref}, I_{ref}	HVDC power and current references

7a-1 Introduction

High voltage direct current (HVDC) transmission has seen applications since the early 1950s. The first such line for commercial purposes was installed in 1954 to interconnect the Swedish mainland 98 km (61 miles) to the island of Gotland in the Baltic Sea; a monopole design employing mercury-arc valves, its capacity was 20 MW at a voltage level of 100 kV [1]. The Sweden-Gotland HVDC connection was unique in that it was a submarine cable; another HVDC submarine cable would not be built until 1965 when the HVDC Inter-Island line was energized in New Zealand, and the Konti-Skan 1 line was energized to connect Denmark to Sweden [1, 2]. The Sweden-Gotland line was highly representative of almost all HVDC lines that came afterwards, at least until recently, because it was a point-to-point (PTP) HVDC line. A PTP HVDC line, also referred to as two-terminal HVDC system, is an HVDC transmission system consisting of two HVDC transmission substations (also referred to as converter stations) and the HVDC transmission line(s) between them [3]. In PTP HVDC systems, one converter operates as a rectifier, converting AC to DC, and the other converter operates as an inverter, converting DC to AC.

Reference [4] provides an extensive and up-to-date list of all HVDC projects around the world. Of the 233 projects listed, which include projects that are decommissioned, existing, or under construction, 226 of them are PTP HVDC configurations and only seven are not. Furthermore, of the 33 planned HVDC projects listed at [4], all are PTP configurations. Therefore, although interest in other HVDC designs is certainly growing (five of the seven non-PTP lines were built after 2013), PTP configurations have and will for the immediate future continue to comprise a large percentage of HVDC projects.

The objective of this module is to characterize PTP HVDC designs. To do so, in Section 7a-2, we summarize other types of HVDC designs and identify the motivations for PTP designs. Section 7a-3 describes PTP design features in terms of configurations (monopolar, bipolar, homopolar, and tripolar) and in terms of components (converters, protection, filters, and conductors. Section 7a-4 describes four different PTP applications, including overhead, back-to-back, underground, and submarine, and provides descriptive examples of each. Section 7a-5 describes PTP applications for offshore wind. Section 7a-6 identifies equity issues for PTP HVDC systems, and Section 7a-7 summarizes the main learning points of this module.

7a-2 Types of HVDC designs

Of the seven non-PTP designs identified in the list of [4], six are multiterminal and one is a DC grid. Reference [3] defines a multiterminal HVDC system as one that consists of more than two separated HVDC converter stations together with the interconnecting HVDC transmission lines. A multiterminal line is, then, when the additional converter stations are arranged along a single HVDC line; a multiterminal line is not meshed. A DC grid is a meshed multiterminal HVDC system, i.e., a multiterminal system for which the topology contains one or more loops. Figure 7a - 1 illustrates the difference between a (a) PTP HVDC line, (b) a multiterminal HVDC line, and (c) a DC grid. Module 8a, Module 9a, and Module 10d provide additional treatment of multiterminal HVDC and HVDC grids.

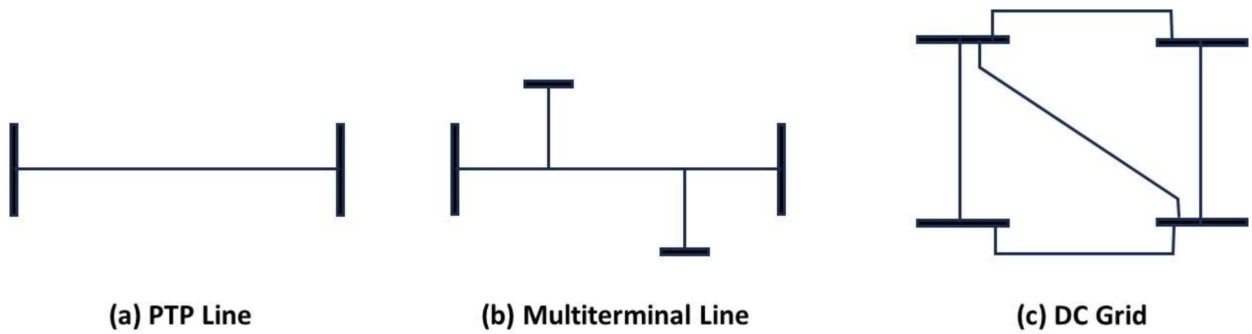

Figure 7a - 1: Three types of HVDC designs

An important feature of any HVDC system is its method of isolating permanent faults on DC components. If the entire HVDC system is identified as a single protection zone, then the HVDC system can isolate permanent faults on DC components by opening circuit breakers on the AC side of all converter stations interconnecting with the HVDC system. This is advantageous, because AC circuit breakers are an established and effective technology; they benefit from the fact that AC crosses zero twice per cycle and as a result offer opportune moments to break the fault current.

DC offers no zero crossings, however, and so DC circuit breakers must interrupt very high currents to isolate a faulted component, and the technology for doing so is an order of magnitude more expensive than AC circuit breakers (Module 5c provides treatment of DC circuit breakers). For PTP designs, this is not a problem because the single protection zone contains only a single HVDC line, and so isolating a fault on a PTP line results in loss of only the one HVDC line. The situation is less desirable for a multiterminal line, but only incrementally so, since the single protection zone includes the main HVDC line and a limited number of lower capacity converter stations. On the other hand, treating a DC grid as a single zone of protection means that a fault on any of its HVDC lines isolates the entire DC grid.

7a-3 PTP design features

In this section, we address three main PTP design features: converter type, components, and configuration.

7a-3.1 Converter type: LCC vs VSC

There are two HVDC converter technologies available: line commutated converters (LCC) and voltage source converters (VSC). LCCs utilize thyristors which handle higher power capacity but offer less control flexibility. Of particular importance, LCCs must be supplied with reactive power, and they usually require MVAR compensation (e.g., switchable shunt capacitors, static var compensators (SVCs), or statcoms), especially at HVDC terminals located at weak (non-stiff) portions of the AC grid. VSCs, on the other hand, utilize insulated gate bipolar transistors (IGBTs) and have lower power handling capability but, unlike LCCs which are line commutated (LCCs turn off only when they see a negative voltage), IGBTs are self-commutated (IGBT turn-off time is controlled), and as a result, VSCs offer highly flexible control capabilities. Indeed, VSCs can absorb or supply reactive power and thus control voltage, enabling converter terminals to be located with less concern for AC-network grid-strength. This tradeoff between thyristor-based LCCs and IGBT-based VSCs can be observed in Figure 7a - 2 [5] via the differences between thyristors and IGBTs in terms of voltage and current ratings (for power handling capability) and in terms of switching speed (for control capabilities). Additional treatment of thyristors and IGBTs is provided in Module 3c.

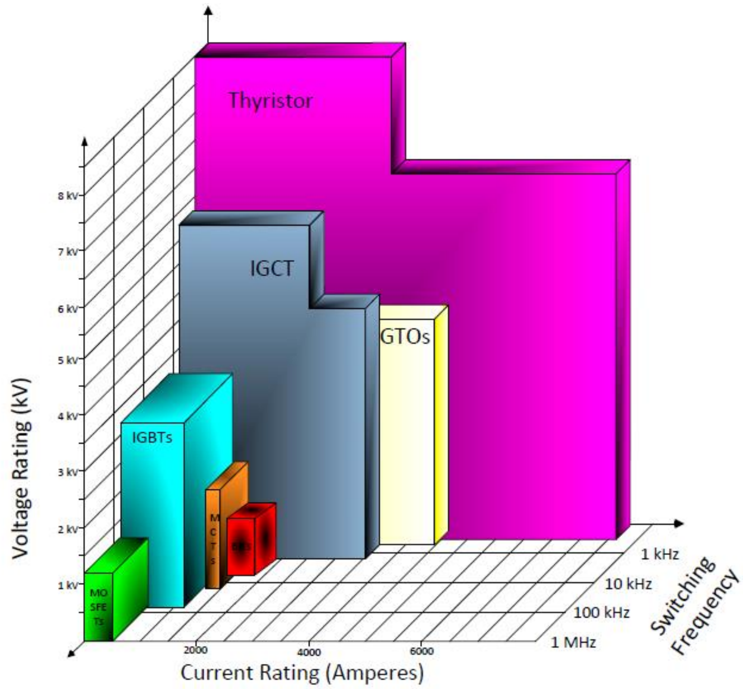

Figure 7a - 2: Comparison of device types in terms of power handling and switching speed [5]

An additional limitation for LCCs is that they are unable to perform a current reversal since thyristors are unidirectional devices. Therefore, if reversal of power flow is desired, LCCs must do a voltage polarity change at the terminal to which it is connected. This is acceptable for PTP designs, but if the terminal has other circuits connected to it as it would for a multiterminal or DC grid design, then the polarity change will also reverse the power flow in the other circuits. In contrast, a VSC allows current reversal and so power flow direction in a circuit may be implemented without affecting the flow direction of other circuits connected to the terminal.

Figure 7a - 3 uses data from [4] to show the number of HVDC PTP systems commissioned worldwide since 1965 that are still existing, by converter type; these data include transmission systems and back-to-back installations. Of the 178 existing HVDC PTP systems, most (131) use LCCs; only 47 use VSCs. However, this began to change during the 2010-2015 period, and since 2015, new HVDC PTP systems using VSC have significantly outnumbered those using LCC. Expectations are that this trend will continue as power-handling capabilities of VSCs increase.

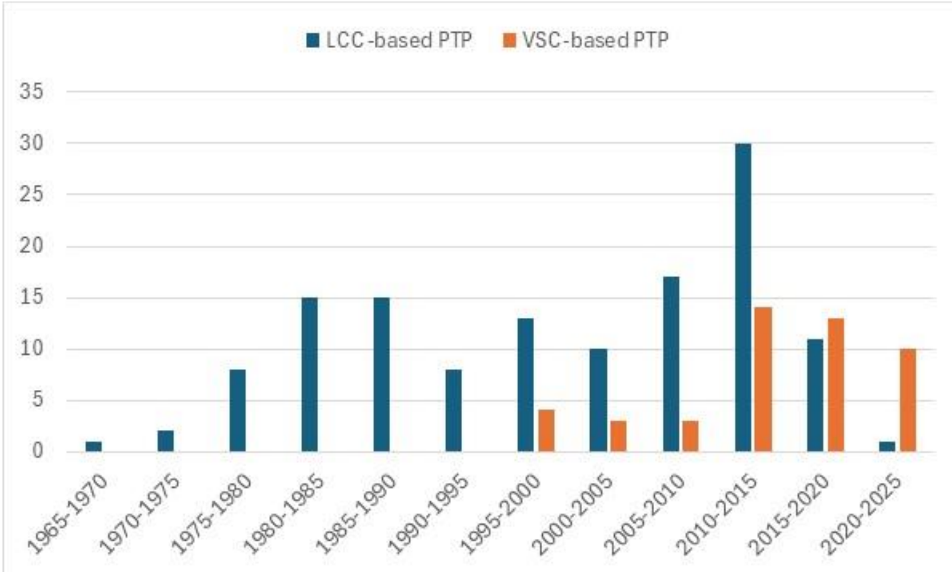

Figure 7a - 3: Number of HVDC PTP systems commissioned worldwide since 1965

INDUSTRY INSIGHT

In 2023, the Midcontinent Independent System Operator (MISO) performed an extensive comparison of HVAC, EHVAC, and HVDC options in preparation for the second “tranche” of their Long-Range Transmission Planning study. Part of those efforts were presented to the MISO Planning Advisory Committee on March 8, 2023, and the presentation is publicly available [6]. A central part of the comparison involved identifying benefits of 765 kV AC transmission vs. ±640 kV HVDC transmission, the most important of which was that 765 kV AC is preferred for transmission distances below 250 miles, and HVDC is preferred for transmission distances exceeding 400 miles. Transmission distances between 250 and 400 miles are in the “interchangeable design region” and require further analysis. These perspectives are illustrated in Figure 7a - 4.

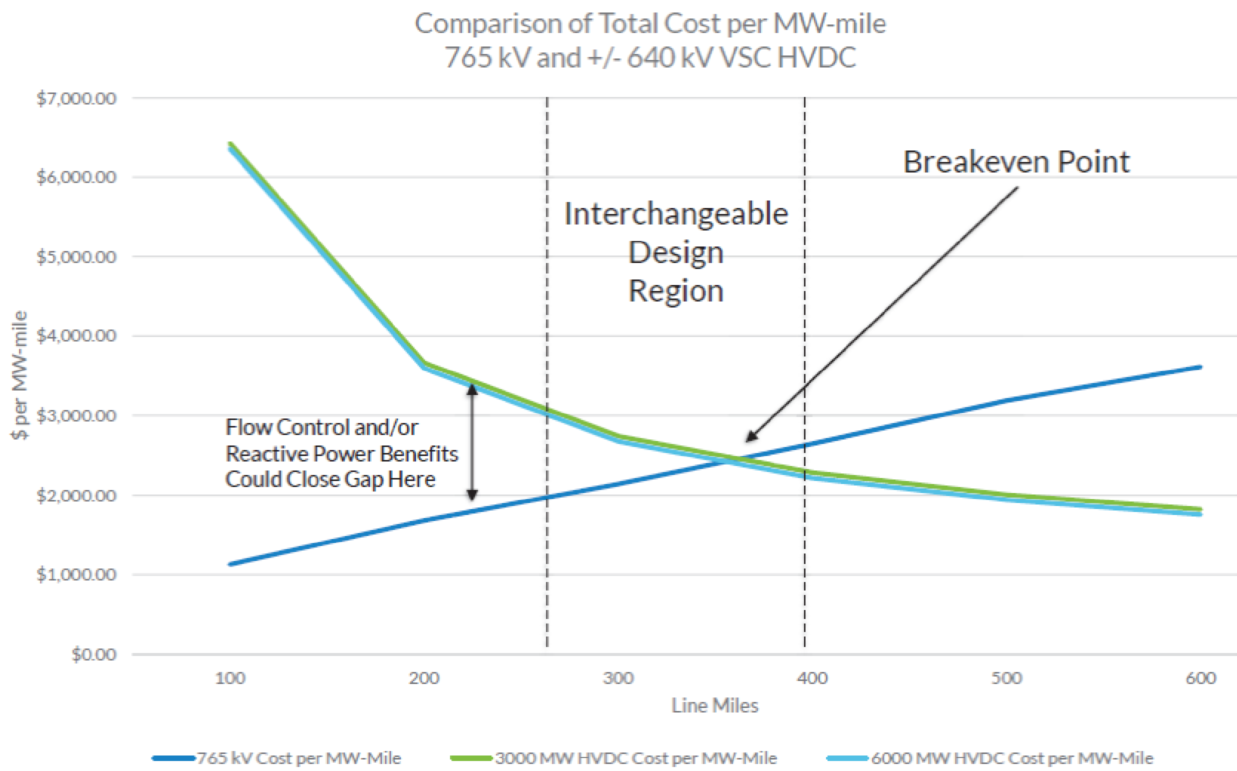

Figure 7a - 4: 765 kV AC vs ±640 kV HVDC - comparison of $/MW-mile

7a-3.2 Electrical configurations for LCC PTP systems

The most common electrical configuration for LCC PTP systems is the bipolar configuration. However, there have been a few monopolar PTP installations using LCC, including the first commercial installation between Gotland and the Swedish mainland and also, a few years later, the Konti-Skan between Sweden and Denmark [1], [7, p. 87], as mentioned in Section 7a-1. Monopolar and Bipolar LCC-based PTP configurations are shown in Figure 7a - 5 and described in the following subsections.

