HVDC and FACTS

By

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<tr><td rowspan="1">2017-18 Onwards (MR-17)</td><td>MALLA REDDY ENGINEERING COLLEGE
(Autonomous)</td><td colspan="3">B.Tech.
VII Semester</td></tr>
<tr><td>Code: 70230</td><td rowspan="2">HVDC AND FACTS
(Professional Elective-IV)</td><td>L</td><td>T</td><td>P</td></tr>
<tr><td>Credits: 4</td><td>3</td><td>2</td><td>-</td></tr>
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Prerequisites: Power Generation and Distribution, Power System Analysis and Power Electronics.

Course Objectives: This course deals with the basic concepts of HVDC transmission system, its applications and analysis of HVDC converters with their control circuitry. It also emphasizes on reactive power control in HVDC system using FACTS devices.

MODULE I: Introduction 13 Periods

Economics & terminal equipment of HVDC transmission systems: Types of HVDC links – Apparatus required for HVDC systems – Comparison of AC & DC transmission, application of DC transmission System – Planning & modern trends in D.C. transmission.

MODULE II: Analysis of HVDC Converters 13 Periods

Choice of converter configuration – Analysis of Graetz – Characteristics of 6 Pulse & 12 Pulse converters – Cases of two 3 phase converters in star-star mode and their performance.

Converter & HVDC System Control:

Principle of DC link control – Converters control characteristics – Firing angle control – Current and extinction angle control – Effect of source inductance on the system. Starting and stopping of DC link - Power Control.

MODULE III: Reactive Power Control in HVDC 13 Periods

A: Reactive Power Requirements in steady state - Conventional control strategies - Alternate control strategies - Sources of reactive power - AC Filters – Shunt capacitors - Synchronous condensers.

B: Power Flow Analysis in AC/DC Systems :

Modeling of DC links - DC network - DC converter - Controller equations - Solution of DC load flow – P.U. system for DC quantities - Solution of AC-DC power flow - Simultaneous method - Sequential method.

MODULE IV: Power Flow and Dynamic Stability 13 Periods

Transmission interconnections, power flow in an AC System, loading capability limits, power flow and dynamic stability considerations, importance of controllable parameters. Opportunities for FACTS, basic types of FACTS controllers, benefits from FACTS controllers. Requirements and characteristics of high power devices – Voltage and current rating, losses and speed of switching, parameter trade - off of devices.

MODULE V: Static Series Compensators 12 Periods

Concept of series capacitive compensation - Improvement of transient stability - Power oscillation damping. Functional requirements of GTO thyristor controlled series capacitor (GSC), thyristor switched series capacitor (TSSC), and thyristor controlled series capacitor (TCSC). Control schemes for GSC, TSSC and TCSC.

TEXT BOOKS

1. K.R.Padiyar, **"HVDC Power Transmission Systems"**, New Age International Publishers Limited, 3rd Edition, 2015.
2. N.G.Hingorani and L.Guygi, **"Understanding FACTS: Concepts and Technology of Flexible AC Transmission Systems"**, John Wiley & Sons, Inc., Reprint, 2012.

REFERENCES

1. Jos Arrillaga, **"HVDC Transmission"** , The Institution of Electrical Engineers, 2nd Edition, 1998.
2. S.Rao**, "EHVAC and HVDC Transmission Engineering and Practice: Theory, Practice and Solved Problems",** Khanna Publishers, 1990.
3. E.W.Kimbark, **"Direct Current Transmission"**, John Wiley & Sons, Inc., 1971.
4. E.Uhlmann, **"Power Transmission by Direct Current"**, Springer, 1st Edition, 2012.
5. Yong Hua Song and Allan T Johns, **"Flexible AC Transmission Systems (FACTS)",** The Institution of Electrical Engineers, 1999.

E - RESOURCES

1. https://www.electrical4u.com/facts-on-facts-theory-and-applications/
2. https://www.electrical4u.com/high-voltage-direct-current-transmission/
3. http://nptel.ac.in/courses/108104013/

Course Outcomes

At the end of the course, students will be able to

1. Understand the applications and different types of HVDC links.
2. Analyze the converter configuration & their characteristics.
3. Describe the reactive power requirements in steady state & modeling of DC links.
4. Analyze the power flow in AC system & apply FACTS controllers for dynamic stability.
5. Describe the working principle of static series compensators.

MODULE I: Introduction

1.1 Economics & Terminal Equipment of HVDC Transmission Systems

1.2 Types of HVDC links

1.3 Apparatus Required for HVDC systems

1.4 Comparison of AC & DC transmission,

1.5 Application of DC Transmission System Planning

1.6 Modern Trends in D. C. Transmission

Introduction:

The industrial growth of a nation requires increased consumption of electrical energy. This has leads to increase in generation and transmission facilities to meet the increasing load demand.

1970's	**Country**	**Demand Doubles**
	U.S.A	Every 10 Years
	India	Every 7 Years

This requires a considerable investment in electric power sector.

A high-voltage, direct current (HVDC) electric power transmission system (also called a power super highway or an electrical super highway) uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses. For underwater power cables, HVDC avoids the heavy currents required to charge and discharge the cable capacitance each cycle. For shorter distances, the higher cost of DC conversion equipment compared to an AC system may still be justified, due to other benefits of direct current links.

HVDC allows power transmission between unsynchronized AC transmission systems. Since the power flow through an HVDC link can be controlled independently of the phase angle between source and load, it can stabilize a network against disturbances due to rapid changes in power. HVDC also allows transfer of power between grid systems running at different frequencies, such as 50 Hz and 60 Hz. This improves the stability and economy of each grid, by allowing exchange of power between incompatible networks.

Power Transmission was initially carried out in the early 1880s using Direct Current (DC). With the availability of transformers (for stepping up the voltage for transmission over long distances and for stepping down the voltage for safe use), the development of robust induction motor (to serve the users of rotary power), the availability of the superior synchronous generator, and the facilities of converting AC to DC when required, AC gradually replaced DC. However in 1928, arising out of the introduction of grid control to the mercury vapour rectifier around 1903, electronic devices began to show real prospects for high voltage direct current (HVDC) transmission, because of the ability of these devices for rectification and inversion.

The most significant contribution to HVDC came when the Gotland Scheme in Sweden was commissioned in 1954 to be the World's first commercial HVDC transmission system. This was capable of transmitting 20 MW of power at a voltage of -100 kV and consisted of a single 96 km cable with sea return.

1.1 Economics & Terminal Equipment:

Comparison of AC and DC transmission:

The relative merits of the two modes of transmission which need to be considered by a system planner are based on the following factors.

1) Economic of Transmission
2) Technical Merits of HVDC
3) Reliability

A major feature of power system is the continuous expansion imposed by increasing power demand.

1) Economic of Power Transmission:

The cost of a transmission line includes the a) Investment cost and
b) Operational costs

a) The investment costs includes

i) Cost of Right of Way (RoW)
ii) Transmission towers
iii) Conductors
iv) Insulators
v) Terminal equipment

b) The operational costs include mainly the cost of losses.

The characteristics of insulators vary with type of voltage applied. For simplicity, if it is assumed that the insulator characteristics are similar for AC and DC and depend on the peak level of voltage applied with respect to ground, there it can be shown that for lines designed with the same insulation level, a DC line can carry as much power with two conductors (with positive and negative terminals w.r.t. ground) as an Ac line with 3 conductors of the same size. This implies that for a given power level, DC line requires less RoW, Simpler and cheaper towers and reduced conductor and insulator costs.

