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HVDC Transmission

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30.1 Introduction

High voltage direct current (HVDC) transmission [1–3] is a major user of power electronics technology. The HVDC technology first made its mark in the early undersea cable interconnections of Gotland (1954) and Sardinia (1967), and then in long distance transmission with the Pacific Intertie (1970) and Nelson River (1973) schemes using mercury arc valves. A significant milestone development occurred in 1972 with the first back-to-back (BB) asynchronous interconnection at Eel River between Quebec and New Brunswick; this installation also marked the introduction of thyristor valves to the technology and replaced the earlier mercury arc valves.

Until 2005, a total transmission capacity of 70,000 MW HVDC is installed in some 95 projects all over the world. To understand the rapid growth of dc transmission (Table 30.1) [4] in the past 50 years, it is first necessary to compare it to conventional ac transmission.

30.1.1 Comparison of AC–DC Transmission

Making a planning selection between either ac or dc transmission is based on an evaluation of transmission costs, technical considerations, and the reliability/availability offered by the two power transmission alternatives.

30.1.1.1 Evaluation of Transmission Costs

The cost of a transmission line comprises of the capital investment required for the actual infrastructure (i.e. right-of-way (ROW), towers, conductors, insulators, and terminal equipment) and costs incurred for operational requirements (i.e. losses). Assuming similar insulation requirements for peak voltage levels for both ac and dc lines, a dc line can carry as much power, with two conductors (having positive/negative polarities with respect to ground), as an ac line with three conductors of the same size. Therefore, for a given power level, a dc line requires a smaller ROW, simpler and cheaper towers

TABLE 30.1 Listing of HVDC installations

HVDC link	Supplier	Year	Power (MW)	DC voltage (kV)	Length (km)	Location
Gotland I[#]	A	1954	20	±100	96	Sweden
English channel	A	1961	160	±100	64	England–France
Volgograd–Donbass[*]	Unknown Russian manufacturer	1965	720	±400	470	Russia
Inter-island	A	1965	600	±250	609	New Zealand
Konti-Skan I	A	1965	250	250	180	Denmark–Sweden
Sakuma	A	1965	300	2 × 125	B-B***	Japan
Sardinia	I	1967	200	200	413	Italy
Vancouver I	A	1968	312	260	69	Canada
Pacific intertie	JV	1970	1440	±400	1362	U.S.A.
Pacific intertie	JV	1982	1600	±400	1362	U.S.A
Nelson River I**	I	1972	1620	±450	892	Canada
Kingsnorth	I	1975	640	±260	82	England
Gotland	A	1970	30	±150	96	Sweden
Eel River	C	1972	320	2 × 80	B-B	Canada
Skagerrak I	A	1976	250	250	240	Norway–Denmark
Skagerrak II	A	1977	500	±250		Norway–Denmark
Skagerrak III	A	1993	440	350	240	Norway–Denmark
Vancouver II	C	1977	370	−280	77	Canada
Shin-Shinano	D	1977	300	2 × 125	B-B	Japan
Shin-Shinano	D	1992	600	3 × 125	B-B	Japan
Square Butte	C	1977	500	±250	749	U.S.A.
David A. Hamil	C	1977	100	50	B-B	U.S.A.
Cahora Bassa	J	1978	1920	±533	1360	Mozambique-S. Africa
Nelson River II	J	1978	900	±250	930	Canada
Nelson River II	J	1985	1800	±500	930	Canada
CU Project	A	1979	1000	±400	710	U.S.A.
Hokkaido–Honshu	E	1979	150	125	168	Japan
		1980	300	250		
		1993	600	±250		
Acaray	G	1981	50	25.6	B-B	Paraguay
Vyborg	F	1981	355	1 × 170(±85)	B-B	Russia (tie w/Finland)
Vyborg	F	1982	710	2 × 170		
Vyborg	F		1065	3 × 170		
Duernrohr	J	1983	550	145	B-B	Austria
Gotland II	A	1983	130	150	100	Sweden
Gotland III	A	1987	260	±150	103	Sweden
Eddy County	C	1983	200	82	B-B	U.S.A.
Chateauguay	J	1984	1000	2 × 140	B-B	Canada
Oklaunion	C	1984	200	82	B-B	U.S.A.
Itaipu	A	1984	1575	±300	785	Brazil
Itaipu	A	1985	2383		785	Brazil
Itaipu	A	1986	3150	±600	785	Brazil
Inga-Shaba	A	1982	560	±500	1700	DR Congo
Pacific Intertie upgrade	A	1984	2000	±500	1362	U.S.A.
Blackwater	B	1985	200	57	B-B	U.S.A.
Highgate	A	1985	200	±56	B-B	U.S.A.
Madawaska	C	1985	350	140	B-B	Canada
Miles City	C	1985	200	±82	B-B	U.S.A.
Broken Hill	A	1986	40	2 × 17(±8.33)	B-B	Australia
Intermountain power project	A	1986	1920	±500	784	U.S.A.
Cross-channel:						
(Les Mandarins)	H	1986	1000	±270	72	France–England
(Sellindge)	I	1986	2000	2 × ±270		
Des Cantons-Comerford	C	1986	690	±450	172	Canada-U.S.A.
Sacoi[##]	H	1986	200	200	415	Corsica Island, Italy
Sacoi[###]	H	1992	300			

TABLE 30.1—Contd

HVDC link	Supplier	Year	Power (MW)	DC Voltage (kV)	Length (km)	Location
Itaipu II	A	1987	3150	±600	805	Brazil
Sidney (Virginia Smith)	G	1988	200	55.5	B-B	U.S.A.
Gezhouba–Shanghai	B+G	1989	600	500	1000	China
		1990	1200	±500		
Konti-Skan II	A	1988	300	285	150	Sweden–Denmark
Vindhyachal	A	1989	500	2 × 69.7	B-B	India
Pacific Intertie Exp.	B	1989	1100	±500	1362	U.S.A.
McNeill	I	1989	150	42	B-B	Canada
Fenno-Skan	A	1989	500	400	200	Finland–Sweden
Sileru–Barsoor	K	1989	100	+100	196	India
			200	+200		
			400	±200		
Rihand-Delhi	A	1991		1500	± 500	India
Quebec-New England	A	1990	2000****	±450	1500	Canada-U.S.A.
Nicolet Tap	A	1992	1800			Canada
DC Hybrid Link	AB	1992	992	+270/−350	617	New Zealand
Etzenricht	G	1993	600	160	B-B	Germany (tie w/Czech)
Vienna-South east	G	1993	600	145	B-B	Austria (tie w/Hungary)
Haenam–Cheju	I	1993	300	±180	100	South Korea
Baltic Cable Project	AB	1994	600	450		Sweden-Germany
Welch–Monticello	AB	1995	600	450	B-B	U.S.A.
Kontek Interconnection	G	1995	600	400	170	Denmark–Germany
Scotland–N. Ireland	G	1996	250	250		United Kingdom
Chandrapur–Ramagundum	I	1996	1000	2 × 500	B-B	India
Chandrapur–Padghe	AB	1997	1500	±500	900	India
Greece–Italy	AB	1997	500	400	200, sea	Italy
Gazuwaka–Jeypore	AB	1997	500		B-B	India
Leyte-Luzun	AB	1997	1600	400	440	Philippines
Cahora Bassa	G	1998	1920	±533	1456	Mozambique–S.Africa
TSQ-Beijao	G	2000	1800	±500	903	China
Thailand–Malaysia	G	2001	300	±300	B-B	Thailand–Malaysia
Moyle	G	2001	2 × 250	250	64	Ireland–Scotland
East-South Intercon.	G	2003	2000	±500	1450	India
Rapid City DC tie	AB	2003	2 × 100	±13	B-B	S.Dakota, U.S.A.
Three Gorges-Changzhou	AB	2003	3000	±500	890	China
Three Gorges-Quangdong	AB	2004	3000	±500	940	China
Guizhou-Guangdong	G	2004	3000	±500	940	China
Celilo Conv. station	AB	2004	2000	±500	upgrade	U.S.A.
Nelson River Bipole II	G	2004	1000	450	Pole 1	Canada
Basslink	G	2005	500	400	350	Australia–Tasmania
Lamar	G	2005	210	63.6	B-B	Colorado, U.S.A.
Vizag II	AB	2005	500	±88	B-B	India
Estlink	AB	2006	350	±150	HVDC Light	Estonia – Finland
Three Gorges-Shanghai	AB	2007	3000	±500	1059	China
NorNed	AB	2007	700	±450	560	Norway – Netherlands
Valhall offshore	AB	2009	950		HVDC Light	Norway

A – ASEA; B – Brown Boveri; C – General Electric; D – Toshiba; E – Hitachi; F – Russian; G – Siemens; H – CGEE Alsthom; I – GEC (Formerly English Electric); J – HVDC Working Group. (AEG, BBC, Gmens); K – (Independent); AB – ABB (ASEA Brown Boveri); JV – Joint Venture (GE and ASEA); *two valve groups replaced with thyristors in 1977; **two valve groups in Pole 1 replaced with thyristors by GEC in 1991; ***Back-to-back HVDC System; ****Multiterminal system. Largest terminal is rated 2250 MW; #Retired from service; ##50 MW thyristor tap; ###Uprated w/thyristor valves.

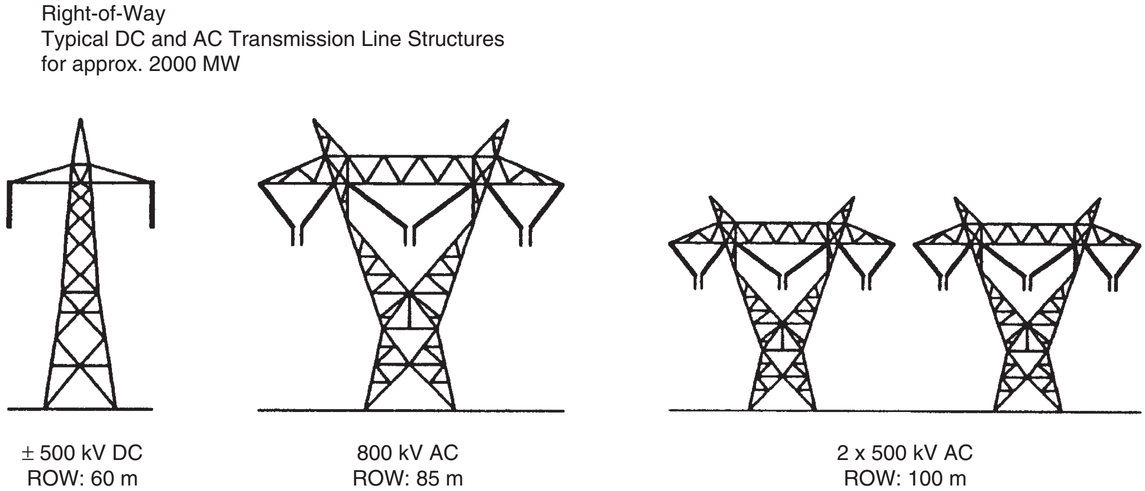

FIGURE 30.1 Comparison of ROW for ac and dc transmission systems.

and reduced conductor and insulator costs. As an example, Fig. 30.1 shows the comparative case of ac and dc systems carrying 2000 MW.

With the dc option, since there are only two conductors (with the same current capacity of three ac conductors), the power transmission losses are also reduced to about two-thirds of the comparable ac system. The absence of skin effect with dc is also beneficial in reducing power losses marginally, and the dielectric losses, in case of power cables is also very much less for dc transmission.

Corona effects tend to be less significant on dc than for ac conductors. The other factors that influence line costs are the costs of compensation and terminal equipment. DC lines do not require reactive power compensation but the terminal equipment costs are increased due to the presence of converters and filters.

Figure 30.2 shows the variation of infrastructure costs with distance for ac and dc transmission. AC tends to be more economical than dc for distances less than the "breakeven distance" but is more expensive for longer distances. This is due to a combination of the terminal equipment costs and line costs for the two types of transmission. The breakeven distances can vary from about 500 to 800 km in overhead lines depending on the per unit line costs. With a cable system, this breakeven distance approaches 50 km.

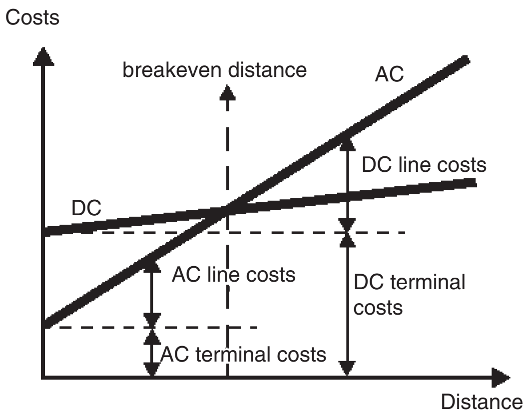

FIGURE 30.2 Comparison of ac and dc transmission system costs.