LCCs are also referred to as current source converters (CSC). As observed from both configurations of Figure 7a - 5, the DC-side of the converter is in series with the smoothing reactor, which is a large inductor; we denote its inductance as L. It is this smoothing reactor that makes the DC-side of the converter appear as a current source (i.e., a constant current supply). This happens because the change in inductor current $di(t)/dt$ must be limited to maintain finite voltages if L is large, as indicated by $di(t)dt=(1/L)\ v(t)$, where $i(t)$ and $v(t)$ are the time-domain expressions for, respectively, the current through and the voltage across the smoothing reactor.

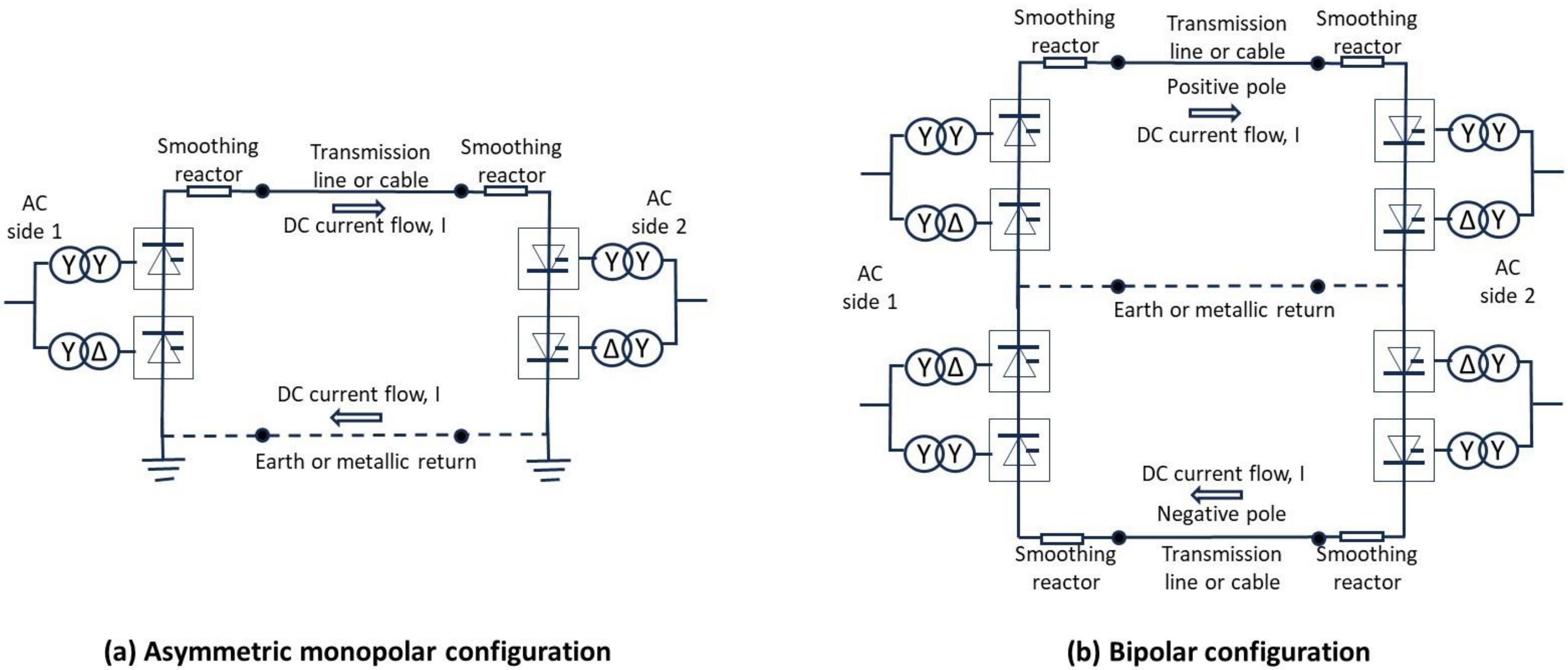

Figure 7a - 5: Electrical configurations for HVDC LCC-based PTP systems

7a-3.2.1 Asymmetric monopolar configuration using LCCs

The LCC-based asymmetric monopolar configuration maintains only one DC conducting path at transmission voltage, with the other conducting path being at ground potential provided either through the earth or sea or through a grounded metallic return as shown at the bottom of Figure 7a - 5a. This configuration is referred to as *asymmetric* because the return is at ground potential, which differs from the transmission voltage.

If the conducting path is through earth or sea, then HVDC electrodes must be employed at both terminals. Full-time use of earth-return monopolar HVDC is prohibited by the National Electric Safety Code (NESC), Paragraph 314-C, which states that "supply circuits shall not be designed to use the earth normally as the sole conductor for any part of the circuit," but that "monopolar operation of a bipolar HVDC system is permissible for emergencies and limited periods for maintenance" [8]. However, temporary monopolar operation of a bipolar HVDC system is permitted. Indeed, it is often used as an initial stage before bipolar operation begins, and as a reduced-capacity (50%) operating state when one pole of a bipolar configuration is out of service.

7a-3.2.2 Bipolar configurations using LCCs

Among existing HVDC systems, the LCC-based bipolar configuration is the most common HVDC design. Reference [4] indicates that, today, LCC-based bipolar HVDC systems exist at various DC voltages but most, particularly new installations, are at ±400, ±500, ±600 (or ±640), and ±800 kV.

It is easy to observe from Figure 7a - 5 that the bipolar configuration can be conceived as two combined monopolar systems, When operating in the bipolar configuration, the power transfer capacity is $(+V_{Rated})(I_{Rated})+(-V_{Rated})(-I_{Rated})=2(V_{Rated})(I_{Rated})$; it is balanced and no flow occurs on the earth or metallic return. As indicated in the previous section, under the condition that a pole experiences a permanent fault, the faulted pole can be isolated, and the system operated in the monopolar configuration with the earth or metallic return carrying full current but at zero voltage. In this case, the power transfer capacity becomes $(V_{Rated})(I_{Rated})$, which is half of that during (normal) unfaulted operation.

7a-3.3 Electrical configurations for VSC PTP systems

The asymmetric monopolar and the bipolar configuration identified for LCC-based HVDC systems and shown in Figure 7a - 5a and Figure 7a - 5b, respectively, may also be used for VSC-based HVDC systems. For example, the 2010 Caprivi overhead link joining Namibia and Zambia in Southern Africa [9] [10, p. 148] is a VSC-based asymmetric monopolar configuration and is planned to become a VSC bipolar configuration in the future. However, most of today's operational VSC-based systems utilize a symmetric monopolar configuration [11]. In contrast to the asymmetric monopolar configuration, where only one conductor is at high voltage, and the other (either earth, sea, or metallic return) is at ground, the symmetric monopolar configuration uses both positive and negative high voltage conductors as in a bipolar configuration. However, unlike the bipolar configuration, the system is operated as a single unit [10, p. 147], as shown in Figure 7a - 6. As indicated in [10, p. 147], the reason for this is that VSC-based HVDC systems have been mostly underground or undersea, with cable voltages limited to 320 kV. Adopting the symmetrical monopole design achieves pole-to-pole voltages of 640 kV without exceeding cable ratings. Examples of existing operational facilities using VSC in a symmetrical monopole design include [12] the 2002 Cross Sound Cable at 330 MW and ±150 kV connecting Connecticut and

Long Island; the 2014 Mackinac, Michigan back-to-back system at 200 MW and ±71 kV; and the 2015 and 2016 Dolwin 1 and 2 cables at 800 MW, ±320 kV and 916 MW, ± 320 kV, respectively, connecting offshore wind to Germany.

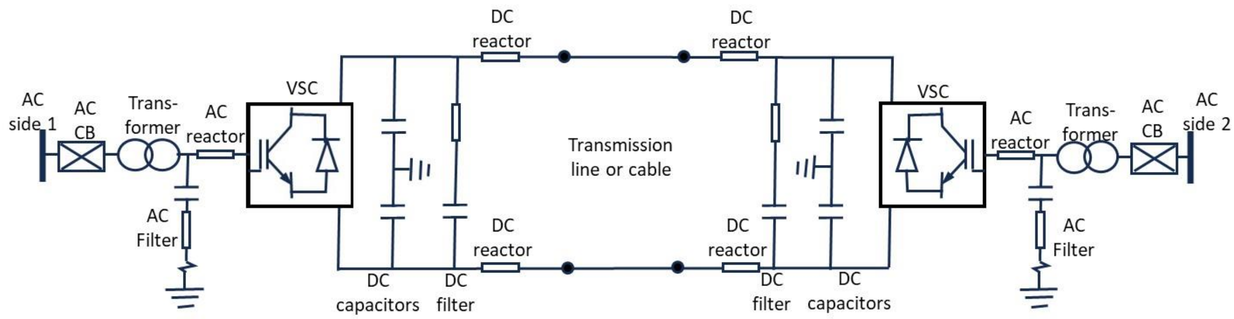

Figure 7a - 6: Symmetric monopolar configuration

7a-3.4 Components for LCC PTP systems

As shown in Figure 7a - 7, there are nine basic components to an HVDC converter station: (A) converter units; (B) converter transformers; (C) smoothing reactors; (D) circuit breakers; (E) AC switchyard; (F) filters; (G) reactive power compensation; (H) lines or cables; (I) control/communication system; (J) and earth, sea, or metallic return. We introduce these components in the following subsections, focusing on LCC-based designs.

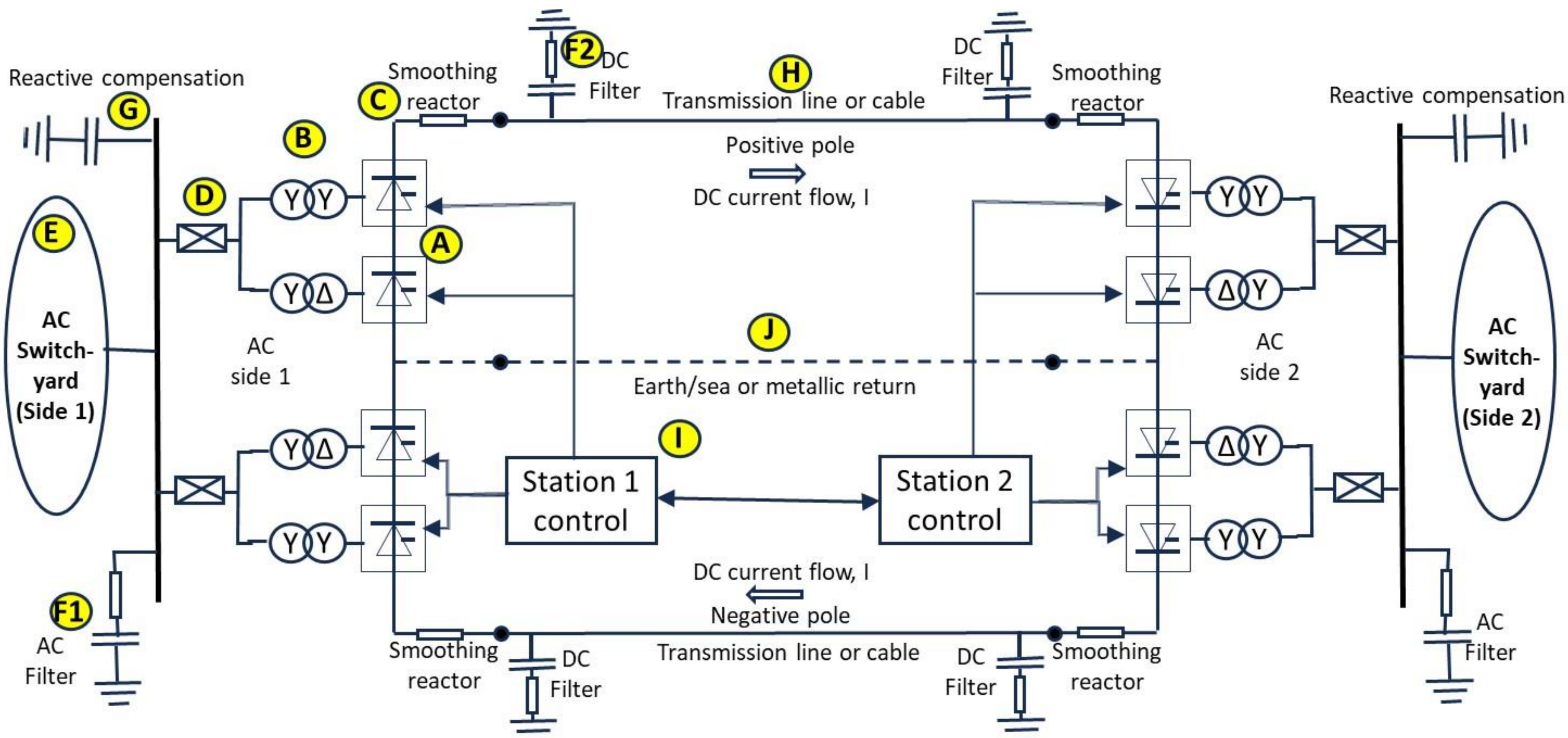

Figure 7a - 7: Components in a LCC PTP HVDC system

7a-3.4.1 Converter unit

The converter unit is shown in Figure 7a - 7 as item A; this is a thyristor-based power electronic circuit that interfaces the DC line with the AC grid. In a PTP HVDC system, there are two converter units, one at either end of the line. For any given DC line flow direction, the converter at the sending end provides rectification (i.e., converts AC to DC), and the converter at the receiving end provides inversion (i.e., converts DC to AC). The standard converter circuit is a three-phase 12-pulse circuit; the word "pulse" refers to the number of distinct operating states that occur over one period of the AC waveform, with each operating state corresponding to an observable pulse in the current waveform on the converter's DC side.