The power losses are also reduced with DC as there are only two conductors (about 2/3=67% of AC with same current carrying capacity of conductors). The absence of skin effect (skin effect α f) with DC also beneficial in reducing power losses marginally. The dielectric losses in case of power cables is also very less for DC transmission.

The variation of transmission costs with distance for AC and DC as shown in Fig. 1.1. From Fig. 1.1, AC transmission is economical before break even distance (d*) and costlier for longer distances when compared to DC. The break even distance can vary from 500-800 km.

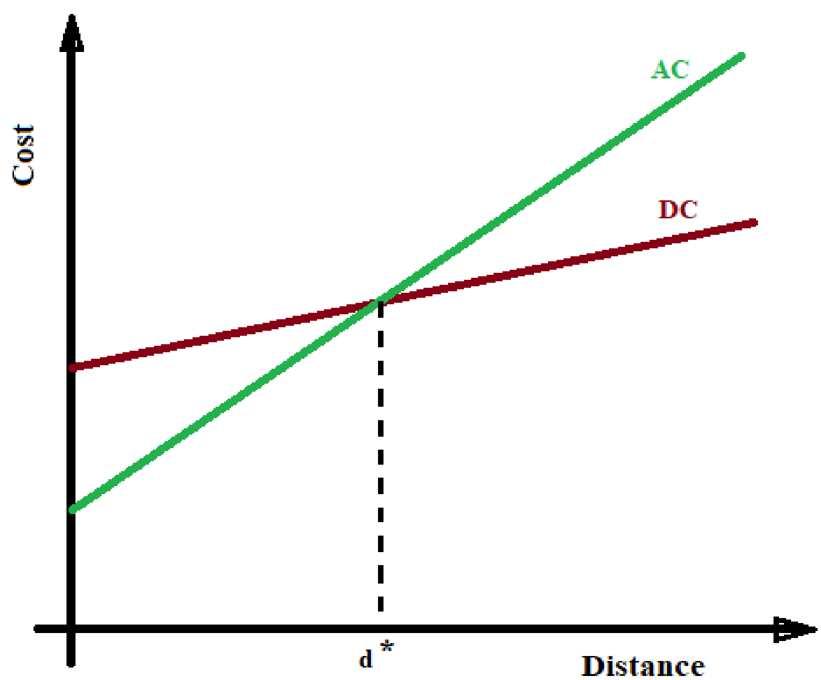


Fig. 1.1: Variation of Cost with Line Length

The corona effects (corona effect α f+25) tend to be less significant on DC conductors than for AC. This leads to the choice of economic size of conductors with DC transmission. The other factors that influence the line costs are the costs of compensation and terminal equipment. DC lines do not require any compensation but the terminal equipment costs are increased due to the presence of converters and filters.

2) Technical Performance:

The DC transmission has some positive features which are linking in AC transmission. These are mainly due to the fast controllability of power in DC lines through converter control. The advantages are

- Full control over power transmitted
- The ability to enhance transient and small signal stability in associated AC networks.
- Fast control to limit fault currents in DC lines. This makes it feasible to avoid DC breakers in two terminal DC links.

In addition to the above, the DC transmission overcomes some of the problems of AC transmission. These are described as follows.

Stability Limits:

The power transfer in AC lines is dependent on the angle difference $(\delta = \delta_1 - \delta_2)$ between the voltage phasors at the two ends

$$P = \frac{E.V}{X}\sin(\delta_1 - \delta_2)$$

The maximum power transfer is limited by the considerations of steady state and transient stability. The power carrying capability of an AC line as a function of distance as shown in Fig. 1.2.

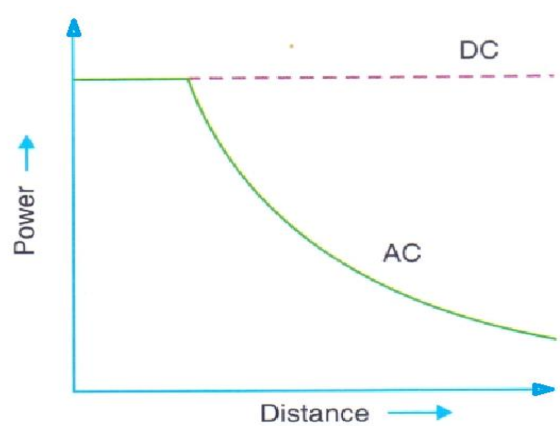


Fig. 1.2: Power Transfer Capability vs Distance

Voltage control:

The voltage control in AC lines is complicated by the line charging and inductive voltage drops. The voltage profile in an AC line is relatively flat for a fixed level of power transfer corresponding to surge impedance loading (SIL). The voltage profile varies with the line loading. For constant voltage at the line terminals, the midpoint voltage is reduced for line loading higher than SIL and increased for loadings less than SIL. This is shown in Fig. 1.3.

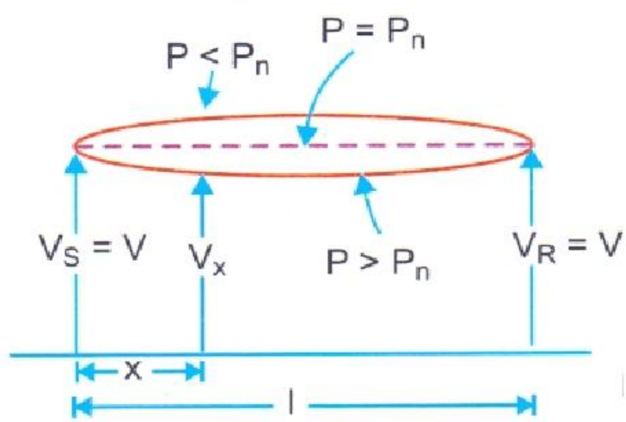


Fig. 1.3: Variation of voltage along the line

Here, x is distance from the sending end

l is length of the line

The maintenance of constant voltages at the two ends requires reactive power control from inductive to capacitive as the line loading is increased. The reactive power requirements increase with the increase in the line lengths. Although DC converter stations with line commutated converters require reactive power related to the line loadings, the line itself does not require reactive power.

Line Compensation:

The AC lines require series and shunt compensation in long distance transmission to overcome the problems of line charging and stability conditions. Series capacitors and shunt inductors are used for this purpose. The increase in power transfer and voltage control is also possible through the use of shunt connected Static Var Compensator (SVC).

In AC cable transmission, it is necessary to provide shunt compensation at regular intervals. This is a serious problem in underwater cables.

Reliability:

The reliability of DC transmission is quite good and comparable to that of AC systems. There are two measures of overall system reliability.

Energy availability: This is defined as

$$\%\ \text{Energy availability} = \left(1 - \frac{\text{equivalent outage time}}{\text{total time}}\right) * 100$$

Transient reliability: This is a factor specifying the performance of HVDC system during recordable faults on the associated AC syatems.

$$\%\ \text{Transient Reliability} = \frac{\text{No.of times HVDC system performed as designed}}{\text{No.of recordable AC faults}} * 100$$

1.2 Types of HVDC links

The DC links are classified into three types. They are

A. Monopolar DC Link
B. Bipolar DC Link
C. Homopolar DC Link

A) Monopolar:

The monopolar link has one conductor usually of negative polarity and use ground return as shown in Fig. 1.4 (a). Sometimes sea return or metallic return is also used.