30.1.1.2 Evaluation of Technical Considerations

Due to its fast controllability, a dc transmission system has full control over transmitted power, an ability to enhance transient and dynamic stability in associated ac networks and can limit fault currents in the dc lines. Furthermore, dc transmission overcomes some of the following problems associated with ac transmission:

Stability limits

The power transfer in an ac line is dependent on the angular difference between the voltage phasors at the two line ends. For a given power transfer level, this angle increases with distance. The maximum power transfer is limited by the considerations of steady state and transient stability. The power carrying capability of an ac line is inversely proportional to transmission distance whereas the power carrying ability of dc lines is unaffected by the distance of transmission.

Voltage control

Voltage control in ac lines is complicated by the line charging requirements and voltage drops. The voltage profile in an ac line is relatively flat only for a fixed level of power transfer, corresponding to its surge impedance loading (SIL). The voltage profile varies with the line loading. For constant voltage at the line ends, the midpoint voltage is reduced for line loadings higher than SIL and increased for loadings lesser than SIL.

The maintenance of constant voltage at the two ends requires reactive power control as the line loading is increased. The reactive power requirements increase with line length.

Although dc converter stations require reactive power related to the power transmitted, the dc line itself does not require any reactive power.

The steady-state charging currents in ac cables pose serious problems and make the breakeven distance for cable transmission around 50 km.

Line compensation
Line compensation is necessary for long distance ac transmission to overcome the problems of line charging and stability limitations. The increase in power transfer and voltage control is possible through the use of shunt inductors, series capacitors, static var compensators (SVCs), and lately, the new generation static compensators (STATCOMs).

In the case of dc lines, such compensation is not needed.

Problems of ac interconnection
The interconnection of two power systems through ac ties requires the automatic generation controllers of both systems to be coordinated using tie line power and frequency signals. Even with coordinated control of interconnected systems, the operation of ac ties can be problematic due to (a) the presence of large power oscillations which can lead to frequent tripping, (b) increase in fault level, and (c) transmission of disturbances from one system to the other.

The fast controllability of power flow in dc lines eliminates all of the above problems. Furthermore, the asynchronous interconnection of two power systems can only be achieved with the use of dc links.

Ground impedance
In ac transmission, the existence of ground (zero sequence) current cannot be permitted in steady state due to the high magnitude of ground impedance that will not only affect efficient power transfer, but also result in telephonic interference.

The ground impedance is negligible for dc currents and a dc link can operate using one conductor with ground return (monopolar operation). The ground return is objectionable only when buried metallic structures (such as pipelines) are present and are subject to corrosion with dc current flow. It is to be noted that even while operating in the monopolar mode, the ac network, feeding the dc converter station operates with balanced voltages and currents. Hence, single-pole operation of dc transmission systems is possible for extended periods, while in ac transmission single-phase operation (or any) unbalanced operation is not feasible for more than a second.

Problems of dc transmission
The application of dc transmission is limited by factors such as:

1. High cost of conversion equipment.
2. Inability to use transformers to alter voltage levels.
3. Generation of harmonics.
4. Requirement of reactive power.
5. Complexity of controls.

Over the years, there have been significant advances in dc technology, which have tried to overcome the disadvantages listed above, except for item 2. These are:

1. Increase in the ratings of a thyristor cell that makes up a valve.
2. Modular construction of thyristor valves.
3. Twelve-pulse operation of converters.
4. Use of force-commutation.
5. Application of digital electronics and fiber optics in the control of converters.

Some of the above advances have resulted in improving the reliability and reduction of conversion costs in dc systems.

30.1.2 Evaluation of Reliability and Availability Costs

Statistics on the reliability of HVDC links are maintained by CIGRE and IEEE Working Groups. The reliability of dc links has been very good and is comparable with ac systems. The availability of dc links is quoted in the upper 90%.

30.1.3 Applications of DC Transmission

Due to their costs and special nature, most applications of dc transmission generally fall into one of the following four categories:

Underground or underwater cables
In the case of long-cable connections over the breakeven distance of about 40–50 km, the dc cable transmission system has a marked advantage over the ac cable connections. Examples of this type of applications were the Gotland (1954) and Sardinia (1967) schemes.

The recent development of voltage source converters (VSCs) and the use of rugged polymer dc cables, with the so-called "HVDC Light" option, are being increasingly considered. An example of this type of application is the180 MW Directlink connection (2000) in Australia.

Long distance bulk power transmission
Bulk power transmission over long distances is an application ideally suited for dc transmission and is more economical than ac transmission whenever the breakeven distance is exceeded.

Examples of this type of application abound from the earlier Pacific Intertie to the recent links in China and India.

The breakeven distance is being effectively decreased with the reduced costs of new compact converter stations possible due to the recent advances in power electronics (discussed in a later section).

Asynchronous interconnection of ac systems

In terms of an asynchronous interconnection between two ac systems, the dc option reigns supreme. There are many instances of BB connections where two ac networks have been tied together for the overall advantage to both ac systems. With recent advances in control techniques, these interconnections are being increasingly made at weak ac systems. The growth of BB interconnections is best illustrated with the example of North America where the four main independent power systems are interconnected with 12 BB links.

In the future, it is anticipated that these BB connection will also be made with VSCs offering the possibility of full four-quadrant operation and the total control of active/reactive power coupled with the minimal generation of harmonics.

Stabilization of power flows in integrated power system

In large interconnected systems, power flow in ac ties (particularly under disturbance conditions) can be uncontrolled and lead to overloading and stability problems, thus endangering system security. Strategically placed dc lines can overcome this problem due to the fast controllability of dc power and provide much needed damping and timely overload capability. The planning of dc transmission in such applications requires detailed study to evaluate the benefits. Examples are the IPP link in the USA and the Chandrapur–Padghe link in India.

Presently the number of dc lines in a power grid is very small compared to the number of ac lines. This indicates that dc transmission is justified only for specific applications. Although advances in technology and introduction of multiterminal dc (MTDC) systems are expected to increase the scope of application of dc transmission, it is unlikely that the ac grid will be replaced by a dc power grid in the future. There are two major reasons for this. First, the control and protection of MTDC systems is complex and the inability of voltage transformation in dc networks imposes economic penalties. Second, the advances in power electronics technology have resulted in the improvement of the performance of ac transmissions using FACTS devices, for instance through introduction of static var systems, static phase shifters, etc.

30.1.4 Types of HVDC Systems

Three types of dc links are considered.

30.1.4.1 Monopolar Link

A monopolar link (Fig. 30.3a) has one conductor and uses either ground- and/or sea-return. A metallic return can also be used where concerns for harmonic interference and/or corrosion exist. In applications with dc cables (i.e. HVDC light), a cable return is used. Since the corona effects in a dc line are substantially less with negative polarity of the conductor as compared to the positive polarity, a monopolar link is normally operated with negative polarity.

30.1.4.2 Bipolar Link

A bipolar link (Fig. 30.3b) has two conductors, one with positive and the other with negative polarity. Each terminal has two sets of converters of equal rating, in series on the dc side. The junction between the two sets of converters is grounded at one or both ends by the use of a short electrode line. Since both poles operate with equal currents under normal operation, there is zero ground current flowing under these conditions. Monopolar operation can also be used in the early stages of the development of a bipolar link. Alternatively, under faulty converter conditions, one dc line may be temporarily used as a metallic return with the use of suitable switching.

30.1.4.3 Homopolar Link

In this type of link (Fig. 30.3c), two conductors having the same polarity (usually negative) can be operated with ground or metallic return.

Due to the undesirability of operating a dc link with ground return, bipolar links are mostly used. A homopolar link has the advantage of reduced insulation costs, but the disadvantages of earth return outweigh the advantages.

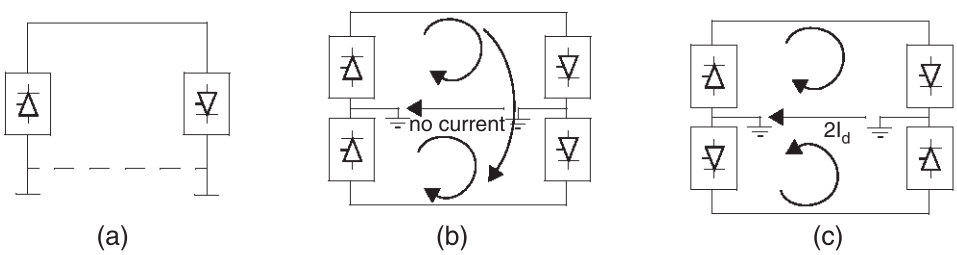

FIGURE 30.3 Types of HVDC links: (a) monopolar link; (b) bipolar link; and (c) homopolar link.

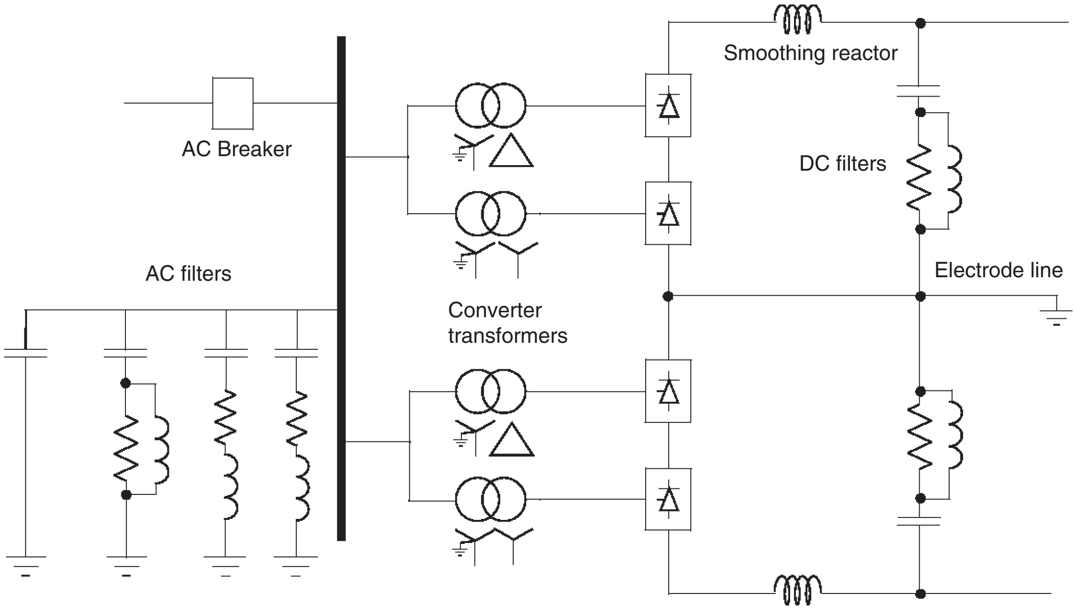

FIGURE 30.4 Typical HVDC converter station equipment.

30.2 Main Components of HVDC Converter Station

The major components of a HVDC transmission system are the converter stations at the ends of the transmission system. In a typical two-terminal transmission system, both a rectifier and an inverter are required. The role of the two stations can be reversed, as controls are usually available for both functions at the terminals. The major components of a typical 12-pulse bipolar HVDC converter station (Fig. 30.4) are discussed below.

30.2.1 Converter Unit

This usually consists of two three-phase converter bridges connected in series to form a 12-pulse converter unit. The design of valves is based on a modular concept where each module contains a limited number of series-connected thyristor levels. The valves can be packaged either as a single-valve, double-valve, or quadruple-valve arrangement. The converter is fed by two converter transformers, connected in star/star and star/delta arrangement, to form a 12-pulse pair. The valves may be cooled by air, oil, water, or freon. However, the cooling using deionized water is more modern and considered efficient and reliable. The ratings of a valve group are limited more by the permissible short-circuit currents than by the steady-state load requirements.

Valve firing signals are generated in the converter control at ground potential and are transmitted to each thyristor in the valve through a fiber-optic light guide system. The light signal received at the thyristor level is converted to an electrical signal using gate drive amplifiers with pulse transformers. Recent trends in the industry indicate that direct optical firing of the valves with light triggered thyristors (LTTs) is also feasible.

The valves are protected using snubber circuits, protective firing, and gapless surge arresters.

30.2.1.1 Thyristor Valves

Many individual thyristors are connected in series to build up an HVDC valve. To distribute the off-state valve voltage uniformly across each thyristor level and protect the valve from di/dt and dv/dt stresses, special snubber circuits are used across each thyristor level (Fig. 30.5).

The snubber circuit is composed of the following components:

- A saturating reactor is used to protect the valve from di/dt stresses during turn-on. The saturating reactor offers a high inductance at low current and a low inductance at high current.
- A dc grading resistor, RG distributes the direct voltage across the different thyristor levels. It is also used as a voltage divider to measure the thyristor level voltage.
- The RC snubber circuits are used to damp out voltage oscillations from power frequency to a few kilohertz.
- A capacitive grading circuit, CFG is used to protect the thyristor level from voltage oscillations at a much higher frequency.