The drawing of Figure 7a - 7, item A, uses shorthand illustration of the converter unit, as identified in Figure 7a - 8. The converter is comprised of 12 thyristor valves. A valve is a power electronic device that provides switching capability; LCC-based HVDC valves use thyristors, packaged as single devices, two devices (a double valve) or four devices (a quadrivalve). Figure 7a - 9 shows the 12-pulse converter with single device packages (left) and with quadrivalves (right); in each case, the12-pulse converter is comprised of two 6-pulse converters connected in series; they are labeled in the diagrams as Bridge 1 and Bridge 2. The switching actions of the 12-pulse converter can be understood in the context of two 6-pulse converters. Principles of AC to DC conversion based on 6-pule and 12-pulse converters are described in Module 1a.

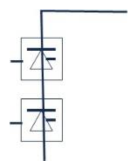

Figure 7a - 8: Shorthand illustration of converter unit

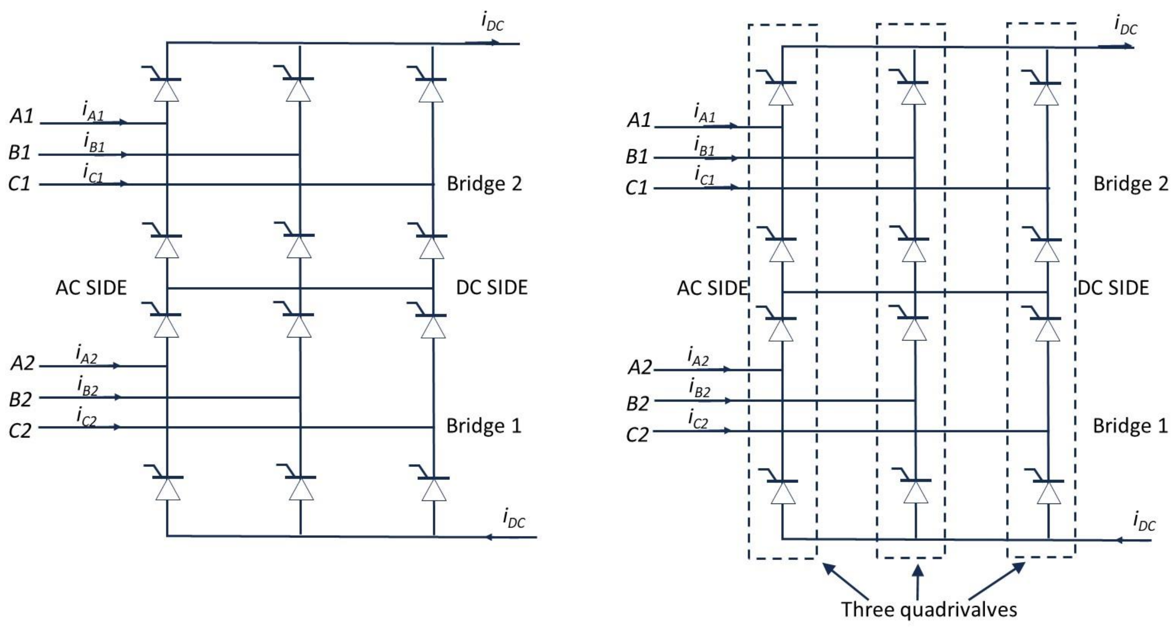

Figure 7a - 9: 12-pulse converter using single device package (left) and quadrivalves (right)

7a-3.4.2 Converter transformer

The converter unit is connected to the AC grid through converter transformers, as indicated by item B of Figure 7a - 7, and as shown in more detail in Figure 7a - 10. The converter transformer provides two functions. The first function is that it steps down the AC voltage input to levels that are compatible with the converter ratings which are significantly lower than transmission level voltages.

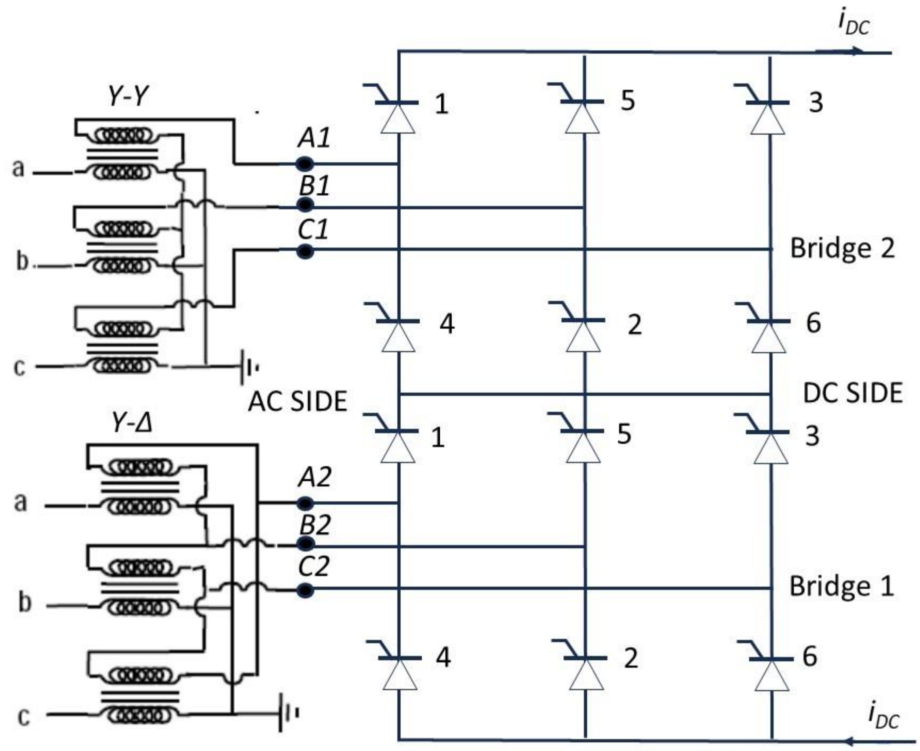

Figure 7a - 10: 12-pulse converter with converter transformers

The second function is that it provides 30° phase displacement of the voltages seen by the converter by using two different three-phase transformer connections. In Figure 7a - 10, the two transformers on the AC side are both fed from the same three-phase AC source, and so the applied line-to-line voltages on the high side V_{ab}, V_{bc} , and V_{ca} are the same for both transformers. However, as indicated in the figure, the top transformer is connected Y-Y, and the bottom transformer is connected Y-Δ, so that secondary line-to-line voltages of the bottom transformer lag their corresponding primary line-to-line voltages by 30º, and therefore secondary line-to-line voltages of the bottom transformer also lag secondary line-to-line voltages of the top transformer by 30º, i.e.,

$$\underline{/V_{A2B2}} = \underline{/V_{A1B1}} - 30°$$
$$\underline{/V_{B2C2}} = \underline{/V_{B1C1}} - 30°$$
$$\underline{/V_{C2A2}} = \underline{/V_{C1A1}} - 30°$$

Using the thyristor numbers indicated in Figure 7a - 10, firing sequence {5,6}, {6,1}, {1,2}, {2,3}, {3,4}, {4,5} is applied to both bridges. The 30° phase delay in bridge 1 output relative to bridge 2 output results in a voltage phasor sequence (rotation in counterclockwise direction) as indicated in Figure 7a - 11 (dotted lines are polarity reversals relative to its 180° solid line counterpart). Equal amplitudes of bridge 2 voltages relative to bridge 1 voltages are obtained using transformers of appropriate winding ratios.

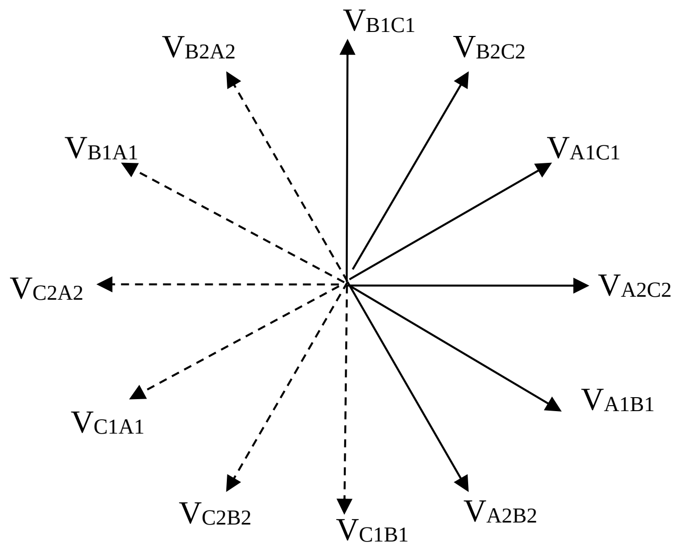

Figure 7a - 11: Voltage phasor sequence

Relative to a 6-pulse bridge, the 12-pulse bridge results in a smoother DC voltage, with less harmonic content. Figure 7a - 12 compares the DC output of a 6-pulse converter with that of a 12-pulse converter.

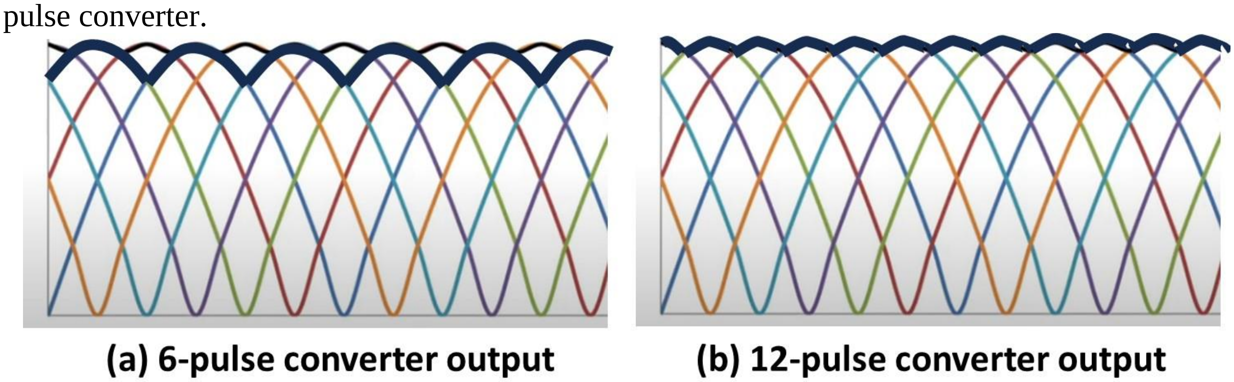

Figure 7a - 12: Comparison of DC voltage for 6-pulse vs. 12-pulse converter

Converter transformers for LCC-based HVDC are typically equipped with tap changing capability to assist in the regulation of the voltage on the AC side of the converter. In addition, harmonics created by the converter can cause additional transformer heating, motivating the need for AC-side filters. Some facilities use specialized measures to monitor harmonics in converter transformers [13].

7a-3.4.3 Smoothing reactors

Smoothing reactors, also known as DC reactors, are positioned in series with the DC conductor, as indicated by item C in Figure 7a - 7. These are inductors having large inductance *L* (typically 0.1-0.5 H [10, p. 5]) and, as indicated at the beginning of Section 7a-3.2, it makes the DC-side of the converter tend towards a constant current source, since the change in inductor current *di(t)/dt* must be limited to maintain finite voltages, as indicated by *di(t)/dt=(1/L) v(t)*. The smoothing reactor influences HVDC operation in several ways:

1. *Limiting the rate of DC current rise*: Short circuits on either side of the converter cause current rise on the DC side. The smoothing reactor reduces the rate at which this rise occurs, which tends to reduce commutation failures following AC-side voltage reductions; it also limits the current peak seen at the rectifying station during DC-line short circuits [14]. To be effective via these influences, the reactor must not saturate during the high DC currents and is therefore often implemented as a "linear" reactor, i.e., one with a partial or total air-core construction.
2. *Harmonic reduction*: The smoothing reactor reduces harmonics seen on the DC side of the converter.
3. *Avoiding DC side resonance*: Resonance conditions at the network frequency can occur for marine or underground cables of length between 30 and 80 km [15, p. 199].

The smoothing reactor may be located on either the high-voltage side of the converter, or on the grounded side (Figure 7a - 7 shows it located in both). It is most common to locate it on the high-voltage side because doing so also provides converter protection against lightning surges [10, p.232].

On the other hand, starting with the 1987 150 MW McNeill HVDC back-to-back connection between the North American Eastern and Western Interconnection, smoothing reactors have not been used in most back-to-back HVDC installations. This is because [16, p. 31], for back-to-back systems, the motivation for doing so is diminished given there is no line (and therefore no lightning transients) or cable (and therefore no large DC-side capacitance to cause an unacceptably high transient current during commutation failures). For a back-to-back system, the smoothing reactor provides benefit only by suppressing harmonic cross-modulation between the two AC systems and to further reduce the transient current during a commutation failure, yet these can be rendered unnecessary via control [16, p. 31].