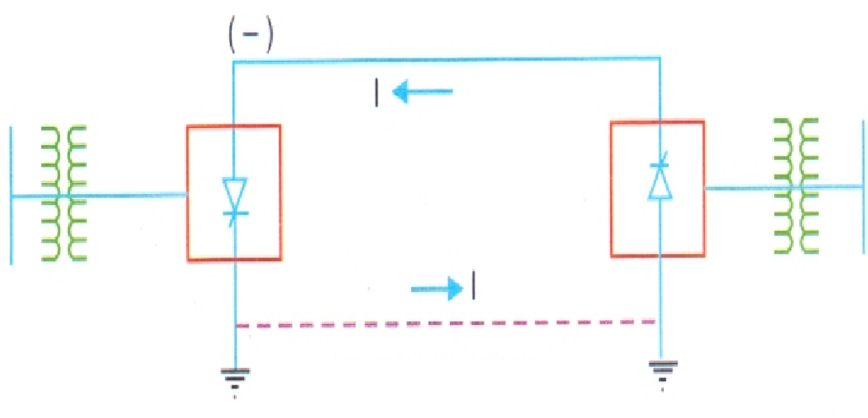


Fig. 1.4: a) Monopolar DC Link

B) Bipolar:

Bipolar link has two conductors, one positive and the other is negative as shown in Fig. 1.4 (b). Each may be bundled conductors in EHV lines. Each terminal has two sets of converters of identical ratings, connected in series on the DC side. The junction between the two sets of converters is grounded at one or both ends. Normally, both poles operate at equal currents and hence there is zero ground current flowing under these conditions.

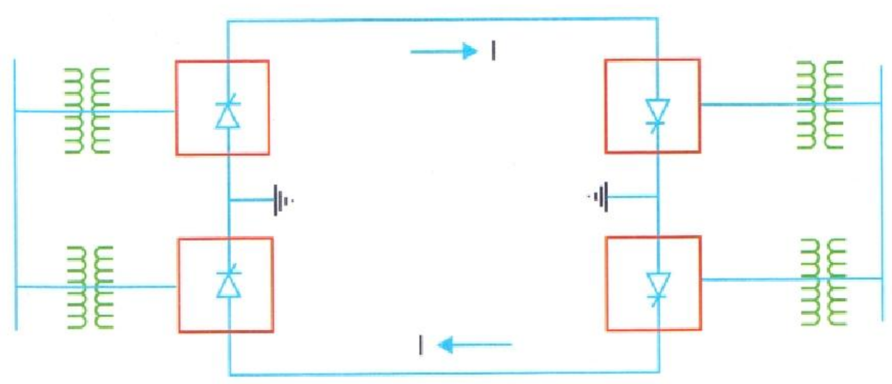


Fig. 1.4: b) Bipolar DC Link

C) Homopolar:

Homopolar link has two are more conductors, all having the same polarity (usually negative) and always operated with ground or metallic return.

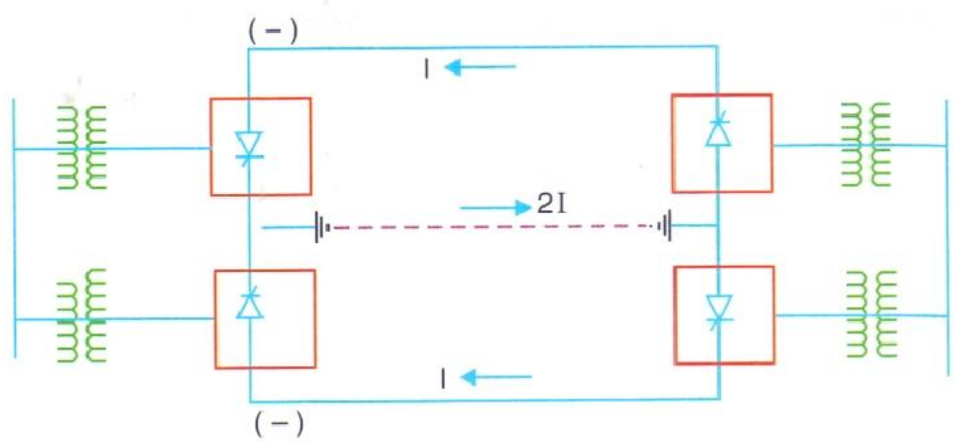


Fig. 1.4: c) Homopolar DC Link

Because of the desirability of operating of a DC link without ground return, Bipolar links are most commonly used. Homopolar link has the advantage of reduced insulation costs, but disadvantages of earth return compensate the advantages. Incidentally, the corona effect in a DC line is substantially less with negative polarity of the conductor when compared to the positive polarity.

The monopolar operation is used in the first stage of the development of a bipolar line, as the investments on converters can be postponed until the growth of load which requires bipolar operation at double the capacity of a monopolar link.

1.3 Converter Station

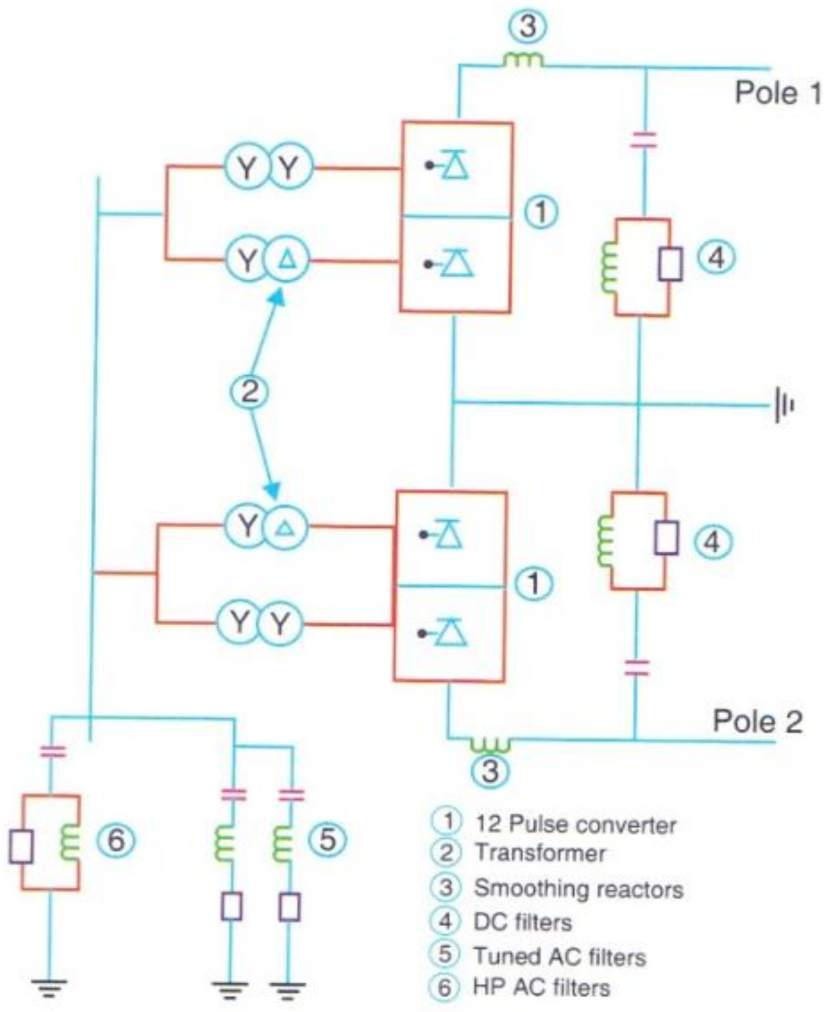


Fig. 1.5: Schematic Diagram of a Typical HVDC Converter Station

The major components of a HVDC transmission system are converter stations where conversions from AC to DC (Rectifier station) and from DC to AC (Inverter station) are performed. A point to point transmission requires two converter stations. The role of rectifier and inverter stations can be reversed by suitable power control.