A thyristor is triggered ON by a firing pulse sent via a fiber-optic cable from the valve base electronics (VBE) unit at earth potential. The fiber-optic signal is amplified by a gate

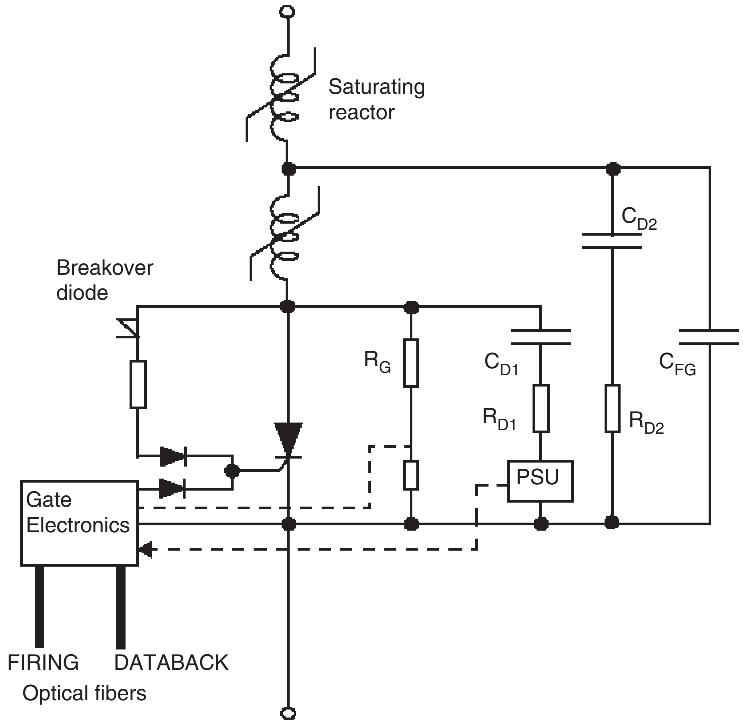

FIGURE 30.5 Electrical circuit of the thyristor level [2].

electronic unit (GEU), which receives its power from the RC snubber circuit during the valve's OFF period. The GEU can also affect the protective firing of the thyristor independent of the central control unit. This is achieved by a breakover diode (BOD) via a current limiting resistor that triggers the thyristor when the forward voltage threatens to exceed the rated voltage for the thyristor. This may arise in a case when some thyristors may block forward voltage while others may not.

It is normal to include some extra redundant thyristor levels to allow the valve to remain in service after the failure of some thyristors. A metal oxide surge arrestor is also used across each valve for overvoltage protection.

The thyristors produce considerable heat loss, typically 24–40 W/cm^2 (or over 1 MW for a typical quadruple valve), and so an efficient cooling system is essential.

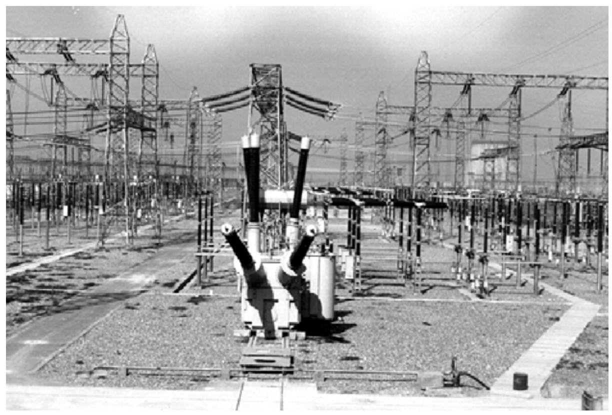

FIGURE 30.6 Spare converter transformer in the switchyard of an HVDC station.

30.2.2 Converter Transformer

The converter transformer (Fig. 30.6) can have different configurations: (a) three phase, two-winding, (b) single-phase, three-winding, and (c) single-phase, two-winding. The valve-side windings are connected in star and delta with neutral point ungrounded. On the ac side, the transformers are connected in parallel with the neutral grounded. The leakage impedance of the transformer (typical value between 15 and 18%) is chosen to limit the short-circuit currents through any valve.

The converter transformers are designed to withstand dc voltage stresses and increased eddy current losses due to harmonic currents. One problem that can arise is due to the dc magnetization of the core due to unsymmetrical firing of valves.

30.2.3 Filters

Due to the generation of characteristic and non-characteristic harmonics by the converter, it is necessary to provide suitable filters on the ac–dc sides of the converter to improve the power quality and meet telephonic and other requirements. Generally, three types of filters are used for this purpose.

30.2.3.1 AC Filters

AC Filters (Fig. 30.7) are passive circuits used to provide low impedance, shunt paths for ac harmonic currents. Both tuned and damped filter arrangements are used. In a typical 12-pulse station, filters at 11th, 13th harmonics are required as tuned filters. Damped filters (normally tuned to the 23rd harmonic) are required for the higher harmonics. In recent years, C-type filters have also been used since they provide more economic designs. Double- or even triple-tuned filters exist to reduce the cost of the filter (see Fig. 30.23).

The availability of cost-effective active ac filters will change the scenario in the future.

30.2.3.2 DC Filters

These are similar to ac filters and are used for the filtering of dc harmonics. Usually a damped filter at the 24th harmonic is utilized. Modern practice is to use active dc filters (see also the application example system presented later). Active dc filters are increasingly being used for efficiency and space saving purposes.

30.2.3.3 High Frequency (RF/PLC) Filters

These are connected between the converter transformer and the station ac bus to suppress any high-frequency currents. Sometimes such filters are provided on the high-voltage dc bus connected between the dc filter and dc line and also on the neutral side.

30.2.4 Reactive Power Source

Converter stations consume reactive power that is dependent on the active power loading (typically about 50–60% of the active power). The ac filters provide a part of this reactive power requirement. In addition, shunt (switched) capacitors and static var systems are also used.

30.2.5 DC Smoothing Reactor

A sufficiently large series reactor is used on the dc side of the converter to smooth the dc current and for the converter protection from line surges. The reactor (Fig. 30.8) is usually designed as a linear reactor and may be connected on the line side, neutral side, or at an intermediate location. Typical values of the smoothing reactor are in the range 240–600 mH for long distance transmission and about 24 mH for a BB connection.

30.2.6 DC Switchgear

This is usually a modified ac equipment and used to interrupt only small dc currents (i.e. employed as disconnecting switches). DC breakers or metallic return transfer breakers (MRTB) are used, if required, for the interruption of rated load currents.

In addition to the equipment described above, ac switchgear and associated equipment for protection and measurement are also part of the converter station.

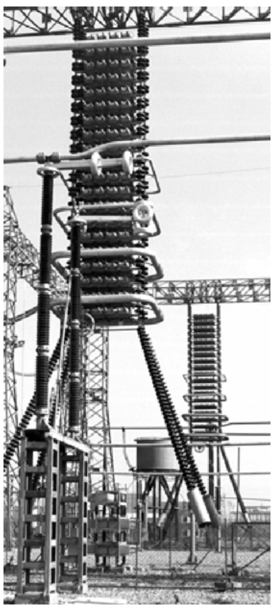

FIGURE 30.7 Installation of an ac filter in the switchyard.

FIGURE 30.8 Installation of an air-cooled smoothing reactor.

30.2.7 DC Cables

Contrary to the use of ac cables for transmission, dc cables do not have a requirement for continuous charging current. Hence the length limit of about 50 km does not apply. Moreover, dc voltage gives less aging and hence a longer lifetime for the cable. The new design of HVDC light cables from ABB are based on extruded polymeric insulating material instead of classic paper-oil insulation that has a tendency to leak. Due to their rugged mechanical design, flexibility, and low weight, polymer cables can be installed in underground cheaply with a plowing technique, or in submarine applications, it can be laid in very deep waters and on rough sea-bottoms. Since dc cables are operated in bipolar mode, one cable with positive polarity and one cable with negative polarity, very limited magnetic fields result from the transmission. HVDC light cables have successfully achieved operation at a stress of 20 kV/mm.

30.3 Analysis of Converter Bridge

To consider the theoretical analysis of a conventional 6-pulse bridge (Fig. 30.9), the following assumptions are made:

- DC current I_d is considered constant.
- Valves are ideal switches.
- AC system is strong (infinite).

Due to the leakage impedance of the converter transformer, commutation from one valve to the next is not instantaneous. An overlap period is necessary and, depending on the leakage, either two, three, or four valves may conduct at any time. In the general case, with a typical value of converter transformer leakage impedance of about 13–18%, either two or three valves conduct at any one time.

The analysis of the bridge gives the following dc output voltages:

For a rectifier:

$$V_{dr} = V_{dor} \cdot \cos\alpha - R_{cr} \cdot I_d \tag{30.1}$$

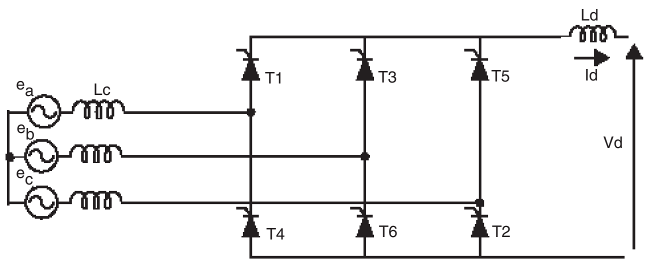

FIGURE 30.9 Six-pulse bridge circuit.

where

$$V_{dor} = \frac{3}{\pi} \cdot \sqrt{2} \cdot V_{LL}$$

$$R_{cr} = \frac{3}{\pi} \cdot \omega L_{cr}$$

where

$$\omega = 2 \cdot \pi \cdot f$$

where "f" is the power frequency.

For an inverter:

There are two options possible depending on choice of the delay angle or extinction angle as the control variable

$$-V_{di} = V_{doi} \cdot \cos\beta - R_{ci} \cdot I_d \tag{30.2}$$

$$-V_{di} = V_{doi} \cdot \cos\gamma - R_{ci} \cdot I_d \tag{30.3}$$

where

V_{dr} and V_{di} – dc voltage at the rectifier and inverter respectively.

V_{dor} and V_{doi} – open circuit dc voltage at the rectifier and inverter respectively.

R_{cr} and R_{ci} – equivalent commutation resistance at the rectifier and inverter respectively.

L_{cr} and L_{ci} – leakage inductance of converter transformer at rectifier and inverter respectively.

I_d – dc current.

α – delay angle.

β – advance angle at the inverter, ($\beta = \pi - \alpha$).

γ – extinction angle at the inverter, $\gamma = \pi - \alpha - \mu$.

30.4 Controls and Protection

In a typical two-terminal dc link connecting two ac systems (Fig. 30.10), the primary functions of the dc controls are to:

- Control the power flow between the terminals.
- Protect the equipment against the current/voltage stresses caused by faults.

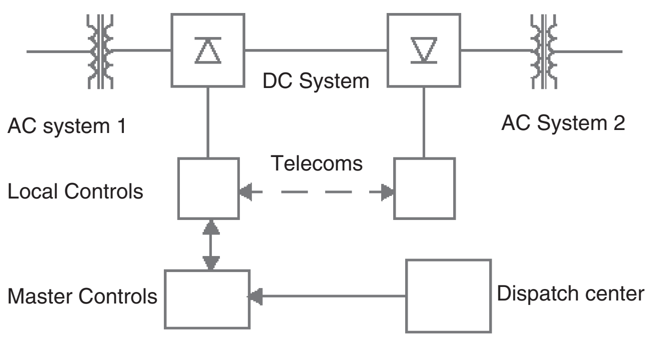

FIGURE 30.10 Typical HVDC system linking two ac systems.

- Stabilize the attached ac systems against any operational mode of the dc link.

The dc terminals each have their own local controllers. A centralized dispatch center will communicate a power order to one of the terminals that will act as a master controller and has the responsibility to coordinate the control functions of the dc link. Besides the primary functions, it is desirable that the dc controls have the following features:

- Limit the maximum dc current: Due to a limited thermal inertia of the thyristor valves to sustain overcurrents, the maximum dc current is usually limited to less than 1.2 pu for a limited period of time.
- Maintain a maximum dc voltage for transmission: This reduces the transmission losses, and permits optimization of the valve rating and insulation.
- Minimize reactive power consumption: This implies that the converters must operate at a low firing angle. A typical converter will consume reactive power between 50 and 60% of its MW rating. This amount of reactive power supply can cost about 15% of the station cost, and comprise about 10% of the power loss.

The desired features of the dc controls are indicated below:

1. Limit maximum dc current: Since the thermal inertia of the converter valves is quite low, it is desirable to limit the dc current to prevent failure in the valves.
2. Maintain maximum dc voltage for transmission purposes to minimize losses in the dc line and converter valves.
3. Keep the ac reactive power demand low at either converter terminal: This implies that the operating angles at the converters must be kept low. Additional benefits of doing this are to reduce the snubber losses in the valves and reduce the generation of harmonics.
4. Prevent commutation failures at the inverter station and hence improve the stability of power transmission.
5. Other features, i.e. the control of frequency in an isolated ac system or to enhance power system stability.

In addition to the above desired features, the dc controls will have to cope with the steady-state and dynamic requirements of the dc link, as shown in Table 30.2.