7a-3.4.4 Circuit breakers and switching

There are three types of circuit breakers and switching equipment within a PTP HVDC design, converter pole circuit breakers, AC switchyard circuit breakers, and DC reconfiguration switches.

Figure 7a - 7 shows item D, the converter pole circuit breaker; it is on the AC side, and there is one for each pole. These circuit breakers open to isolate the HVDC system from the overall grid for faults on the converter side of the circuit breaker, including faults on either converter or on the HVDC line itself. They allow for HVDC line faults to not be isolated by DC circuit breakers, a significant influence since DC circuit breakers are expensive, as mentioned in Section 7a-2.

Figure 7a - 7 also shows item E, the AC switchyard. The AC switchyard employs AC circuit breakers in one of the standard AC substation configurations. These different configurations vary in cost and reliability. Figure 7a - 13 shows two; the simplest of these is the single busbar scheme, Figure 7a - 13a. The one offering higher reliability is the breaker-and-a-half scheme of Figure 7a - 13b, so-called because it requires 1.5 breakers for each connected circuit, reliable because a busbar fault only results in loss of a single circuit.

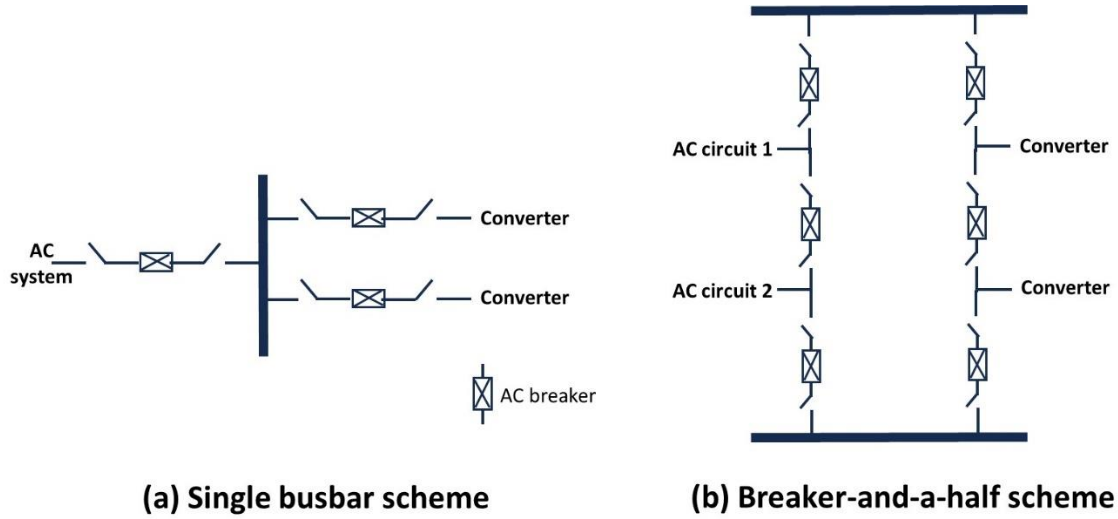

Figure 7a - 13: Two AC switchyard configurations

The third type of switching device typically found within HVDC PTP configurations are reconfiguration switches. These switches facilitate the continued use of the HVDC system during permanent faults on the DC system, as described in the remainder of this section. Module 5a, Module 5b, and 5d provide additional treatment of fault management for HVDC systems.

Bridge faults

In case of a bridge fault, the pole can still operate using the remaining 6-pulse bridge. To do so, the faulted bridge is tripped, and a (normally open) bypass switch (BPS) is closed, providing a current path around the faulted bridge. The corresponding bridge at the other terminal is also bypassed. This is illustrated in Figure 7a - 14.

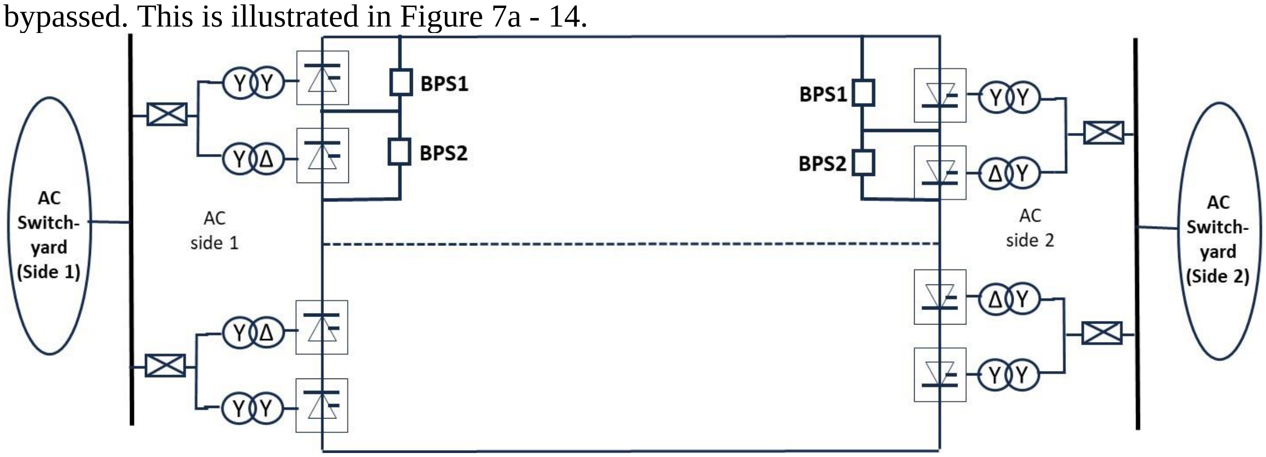

Figure 7a - 14: Illustrating by bypass switch (BPS) response to bridge fault

Pole faults

Under the condition that a permanent pole fault occurs rendering the pole unable to operate at non-zero voltage level, there is an advantage to using the pole as the grounded return in that it is lower impedance. Referring to Figure 7a - 15, and assuming a fault on pole 1 (as shown in the figure), this is done based on the following switching sequence (i) Neutral bus switch (NBS)1 opens, (ii)

Disconnect switch (DS)1 closes, (iii) Earth return transfer breaker (ERTB) closes, (iv) Metallic return transfer breaker (MRTB) opens. This sequence is described as follows [10, p. 117-119], [17, p. 34-35], [16, p. 382-383]:

- NBS1 opens: Both NBS1 and NBS2 are normally closed switches, and they carry full load current during unfaulted operation. Under a fault on pole 1, NBS1 current increases and protection trips it.
- DS1 closes and ERTB closes: The DS1 and ERTB are normally open. When they are closed, some of the current from the earth return transfers to the faulted pole.
- MRTB opens: The normally closed MRTB carries no current under unfaulted condition, but following the opening of NBS1, it carries full load current. Following the closing of DS1 and ERTB, the MRTB will carry significantly lower current since the metallic return is in parallel with the faulted pole. However, there are safety issues related to operating under an earth return. Therefore, the MRTB is opened.

Similar actions would be taken on side 2. In Figure 7a - 15, the thick red arrow indicates the post-switching current flow for side 1.

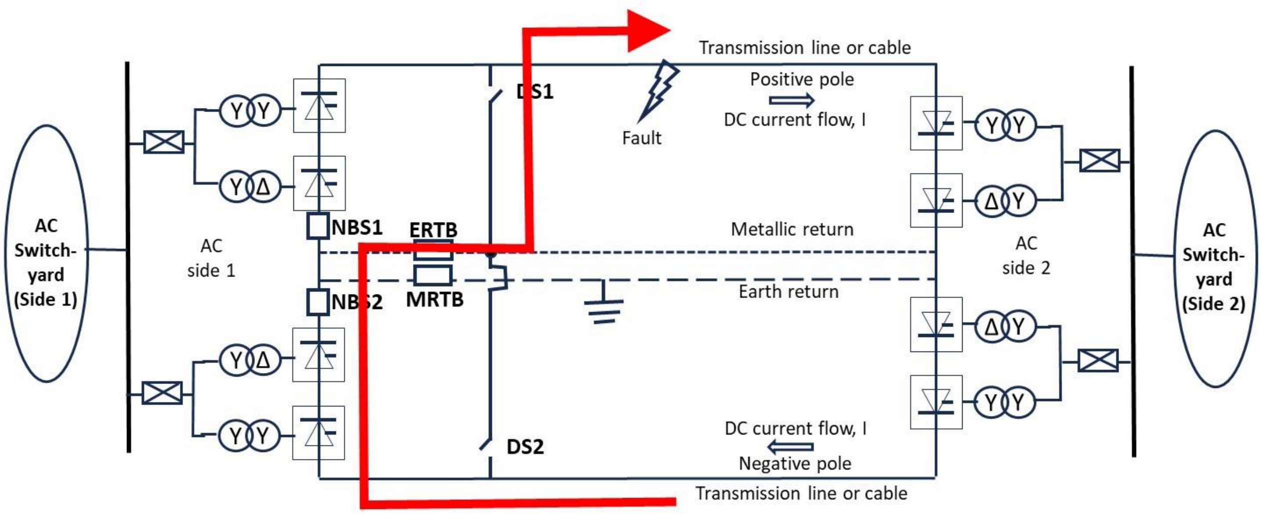

Figure 7a - 15: Reconfiguration to monopole operation following permanent pole fault

INDUSTRY INSIGHT

The Pacific DC Intertie (PDCI) is a PTP HVDC system from the Celilo converter terminal in Oregon to the Sylmar converter terminal in Los Angeles; it was commissioned in 1970. On February 9, 1971, at 6:01am PST, the San Fernando earthquake struck Los Angeles with 6.6 magnitude and epicenter six miles northeast of Sylmar. It resulted in extensive damage to the Sylmar converter terminal and the shutdown of the PDCI. Immediate effort was made to repair one pole, and the system was operated in monopolar metallic return mode while work on the other pole continued. The effort was coordinated among engineers from the Bonneville Power Administration in Portland, Oregon, the Los Angeles Department of Water and Power, the Electric Power Research Institute in Palo Alto, California, and the Westinghouse Research and Development Center in Pittsburg, Pennsylvania. This was the first case of bipolar DC system design adapted to facilitate monopolar metallic return operation and led to a 1982 paper published in the IEEE Transactions on Power Apparatus and Systems [18]. The abstract of that paper reads as follows:

> "When a bipolar HVDC transmission system is operating monopolar using the earth as a return path, it is often desired to divert the return current from the earth to the line from the unused pole. To do so requires either that the system be shut down temporarily or that a dc circuit breaker be used. This paper describes the development of such a new dc circuit breaker, and its application on the Pacific Intertie as a Metallic Return Transfer Breaker (MRTB)."

7a-3.4.5 Filters

The discontinuous nature of converter switching generates harmonics, and as a result, filtering is necessary on both the AC and the DC sides, as indicated by the components labeled F1 and F2 in Figure 7a - 7. Additional treatment of harmonics is provided in Module 2a and Module 10e, and filter design is treated in Module 2a.

AC filters

IEEE Standard 519 [19] and IEC Standard 61000-3-6 [20] impose limits on harmonic presence in AC grids. This is motivated to avoid interference with communication systems and to avoid increased losses and heating in electromagnetic devices such as motors and transformers.

The primary task of AC filters is to reduce harmonic currents generated by the HVDC converter and to reduce their impact on the AC grid. It can be shown (see problem 6) that a Y-Y and Y-Δ connected 12-pulse converter generates all 12k±1 (k=2, 3, …) harmonics, i.e., the 11th, 13th, 23rd, 25th, etc., as given below [10, p. 123].

$$I = 4\frac{\sqrt{3}}{\pi} I_{DC} \left[sin\omega t - \frac{1}{11} sin11\omega t + \frac{1}{13} sin13\omega t - \frac{1}{23} sin23\omega t + \frac{1}{25} sin25\omega t + \cdots \right]$$

These are the so-called "characteristic" harmonic currents, generated even during the ideal conditions of symmetry in AC voltages, transformer impedances, and firing angles. Tuned filters are used to address the 11th and 13th harmonics, and high-pass filters are used to address the higher order harmonics, as indicated in Figure 7a - 16.

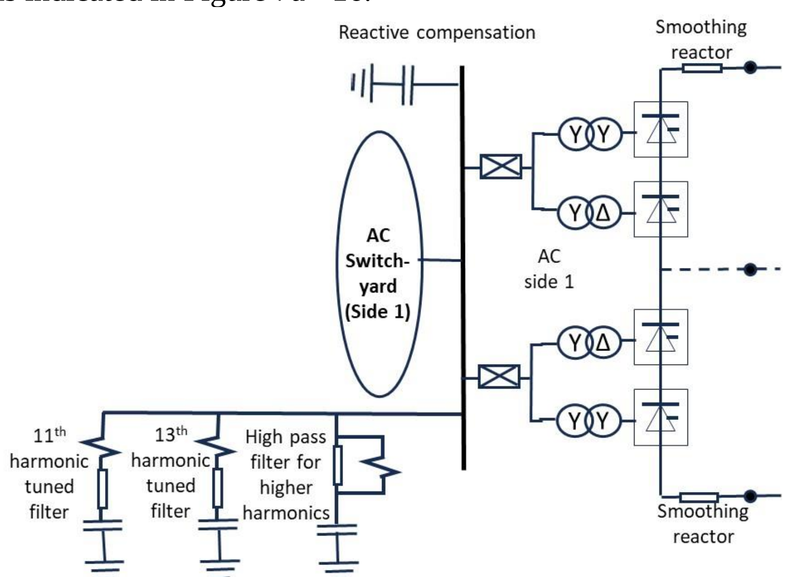

Figure 7a - 16: Harmonic filters for converter station

DC filters

Figure 7a - 12b shows the DC waveform produced by a 12-pulse converter, clearly resulting in harmonics. Harmonic voltages occurring on the DC side of a converter result in the flow of AC currents on the HVDC line. Although there are no loads on the DC side that can be affected by these harmonic currents, they create an alternating magnetic field that can cause harmonic voltages to be induced in any other conductors within the zone of influence of the magnetic field [21]. As a result, they can interfere with wireline communication systems, and so filters are applied to mitigate them, as indicated by component F2 in Figure 7a - 7. A 12-pulse converter generates all 12k (k=1, 2, 3, …) harmonics, i.e., the 12th, 24th, 36th, etc. [15, p. 65].