A typical converter station with one 12-pulse converter unit per pole as shown in Fig.1.5. The various components of a converter station are

- 12-pulse converter
- Transformer
- Smooth Reactors
- DC switchgear
- Reactive power source
- DC Filters
- Tuned AC Filters
- HP AC Filters

Converter Unit:

This is usually consists of two 3-ø converter bridges connected in series to form a 12-pulse converter unit as shown in Fig. 1.6. The total numbers of valves in such a unit are twelve. The valves can be packaged as a single valve, double valve or quadric valve arrangements. Each valve is used to switch in a segment of an AC voltage waveform. The converter is fed by converter transformer connected in star/star arrangements.

The valves can be cooled by air, oil and water. Liquid cooling using deionized water is more efficient and results in the reduction of station losses. The ratings of a valve are limited more by the permissible short circuit currents than steady state load requirements. The design of valves based on the modular concept, where each module contains a limited number of series connected thyristor valves.

Valve firing signals are generated in the converter control at ground potential and are transmitted to each of the 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. The valves are protected by snubber circuits, protective firing and gapless surge arresters.

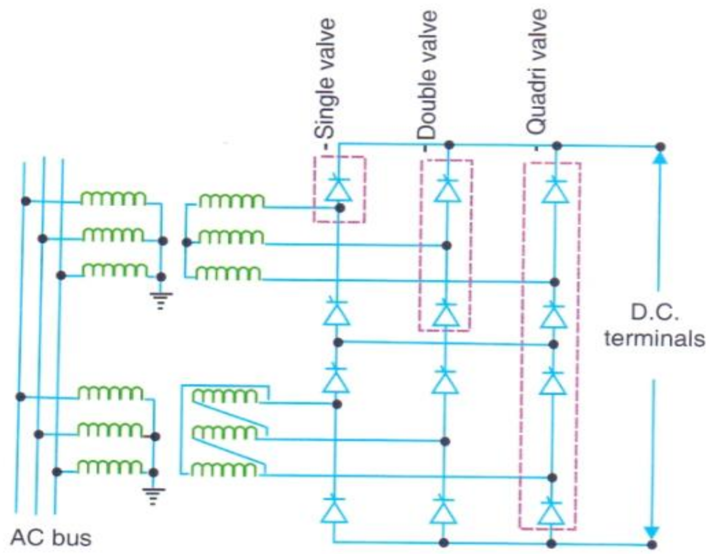


Fig. 1.6: A 12-pulse converter unit

Converter Transformer:

The converter transformer can have different configurations as

(i) 3-ø, 2-winding

(ii) 1-ø, 3-winding

(iii) 1-ø, 2-winding

The valve side windings are connected in star and delta with neutral grounded. On the AC side, the transformers are connected in parallel with neutral grounded. The leakage reactance of the transformer is chosen to limit the short circuit currents through any valve.

The converter transformers are designed to withstand DC voltage stress and increased eddy current losses due to harmonic currents. One problem that can arise is caused by the DC magnetization of the core due to un-symmetric firing of valves.

In back to back links, which are designed for low DC voltage levels, an extended delta configuration can result in identical transformers being used in 12-pulse converter units. This result in the reduction of the spare capacity required. However, the application is extended to delta transformers is limited.

Filters:

There are 3 types of filters used.

- AC Filters
- DC Filters
- High Frequency Filters

AC Filters:

These are passive circuits used to provide low impedance, shunt paths for AC harmonic currents. Both tuned and damped filter arrangements are used.

DC Filters:

These are similar to AC filters and are used for the filtering of DC harmonics.

High Frequency 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 high voltage DC bus connected between the DC filter and DC line and also on the neutral side.

Reactive power source:

Converter stations require reactive power supply that is dependent on the active power loading (about 50-60% of the active power). This is due to the fact that current drawn by a line commutated (current source) converter (LCC) can only lag the supply voltage. Fortunately, part of this reactive power requirement is provided by AC filters. In addition, shunt capacitors, synchronous condensers and static var systems (SVC or STATCOM) are used depending on the speed of control desired.

Smooth Reactor:

A sufficiently large series reactor is used on DC side to smooth DC current and also for protection. The reactor is designed as a linear reactor and is connected on the line side, neutral side or at intermediate location.

DC switchgear:

This is a usually a modified equipment used to interrupt small DC currents. DC breakers or metallic return transfer breakers (MRTB) are used, if required for interruption of rated load currents.

In addition to the above equipment, AC switchgear and associated equipment for protection and measurement are also part of the converter station. This includes DC current and voltage transducers.

1.5 Application of DC Transmission System Planning

The system planner must consider DC alternatives in transmission expansion. The factors to be considered are i) cost ii) technical performance iii) reliability.

Generally, the last two factors are considered as constraints to be met and the minimum cost option is selected among various alternatives that meet the specifications on technical performance and reliability.

For submarine, cable transmission and interconnecting two systems of differential nominal frequencies, the choice of DC is obvious. In other cases, the choice is to be based on detailed techno economic comparison.

The considerations in the planning for DC depend on the application. Two applications can be considered as representative. These are

1. Long Distance bulk power transmission
2. Interconnection between two adjacent systems

In the first application, the DC and AC alternatives for the same level of system security and reliability are likely to have the same power carrying capability. Thus, the cost comparisons would form the basis for the selection of the DC or AC alternative, if the requirements regarding technical performance are not critical.

In the second application, AC interconnection causes several problems in certain cases. For the same level of system security (and reliability), the capability of AC interconnection will be much more than that for DC. Thus, the choice for interconnection will be based on the following considerations.

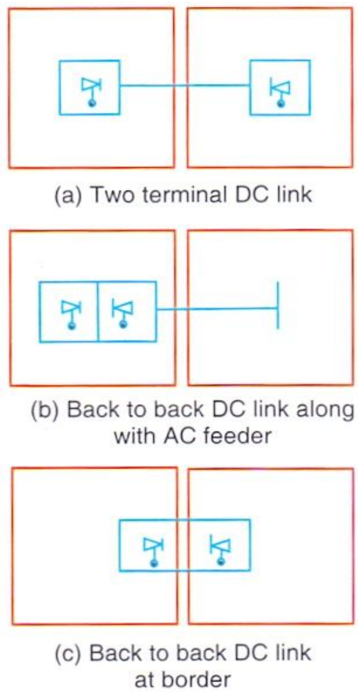


Fig. 1.7: Different configurations for asynchronous interconnection

1. Small fluctuations in the voltage and frequency do not affect the power flow which can be set at any desired value.
2. The system security can be enhanced by fast control of DC power.

Having settled on the DC link for interconnection, there are three possible configurations for interconnection. These are

1. A two terminal transmission where each terminal is located at a suitable place somewhere within the network and connected by a DC overhead line or cable.
2. A back to back HVDC station (also called HVDC coupling station) located somewhere within one of the network and an AC line from the other network to the common station.
3. A back to back station located close to the border between the two systems. This is a special case of the above.

In the choice between the first and second configuration, it is to be noted that converter costs are less for the common coupling station and the AC line costs are greater than the DC line costs. If the distances involved are less than 200 km, the second configuration is to be preferred. If the short circuit ratio (SCR) is acceptable then the third alternative will be the most economic.

The specifications and design of DC system require an understanding of the various interactions between the DC and AC systems. The interruption of power in a DC link can occur due to

a) DC line faults
b) AC system faults

The speed of recovery from transient DC line faults is of concern in maintaining the integrity of the overall system. The power flow and stability studies are used in this context. The recovery of DC link from AC system faults is more complex. The depression of AC voltage at the inverter bus can lead to commutation failure and loss of DC power. The DC power is ramped up on the clearing of the fault. Too fast an increase in DC power output can lead to reduction of AC voltage and failure of commutation. An optimum rate of increase in DC power can be determined by control strategy and system characteristics.