TABLE 30.2 Requirements of the dc link

Steady-state requirements	Dynamic requirements
Limit the generation of non-characteristic harmonics	Step changes in dc current or power flow
Maintain the accuracy of the controlled variable, i.e. dc current and/or constant extinction angle	Start-up and fault induced transients
Cope with the normal variations in the ac system impedances due to topology changes	Reversal of power flow
	Variation in frequency of attached ac system

30.4.1 Basics of Control for a Two-terminal DC Link

From converter theory, the relationship between the dc voltage V_d and dc current I_d is given by Eqs. (30.1)–(30.3). These three characteristics represent straight lines on the V_d–I_d plane. Notice that Eq. (30.2), i.e. beta characteristic, has a positive slope while the Eq. (30.3), i.e. gamma characteristic, has a negative slope. The choice of the control strategy for a typical two-terminal dc link is made according to the conditions in the Table 30.3.

Condition 1 implies the use of the rectifier in constant current control mode and condition 3 implies the use of the inverter in constant extinction angle (CEA) control mode. Other control modes may be used to enhance the power transmission during contingency conditions depending upon applications. This control strategy is illustrated in Fig. 30.11.

The rectifier characteristic is composed of two control modes: alpha-min (line AB) and constant current (line BC). The alpha-min mode of control at the rectifier is imposed by the natural characteristics of the rectifier ac system, and the ability of the valves to operate when alpha is equal to zero, i.e. in the limit the rectifier acts a diode rectifier. However, since a minimum positive voltage is desired before firing of the valves to ensure conduction, an alpha-min limit of about 2–5° is typically imposed.

TABLE 30.3 Choice of control strategy for two-terminal dc link

Condition no.	Desirable features	Reason	Control implementation
1	Limit the maximum dc current, I_d	For the protection of valves	Use constant current control at the rectifier
2	Employ the maximum dc voltage, V_d	For reducing power transmission losses	Use constant voltage control at the inverter
3	Reduce the incidence of commutation failures	For stability purposes	Use minimum extinction angle control at inverter
4	Reduce reactive power consumption at the converters	For voltage regulation and economic reasons	Use minimum firing angles

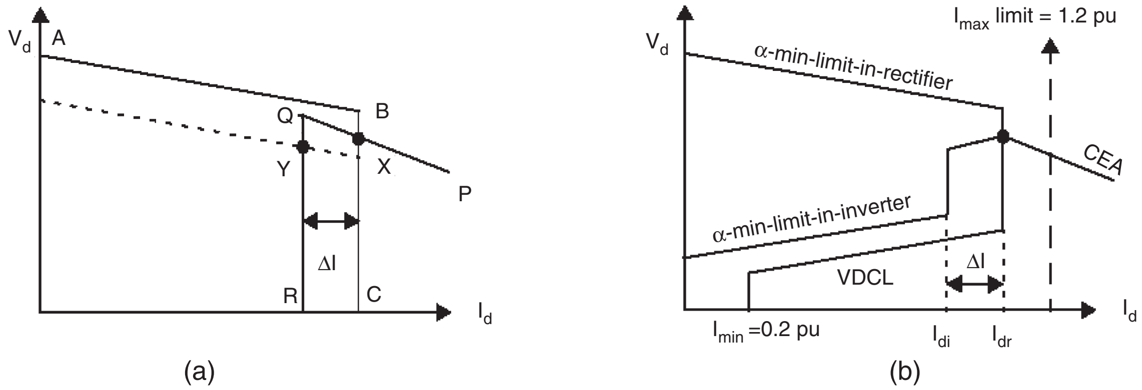

FIGURE 30.11 Static V_d–I_d characteristic for a two-terminal link: (a) unmodified and (b) modified.

The inverter characteristic is composed of two modes: gamma-min (line PQ) and constant current (line QR). The crossover point X of the two characteristics defines the operating point for the dc link. In addition, a constant current characteristic is also used at the inverter. However, the current demanded by the inverter I_{di} is usually less than the current demanded by the rectifier I_{dr} by the current margin ΔI which is typically about 0.1 pu; its magnitude is selected to be large enough so that the rectifier and inverter constant current modes do not interact due to any current harmonics which may be superimposed on the dc current. This control strategy is termed as the current margin method.

The advantage of this control strategy becomes evident if there is a voltage decrease at the rectifier ac bus. The operating point then moves to point Y. In this way, the current transmitted will be reduced to 0.9 pu of its previous value and voltage control will shift to the rectifier. However, the power transmission will be largely maintained near to 90% of its original value.

The control strategy usually employs the following other modifications to improve the behavior during system disturbances:

At the rectifier:

1. **Voltage dependent current limit, VDCL**
   This modification is made to limit the dc current as a function of either the dc voltage or, in some cases, the ac voltage. This modification assists the dc link to recover from faults. Variants of this type of VDCL do exist. In one variant, the modification is a simple fixed value instead of a sloped line.
2. **I_d-min limit**
   This limitation (typically 0.2–0.3 pu) is to ensure a minimum dc current to avoid the possibility of dc current extinction caused by the valve current dropping below the hold-on current of the thyristors; an eventuality that could arise transiently due to harmonics superimposed on the low value of the dc current. The resultant current chopping would cause high overvoltages to appear on the valves. The magnitude of I_d-min is affected by the size of the smoothing reactor employed.

At the inverter:

1. **Alpha-min limit at inverter**
   The inverter is usually not permitted to operate inadvertently in the rectifier region, i.e. a power reversal occurring due to an inadvertent current margin sign change. To ensure this, an alpha-min-limit in inverter mode of about 100–110° is imposed.
2. **Current error region**
   When the inverter operates into a weak ac system, the slope of the CEA control mode characteristic is quite steep and may cause multiple crossover points with the rectifier characteristic. To avoid this possibility, the inverter CEA characteristic is usually modified into either a constant beta characteristic or constant voltage characteristic within the current error region.

30.4.2 Control Implementation

30.4.2.1 Historical Background

The equidistant pulse firing control systems used in modern HVDC control systems were developed in the mid-1960s [5, 6]; although improvements have occurred in their implementation since then, such as the use of microprocessor based equipment, their fundamental philosophy has not changed much. The control techniques described in [5, 6] are of the pulse frequency control (PFC) type as opposed to the now-out-of-favor pulse phase control (PPC) type. All these controls use an independent voltage controlled oscillator (VCO) to decouple the direct coupling between the firing pulses and the commutation voltage, V_{com}. This decoupling was necessary to eliminate the possibility of harmonic instability detected in the converter operation when the ac system capacity became nearer to the power transmission capacity of the HVDC link, i.e. with the use of weak ac systems. Another advantage of the equidistant firing pulse control was the elimination of non-characteristic harmonics during steady-state operation. This was a prevalent feature during the use of the earlier individual phase control (IPC) system where the firing pulses were directly coupled to the commutation voltage, V_{com}.

30.4.2.2 Firing Angle Control

To control the firing angle of a converter, it is necessary to synchronize the firing pulses emanating from the ring counter to the ac commutation voltage that has a frequency of 60 Hz in steady state. However, it was noted quite early on (early 1960s), that the commutation voltage (system) frequency is not a constant, neither in frequency nor in amplitude, during a perturbed state. However, it is the frequency that is of primary concern for the synchronization of firing pulses. For strong ac systems, the frequency is relatively constant and distortion free to be acceptable for most converter type applications. But, as converter connections to weak ac systems became required more often than not, it was necessary to devise a scheme for synchronization purposes which would be decoupled from the commutation voltage frequency for durations when there were perturbations occurring on the ac system. The most obvious method is to utilize an independent oscillator at 60 Hz that can be synchronously locked to the ac commutation voltage frequency. This oscillator would then provide the (phase) reference for the generation of firing pulses to the ring counter during the perturbation periods, and would use the steady-state periods for locking in step with the system frequency. The advantage of this independent oscillator would be to provide an ideal (immunized and clean) sinusoid for synchronizing and timing purposes. There are two possibilities for this independent oscillator:

- Fixed frequency operation.
- Variable frequency operation.

Use of a fixed frequency oscillator (although feasible, and called the PPC oscillator) is not recommended, since it is known that the system frequency does drift, between 55 and 65 Hz, due to the rotating machines used to generate electricity. Therefore, it is preferable to use a variable frequency oscillator (called the PFC oscillator) with a locking range of between 50 and 70 Hz and the center frequency of 60 Hz. This oscillator would then need to track the variations in the system frequency and a control loop of some sort would be used for this tracking feature; this control loop would have its own gain and time parameters for steady-state accuracy and dynamic performance requirements.

The control loop for frequency tracking purposes would also need to consider the mode of operation for the dc link. The method widely adopted for dc link operation is the so-called current margin method.

30.4.3 Control Loops

Control loops are required to track the following variables:

- Ordered current I_{or} at the rectifier and the inverter.
- Ordered extinction angle (γ_o) at the inverter.

30.4.3.1 Current Control Loops

In conventional HVDC systems, a proportional integral (PI) regulator is used (Fig. 30.12) for the rectifier current controller. The rectifier plant system is inherently non-linear and has a relationship given in Eq. (30.1). For constant I_d and for small changes in α, we have

$$\frac{\Delta V_d}{\Delta \alpha} = -V_{dor} \cdot \sin \alpha \tag{30.4}$$

It is obvious from Eq. (30.4) that the maximum gain ($\Delta V_d/\Delta\alpha$) occurs when $\alpha = 90°$. Thus the control loop must be stabilized for this operation point, resulting in slower dynamic properties at normal operation within the range 12–18°. Attempts have been made to linearize this gain and have met with some limited success. However, in practical terms, it is not always possible to have the dc link operating with the rectifier at 90° due to harmonic generation and other protection elements coming into operation also. Therefore, optimizing the gains of the PI regulator can be quite arduous and take a long time. For this reason, the controllers are

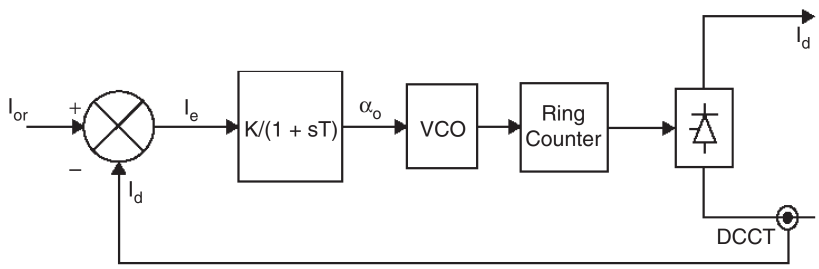

FIGURE 30.12 Control loop for the rectifier.

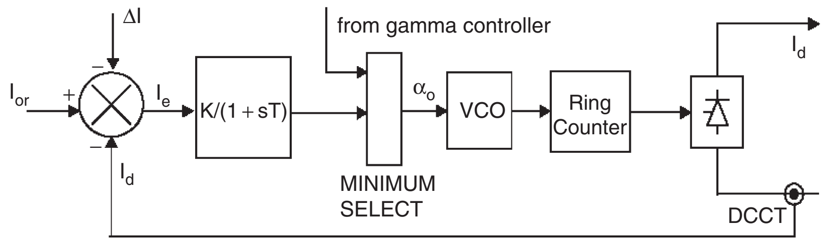

FIGURE 30.13 Current controller at the inverter.

often pre-tested in a physical simulator environment to obtain approximate settings. Final (often very limited) adjustments are then made on site.

Other problems with the use of a PI regulator are listed below:

- It is mostly used with fixed gains, although some possibility for gain scheduling exists.
- It is difficult to select optimal gains, and even then they are optimal over a limited range only.
- Since the plant system is varying continually, the PI controller is not optimal.

A similar current control loop is used at the inverter (Fig. 30.13). Since the inverter also has a gamma controller, the selection between these two controllers is made via a MINIMUM SELECT block. Moreover, in order to bias the inverter current controller off, a current margin signal ΔI is subtracted from the current reference I_{or} received from the rectifier via a communication link.

Telecommunication requirements

As was discussed above, the rectifier and inverter current orders must be coordinated to maintain a current margin of about 10% between the two terminals at all times, otherwise there is a risk of loss of margin and the dc voltage could run down. Although, it is possible to use slow voice communication between the two terminals, and maintain this margin, the advantage of fast control action possible with converters may be lost for protection purposes. For maintaining the margin during dynamic conditions, it is prudent to raise the current order at the rectifier first followed by the inverter; in terms of reducing the current order, it is necessary to reduce at the inverter first and then at the rectifier.

30.4.3.2 Gamma Control Loop

At the inverter end, there are two known methods for the gamma control loop. The two variants are different only due to the method of determining the extinction angle:

- Predictive method for the indication of extinction angle (gamma).
- Direct method for actual measurement of extinction angle (gamma).

In either case, a delay of one cycle occurs from the indication of actual gamma and the reaction of the controller to this measurement. Since the avoidance of a commutation failure often takes precedence at the inverter, it is normal to use the minimum value of gamma measured for the 6- or 12-inverter valves for the converter(s).

1. Predictive method of measuring gamma

The predictive measurement tries to maintain the commutation voltage–time area after commutation larger than a specified minimum value. Since the gamma prediction is only approximate, the method is corrected by a slow feedback loop that calculates the error between the predicted value and actual value of gamma (one cycle later) and feeds it back.

The predictor calculates continuously, by a triangular approximation, the total available voltage–time area that remains after commutation is finished. Since an estimate of the overlap angle m is necessary, it is derived from a well-known fact in converter theory that the overlap commutation voltage–time area is directly proportional to direct current and the leakage impedance (assumed constant and known) value of the converter transformer.