7a-3.4.6 Reactive power compensation

In an LCC, the current at both rectifier and inverter terminals is lagging, and therefore both terminals draw reactive power. This is because the converter is line commutated, i.e., thyristor control is only for turning *on* the device; it is then turned *off* by the circuit (or the "line"). As a result, the current initiation in each thyristor can only be delayed with respect to the zero crossing of the voltage, and so current must lag the corresponding voltage. This results in lagging power factor operation on both rectifier and inverter sides. Therefore, both LCC-based rectifier and inverter are reactive sinks and require capacitive compensation.

Thus, the secondary task of AC filters is to compensate the reactive demand of the converter station, and this secondary task motivates the need for multiple filter banks, since the converter station reactive demand is variable. Most DC PTP systems have at least one capacitor bank dedicated to reactive compensation, as indicated by component G in Figure 7a - 7.

7a-3.4.7 Conductor systems

The HVDC conductor system differs significantly depending on whether the design is for overhead or for underground/undersea, and so we address these two instances separately.

Overhead HVDC conductor systems

For overhead transmission, the conductor system includes the conductor, clamps and connectors, insulators, and towers. Conductors, clamps, and connectors used for overhead HVDC systems are similar to those used for overhead HVAC transmission in the 345 and 500 kV class. The most common conductor types used for overhead HVDC are all aluminum conductor (AAC) and aluminum conductor steel reinforced (ACSR). Like AC transmission phases, each HVDC pole may utilize bundled conductors. This not only provides N_b times the single conductor MW transfer capacity (N_b is the number of conductors per bundle), but it also reduces the electric field strength surrounding the conductors and thus the tendency to produce corona, an effect that decreases losses. Figure 7a - 17 illustrates the PDCI a few miles northeast of the southern (Sylmar) terminal, where it is easy to observe that each pole utilizes a two-conductor bundle.

Figure 7a - 17: A tower for the PDCI showing two conductors per pole

Relative to AC transmission, HVDC losses per MW-mile of transfer are lower. This is because the skin effect, where AC current concentrates near the conductor's surface and increases its effective resistance, it is not a factor in HVDC lines and results in a lowered resistance – the "DC resistance." In addition, considering the power transfer equations for both AC and DC transmission,

$$P_{DC} = 2V_{P-G}I_{DC}$$

$$P_{AC} = \sqrt{3}V_{LL}I_{rms}$$

it can be shown that, for equal power transfers and equal nominal voltages (line to line for AC and pole to ground for DC), the AC rms current is about 1.15 times the DC current [22] (see problem 7a). Expressing DC and AC losses, respectively, as

$$P_{Loss,DC} = 2R_{DC}[I_{DC}]^2$$

$$P_{Loss,AC} = 3R_{AC}[I_{rms}]^2$$

we can use the previous result, that is, I_{rms}/ I_{DC}=1.15, to show that

$$\frac{P_{Loss,AC}}{P_{Loss,DC}} = 2 * \frac{R_{AC}}{R_{DC}}$$

and using, for transmission-size conductors at 60 Hz, $R_{AC}/ R_{DC} \approx 1.1$, we find that for the same nominal power transfer and voltage levels, the HVAC losses are about 2.2 times greater than the HVDC losses [22] (see problem 7b). The difference in losses is driven by the number of poles versus phases, their relative current density, and the difference in resistances (see problem 7c).

The treatment so far in this section has addressed losses only in the conductor. In comparing losses for DC vs AC transmission, it is also important to consider terminal losses. For AC transmission, this includes substation losses, mainly dominated by the effect of transformers. For HVDC transmission, this includes transformer losses as well as converter losses. Converter losses are low for LCC-based HVDC, typically less than 1% per converter station, but higher for VSC, typically between 1-3% per converter station [23]. For short distances, AC transmission results in lower losses relative to HVDC; therefore, HVDC lines must be long before the savings in conductor losses outweigh the additional cost of converter losses.

Cables

Underground or undersea HVDC applications use cables, where the conductor is insulated. There are two types of cable technologies used in HVDC applications, crosslinked polyethylene (XLPE) and mass impregnated (MI) insulation, as illustrated in Figure 7a - 18 [24]. MI cables consist of paper impregnated with a high-viscosity oil; XLPE cables are called "extruded" because the insulating material (polyethylene) is applied by forcing it through a die, essentially "squeezing" the insulation onto the cable. Both types of cables use a copper or aluminum conductor surrounded by an insulation layer, a metallic sheath to prevent penetration of moisture, and a protective outer coating. Cables used for subsea application include steel wires wound around the cable that serves as an armoring that protects the cable from the subsea environment.

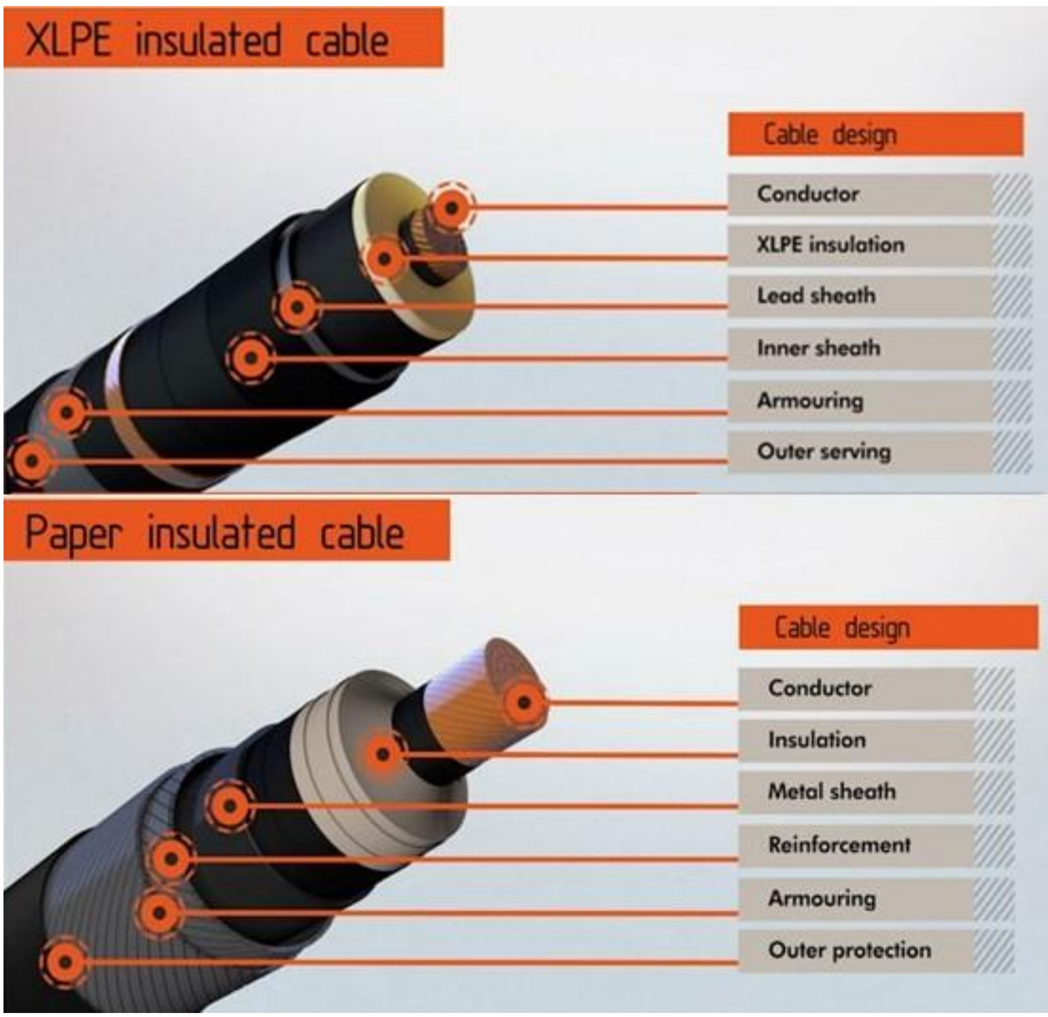

Figure 7a - 18: XLPE cable (top) and MI paper insulated cable (bottom) [24]

XLPE cables cannot withstand polarity reversal; this is due to so-called space-charge accumulation, where, as described in [25], a weak, non-uniform (due to local non-homogeneity of the material) electrical conduction occurs within the insulation, resulting in accumulation of charge, and this charge accumulation adds a component to the external electric field induced by the applied voltage. On reversing the voltage, these two fields add, causing distortion, with the resultant being as much as twice the strength of the external field, a level for which repeated application can accelerate aging and in the worst-case result in insulation failure[1]. Because of this effect, XLPE cables are not effective in LCC-based PTP bidirectional applications; therefore, most LCC applications have used MI cables. Space-charge effects on XLPE cables as a function of polarity reversal for LCC-based HVDC is a well-researched topic as indicated by several papers in IEEE's 2017 "Special issue on Insulation Materials for HVDC Polymeric Cables," [26], and in particular [27, 28]. Additional treatment of cable technologies is provided in Module 6a.

7a-3.4.8 Control and communication system

The basic control objective for HVDC PTP systems is to maintain constant DC voltage and control the current to achieve a desired MW transfer level. The essential control tasks for an HVDC PTP system are illustrated in Figure 7a - 19. These control tasks are described in this section [29].

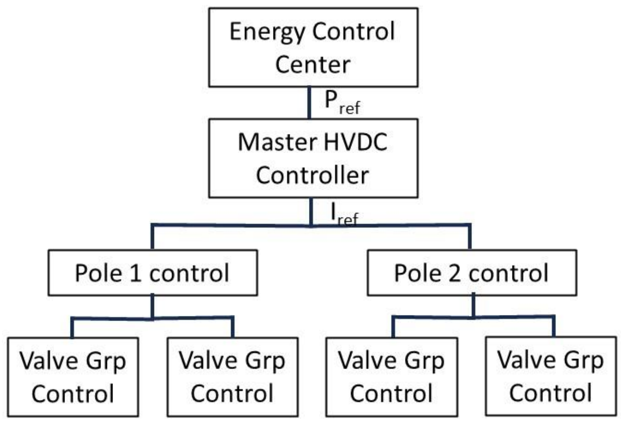

Figure 7a - 19: Essential control tasks for an HVDC PTP system

- *Energy control center (ECC)*: The ECC provides the directionality and the power transfer order P_{ref} to the master controller, typically located at one of the terminals. These orders are dialed in by a schedule set by the system operator.
- *Master controller*: The master controller receives the directionality and the power transfer order from the ECC and then computes the current reference I_{ref} to the pole 1 and 2 controllers. This information is communicated to the other terminal by telemetry or by fiber optics. The master controller may provide AC voltage and reactive power control, oscillation damping, and torsional damping; it also oversees paralleling sequences, transient pole current increase for pole outage, and pole current balancing; it can contribute to frequency control within the automatic generation control (AGC) loop [29, p. 93]. A useful control dimension is the transformer tap changers; at the rectifier (sending) end, it is used to minimize reactive power consumption. At the inverter (receiving) end, it is used to help regulate the DC voltage [14, p. 248].
- *Pole control*: The pole controllers send a firing angle order to the valve group controllers. Pole control also includes pole protection, DC line protection, and optional converter paralleling and de-paralleling sequences [29, p. 93].

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[1] The phenomenon occurs as well in MI cables used for HVDC, but following polarity reversal, MI cables exhibit much faster charge depletion, and resultant maximum field strengths are much lower than in the case of XLPE cables [25]. The phenomenon also occurs in AC XLPE applications, but here, the flow of charges inverts its direction too quickly to allow for significant growth of space charge at the insulation inhomogeneities [25].

- *Valve group (converter) control*: The valve group controllers oversee the firing logic applied to each valve group. The firing instant for all valves are sent to each thyristor via either electric conduction (for electrically triggered thyristors) or via fiber optic cables (for light triggered thyristors). The firing pulses are generated using the so-called "phase-locked oscillator" principle [30] which evolved to phase-locked loops (PLLs) to provide that the reference signal is synchronized with the AC commutation voltage [10, p. 38]. At the rectifier end, the converter controls the firing angle to control the current. At the inverter end, the converter controls the extinction angle via three paths: extinction angle proportional-integral (PI) control, DC voltage PI control, and DC current PI control. Each path generates an extinction angle, and the one that gives the minimal angle defines the operating mode [10, pp. 43-45]. Valve group control also includes commutation failure protection, tap changer control, converter start/stop sequences, margin switching, and valve protection [29, p. 93].

7a-3.4.9 Electrodes and earth/sea/metallic return

As indicated by item "J" in Figure 7a - 7, HVDC systems may have earth or sea and/or metallic returns. If an earth or sea return is present, then electrodes are needed to provide conduction through the earth or through the sea. Effective earth electrodes require high path conductivity through the earth to avoid (i) risk to human safety due to step potential (the voltage difference across a step) and touch potential (the voltage between the ground surface and any object such as a fence that might be touched by a person standing close to the object [31]); (ii) corrosion to underground facilities; and (iii) transformer saturation due to the current flowing across parallel AC system paths via AC system ground connections. Most existing earth electrodes reach depths of only about 100 meters; a 1997 investigation concluded that electrode depths of 500 meters would have only incremental benefits [32].

Because salt water is highly conductive, sea electrodes may be attractive when an HVDC terminal is close to the ocean. In this approach, current flows from the electrode to the seawater; however, the terminal to electrode connection must be provided by a cable, a connection that may be costly since it spans the distance from the terminal to the shoreline and from the shoreline undersea to the electrode. References [31, 33] provide excellent summaries of design and operational issues related to HVDC electrodes.

INDUSTRY INSIGHT

The Sylmar Ground Return System (SGRS), completed in 2018, is comprised of two primary cables that are tied into the PDCI at the Los Angeles Department of Water and Power Sylmar converting station facility. It provides a ground return by sea for the PDCI. These cables run from the Sylmar converter station about 28 miles on overhead lines and then an additional 9 miles underground. The system then extends 2 miles offshore into Santa Monica Bay. At that point, the primary power cables tie into a large area electrode array that consists of 144 electrodes distributed through 36 large concrete vaults. The design of the array is such that it distributes the electrical discharge over a large area making it safe for marine life, divers, and the nearby infrastructures. The video at www.youtube.com/watch?v=9Ddi6sbSMwY (used with permission from the L3Harris company) describes the development of the SGRS.