The following aspects also require a detailed study of the system interactions.

1. VAr requirements of converter stations and voltage stability.
2. Dynamic over voltages
3. Harmonic generation and design of filters
4. Damping of low frequency and sub-synchronous torsional oscillations
5. Carrier frequency interference caused by spiky currents in valves due to the discharge of stray capacitances and snubber circuits.

The converter control plays a major role in these interactions and control strategy should be such as to improve the overall system performance. Digital simulation and HVDC simulators are used for planning and design studies.

Choice of voltage level:

For long distances bulk power transmission, the voltage level is chosen to minimize the total costs for a given power level P. the total costs include investment (C_1) and cost of losses (C_2).

The investment costs per unit is given by

$$C_1 = A_0 + A_1 n V + A_2 n q \quad \ldots(1.1)$$

$Where\ V\ is\ the\ voltage\ level\ w.r.t.ground$

$n\ is\ the\ number\ of\ conductors$

q *is the total cross section of each conductor*

A_0 A_1 *and* A_2 *are constants*

The cost of losses per unit length is given by

$$C_2 = \frac{\left[n\left(\frac{P}{nV}\right)^2 \rho T L_p\right]}{q} \quad \ldots(1.2)$$

where, ρ *is the conductivity*

T *is the time operation in a year*

L *is Loss Load Factor*

p *is cost per unit energy*

C_2 can be simplified as

$$C_2 = \frac{\left[A_3\left(\frac{P}{V}\right)^2 \rho\right]}{nq} \quad \ldots(1.3)$$

Where, $A_3 = TL_p$

By minimizing the sum of C_2 and the third term in C_1, We have,

$$nq = \sqrt{A_3\rho/A_2}\ .\ (P/V) \quad \ldots(1.4)$$

$$J = \frac{P}{(nqV)} = \sqrt{A_2/(A_3\rho)} \quad \ldots(1.5)$$

Where, J is the current density.

The total cost can be written as

$$C = C_1 + C_2 = A_0 + A_1 n\,V + 2\sqrt{A_2 A_3 \rho}\ .\ (P/V) \quad \ldots(1.6)$$

The voltage level *V* is chosen to minimize *C*. The eq.(1.6) ignores the variation of terminal costs with the voltage. Fig. 1.8 shows the selection of optimum system voltage to minimize the sum of converter and line costs.

In case of back to back DC ties, the line costs are absent. Hence, the voltage level is chosen to minimize converter costs. This level is generally much lower than that in the presence of an overhead line.

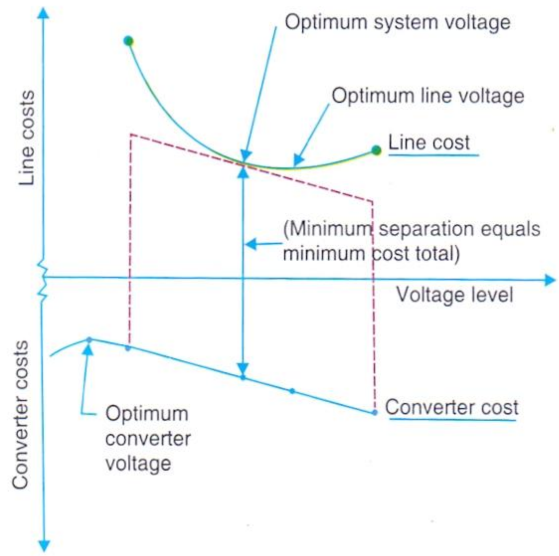


Fig. 1.8: selection of optimum voltage for a fixed power transfer

1.6 Modern Trends in HVDC Technology

The continuing technological developments in the areas of power semiconductor devices, digital electronics, adaptive control, DC transmission. The major contribution of these developments is to reduce the cost of converter stations while improving the reliability and performance.

1. Power Semiconductors and Valves:

The cost of the converters can come down, if the number of devices to be connected in series and parallel can be brought down. The size of the devices has gone up to 125 mm (in diameter) and there is no need for parallel connection. The increase in the current rating of the devices has made it possible to provide higher overload capability at reasonable costs and reduce the lower limits on transformer leakage impedance thereby improving the power factor. The voltage ratings are also on the increase. The development of direct light triggered thyristors (LTT) should also improve the reliability of converter station. The cost of the valves is also reduced by the application of zinc oxide gapless arresters and protective firing methods.

The power rating of thyristors is increased by better cooling methods. Deionized water cooling has now become a standard and results in reduced losses in cooling. The power rating of a 12-pulse converter unit has increased upto 3000 MW at 500 kV. Two phase flow using forced vaporization is also being investigated as a means of reducing thermal resistance between the heat sink and the ambient.

As forced commutated converters operating at high voltages are uneconomic, the development of devices that can be turned off by application of a gate signal would be desirable. Gate Turn Off (GTO) thyristors are already available at 6 kV and 4000A. However, the main disadvantage of GTO's is the large gate current needed to turn them off. MOS (metal oxide semiconductor) controlled thyristor or MCT appears to be a promising technology. An MCT would consists of an MOS integrated circuit created can be switched off by a small gate current. The turn - off time of MCT is also less than one third that of GTOs. However, MCTs are still in the early stages of development.

The cost of silicon used in the manufacture of power semiconductor devices can be brought down (by 15 to 20 percent) from the use of magnetic CZ (Czochralski) method, instead of the conventional FZ (float zone) method. Research is also underway in reducing this packaging cost of a device.

2. Converter Control:

The development of micro-computer based converter control equipment has now made it possible to design systems with completely redundant converter control with automatic transfer between systems in the case of a malfunction. Not only is the forced outage rate of control equipment reduced but it is also possible to perform scheduled preventive maintenance on the stand -by systems when the converter is in operation. The use of a mini-simulator will make it feasible to check vital control and protection functions.

The micro-computer based control also has the flexibility to try adaptive control algorithms or even the use of expert systems for fault diagnosis and protection.

3. DC Breakers:

With the development and testing of prototype DC breakers, it will be possible to go in for tapping an existing DC link or the development of new MTDC systems. Parallel, rather than series operation of converters is likely as it allows certain flexibility in the planned growth of system. The DC breaker rating as the control intervention is expected to limit the fault current.

The control and protection of MTDC systems is not a straightforward extenction of that used in the two terminal DC systems. The possibility of decentralized control necessitated by communication failure, the coordination of control and protection are some of the issues currently being studied.

4. Conversion of Existing AC Lines:

The constraints on RoW are forcing some utilities to look into the operation of converting existing AC circuits to DC in order to increase the power transfer limit. There could be some operational problems due to electromagnetic induction from AC circuits operating in the same RoW.

An experimental project of converting a single circuit of a double circuit 220kV line is currently under commissioning stage in 1989-90 in india.

5. Operation with Weak AC Systems:

The strength of AC systems connected to the terminals of a DC link is measured in terms of short circuit ratio (SCR) which is defined as

$$SCR = \frac{short\ circuit\ level\ at\ the\ converter\ bus}{Rated\ DC\ Power}$$

If SCR is less than 3, the AC System is said to be weak. The conventional constant extinction angle control may not be satisfactory with weak AC system. The recovery of inverters following the clearing of fault in the connected AC system can also be problematic.

Constant reactive current control or AC voltage control has been suggested to overcome some of the problems of weak AC systems. The use of fast reactive power control at the converter bus by applying static var systems is another alternative. Limiting dynamic over voltages through converter control during load rejection is becoming a standard practice.