The prediction process is inherently of an individual phase firing character. If no further measures were taken, each valve would fire on the minimum margin condition. To counteract this undesired property, a special firing symmetrizer is used; when one valve has fired on the minimum margin angle, the following two or five valves fire equidistantly. (The choice of either two or five symmetrized valves is mainly a stability question.)

2. Direct method of measuring gamma

In this method, the gamma measurement is derived from a measurement of the actual valve voltage. Waveforms of the gamma measuring circuit are shown in the Fig. 30.14. An internal timing waveform, consisting of a ramp function of fixed slope, is generated after being initiated from the instant of zero anode current. This value corresponds to a direct voltage proportional to the last value of gamma. From the gamma values of all (either 6 or 12) valves, the smallest value is selected to

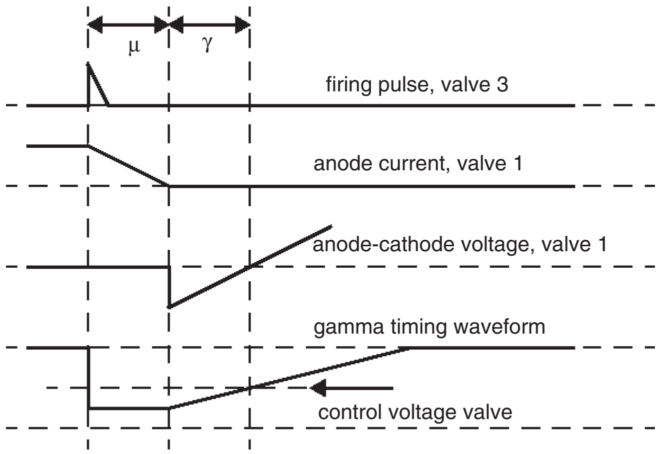

FIGURE 30.14 Waveforms for the gamma measuring circuit [5].

produce the indication of measured gamma for use with the feedback regulator.

This value is compared to a gamma-ref value and a PI regulator defines the dynamic properties for the controller (Fig. 30.15). Inherently, this method has an individual phase control characteristic. One version of this type of control implementation overcomes this problem by using a symmetrizer for generating equidistant firing pulses. The 12-pulse circuit generates 12 gamma measurements; the minimum gamma value is selected and then used to derive the control voltage for the firing pulse generator with symmetrical pulses.

30.4.4 Hierarchy of DC Controls

Since HVDC controls are hierarchical in nature, they can be subdivided into blocks that follow the major modules of a converter station (Fig. 30.16). The main control blocks are:

1. The bipole (master) controller is usually located at one end of the dc link, and receives its power order from a centralized system dispatch center. The bipole controller derives a current order for the pole controller using a local measurement of either ac or dc voltage. Other inputs, i.e. frequency measurement, may also be used by the bipole controller for damping or modulation purposes. A communication to the remote terminal of the dc link is also necessary to coordinate the current references to the link.
2. The pole controller then derives an alpha order for the next level. This alpha order is sent to both the positive and negative poles of the bipole.
3. The valve group controllers generate the firing pulses for the converter valves. Controls also receive measurements of dc current, dc voltage, and ac current into

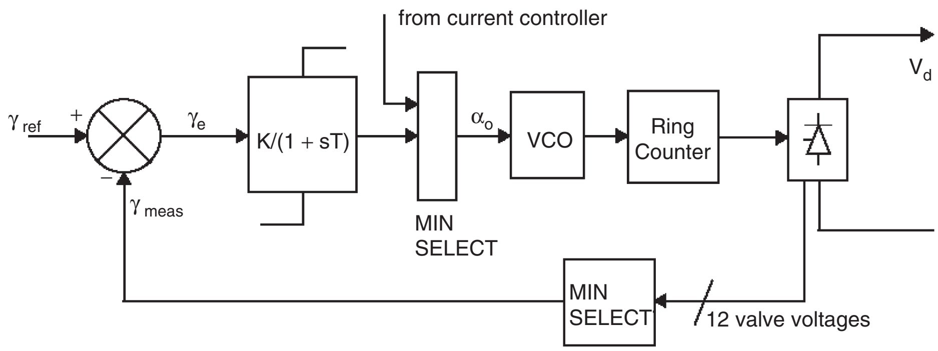

FIGURE 30.15 Gamma feedback controller.

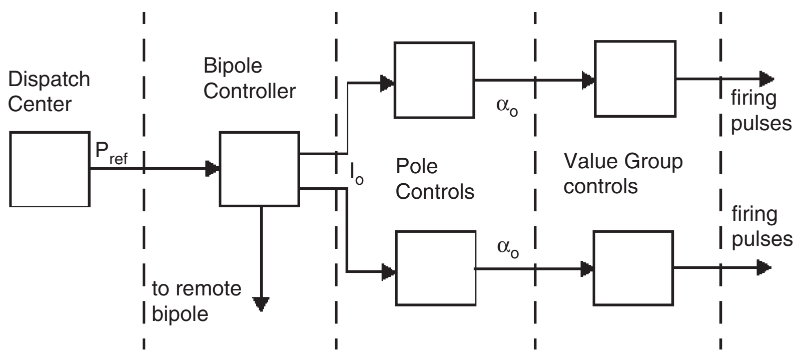

FIGURE 30.16 Hierarchy of controllers.

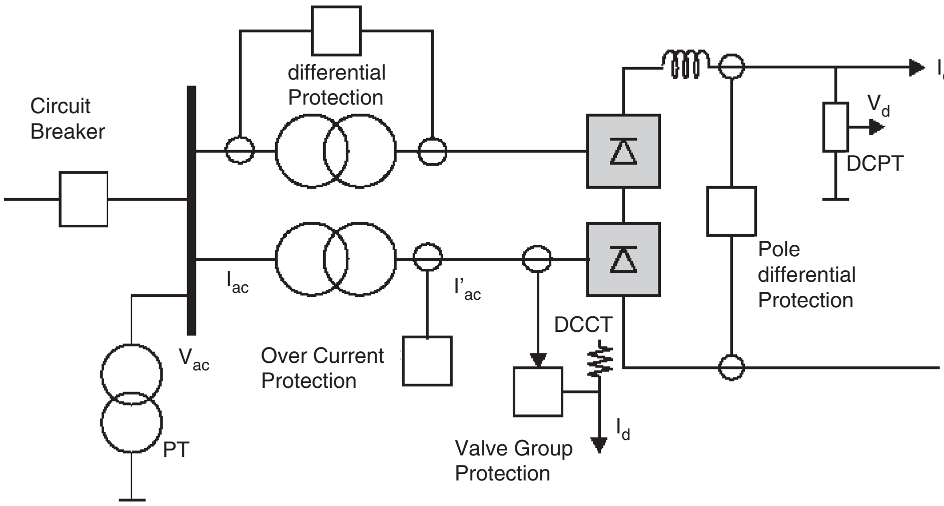

FIGURE 30.17 Monitoring points for the protection circuits.

the converter transformer. These measurements assist in the rapid alteration of firing angle for protection of the valves during perturbations. A slow loop for control of tap changer position as a function of alpha is also available at this level.

30.4.5 Monitoring of Signals

As described earlier, monitoring of the following signals is necessary for the controls (Fig. 30.17) to perform their functions and assist in the protection of the converter equipment:
V_d, I_d – dc voltage and dc current respectively.
I_{ac}, I'_{ac} – ac current on line side and converter side of the converter transformer respectively.
V_{ac} – ac voltage at the ac filter bus.

30.4.6 Protection against Overcurrents

Faults and disturbances can be caused by malfunctioning equipment or insulation failures due to lightening and pollution. First, these faults need to be detected with the help of monitored signals. Second, the equipment must be protected by control or switching actions. Since dc controls can react within one cycle, control action is used to protect equipment against overcurrent and overvoltage stresses, and minimize loss of transmission. In a converter station, the valves are the most critical (and most expensive) equipment that needs to be protected rapidly due to their limited thermal inertia.

The basic types of faults that the converter station can experience are:

Current extinction (CE)
Current extinction can occur if the valve current drops below the holding current of the thyristor. This can happen at low-current operation accompanied by a transient leading to current extinction. Due to the phenomena of current chopping of an inductive current, severe overvoltages may result. The size of the smoothing reactor and the rectifier minimum current setting I_{min} helps to minimize the occurrence of CE.

Commutation failure (CF) or misfire
In line-commutated converters, the successful commutation of a valve requires that the extinction angle γ-nominal be maintained more than the minimum value of the extinction angle γ-min. Note that γ-nominal $= 180-\alpha-\mu$. The overlap angle, μ is a function of the commutation voltage and the dc current. Hence, a decrease in commutation voltage or an increase in dc current can cause an increase in μ, resulting in a decrease in γ-nominal. If γ-nominal $<$ γ-min, a CF may result. In this case, the outgoing valve will continue to conduct current and when the incoming valve is fired in sequence, a short circuit of the bridge will occur.

A missing firing pulse can also lead to a misfire (at a rectifier) or a CF (at an inverter). The effects of a single misfire are similar to those of a single CF. Usually a single CF is self-clearing, and no special control actions are necessary. However, a multiple CF can lead to the injection of ac voltages into the dc system. Control action may be necessary in this case.

The detection of a CF is based on the differential comparison of dc current and the ac currents on the valve side of the converter transformer. During a CF, the two valves in an arm of the bridge are conducting. Therefore, the ac current goes to zero while the dc current continues to flow.

The protection features employed to counteract the impact of a CF are indicated in Table 30.4.

Short circuits – internal or dc line
An internal bridge fault is rare as the valve hall is completely enclosed and is air-conditioned. However, a bushing can fail,

TABLE 30.4 Protection against overcurrents

Fault type	Occurrence	Fault current level	Protection method
Internal faults	Infrequent	10 pu	Valve is rated to withstand this surge
DC line faults	Frequent	2–3 pu	– Forced retard of firing angle – Dynamic VDCL deployment – Trip ac breaker CB after third attempt
Commutation failures (single or multiple)	Very frequent	1.5–2.5 pu	Single CF: – Self-clearing Multiple CF: –Beta angle advanced in stages – Static VDCL deployment

or valve-cooling water may leak resulting in a short circuit. The ac breaker may have to be tripped to protect against bridge faults.

The protection features employed to counteract the impact of short circuits are indicated in Table 30.4.

The fast-acting HVDC controls (which operate within one cycle) are used to regulate the dc current for protection of the valves against ac and dc faults.

The basic protection (Fig. 30.18) is provided by the VGP differential protection that compares the rectified current on the valve side of the converter transformer with the dc current measured on the line side of the smoothing reactor. This method is applied because of its selectivity possible due to high impedances in the smoothing reactor and converter transformer.

The over current protection (OCP) is used as a back-up protection in case of malfunction in the VGP. The level of overcurrent setting is set higher than the differential protection.

The pole differential protection (PDP) is used to detect ground faults, including faults in the neutral bus.

30.4.7 Protection against Overvoltages

The typical arrangement of metal oxide surge arrestors for protecting equipment in a converter pole is shown in the

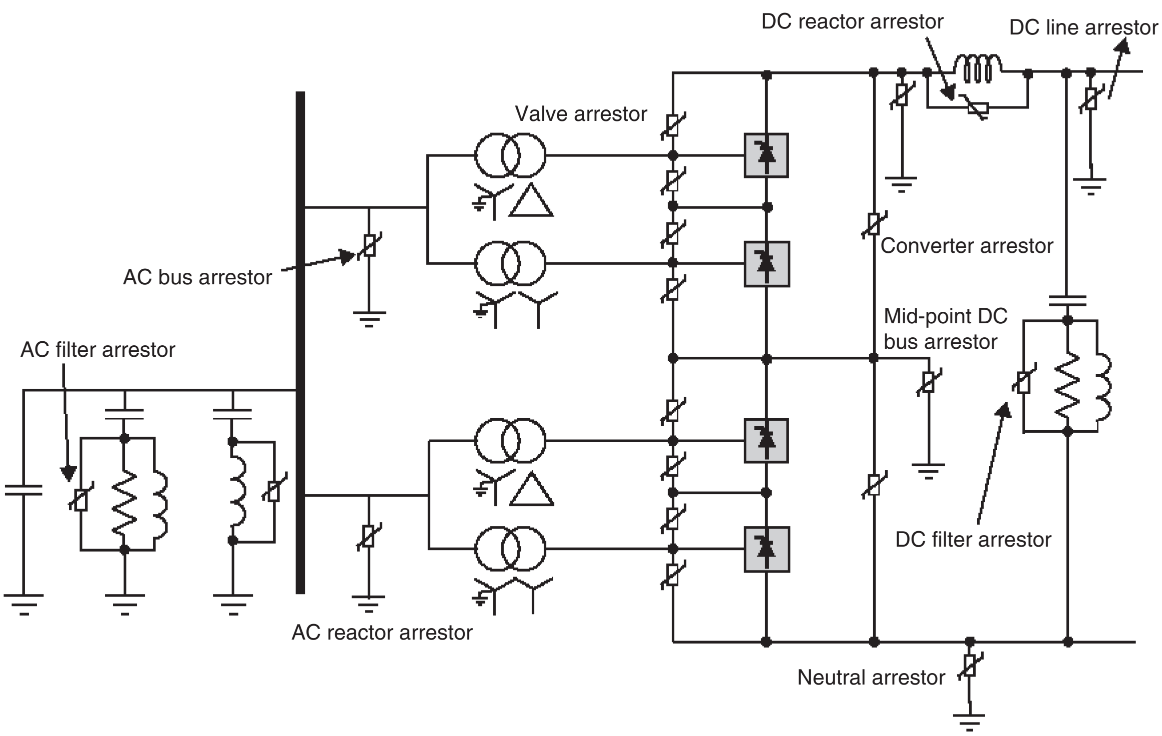

FIGURE 30.18 Typical arrangement of surge arrestors for a converter pole.