7a-3.5 Components for VSC PTP systems

There exist some differences in VSC-based PTP systems relative to LCC-based PTP systems, in terms of the nature of components needed, as summarized in what follows.

- **Converter units:** As indicated in Section 7a-3.1, whereas LCCs use thyristors, VSCs use IGBTs, and as a result, VSCs have increased control capability. However, the cost per unit of converter capacity is higher with VSCs since IGBTs are more costly than thyristors. Although the earlier VSC designs incurred greater losses than LCCs, this disadvantage is largely mitigated with modular multilevel converters (MMCs) – the cascading of multiple smaller converter modules (MMCs are further treated in Module 3d). In addition, application of VSCs have been almost completely limited to underground systems where transient DC faults, as due to, for example, lightning strikes, are extremely rare. There has, so far, been little application of VSCs for overhead HVDC systems because they do not effectively handle DC fault currents with their fast rise and large peaks [34][2]. The 2010 Caprivi VSC HVDC link is currently the only VSC HVDC circuit with overhead DC lines, but it has an additional DC-side breaker for managing DC faults [10, p. 147].
- **Converter transformers**: Whereas converter transformers for LCC-based HVDC must provide tap changing, those for VSC-based HVDC typically do not. In addition, harmonic concerns for VSC-based HVDC are much lower and so converter transformers need no special monitoring equipment for the heating effects of harmonics [29, p. 22]. In contrast to LCC-based HVDC, converter transformers for VSC-based HVDC generally need no special design features.
- **Smoothing reactors**: Although smoothing reactors are usually deployed for VSC-based HVDC, they are less critical than they are for LCC, because VSCs produce smoother DC current with less ripple, so that the need for large smoothing reactors is significantly reduced; however, they are still used to manage harmonics and fault current levels in VSC systems.
- **AC filters**: VSC-based HVDC uses PWM switching and produce harmonics near the effective switching frequency [35], usually 1-2 kHz, and near multiples of the switching frequency. Therefore, for VSC-based HVDC, the harmonic filters are at higher frequencies and as a result are smaller in size and cost and incur less losses [10, p. 139]. This contributes to the typically smaller size land requirements associated with VSC stations.
- **DC filters**: As with LCC-based HVDC, DC capacitors provide harmonic filtering of the voltage. However, MMC-based VSC provides smoother DC voltages and therefore requires less DC side filtering, and if the converter is connected directly to an underground or underwater DC cable, no additional DC filtering may be needed [35].
- **Conductor systems**: As indicated in Section 7a-3.1, LCC-based HVDC are unable to perform a current reversal since thyristors are unidirectional devices. Therefore, power flow reversal in LCC-based HVDC must do a voltage polarity change at the terminal to which it is connected. This has little impact on conductor choice for overhead systems. But for LCC-based underground systems, as indicated in Section 7a-3.4.7, the cables must be MI if bi-directional flow is desired (and it usually is). This restriction is not imposed for VSC-based HVDC systems (underground or overhead), because they utilize current reversal to reverse power flow. Therefore, VSC-based HVDC typically utilizes the simpler (and less costly) XLPE cables.

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[2] When a DC fault occurs, the converter's IGBTs are blocked rapidly, leaving the anti-parallel diodes exposed to fault circuits. This can lead to a rapid drop in DC voltage, causing some of the diodes to conduct automatically.

- **Reactive compensation**: As indicated in Section 7a-3.1, LCCs must be supplied with reactive power, whereas VSC can absorb or supply reactive power. In addition to network implications (locating in stiff or non-stiff parts of the network, and the operational ability to control voltage), this also means that area requirements for VSC stations are typically significantly less than those for LCC stations, since reactive power compensators are not needed.
- **Communication and control**: The structure of the communication and control system for VSC-based HVDC is like that illustrated in Figure 7a - 19 for LCC-based HVDC, with the exceptions of differences in pole control and the signals communicated to the valve groups. With VSC-based HVDC, pole control may be divided into upper and lower-level control functions as described below [36].
  - *Upper-level controls*: Here, assuming the system is operating in so-called "non-islanded" mode[3] (meaning there are active synchronous machines in the AC system to which the converter is connected), the upper-level control accepts P_{ref}, Q_{ref} , V_{DC}, and V_{AC} from the master control, uses a PLL to generate the reference frame angle θ from the three AC phased voltages; this information is used via Park's transformation to generate the d- and q-axis reference currents. The active power control loop controls either P_{ref} or V_{DC}, and the reactive power control loop controls either Q_{ref} or V_{AC}. Regardless of what is controlled in the upper level, the *a-b-c* AC reference voltages are passed to the lower-level controls.
  - *Lower-level controls*: The lower-level controls develop firing pulses necessary to produce the AC voltage waveforms requested by the upper-level controls. There are a variety of lower-level controls that can be implemented, depending on the VSC topology deployed. The early VSCs were two- or three-level and primarily relied on pulse-width modulation (PWM). MMCs use phase-disposition modulation, phase-shift modulation, space-vector modulation, selective harmonic elimination, and nearest-level control [36].

Additional treatment of VSC is provided in Module 2b.

INDUSTRY INSIGHT

With respect to VSC-based HVDC controls, the following vendor-specific systems are of interest:

- Referring to its eLumina™ control system, GE-Vernova "provides a fully digital, highly redundant control platform for both Voltage Source Converter and Line Commutated Converter HVDC schemes" that is "…compact, flexible and designed with standard building blocks that are easily configured for point-to-point, multi-terminal, or back-to-back converter arrangements with most functions remaining common" [37].
- Siemens states, "HVDC PLUS® is completely appropriate for steady state and dynamic AC voltage control, independently on each station. Its typical advantages are apparent when weak AC networks are being connected" [38].
- Hitachi writes, "Thanks to the modularity and high performance of the MACH equipment, the type of hardware and system software used for a VSC-HVDC control system are the same as in an LCC-HVDC or a FACTS control system. In fact, only the application software and the valve control differ" [39].

[3] In contrast, an "islanded" mode is when the system to which the converter connects has no synchronous machine to establish its frequency, and so the DC system must do so. Such a condition has also been referred to as a "passive load," or, more recently, as the "grid-forming mode." Reference [36] also describes VSC-based HVDC control for this mode, but this mode has been uncommon. It may become of more interest as more systems are operated without synchronous machines, thus requiring grid-forming converters.

- Mitsubishi states, “HVDC-Diamond® is Mitsubishi Electric’s latest offering in the field of HVDC. Our converter uses the well-proven Modular Multi-level Converter (MMC) topology, which gives a flexible solution in terms of scaling of power output, from 50 MW to 1000 MW and more. Being a Voltage Source Converter (VSC), the system has significant ancillary benefits to the operator, such as reactive-power support, black-start capability, fast power-flow reversal, improved grid accessibility for weak systems, low harmonic distortion, etc.” [40].
- With respect to its Honshu-Hokkaido HVDC line, Toshiba writes, “The VSC HVDC system ensures more flexible grid operations than the LCC HVDC system due to its capability for black-start operations to assist grid restoration by transmitting power from Honshu to Hokkaido during a blackout situation in Hokkaido. Furthermore, it can also control reactive power output independently from active power transmission. The VSC HVDC system contributes to lowering the initial investment amount as it does not need harmonic filters or reactive power plants which LCC HVDC systems normally require” [41].

7a-4 Point-to-point applications

All existing and proposed HVDC projects in North America today are PTP, as indicated by Figure 7a - 20. There are four basic types of PTP applications: overhead, asynchronous, underground, and submarine. We describe these four applications in Subsections 7a-4.1, 7a-4.2, 7a-4.3, and 7a-4.4, respectively.

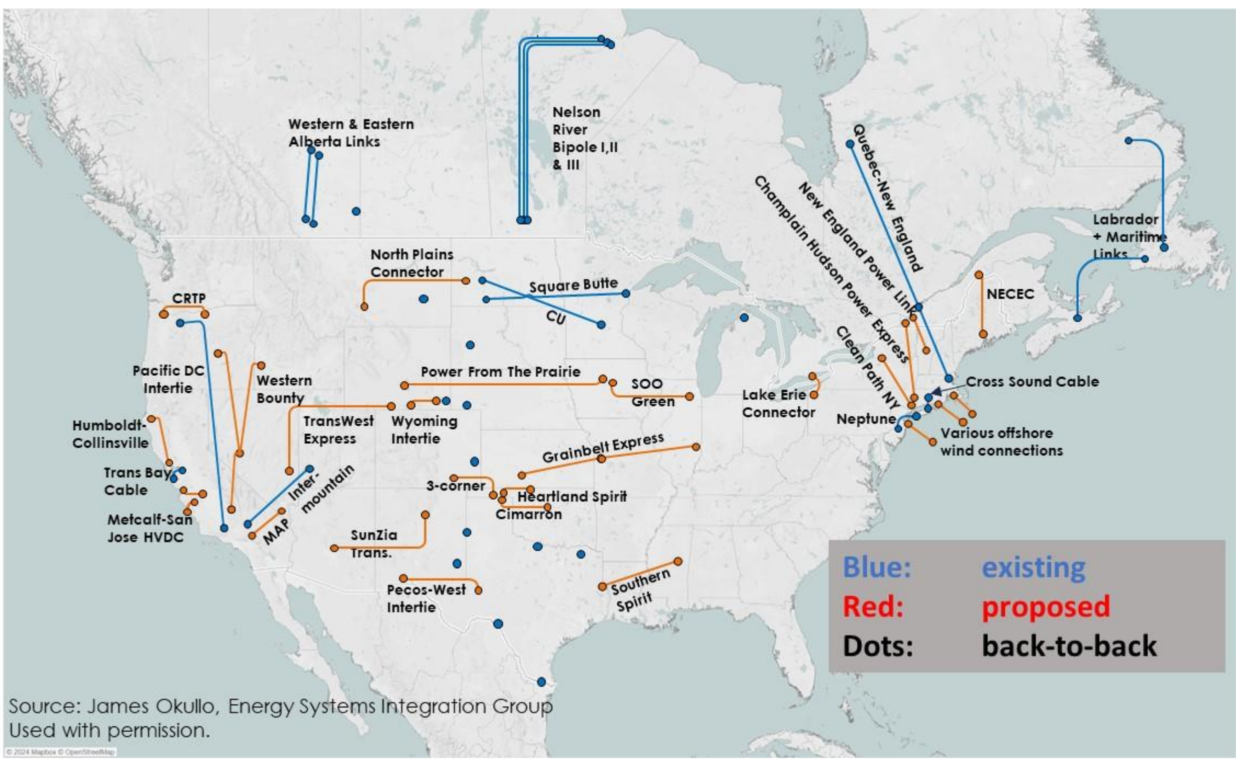

Figure 7a - 20: All existing and proposed HVDC projects

7a-4.1 Overhead

When compared to overhead extra-high voltage AC (EHVAC) transmission, overhead HVDC transmission can be the least-cost choice when the transmission distance is large; a figure of about 400 miles is often used as the approximate breakover distance, as shown in Figure 7a - 4. This occurs because, although HVDC terminal costs are much higher than terminal costs for EHVAC lines, HVDC overhead has much greater transfer capacity per unit required right-of-way (ROW). For example, Figure 7a - 21 shows (on the left) a ±500kV HVDC bipole line with power transfer capacity of 3100 MW, next to a 345kV AC transmission line having power transfer capacity of about 300MW. Both have approximately the same ROW requirement (~50m), so that the capacity per unit ROW of the HVDC line is an order of magnitude greater than that of the AC line, i.e., for the same ROW, this HVDC line gives ~10 times the power transfer capacity of the adjacent 345 kV line. Use of 765 kV in this situation, instead of 345 kV, reduces this ratio from 10 to about 2 [42]; nonetheless, these examples show why DC can be so effective in minimizing ROW requirements in response to public concerns.

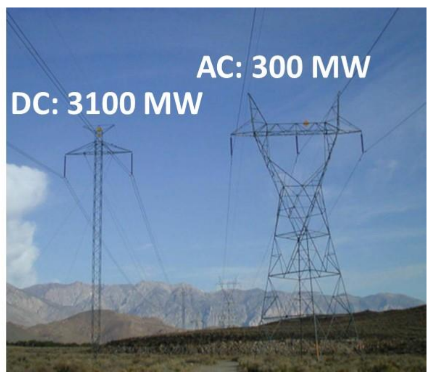

Figure 7a - 21: Comparison of Capacity-to-ROW requirement ratio

When compared to underground HVDC, estimates of the ratio of cost per mile of underground HVDC to that of overhead HVDC range from 2-3 [43] to 2-4 [44] to 4-14 [45][4]. The reason for this high variability is that, although bare conductors, towers/poles, and insulator strings are less expensive than the cost of cables, the amount of ROW required for overhead HVDC is up to five times [44] that of the ROW required for underground HVDC, and the cost for obtaining that ROW can vary greatly. When ROW for overhead is simply unattainable at any cost, underground HVDC may be the only viable solution. Compared to underground, overhead is more exposed to the elements and therefore has a higher outage rate than underground or submarine designs; on the other hand, it is less expensive to find and repair failures on overhead lines.

7a-4.2 Asynchronous interconnections

In a synchronous grid, all nodes see the same steady-state frequency. Obviously, two grids that normally operate at different frequencies, e.g., 50 and 60 Hz, are not synchronous, i.e., they are asynchronous, and an interconnection between two such grids is called an asynchronous interconnection. In addition, two grids operating at the same frequency but not sharing an AC

[4] These cost estimates are of course only meaningful if it is *possible* to obtain overhead right-of-way. There are some population-dense regions where overhead transmission cannot be built at any cost due to public resistance.

connection are asynchronous. In general, an asynchronous interconnection is defined as one bridging grids for which the grids' steady-state frequencies differ from moment to moment.