The power modulation techniques used to improve dynamic stability of power systems will have to be modified in the presence of weak AC systems. Coordinated reactive and active power modulation has been suggested to overcome the problems of voltage variations that can limit the effective of power modulation.

6. Active DC filter:

In the nineties, a hybrid filter made up of an active filter in series with the passive passive filter has been developed to improve the filtering of harmonic currents flowing in the HVDC lines. The active filter can eliminate both characteristic and low frequency non-characteristic harmonics. Both Siemens and ABB have supplied active filters. In India, Chandrapur-Padghe HVDC project uses an active filter in each pole.

LINE COMMUTATED AND VOLTAGE SOURCE CONVERTERS

2

2.1 INTRODUCTION

In this chapter we will take up the study of converter circuits used in both Line Commutated (current source) Converters (LCC) and Voltage Source Converter (VSC) stations.

The basic configuration of a three phase converter (both LCC and VSC) is a bridge converter (also called Graetz Bridge) which can be fed from transformer windings connected in star or delta. The converter transformer feeding a Graetz bridge serves the objectives of providing

(*i*) galvanic separation between AC and DC sides

(*ii*) voltage transformation between AC and DC networks

(*iii*) adjustment of the applied AC voltage by On Load Tap Changer (OLTC).

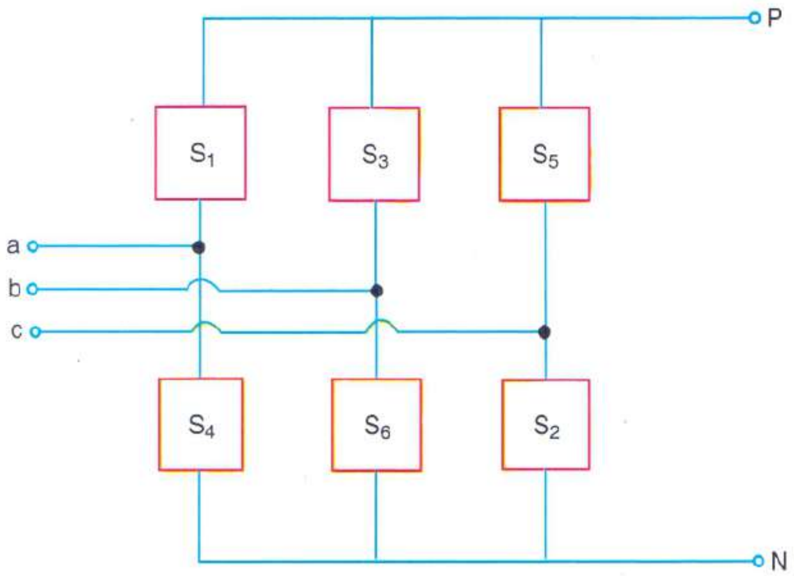


Fig. 2.1: A Graetz bridge

Note that an autotransformer can meet the last two objectives but cannot provide galvanic separation. The Graetz bridge circuit is shown in Fig. 2.1.

There are 6 switches numbered in the order in which they are turned on. In a LCC, the switches are made of thyristor valves, whereas in a VSC, they are made up of IGBT valves (a series connection of IGBT and anti-parallel connected diode). It is assumed that the phase sequence is 'abc'.

2.2 LINE COMMUTATED CONVERTER

2.2.1 Analysis of Graetz Bridge Neglecting Overlap

In a LCC, the Graetz Bridge is connected to three balanced sinusoidal voltage sources on the AC side and constant DC current source on the DC side as shown in Fig. 2.2.

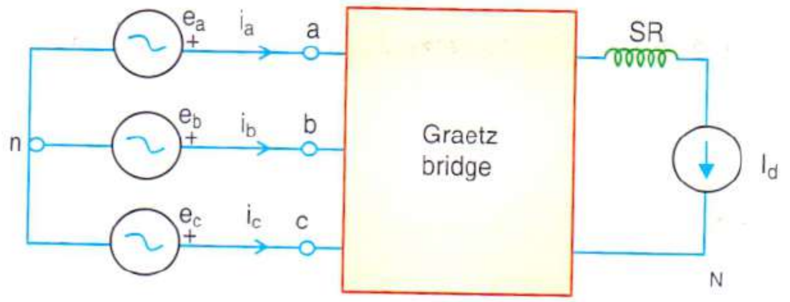


Fig. 2.2: Line commutated converter

Each of the switches S_1 to S_6 in the Graetz bridge are made of series connected thyristor devices (to provide the required voltage rating). The description of thyristor valve is given in Appendix A. The valve is denoted by the thyristor symbol shown in Fig. 2.3.

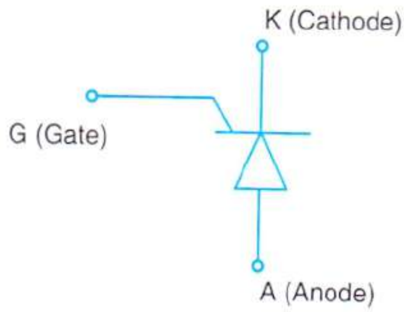


Fig. 2.3: Thyristor symbol

A thyristor valve (ideally) can be viewed as a switch which can be turned on when the terminal A (anode) is positive with respect to the terminal K (cathode) and a gate (firing) signal is provided at the terminal G. Once the thyristor switch is turned on, it can be turned off only when the current through it goes to zero and there is a minimum commutation margin (when the voltage across the thyristor is reverse biased – the voltage at terminal A is negative with respect to K). In modern high voltage thyristor device (rated at 8 kV and above), the margin required may be hundreds of microseconds. In general, when no gate pulse is present, the switch should withstand both positive and negative voltages. Neglecting losses in the thyristor valves, the voltage across the device is zero when it is turned on and the current through the devices is zero when it is not conducting. In other words, the valves can be viewed as ideal switches subject to the constraints mentioned above.

Note that the current can flow only in one direction through the thyristor switch (from anode to cathode) when it is on. Thus, the switches S_1, S_3 and S_5 carry current towards the terminal 'P' while the switches S_2, S_4 and S_6 carry current from the terminal 'N'. The direct current I_d has to flow through at least one valve in the upper group (S_1, S_3 and S_5) and one valve in the lower group (S_2, S_4 and S_6). Neglecting overlap between any two valves in a group, we can state that only one valve conducts in the upper group or lower group. Thus, in a cycle of the applied AC voltage, these are six equal intervals as shown in Fig. 2.4.

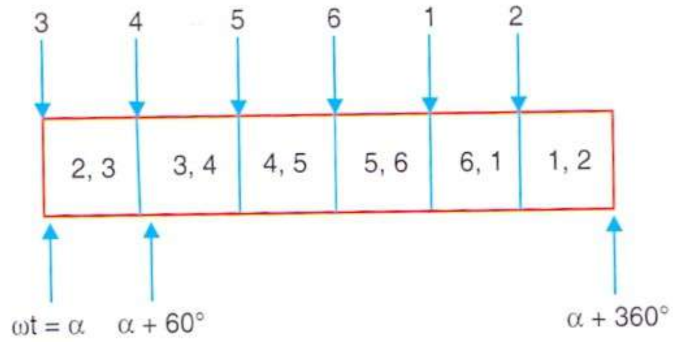


Fig. 2.4: Timing diagram

We assume that the switch S_3 is turned on at $\omega t = \alpha$. Prior to this, switches S_1 and S_2 are conducting and we also assume that the switch S_1 turns off as soon as the switch S_3 turns on (neglecting the overlap). Overlap between the switches S_1 and S_3 cannot be neglected if there are inductors in the circuit (due to leakage reactance of the converter transformer). We will analyze the converter circuit with overlap in the next chapter. Table 2.1 shows the DC voltages across the converter (V_{PN}) for each of the six intervals.