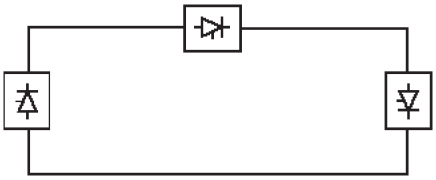

FIGURE 30.19 Series tap.

Fig. 30.18. In general, overvoltages entering from the ac bus are limited by the ac bus arresters; similarly, overvoltages entering the converter from the dc line are limited by the dc arrestor. The ac and dc filters have their respective arrestors also. Critical components such as the valves have their own arrestors placed close to these components. The protective firing of a valve is used as a back-up protection for overvoltages in the forward direction. Owing to their varied duty, these arrestors are rated accordingly for the location used. For instance, the converter arrestor for the upper bridge is subjected to higher energy dissipation than for the lower bridge.

Since the evaluation of insulation coordination is quite complex, detailed studies are often required with dc simulators to design an appropriate insulation coordination strategy.

30.5 MTDC Operation

Most HVDC transmission systems are two-terminal systems. A multiterminal dc system (MTDC) has more than two terminals and there are two existing installations of this type. There are two possible ways of tapping power from an HVDC link, i.e. with series or parallel taps.

30.5.1 Series Tap

A monopolar version of a three-terminal series dc link is shown in Fig. 30.19. The system is grounded at only one suitable location. In a series dc system, the dc current is set by one terminal and is common to all terminals; the other terminals are operated at a constant delay angle for a rectifier and CEA for inverter operation with the help of transformer tap changers.

Power reversal at a station is done by reversing the dc voltage with the aid of angle control.

No practical installation of this type exists in the world at present. From an evaluation of ratings and costs for series taps, it is not practical for the series tap to exceed 20% of the rating for a major terminal in the MTDC system.

30.5.2 Parallel Tap

A monopolar version of a three-terminal parallel dc link is shown in Fig. 30.20. In a parallel MTDC system, the system voltage is common to all terminals. There are two variants possible for a parallel MTDC system: radial or mesh. In a radial system, disconnection of one segment of the system will interrupt power from one or more terminals. In a mesh system, the removal of one segment will not interrupt power flow providing the remaining links, the capability of carrying the required power.

Power reversal in a parallel system will require mechanical switching of the links as the dc voltage cannot be reversed.

From an evaluation of ratings and costs for parallel taps, it is not practical for the parallel tap to be less than 20% of the rating for a major terminal in the MTDC system.

There are two installations of parallel taps existing in the world. The first is the Sardinia–Corsica–Italy link where a 50 MW parallel tap at Corsica is used. Since the principal terminals are rated at 200 MW, a commutation failure at Corsica can result in very high overcurrents (typically 7 pu); for this reason, large smoothing reactors (2.5 H) are used in this link.

The second installation is the Quebec–New Hampshire 2000 MW link where a parallel tap is used at Nicolet. Since the rating of Nicolet is at 1800 MW, the size of the smoothing reactors was kept to a modest size.

30.5.3 Control of MTDC System

Although several control methods exist for controlling MTDC systems, the most widely utilized method is the so-called

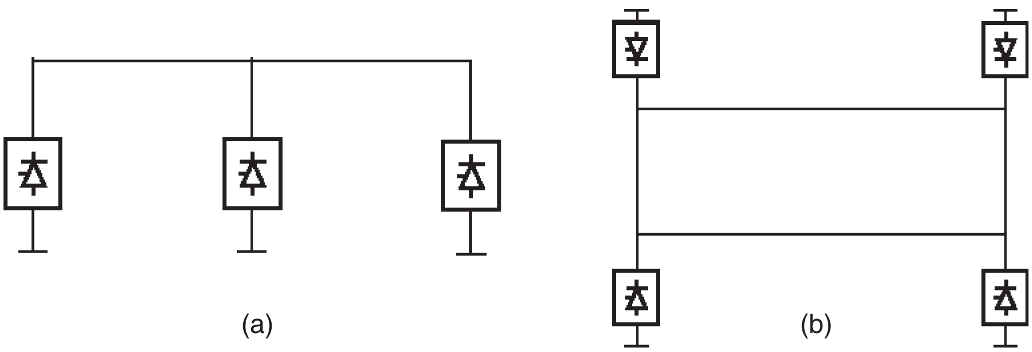

FIGURE 30.20 Parallel tap: (a) radial type and (b) mesh type.

current margin method, which is an extension of the control method, used for two-terminal dc systems.

In this method, the voltage setting terminal (VST) operates at the angle limit (minimum alpha or minimum gamma) while the remaining terminals are controlling their respective currents. The control law that is used sets the current reference at the voltage setting terminal according to

$$\sum I_{\mathrm{jref}} = \Delta I \tag{30.5}$$

where ΔI is known as the current margin.

The terminal with the lowest voltage ceiling acts as the VST.

An example of the control strategy is shown in Fig. 30.21 for a three-terminal dc system with one rectifier, REC and two inverters, INV 1 at 40% and INV2 at 60% rating. The REC 1 and INV 2 terminals are maintained in current control, while INV 1 is the VST operating in CEA mode.

Due to the requirement to maintain current margin for the MTDC system at all times, a centralized current controller, known as the current reference balancer (CRB) (Fig. 30.22), is required. With this technique, reliable two-way telecommunication links are required for current reference coordination purposes. The current orders, $I_{\mathrm{ref1}} - I_{\mathrm{ref3}}$, at the terminals must satisfy the control law according to Eq. (30.5). The weighting factors (K_1, K_2, and K_3) and limits are selected as a function of the relative ratings of the terminals.

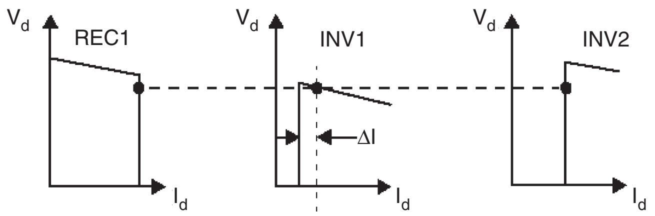

FIGURE 30.21 Current margin method of control for MTDC system.

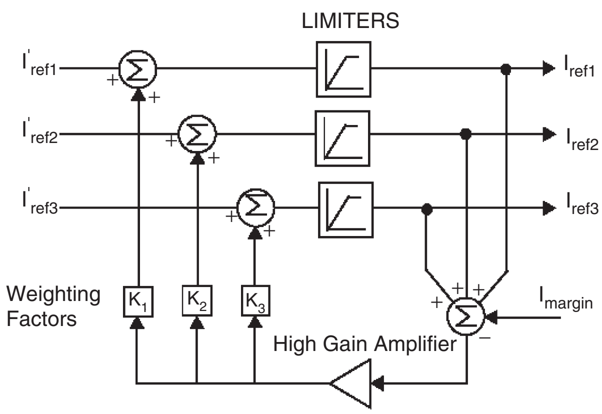

FIGURE 30.22 Current reference balancer.

30.6 Application

30.6.1 HVDC Interconnection at Gurun (Malaysia)

The 240/600 MW HVDC interconnection between Malaysia and Thailand is a major first step in implementing electric power network interconnections in the ASEAN region (Fig. 30.23). It is jointly undertaken by two utilities, Tenaga Nasional Berhad (TNB) of Malaysia and Electricity Generating Authority of Thailand (EGAT). This will be the first HVDC project for both these utilities. The HVDC interconnection consists of a 110 km HVDC line (85 km owned by TNB and 25 km owned by EGAT) with the dc converter stations at Gurun in the Malaysian side and Khlong Ngae in the Thailand side. The scheme entered into commercial operation in 2000. The interconnection provides a range of diverse benefits such as:

- Spinning reserve sharing.
- Economic power exchange – commercial transactions.
- Emergency assistance to either ac system.
- Damping of ac system oscillations.
- Reactive power support (voltage control).
- Deferment of generation plant up.

30.6.1.1 Power Transmission Capacity

The converter station is presently constructed for monopolar operation for power transfer of 240 MW in both directions with provisions for future extensions to a bipole configuration giving a total power transfer capability of 600 MW. The HVDC line is constructed with two pole conductors to cater for the second 240 MW pole. Full-length neutral conductors are used instead of ground electrodes because of high land costs and inherently high values of soil resistivity.

The monopole is rated for a continuous power of 240 MW (240 kV, 1000 A) at the dc terminal of the rectifier station. In addition, there is a 10 minutes overload capability of up to 450 MW, which may be utilized once per day when all redundant cooling equipment is in service (Tables 30.5 and 30.6).

The HVDC interconnection scheme is capable of continuous operation at a reduced dc voltage of 210 kV (70%) over the whole load range up to the rated dc current of 1000 A with all redundant cooling equipment in service.

30.6.1.2 Performance Requirements

A high degree of energy availability was a major design objective. Guaranteed targets for both stations are:

Energy availability	> 99.5%.
Forced energy unavailability	< 0.43%.
Forced outage rate	< 5.4 outages per year.

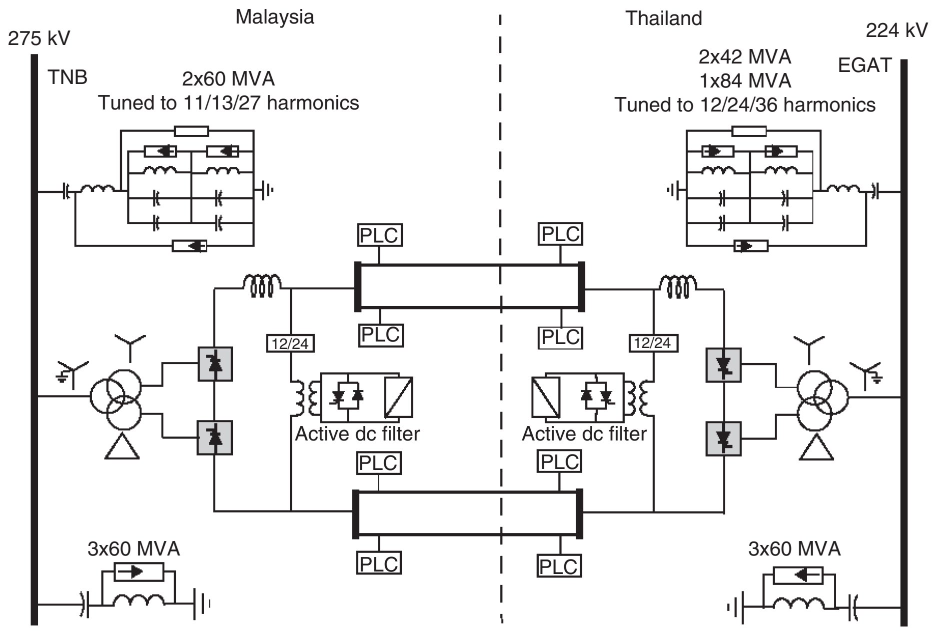

FIGURE 30.23 One-line diagram of the HVDC interconnection between Malaysia and Thailand.

30.6.1.3 Technical Information

TABLE 30.5 Main data 1

Monopolar operation		Rectifier (Malaysia)	Inverter (Thailand)
DC power, P_{dn}	Rated	240 MW (Stage 1)	240 MW
	Maximum overload (10 min).	450 MW	
	Minimum (10% of rated)	24 MW	
DC current, I_{dn}		1000 A	1000 A
DC voltage, U_{dn}		240 kV	293.5 kV
Firing angle, alpha		15.0°	–
Extinction angle, gamma		–	19.6°
Transformer secondary voltage, U_v		122.2 kV	122.2 kV
Converter reactive power, Q_{dc}		133.3 MVAr	150.9 MVAr
Reduced dc voltage operation	210 kV (70% dc voltage)		
AC system voltage		275 kV, 50 Hz	224 kV, 50 Hz
DC transmission line distance	110 kms		

TABLE 30.6 Main data 2

Main equipment	GURUN converter station
Smoothing reactor	100 mH
DC filter	Active type dc filters including passive type (12th/24th harmonics)
AC filter	2 × 60 MVAr (11/13/27)
Reactive power compensation	3 × 60 MVAr C-shunt
Power thyristor:	Type T1501 N75T-S34
Diameter	100 mm
Blocking voltage	7.5 kV repetitive, 8.0 kV non-repetitive
Maximum dc current	1550 A. 120° electrical. $T_c = 60°C$
Maximum effective current	3240 A
Converter transformer	Single-phase, three winding
	Rated power = 275 kV/116 MVA
Transmission line:	
Pole conductor	Cardinal ACSR 546 mm^2, twin conductors per pole
Neutral conductor	Hen ACSR 298 mm^2

30.6.1.4 Major Technical Features

The station incorporates the latest state-of-the-art technology in power electronics and control equipment. The features include:

- A fully decentralized control and protection system.
- Active dc filter technology.
- Hybrid dc current shunt measuring devices.
- A triple-tuned ac filter.