An asynchronous HVDC connection may consist of two converter stations in the same substation, i.e., an HVDC PTP system but without a line between the two converter stations. That is, the converter stations are directly connected on their DC sides, and as a result are called back-to-back (BTB) connections. BTB HVDC is always asynchronous[5]. There are seven such connections between the US Eastern and Western Interconnections, one between Quebec and the US Eastern Interconnection, two between ERCOT and the US Eastern Interconnection, one between ERCOT and the Western Interconnection, and two between ERCOT and Mexico. These BTB connections are summarized in Table 7a - 1 [46, 47, 48, 49, 50, 51]. (There is a third asynchronous interconnection between ERCOT and Mexico, at Laredo, Texas, with 100 MW of capacity, but it is made using a variable frequency transformer and not an HVDC BTB system [52].) With one exception, all these BTB HVDC systems are LCC (using thyristors); the exception is the Eagle Pass installation which is a VSC (using IGBTs). BTB HVDC systems are further described in Module 1b.

Table 7a - 1: Summary of asynchronous BTB HVDC links in N. America

Name	**Location**	**Grids connected**	**kV**	**Rating (MW)**	**Year**
David A Hamel	Stegall, NE	Eastern & Western Intrcnnctns	50	100	1977
Eddy County	Artesia, NM	Eastern & Western Intrcnnctns	82	200	1983
Miles City	Miles City, MT	Eastern & Western Intrcnnctns	82	200	1985
Virginia Smith	Sidney, NE	Eastern & Western Intrcnnctns	50	200	1988
McNeill	McNeill, AB	Eastern & Western Intrcnnctns	42	150	1989
Rapid City	Rapid City, SD	Eastern & Western Intrcnnctns	13	200	2003
Lamar	Lamar, CO	Eastern & Western Intrcnnctns	63.6	210	2005
Châteauguay	Châteauguay, Canada	Quebec & Eastern Intrcnnctn	140	1500	1984
North (DC_N)	Oklaunion, OK	ERCOT & Eastern Intrcnnctn	82	220	1984[6]
East (DC_E)	Monticello, TX	ERCOT & Eastern Intrcnnctn	162	600	1998
Blackwater	Clovis, NM	ERCOT & Western Intrcnnctn	57	200	1984
Eagle Pass	Eagle Pass, TX	ERCOT & Mexico	15.9	36	2000
Railroad (Sharyland 1)	McAllen/Mission, TX	ERCOT & Mexico	21	150	2007
Railroad (Sharyland 2)	McAllen/Mission, TX	ERCOT & Mexico	21	150	2014

Asynchronous HVDC connections are not limited to BTB configurations; they may also include lines or cables. We provide three examples of such asynchronous links.

- *Quebec-New England Interconnection*: This HVDC system links Québec to New England with capacity of 2000 MW from the Radisson station at the James Bay hydroelectric plant in northern Québec to the Sandy Pond station in Massachusetts [53]. Although this system

[5] It is possible to embed a BTB connection within a synchronized AC grid, but there is no purpose to moving power such a short distance within the same AC grid that would justify the cost of building two converter stations.
[6] Upgraded in 2014 to the 220 MW capacity indicated in the table.

normally operates as a three-terminal system (and is therefore not a PTP system), it is capable of operating as a two-terminal PTP system, and it sometimes does [54].

- *Southern Spirit Transmission project*: This project is scheduled to begin construction in 2026; when complete, it will be a 320-mile ±525 KV, 3 GW HVDC transmission line connecting ERCOT and the southeastern region of the Eastern Interconnection [55].
- *England-to-Europe Interconnections:* There are several HVDC asynchronous connections using submarine cables between England and Europe including, with France, the Cross-Channel (Interconnexion France Angleterre or IFA), the IFA-2, and the ElecLink; the BritNed to the Netherlands; the Nemo Link to Belgium; the North Sea Link to Norway; and the Viking Link to Denmark [56].

7a-4.3 Underground

Long-distance underground transmission is not possible with AC due to the very large capacitive "charging" currents that are generated by cables; these currents are not generated when operating DC, and so this does not constrain long-distance underground transmission. Relative to overhead HVDC, underground is more expensive, yet it offers the advantages of reducing ROW requirements and of eliminating what would otherwise be the undesirable visual presence of towers, poles, and overhead conductors.

There are just a few underground HVDC installations worldwide, including the world's longest underground high voltage interconnection, the 220 MW 109-mile Murraylink in Australia [57], and the 1200 MW 19-mile portion of the Dogger Bank offshore wind farm in UK [58]. One North American HVDC underground installation is the 660 MW Neptune Transmission System, which links the PJM grid in New Jersey to North Hempstead on Long Island [59].

Another North American underground project currently under development is the 2100 MW, 360-mile SOO Green HVDC Link to connect Mason City in the wind-rich North Central Iowa of the MISO region to the Plano, Illinois area at the western edge of the PJM region. This project has been of high interest not only because of its underground design but also because it co-locates the line on existing rail ROW and therefore requires very little new ROW [60, 61]. As a result, development of the SOO Green project has incurred much less public resistance than equivalent overhead transmission projects [62].

7a-4.4 Submarine

While the basic principles of HVDC cables are similar for both submarine and underground applications, the key difference lies in design features needed to withstand the harsher marine environment for submarine cables, including thicker insulation layers, stronger outer jackets, and specialized materials to resist corrosion. In contrast, underground cables prioritize heat dissipation and mechanical protection against soil conditions.

One North American installation is the 330 MW Cross Sound Cable Interconnector between Connecticut and Long Island, which uses the same polymer insulated, extruded cable for both the submarine section and the underground section used to connect to the onshore converter station [63]. Another North American project currently under construction, using both underground and submarine cables, is the Champlain Hudson Power Express [64]. As shown in Figure 7a - 22, this 1250 MW project uses both submarine (193 miles) and underground (146 miles) through its 339-

mile route from the Canadian border to the Astoria generating station in Queens, New York [65]. Although the submarine sections of the route required considerable effort to minimize environmental impact on Lake Champlain and on the Hudson River, the project benefited from the avoidance of land easements enabled by these sections.

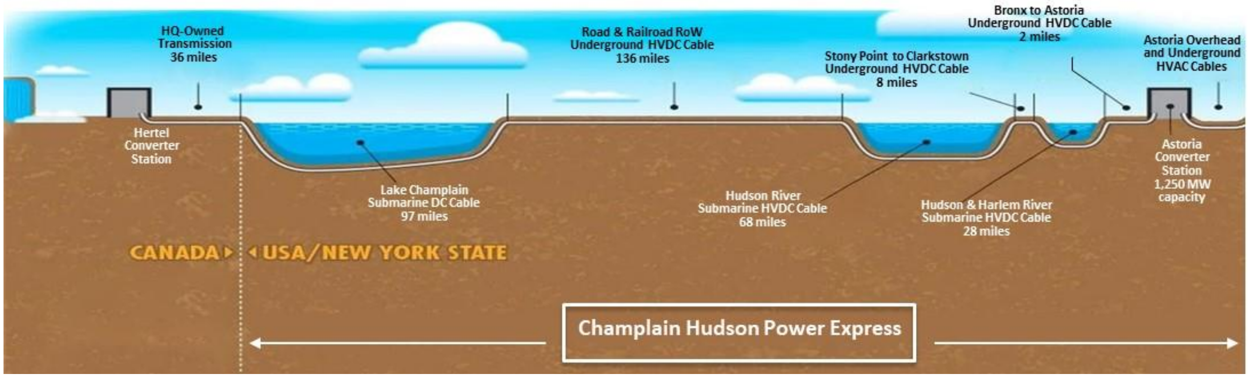

Figure 7a - 22: Illustration of the Champlain Hudson Power Express

Submarine or underground HVDC systems installed before about 1995 used LCC technologies. Since 1995, almost all submarine or underground HVDC systems have used VSC technologies. For example, in 1979 the Hokkaido and Honshu islands of Japan were interconnected by a 600 MW LCC-based HVDC bipole system; an additional 300 MW HVDC VSC-based tie was added in 2019 [66]. Submarine HVDC systems are also used for offshore wind, as indicated in Section 7a-5.

7a-5 PTP for offshore wind

Power from an offshore wind farm, i.e., an array of offshore turbines, is collected through an AC network of submarine inter-array cables that transfers power from the wind turbines to an offshore collection substation. Array cables also provide auxiliary power to turbines when they are not generating electricity, and normally, they are coupled with a fiber optic line to enable communication with each turbine. If the objective is to connect one or a limited number of wind farms to shore, then the so-called lead-line design (also called radial design) is generally least-cost. The lead-line design is a PTP system that interconnects the offshore substation to the onshore point of interconnection (POI). Figure 7a - 23 shows, on the left, five wind farms interconnected to shore via a lead-line design, and on the right, an expanded view of a single lead-line design.

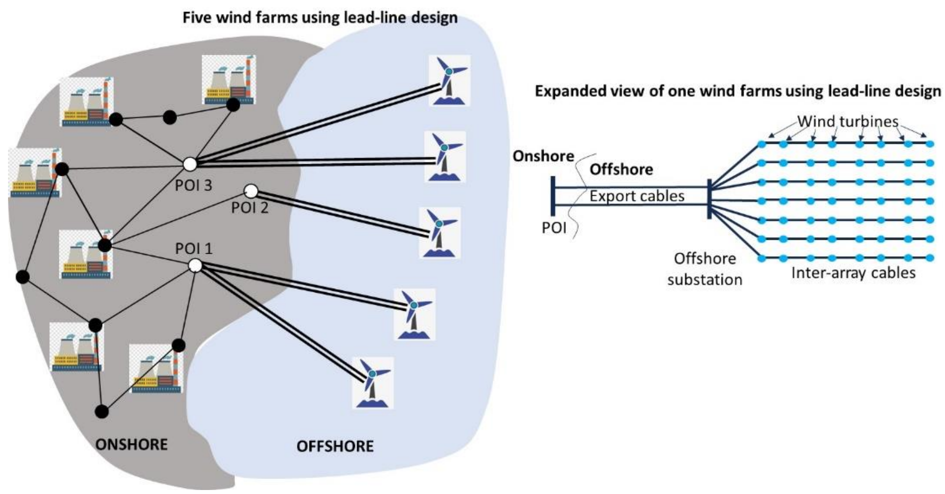

Figure 7a - 23: Illustration of lead-line design

The export cable may use either AC or DC transmission. AC may be preferred if the transmission distance from offshore substation to POI is less than about 40 miles, whereas HVDC is usually the best choice if this transmission distance exceeds about 60 miles. This is in part due to the high charging currents generated by AC cables (also mentioned in Section 7a-4.3). It is also influenced by the fact that lengths of AC cables are expensive to joint offshore [67]. On-site jointing is almost always required for export cables because of their longer transmission length, and doing so at sea is a complex and time-consuming process requiring, for each joint, from one [68] to seven days [59]. AC cable jointing is more difficult than DC cable jointing because AC cables utilize stranded conductors to minimize the skin effect, and the stranding increases the time required for on-site jointing. In contrast, DC cables may utilize solid conductors, particularly in submarine applications where high mechanical strength is needed. Power transfer requirements may also play a role as capacity for a single DC cable can be significantly higher than the capacity for a single AC cable. For example, the highest voltage HVAC export cables that are currently available are 420 kV with a capacity of approximately 400 MW per three-phase installation, whereas the highest voltage HVDC export cable that will be available soon is ±525 kV with a capacity of approximately 2000 MW in a bipolar configuration [67]. HVDC for offshore wind is further described in Module 1c.

7a-6 Energy equity issues related to PTP HVDC

In Section 7a-6.1 we address energy equity issues for PTP HVDC as used for onshore systems; energy equity issues for PTP HVDC as used for offshore systems is addressed in Section 7a-6.2. Module 12a further addresses effects of HVDC on energy equity and environmental justice.

7a-6.1 Energy equity issues for onshore HVDC systems

Building onshore HVDC transmission has two different kinds of impacts: terminal impacts and line impacts. There are three kinds of terminal impacts: land use, economic development, and energy cost.

Land use: The terminal requires some amount of land for the converter. LCC stations can vary in size, but a reasonable range is 5-10 acres, including indoor and outdoor equipment [23, 69]. This level of land requirement can have significant influence on displacing other usages, including

farmland, dwellings, or businesses. VSC stations are generally smaller than their LCC counterparts, approximately 60 to 70% the size for comparable power ratings.
Local economic development: Operation and maintenance of the HVDC terminal motivate some employment opportunities local to the community. However, the largest impact on local jobs occurs from the power generating resources constructed that will use the HVDC transmission system. This impact is a positive one if the terminal is primarily an exporting terminal; indeed, in this case, the local community benefits from increased property tax revenues (usually paid by the generation plant developer) and land lease payments as well. On the other hand, this impact can be a negative one if the terminal is primarily an importing terminal, assuming the power import results in reduction of local generating sources.
Energy costs: Extraction of resources from an area for export to another area generally increases energy cost for the sending area and decreases energy cost for the receiving area.

The last two impacts are generally conflicting, i.e., exporting areas see economic development in the form of job creation for the local economy but increased energy cost. Importing areas see little job creation, perhaps even job loss if local generation resources are retired, but simultaneously they see energy cost reduction. In both cases, one needs to quantify these effects and make decisions based on their composite influence.

The line impacts (distinct from terminal impacts addressed above) of onshore HVDC PTP transmission are not large in terms of local economic development; they are almost zero in terms of the influence on local energy costs. However, line impacts are significant in terms of land use when new ROW is required. As a result, so-called “flyover” regions, i.e., those where HVDC transmission is routed but no terminals are sited, are often rejected by local communities. There are three ways to address this. The first way is to compensate local landowners with tangible benefits that balance the loss of land use. Such benefits can be ongoing monetary payments and/or additional infrastructure currently unavailable in the community, e.g., broadband communication systems or public parks and bike paths. The second way is to reduce ROW requirements by re-using existing transmission ROW, co-locating the new HVDC lines in existing ROW of other infrastructure (e.g., see description of the SOO-Green HVDC line in Section 7a-4.3), or utilizing submarine HVDC cables in river beds (e.g., see description of the Champlain-Hudson Power Express in Section 7a-4.4). The third way to address line impacts is to install terminals along the HVDC transmission route to enable energy injection by local generators and energy withdrawals by local loads. However, doing so changes the design from PTP to multiterminal and requires use of VSC-based HVDC, as it is not technically feasible with LCC-based HVDC. ROW requirements for HVDC systems are further addressed in Module 11b.