Table 2.1: DC Bus Voltage During Each Interval

Interval	I	II	III	IV	V	VI
Valves Conducting	2,3	3,4	4,5	5,6	6,1	1,2
Voltage (V_{PN})	e_{bc}	e_{ba}	e_{ca}	e_{cb}	e_{ab}	e_{ac}

Note that the voltage across the valve (switch S_3) is e_{ba} before it is fired (turned on). If we denote e_{ba}

$$e_{ba} = \sqrt{2}E_{LL} \sin \omega t \tag{2.1}$$

the voltage across the switch S_3 is negative when $\omega t < 0$ and becomes positive when $\omega t > 0$. For a thyristor valve, we can delay the turn on by a delay angle (α) by applying a gate pulse at $\omega t = \alpha$. It is assumed that the delay angle is constant in steady state.

The expression for e_{ba} given in Equation (2.1) implies that

$$\left.\begin{aligned} e_a(t) &= \sqrt{\frac{2}{3}}E_{LL} \sin(\omega t + 150^\circ) \\ e_b(t) &= \sqrt{\frac{2}{3}}E_{LL} \sin(\omega t + 30^\circ) \\ e_c(t) &= \sqrt{\frac{2}{3}}E_{LL} \sin(\omega t - 90^\circ) \end{aligned}\right\} \tag{2.2}$$

Note that we assume only positive sequence supply voltages. The expressions for the DC voltage (v_{PN}) and voltage across valve 1 for each interval, are shown in Table 2.2. The waveforms of these voltages for $\alpha = 0°$, $45°$, $90°$, $135°$ and $180°$ are shown in Fig. 2.5. The DC voltage waveform shows that there are six pulsations (cycles of ripple) per cycle of the AC voltage. The pulse number (which is defined as the ratio of the base frequency of the DC voltage ripple to the fundamental frequency of the AC voltage) for Graetz bridge is six. We also note that the average DC voltage reduces (and ripple content increases) as α is increased from 0° to 90°. On the other hand, as α is increased from 90° to 180°, the average DC voltage (in the negative direction) increases and the ripple content reduces.

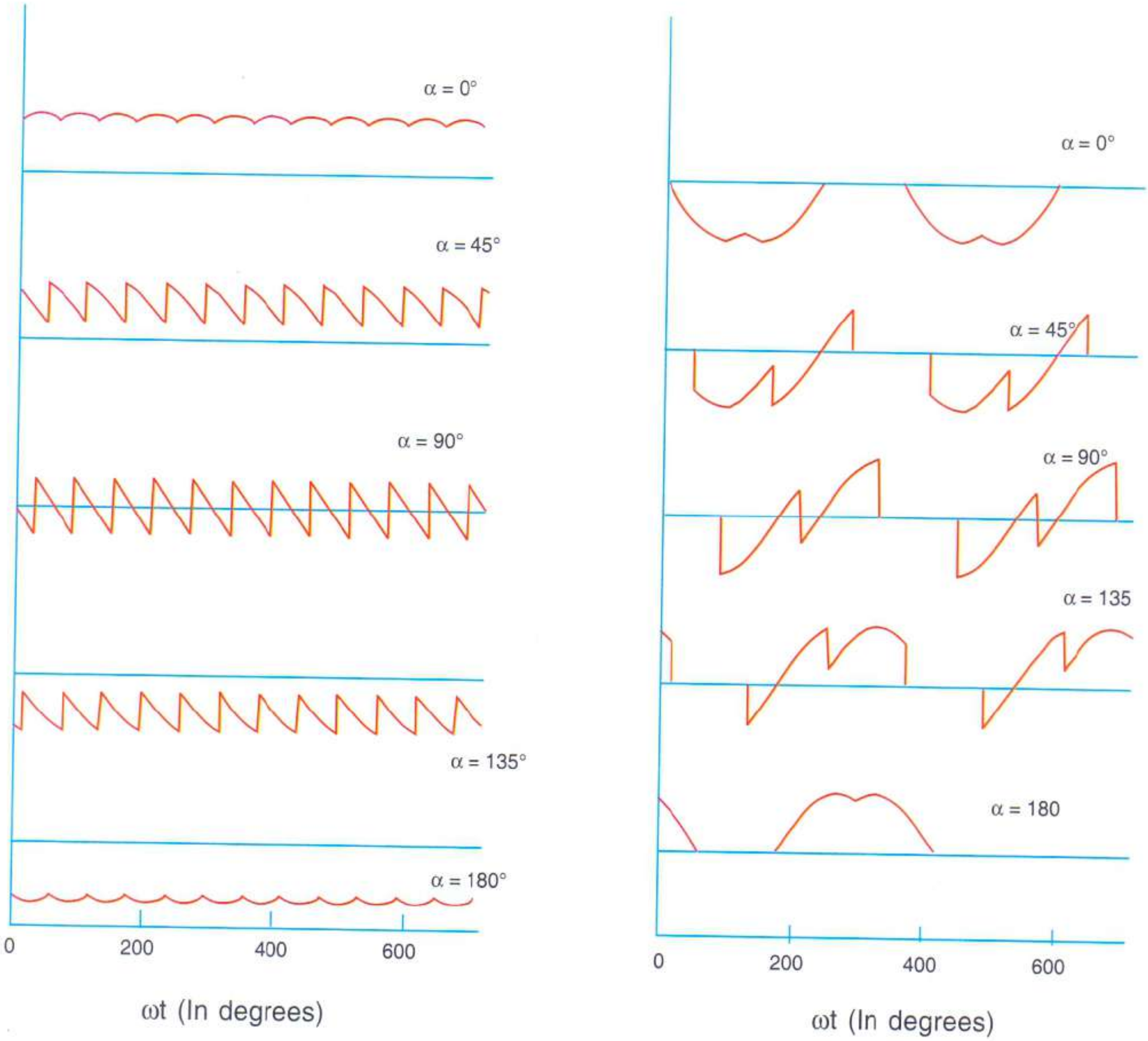


Fig. 2.5: DC and valve voltage waveforms

Table 2.2: DC and Valve Voltages

Interval No.	Conducting Valves	DC Voltage	Voltage Across Valve 1
I	2, 3	$\sqrt{2}E_{LL}\sin(\omega t+60^\circ)$	$e_{ab}=-\sqrt{2}E_{LL}\sin(\omega t)$
II	3, 4	$\sqrt{2}E_{LL}\sin(\omega t)$	$e_{ab}=-\sqrt{2}E_{LL}\sin(\omega t)$
III	4, 5	$\sqrt{2}E_{LL}\sin(\omega t-60^\circ)$	$e_{ac}=\sqrt{2}E_{LL}\sin(\omega t+120^\circ)$
IV	5, 6	$\sqrt{2}E_{LL}\sin(\omega t-120^\circ)$	$e_{ac}=\sqrt{2}E_{LL}\sin(\omega t+120^\circ)$
V	6, 1	$\sqrt{2}E_{LL}\sin(\omega t-180^\circ)$	0
VI	1, 2	$\sqrt{2}E_{LL}\sin(\omega t-240^\circ)$	0

The DC voltage waveform repeats for each interval and hence average DC voltage can be found by taking the average of v_{PN} over one interval during which, a pair of valves conduct. This is based on the assumption that the applied voltages are balanced, sinusoidal (defined by Eq. 2.2) and E_{LL} remains constant (over a cycle of the supply frequency). We also assume that the firing of the valves is equidistant (at the interval of 60°). This also implies that each valve conducts for 120° duration.