30.7 Modern Trends

30.7.1 Converter Station Design of the 2000s

The 1500 MW, ±500 kV Rihand–Delhi HVDC transmission system (commissioned in 1991) serves as an example of a typical design of the last decade. Its major design aspects were:

- Stations employ water-cooled valves of indoor design with the valves arranged as three quadruple valves suspended from the ceiling of the valve hall.
- Converter transformers are one-phase, three-winding units situated close to the valve hall with their bushings protruding into the valve hall.
- AC filtering is done with conventional, passive, double-tuned, and high-pass units employing internally-fused capacitors and air-cored reactors; these filters are mechanically switched for reactive power control.
- DC filtering is done with conventional, passive units employing a split smoothing reactor consisting of both an oil-filled reactor and an air-cored reactor.
- DC current transformer (DCCT) measurement is based on a zero-flux principle.
- Control and protection hardware is located in a control room in the service building in between the two valve halls. The controls still employed some analog parts, particularly for the protection circuits. The controls were duplicated with an automatic switchover to hot standby for reliability reasons.

This design was done in the 1980s to meet the requirements of the day for increased reliability and performance requirements, i.e. availability, reduced losses, higher overload capability, etc. However, these requirements led to increased costs for the system.

The next generation equipment is now being spearheaded by a desire to reduce costs and make HVDC as competitive as ac transmission. This is being facilitated by the major developments of the past decade that have taken place in power electronics. Therefore, the following will influence the next generation HVDC equipment.

30.7.1.1 Thyristor Development

The HVDC thyristors are now available with a diameter of 150 mm at a rating of 8–9 kV and power-handling capacity of 1500 kW, which will lead to a dramatic decrease in the number of series connected components for a valve with consequential cost reductions and improvement in reliability.

The development of the LTT (Figs. 30.24 and 30.25) is likely to eliminate the electronic unit (with their high number of electronic components) for generating the firing pulses for the thyristor (Fig. 30.26). The additional functional requirements of monitoring and protection of the device are being incorporated also.

Both of the above developments present the possibility of achieving compact valves that can be packaged for outdoor construction thereby reducing the overall cost and reliability of the station.

30.7.1.2 Higher DC Transmission Voltages

For long distance transmission, there is a tendency to use a high voltage to minimize the losses. The typical transmission voltage has been ±500 kV, although the Itaipu project in Brazil uses 600 kV. The transmission voltage has to be balanced against the cost of insulation. The industry is considering raising the voltage to ±800 kV.

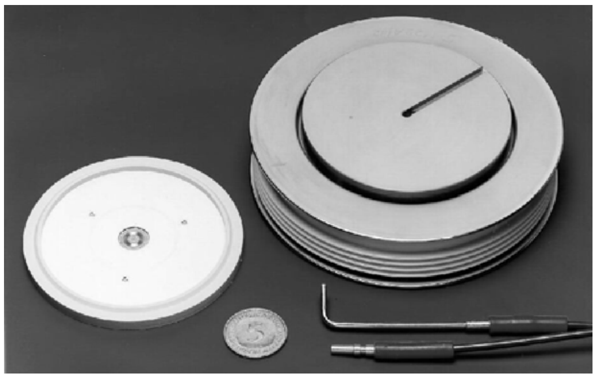

FIGURE 30.24 Silicon wafer and construction of the LTT. The light guides appear in the bottom right-hand corner.

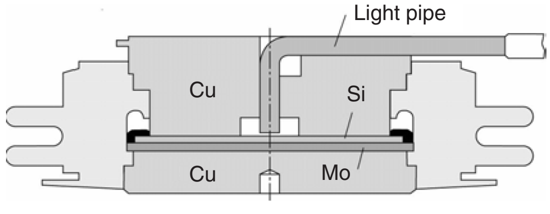

FIGURE 30.25 Cross section of the LTT with the light pipe entry.

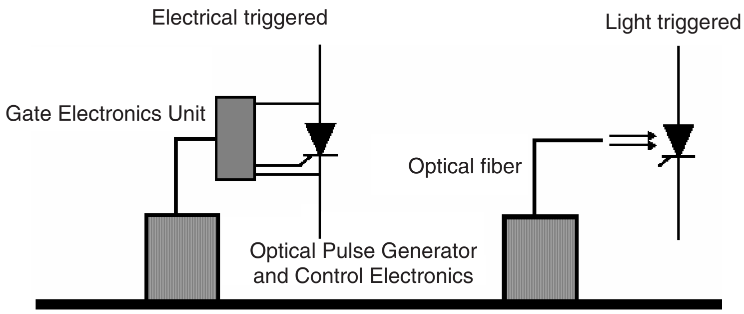

FIGURE 30.26 Conventional firing vs light triggered firing.

30.7.1.3 Controls

It is now possible to operate an HVDC scheme into an extremely weak ac system, even with short-circuit capacity down to unity.

Using programmable digital signal processors (DSPs) has resulted in a compact and modular design that is low cost; furthermore, the number of control cubicles has decreased by a factor of almost 10 times in the past decade. Now all control functions are implemented on digital platforms. The controls are fully integrated having monitoring, control and protection features. The design incorporates self-diagnostic and supervisory characteristics. The controls are optically coupled to the control room for reliable operation. Redundancy and duplication of controls is resulting in very high reliability and availability of the equipment.

30.7.1.4 Outdoor Valves

The introduction of air-insulated, outdoor valves will reduce the cost requirements for a valve hall. The use of a modular, compact design that can be preassembled in the manufacturing plant will save installation time and provide for a flexible station layout. This design has been feasible because of the development of a composite insulator for dc applications that is used as a communications channel for fiber-optics, cooling water, and ventilation air between the valve-unit and ground.

30.7.1.5 Active DC Filters

This development, made possible due to advances in power electronics and microprocessors, has resulted in a more efficient dc filter operating over a wide spectrum of frequencies and provides a compact design (Fig. 30.27).

30.7.1.6 AC Filters

Conventional ac filters used passive components for tuning out certain harmonic frequencies. Due to the variations in frequency and capacitance, physical aging and thermal characteristics of these tuned filters, the quality factors for the filters were typically about 100–125, which meant that the filters could not be too sharply tuned for efficient harmonic filtering. The advent of electronically tunable inductors based on the transductor principal, means that the Q-factors could now approach the natural one of the inductor. This will lead to much more enhanced filtering capacities (Fig. 30.28).

30.7.1.7 AC–DC Current Measurements

The new optical current transducers utilize a precision shunt at high potential. A small optical fiber link between ground and high potential is utilized resulting in a lower probability of a flashover. The optical power link transfers power to high potential for use in the electronics equipment. The optical data link transfers data to ground potential. This transducer results

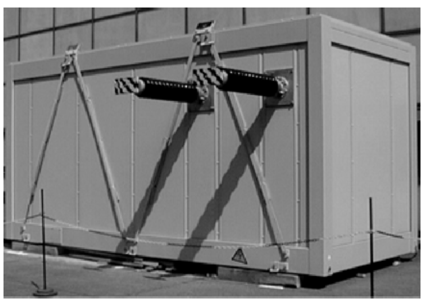

FIGURE 30.27 Compact outdoor container with an active dc filter.

FIGURE 30.28 Installation of the triple-tuned filter at the Gurun station in Malaysia.

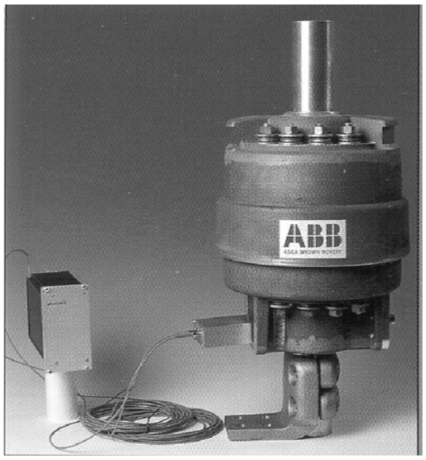

FIGURE 30.29 The optical current transducer.

in high reliability, compact design, and efficient measurement (Fig. 30.29).

30.7.1.8 New Topologies

Two new topological changes to the converter design will impact greatly on future designs.

1. **Series compensated commutation:** There are two variants to this topology: the capacitor-commutated converter (CCC) (Fig. 30.30a) and the controlled series capacitor converter (CSCC) (Fig. 30.30b). Essentially, the behavior of the two variants is very similar. The insertion of a capacitor in series with the converter transformer leakage reactance causes a major reduction in the commutation impedance of the converter resulting in a reduction in the reactive power requirement of the converter. An increase in the size of the series capacitor can even result in the converter operation at a leading power factor if so desired. However, the negative impact of lower commutation impedance results in additional stresses on the valves and transformers and additional cost implications [7].

   The first CCC back-back converter station (rated at $2 \times 550\,\text{MW}$), has been put into service at Garabi, on the Brazilian side of the Uruguay river. The system interconnects the electrical systems of Argentina and Brazil.
2. **Voltage source converters (VSC):** The use of self-commutation with the new generation switching devices (i.e. gate turn off thyristors (GTOs) and insulated gate bipolar transistors (IGBTs) has resulted in the topology of a VSC (Fig. 30.31) as opposed

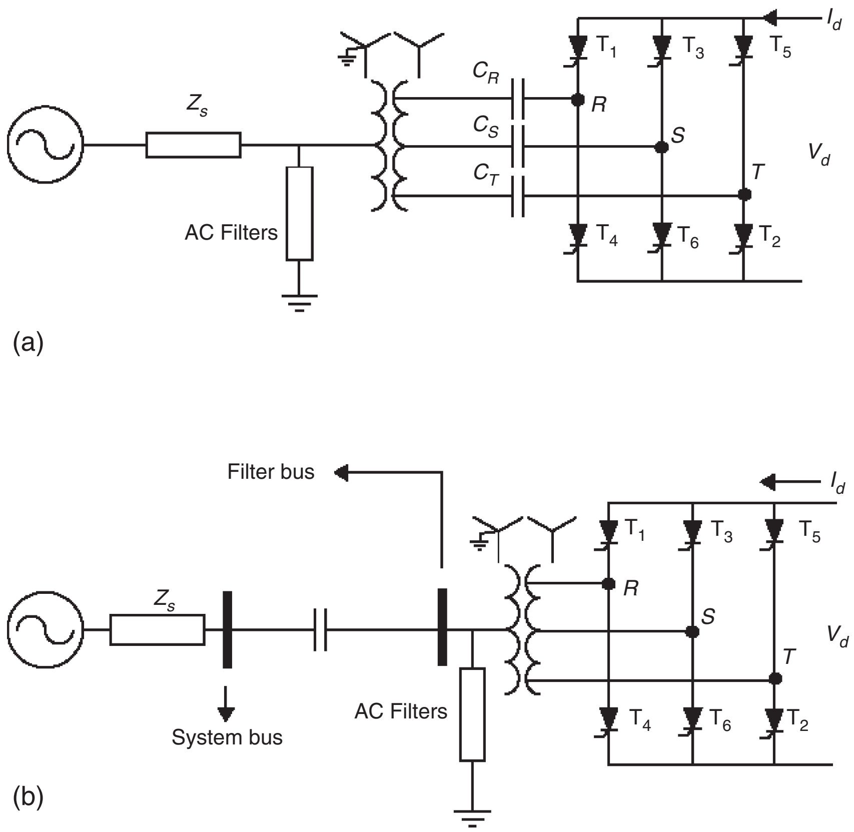

FIGURE 30.30 (a) Capacitor-commutated converter circuit and (b) controlled series capacitor converter circuit.

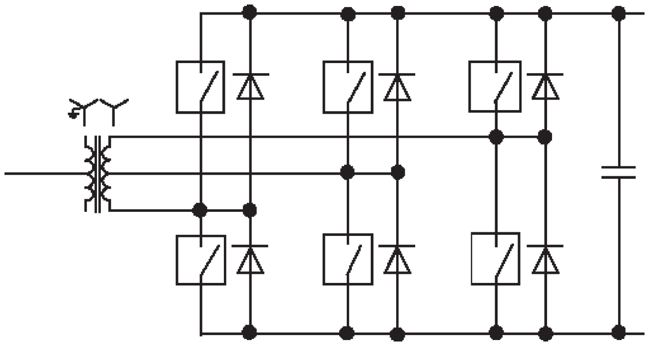

FIGURE 30.31 Voltage source converter topology.

to the conventional converter using line-commutated thyristors and current source converter (CSC) topology. The VSC, being self-commutated, can control active/reactive power and, with PWM techniques, control harmonic generation as well. The application of such circuits is presently limited by the switching losses and ratings of available switching devices. The ongoing advances in power electronic devices are expected to have a major impact on the future application of this type of converter in HVDC transmission. New application areas, particularly in distribution systems, are being actively investigated with this topology. Table 30.7 provides a partial list of the HVDC links in operation using this technique.