7a-6.2 Energy equity issues for offshore HVDC systems

Equity issues for offshore HVDC systems that bring offshore energy to shore include the same two categories as identified for onshore HVDC systems in Section 7a-6.1, terminal impacts and line impacts, but their nature is different. One of the main reasons for this difference is that there is significant human impact only at the receiving terminal as the sending-end terminal is offshore. At the receiving end terminal, there are also land-use issues and uniquely so since the land often includes coastal regions involving sensitive marine life and areas of human recreation. The economic development influence can be significant, since the local economy benefits from the development at both terminals, and the wind generating resources at the (offshore) sending end terminal can be significant. And for the same reason, the impact on local energy cost can be highly desirable relative to energy costs associated with existing local generating resources. Of course, any offshore energy development must address the visual impact of the wind turbines and the impact of the undersea cabling on marine life, shipping, and other subsea infrastructure, but these impacts are not unique to HVDC transmission.

7a-7 Summary of main learning points

We summarize the main learning points of HVDC PTP transmission addressed in this module.

1. *HVDC designs:* There are three main HVDC designs: PTP, multiterminal, and DC grid. This module focuses on the PTP design.
2. *Two basic technologies*: There are two basic technologies used for HVDC PTP transmission, depending on the converter type. LCC-based HVDC uses thyristors; VSC-based HVDC uses IGBTs. For LCC-based HVDC, power handling capability is higher and cost per unit power-handling capability is lower, VSC-based HVDC tends to require smaller land areas and has greater control capabilities.
3. *Electrical configurations*: There are two main electrical configurations used for LCC-based PTP transmission – the asymmetrical monopolar configuration and the bipolar configuration, with the bipolar configuration being the most common. VSC-based PTP transmission may also be configured in either of these two ways; in addition, VSC-based PTP often uses the symmetrical monopolar configuration.
4. *HVDC PTP components*: The main components of any HVDC system include the converters, converter transformers, smoothing reactors, circuit breakers and switches, filters, reactive power compensation devices (LCC-based HVDC only), conductor systems, control and communication systems, and electrodes and return circuits. With the exception of the reactive power compensation devices, both LCC-based and VSC-based systems have all of these components, although their design and specific attributes are somewhat different.
5. *Applications*: Most PTP applications in service today are LCC-based, and these systems will remain in operation for at least several decades to come. As a result, it is important to maintain LCC-based HVDC expertise. However, because of the faster and broader control capabilities of VSC-based HVDC, including their ability to be used in HVDC grids, it is likely that most HVDC transmission systems implemented in the future will be VSC-based.
6. *Energy equity*: Unlike AC transmission, PTP HVDC systems are capable of bridging attractive low-carbon/low-cost generation resources across long distances to major load centers, at affordable costs. This makes PTP HVDC a socially attractive technology. However, it is important when designing such systems to identify and communicate impacts on land, energy cost, and economic development, to ensure energy equity for local populations.

Problems

Problem 1: An HVDC developer in the Midwest has settled on building an overhead HVDC VSC ±640 kV PTP line, and current plans have one terminal in Davenport, Iowa, using right-of-way along I-74 to reach the other terminal in Indianapolis, Indiana, a distance of 311 miles. But this plan makes Illinois a "flyover" (see Section 7a-6.1) state, and the Illinois Commerce Commission is uncomfortable as a result. In response, the developer is considering moving the eastern terminal of the line to Danville, an Illinois town just west of the Illinois-Indiana state border, which would be a line of 219 miles. (a) Considering Figure 7a - 4, explain why the economics of this change might not favor use of HVDC as a solution and what alternatives you would recommend be considered. (b) Related to this same figure, note the statement that "flow control and/or reactive power benefits could close gap here" – what does this mean?

Solution: (a) Figure 7a - 4 shows that, at 219 miles, a 765 kV AC transmission line may cost significantly less than the proposed HVDC VSC line, and so a 765 kV line should be considered instead of an HVDC line. The reason for the difference is that, at 219 miles, relative to 765 kV AC transmission, the extra cost of HVDC converter stations is not outweighed by the savings from the simpler and shorter towers and less ROW associated with the HVDC line. (b) The economic valuation of the figure, apparently, did not account for flow control and reactive power benefits provided by VSC, as compared to the 765 kV AC transmission approach. A PTP HVDC line is a MW flow-controllable branch in the network, and that controllability can be used to relieve AC transmission congestion elsewhere. In addition, a VSC-based HVDC line provides voltage control via the ability to absorb or produce reactive power. A 765 kV AC transmission line provides neither of these benefits.

Problem 2: From Section 7a-3.2 we read that "It is this smoothing reactor that makes the DC-side of the converter appear as a current source (i.e., a constant current supply). This happens because the change in inductor current *di/dt* must be limited to maintain finite voltages if *L* is large, as indicated by *di(t)dt=(1/L) v(t)*, where *i(t)* and *v(t)* are the time-domain expressions for, respectively, the current through and the voltage across the smoothing reactor." Assume the voltage across the smoothing reactor is *v(t)*=100*u(t)* volts, where *u(t)* is the unit step function. Express the rate of change of current and the current for (i) *L*=1 henry and (ii) *L*=0.001 henry. In both cases, assume *i*(*t*=0)=0.

Solution:

i. $\frac{di(t)}{dt} = \frac{1}{1}100u(t) = 100u(t) \rightarrow i(t) = \int_0^t 100u(\tau)d\tau = 100tu(t)$amperes

ii. $\frac{di(t)}{dt} = \frac{1}{0.001}100u(t) = 100{,}000u(t) \rightarrow i(t) = \int_0^t 100{,}000u(\tau)d\tau = 100{,}000tu(t)$amperes

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Problem 3: As indicated in Section 7a-3.2.1, the National Electric Safety Code (NESC), Paragraph 314-C, states that "supply circuits shall not be designed to use the earth normally as the sole conductor for any part of the circuit," but that "monopolar operation of a bipolar HVDC system is permissible for emergencies and limited periods for maintenance."

a. Why does the NESC restrict use of the earth as a conductor (i.e., use of earth electrodes)? Hint: See Section 7a-3.4.9.
b. Under what conditions would it be desirable to operate a bipolar HVDC system as a monopolar HVDC system?
c. What changes are necessary to operate a bipolar HVDC system as a monopolar HVDC system?

Solution:

a. As implied in Section 7a-3.4.9, use of earth electrodes poses risk to human safety due to step potential (the voltage difference across a step) and touch potential (the voltage between the ground surface and any object such as a fence that might be touched by a person standing close to the object.

b. From Section 7a-3.2.1, it may be desirable to operate a bipolar system in the monopolar configuration in the initial stage before bipolar operation begins, and as a reduced-capacity (50%) operating state when one pole of a bipolar configuration is out of service.
c. From Section 7a-3.2.2, under the condition that a pole experiences a permanent fault, the faulted pole can be isolated, and the system operated in the monopolar configuration with the earth or metallic return carrying full current but at zero voltage.

Problem 4: How do VSC-based HVDC systems achieve pole-to-pole voltages twice that of the cable ratings used for each pole? Hint: see Section 7a-3.3.
Solution: VSC-based HVDC systems built to-date have almost always been underground or submarine systems and as a result have deployed the symmetric monopolar configuration. This configuration uses both positive and negative high voltage conductors as in a bipolar configuration, where, unlike the bipolar configuration, the system is operated as a single unit.

Problem 5: Describe the difference between a thyristor, a valve, and a converter unit.
Solution: A thyristor is the basic element in a converter unit; it is a power electronic device that has controllable (via a gate pulse) turn-on (conducting) capability, but turn-off capability occurs only when the device is reverse bias (and thus it is called a "line commutated" device). A valve is a package of thyristors (and may be just a single thyristor). A converter unit is an arrangement of valves in a topology together with a control scheme to provide conversion between an AC and a DC system.

Problem 6 [10, p. 123]: At full power, the AC current for a six-pulse converter bridge connected through a Y-Y transformer can be expressed using Fourier series (neglecting commutation overlap) as:

$$I_{YY} = 2\frac{\sqrt{3}}{\pi}I_{DC}\left[sin\omega t - \frac{1}{5}sin5\omega t - \frac{1}{7}sin7\omega t - \frac{1}{11}sin11\omega t + \frac{1}{13}sin13\omega t + \cdots\right]$$

Likewise, the AC current for a six-pulse converter bridge connected through a Y-Δ transformer can be expressed using Fourier series (neglecting commutation overlap) as:

$$I_{Y\Delta} = 2\frac{\sqrt{3}}{\pi}I_{DC}\left[sin\omega t + \frac{1}{5}sin5\omega t + \frac{1}{7}sin7\omega t - \frac{1}{11}sin11\omega t + \frac{1}{13}sin13\omega t + \cdots\right]$$

Show that the total AC current is given as indicated in Section 7a-3.4.5.
Solution: The current in a 12 pulse converter is the sum of the current from the Y-Y transformer and the current from the ΔΔ transformer, which is

$$I = I_{YY} + I_{Y\Delta} = 2\frac{\sqrt{3}}{\pi}I_{DC}\left[sin\omega t - \frac{1}{5}sin5\omega t - \frac{1}{7}sin7\omega t - \frac{1}{11}sin11\omega t + \frac{1}{13}sin13\omega t + \cdots\right]$$
$$+2\frac{\sqrt{3}}{\pi}I_{DC}\left[sin\omega t + \frac{1}{5}sin5\omega t + \frac{1}{7}sin7\omega t - \frac{1}{11}sin11\omega t + \frac{1}{13}sin13\omega t + \cdots\right]$$

$$=2\frac{\sqrt{3}}{\pi}I_{DC}\left[2sin\omega t - \frac{2}{11}sin11\omega t + \frac{2}{13}sin13\omega t + \cdots\right]$$
$$= 4\frac{\sqrt{3}}{\pi}I_{DC}\left[sin\omega t - \frac{1}{11}sin11\omega t + \frac{1}{13}sin13\omega t + \cdots\right]$$

Problem 7: (a) Referring to Section 7a-3.4.7, show that, for equal power transfers and equal nominal voltages (line to line for AC and pole to ground for DC), the AC rms current is about 1.15 times the DC current. (b) Using $P_{Loss,DC} = 2R_{DC}[I_{DC}]^2$, $P_{Loss,AC} = 3R_{AC}[I_{rms}]^2$, and I_{rms}/I_{DC}=1.15, show that for equal power transfers and equal nominal voltage levels, the HVAC losses are about 2.2 times greater than the HVDC losses. (c) Section 7a-3.4.7 indicates that AC losses being about 2.2 times greater than the HVDC losses is driven by the number of poles vs phases, their relative current density, and the difference in resistances. Explain each one of these effects.

Solution: (a) Given the relations from Section 7a-3.4.7,

$$P_{DC} = 2V_{P-G}I_{DC}$$
$$P_{AC} = \sqrt{3}V_{LL}I_{rms}$$

and under the conditions of the problem, which are $P_{DC} = P_{AC}$, and $V_{P-G} = V_{LL}$, the above two equations may be equated as

$$2V_{P-G}I_{DC} = \sqrt{3}V_{LL}I_{rms} \Rightarrow 2I_{DC} = \sqrt{3}I_{rms} \Rightarrow \frac{I_{rms}}{I_{DC}} = \frac{2}{\sqrt{3}} = 1.1547$$

(b) With $P_{Loss,DC} = 2R_{DC}[I_{DC}]^2$, $P_{Loss,AC} = 3R_{AC}[I_{rms}]^2$, we can write that

$\frac{P_{Loss,AC}}{P_{Loss,DC}} = \frac{3}{2}\left(\frac{I_{rms}}{I_{DC}}\right)^2 \frac{R_{AC}}{R_{DC}}$, and using $\frac{I_{rms}}{I_{DC}}$ =1.15$\Rightarrow \left(\frac{I_{rms}}{I_{DC}}\right)^2 = 1.15^2 = 4/3$, we have that

$\frac{P_{Loss,AC}}{P_{Loss,DC}} = \frac{3}{2}\,\frac{4}{3}\frac{R_{AC}}{R_{DC}} \Rightarrow \frac{P_{Loss,AC}}{P_{Loss,DC}} = 2\frac{R_{AC}}{R_{DC}}$. Then, with $\frac{R_{AC}}{R_{DC}} = 1.1$, we have that $\frac{P_{Loss,AC}}{P_{Loss,DC}} = 2.2$.

(c) For HVDC, assuming a bipole configuration, the number of poles is two, whereas in AC transmission, the number of phases is three; relative current density refers to the fact that AC rms current is about 1.15 times the DC current; the difference in DC and AC resistance is due to the skin effect which makes a conductor use for AC have a higher effective resistance.

Problem 8: Section 7a-3.4.7 indicates that converter transformers used in LCC-based HVDC systems must provide tap changing, whereas Section 7a-3.5 indicates this is unnecessary for converter transformers used in VSC-based HVDC systems. Why is this the case?

Solution: Tap changing is a voltage control method. Because LCC-based HVDC converters always absorb reactive power (i.e., they cannot supply reactive power), they do not have inherent voltage control capabilities. VSC-based HVDC converters, on the other hand, absorb and supply reactive power and therefore can effectively control AC-side voltages without tap changing.

Problem 9: Referring to the discussion of underground conductor systems in Section 7a-3.4.7 and in Section 7a-3.5, why do bidirectional LCC-based underground HVDC use MI paper-insulated cables, yet, any VSC-based underground HVDC uses XLPE cables?

Solution: XLPE cables are less expensive and so are preferred where they can be used. They cannot be used with bidirectional LCC-based underground HVDC because, with LCC-based HVDC, bidirectionality can only be achieved via polarity reversal, and polarity reversal cannot be performed with XLPE cables because frequent polarity reversal can lead to the formation of voids within the insulation due to the different thermal expansion coefficients of the paper and impregnating

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