One major difficulty for the use of the VSC is the threat posed to the valves from a short circuit on the dc line. Unlike the CSC where the valves are inherently protected against short-circuit currents by the presence of the smoothing reactor, the VSC is relatively unprotected. For this reason, the VSC applications are almost always used with dc cables where the risk of a dc line short circuit is greatly reduced.

30.7.1.9 Compact Station Layout

The advances discussed above have resulted in marked improvement of the footprint requirement of the compact station [8] of the year 2000 which has about 24% space requirement of the comparable HVDC station designed in the past decade (Fig. 30.32).

30.8 HVDC System Simulation Techniques

Modern HVDC systems incorporate complex control and protection features. The testing and optimization of these features require powerful tools that are capable of modeling all facets of the system and have the flexibility to do the evaluation in a rapid, effective, and cost efficient manner.

30.8.1 DC Simulators and TNAs [9]

For decades, this has been achieved with the aid of physical power system simulators or transient network analyzers (TNAs) which incorporate scaled physical models of all power system elements (three-phase ac network lines/cables, sources as e.m.f. behind reactances, model circuit breakers for precisely timed ac system disturbances, transformers (system and convertor transformers with capacity to model saturation characteristics), filter capacitors, reactors, resistors, arrestors, and machines). Until the 1970s, these were built with analog components. However, with the developments in microprocessors, it is now feasible to utilize totally digital simulators operating in real time for even the most complex HVDC system studies. Most simulators operating scale is in the range 20–100 V dc, 0.2–1 A ac and at power frequency of 50 or 60 Hz. The stray capacitances and inductances are, however, not normally represented since the simulator is primarily used to assess control system behavior and temporary overvoltages of frequencies below 1000 Hz. Due to the developments of flexible ac transmission systems (FACTS) application, most modern simulators now include similarly scaled models of HVDC converters, static compensators, and other thyristor-controlled equipments. The controls of these equipments are usually capable of realistic performance during transients such as the ac faults and commutation failure. The limited

TABLE 30.7 Applications of HVDC light technology

No.	Project	Rating		Distance (km)	Application	Commissioned
		MVA	kV			
1	Hellsjon	3	±10	10	AC–DC conversion	Mar. 1997
2	Gotland	50	±80	70	Feed from wind power generation	June 1999
3	Tjaereborg	7	±10	4	Feed from wind power generation	Aug. 1999
4	Directlink	180	±140	65	Asynchronous interconnection	Dec. 1999
5	Murraylink	220	±140	180	Asynchronous interconnection	2002
6	Shoreham	330	±140	40	Cross sound cable link	2002
7	Troll A	2 × 42	±60	70	Gas production offshore platform	2005

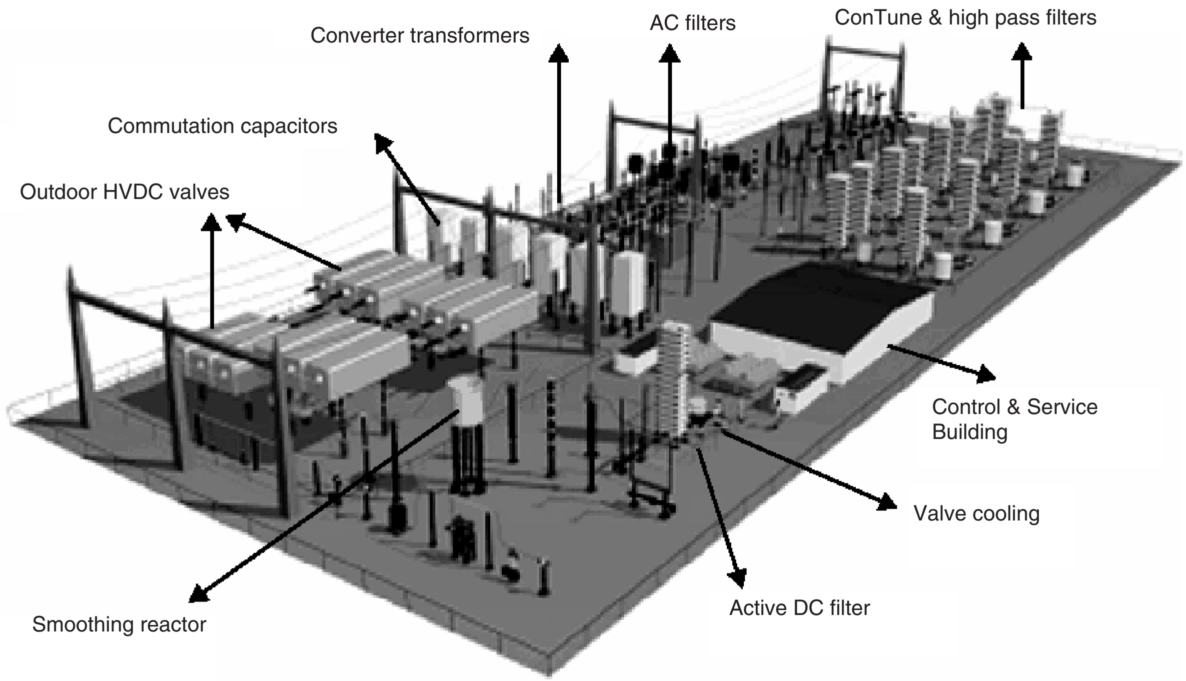

FIGURE 30.32 Layout of a compact HVDC station (graphic reproduced here courtesy of ABB).

availability of adequate models of some of the system elements restricts the scope of the studies which can be completed entirely by means of the simulator. Due to the scaling problems, the losses in the simulator may be disproportionately high and need to be partly compensated by electronic circuits (negative resistances) to simulate appropriate damping of overvoltages and other phenomena.

30.8.2 Digital Computer Analysis

The main type of program employed for studies is an electromagnetic transients program (EMTP) that solves sets of differential equations by step-by-step integration methods. The digital program must allow for the modeling of both the linear and non-linear components (single- and three-phase) and of the topological changes caused; for example, by valve firing or by circuit-breaker operation. Detailed modeling of the converter control system is necessary depending on the type of study.

The EMTP has become an industrial standard analysis tool for power systems and is widely used. The program has had a checkered history and numerous variants have appeared. Initially, the development of the program was supported by the Bonneville Power Administration (BPA). Some of the drawbacks in the capabilities of EMTP became more pronounced as the modeling of FACTS with power electronic switches and VSCs became more desirable.

Some of the drawbacks of the original EMTP version were:

1. The use of a fixed timestep that did not take into account the relatively long periods of inaction during non-switching events. This results in unnecessarily long simulation times and huge amounts of data to be manipulated. This is particularly problematic for simulating power electronic converters.
2. The use of a fixed timestep results in the modeled switches chopping inductive current that causes numerical oscillations. The use of artificial RC "snubbers" helped to alleviate some of these problems. The choice of the snubber capacitor was a function of the magnitude of the current to be chopped and the timestep size.
3. The use of the trapezoidal integration method results in numerical oscillations when the network admittance matrix to be inverted becomes singular. This is the direct result of modeling switches as truly either ON or OFF without representation of their intermediate non-linear characteristics.
4. The requirement of a one-timestep delay between the main program and the transient analysis of control systems (TACS) subroutine for controls simulation.
5. The use of new VSCs with multiple switching per cycle made the problem of switching "jitter" much more evident.
6. The lack of user-friendly input and output processors.

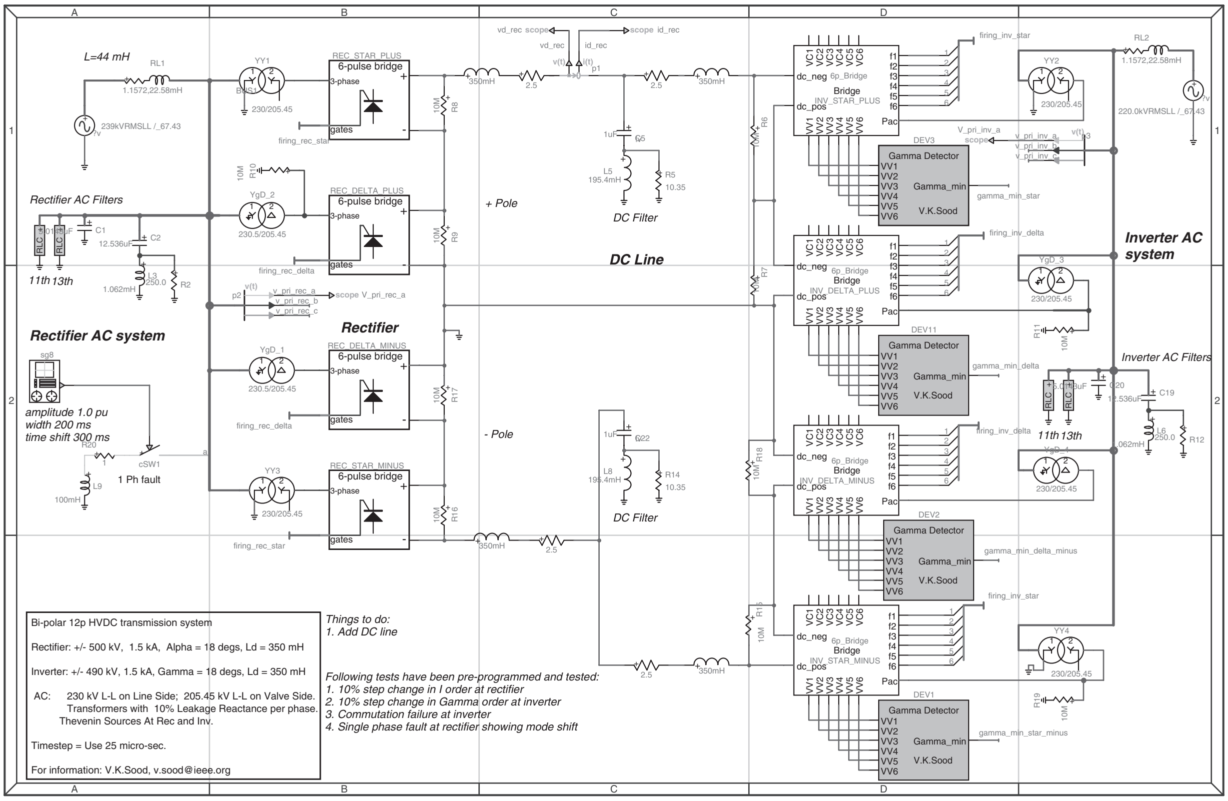

FIGURE 30.33 A sample of the graphical input file of EMTP RV.

In recent years, considerable effort has been made by the EMTP Development Coordination Group (DCG) to restructure the program. This has resulted in the latest version called the EMTP RV (restructured version) (see www.emtp.com). The entire code of the program has been re-written and graphical input and output processors have been added. A sample of the graphical input file is shown in Fig. 30.33.

The main advantage of digital studies is the possibility of correct representation of the damping present in the system. This feature permits more accurate evaluation of the nature and rate of decay of transient voltages following their peak levels in the initial few cycles, and also a more realistic assessment of the peak current and total energy absorption of the surge arresters. The digital program also allows modeling of stray inductances and capacitances and can be used to cover a wider frequency range of transients than the dc simulator.

The main disadvantage of the digital studies is the lack of adequate representation of commutation failure phenomena with the use of power electronic converters. However, with the increasing capacity of computers, this is likely to be overcome in the future.

The models used in the simulators and digital programs depend on the assumptions made and on the proper understanding of the component and system characteristics; therefore, they require care in their usage to avoid unrealistic results in inexperienced hands.

30.9 Concluding Remarks

The HVDC technology is now mature, reliable, and accepted all over the world. From its modest beginning in the 1950s, the technology has advanced considerably and maintained its leading edge image. The encroaching technology of flexible ac transmission systems (FACTS) has learned and gained from the technological enhancements made initially by HVDC systems. The FACTS technology may challenge some of the traditional roles for HVDC applications since the deregulation of the electrical utility business will open up the market for increased interconnection of networks [7]. HVDC transmission has unique characteristics, which will provide it with new opportunities. Although the traditional applications of HVDC transmission will be maintained for bulk power transmission in places like China, India, South America, and Africa, the increasing desire for the exploitation of renewable resources will provide both a challenge and an opportunity for innovative solutions in the following applications:

- Connection of small dispersed generators to the grid.
- Alternatives to local generation.
- Feeding to urban city centers.

Acknowledgments

The author pays tribute to the many pioneers whose vision of HVDC transmission has led to the rapid evolution of the power industry. It is not possible here to name all of them individually.

A number of photographs of equipment have been included in this chapter, and I thank the suppliers (Mr. P. Lips of Siemens and Mr. R. L. Vaughan from ABB) for their assistance.

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