Let us consider the interval corresponding to the conduction of valves 2 and 3. At the beginning of the interval, valve 3 is fired and at the end of the interval, valve 2 turns off.

Assuming the firing of valve 3 is delayed by an angle α, (that is $\alpha°$ after the zero crossing of the commutation voltage for valve 3 –voltage e_{ba}), the instantaneous DC voltage v_d during the interval is given by

$$v_d = v_{PN} = e_b - e_c = e_{bc}, \quad \alpha \le \omega t \le \alpha + 60^\circ$$

If, $\quad e_{ba} = \sqrt{2}E_{LL}\sin\omega t$ from Eq. 2.1

then, $\quad e_{bc} = \sqrt{2}E_{LL}\sin(\omega t + 60^\circ)$

$$\text{Average DC voltage} = V_d = \frac{3}{\pi}\int_{\alpha}^{\alpha+60^\circ}\sqrt{2}E_{LL}\sin(\omega t+60^\circ)d\omega t$$

$$= \frac{3}{\pi}\sqrt{2}E_{LL}\left[\cos(\alpha+60^\circ)-\cos(\alpha+120^\circ)\right]$$

$$V_d = \frac{3\sqrt{2}}{\pi}E_{LL}\cos\alpha = 1.35E_{LL}\cos\alpha$$

$$= v_{do}\cos\alpha \tag{2.3}$$

Equation (2.3) indicates that for different values of α, V_d is variable. The range of α is 180° (from 0° to 180°) and correspondingly V_d can vary from V_{do} to $-V_{do}$. Thus the same converter can act as a rectifier or inverter depending upon whether the DC voltage is positive or negative.

It is to be noted that this is based on the assumption of continuous conduction of current by any valve over the 120° interval. Note that the DC current flow is unidirectional.

DC voltage harmonics

The DC voltage waveform contains a ripple whose fundamental frequency is six times the supply frequency. This can be analysed in Fourier series and contains harmonics of the order

$$h = 6n$$

where n is an integer.

The harmonic (rms value) in the DC voltage is given by

$$V_h = \frac{\sqrt{a_h^2 + b_h^2}}{\sqrt{2}}$$

where, $$a_h = \frac{1}{\pi}\int_{\alpha}^{\alpha+2\pi} V_d \cos(h\theta)d\theta,\ b_h = \frac{1}{\pi}\int_{\alpha}^{\alpha+2\pi} V_d \sin(h\theta)d\theta$$

It can be shown that the rms value of the h^{th} order harmonic in DC voltage is given by

$$V_h = V_{do}\frac{\sqrt{2}}{h^2-1}\left[1+(h^2-1)\sin^2\alpha\right]^{1/2} \tag{2.4}$$

Valve voltage waveform

Figure 2.5 also shows the valve voltage waveform which shows three voltage jumps that arise due to the commutation from one valve to the next in the same commutation group. The valve voltage waveform can be obtained from the expressions for a valve voltage given in Table 2.2 (Note that the waveform is similar for all valves). The voltage jumps are all of the same magnitude given by

$$V_j = \sqrt{2}E_{LL}\sin\alpha = (\pi/3)V_{do}\sin\alpha \tag{2.5}$$

These voltage jumps contribute to the voltage stresses (dv/dt) across the valve. Valve damping circuits are provided to relieve these stresses.

Although α can vary from 0° to 180°, the full range cannot be utilized. In order to ensure the firing of all the series connected thyristors, it is necessary to provide a minimum limit of α greater than zero, (say 5°). Also, in order to allow for the turn-off time of a valve, it is necessary to provide an upper limit less than 180°. The delay angle α is not allowed to go beyond $(180°-\gamma)$ where γ is called the extinction angle (sometimes also called the margin angle). The minimum value of the extinction angle is typically 10°, although in normal operation as an inverter, it is not allowed to go below 15° or 18°.

In the absence of forced commutation, α cannot be made negative.

AC current waveform

It is assumed that the direct current has no ripple (or harmonics). This is normally valid because of the smoothing reactor provided in series with the bridge circuit. The AC currents flowing through the valve (secondary) and primary windings of the converter transformer contain harmonics. The waveform of the current in a valve winding (say in phase b) is shown in Fig. 2.6.

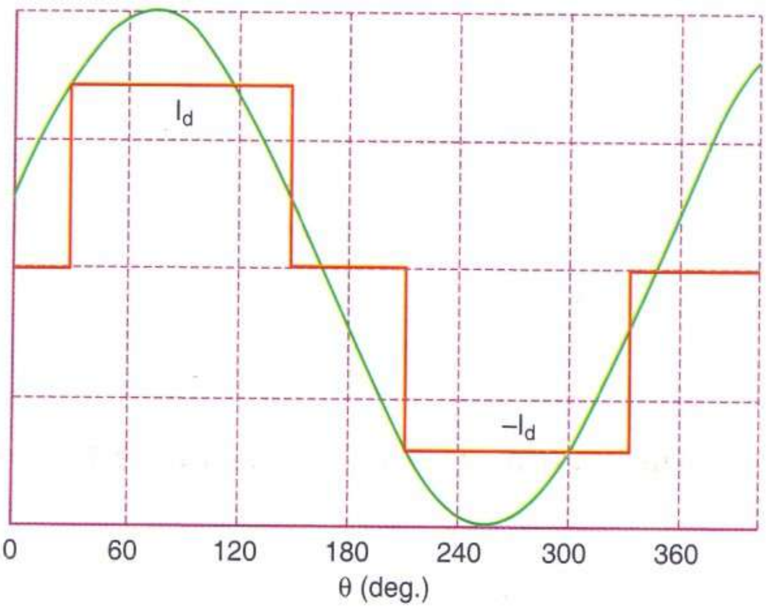


Fig. 2.6: Waveforms of i_b and e_b

The current in a valve winding is determined by the currents flowing in the valves connected to that winding. For example, the current in the phase 'b', i_b (see Fig. 2.2) is i_3 when valve 3 is conducting and $-i_6$ when valve 6 is conducting. Note that each valve conducts for 120° and valve 6 is turned on 180° after the firing of valve 3. Figure 2.6 also shows the applied voltage $e_b = \sqrt{2}E_{LL}\sin(\omega t + 30°)$. From equations (2.1) and (2.2), we have

$$\begin{aligned} i_b &= i_3 = I_d,\ \alpha \le \omega t \le \alpha + 120° \\ &= -i_6 = -I_d,\ \alpha + 180° \le \omega t \le \alpha + 300° \end{aligned}$$

Defining $\theta = \omega t - \alpha - 60°$, the rms value of the fundamental component is given by

$$I_1 = \frac{1}{\sqrt{2}}\frac{2}{\pi}\int_{-\frac{\pi}{3}}^{\frac{\pi}{3}} I_d \cos\theta \, d\theta = \frac{\sqrt{6}}{\pi} I_d \tag{2.6}$$

whereas rms value of the current is

$$I = \sqrt{\frac{2}{3}} I_d \tag{2.7}$$

The harmonics contained in the waveform are of the order given by

$$h = 6n \pm 1$$

where n is an integer. Thus, the order of AC harmonics are 5, 7, 11, 13 and higher. These are filtered out by using tuned filters for each one of the first four harmonics and a high pass filter for the rest. The rms value of the h^{th} harmonic is given by

$$I_h = \frac{I_1}{h} \tag{2.8}$$

The power factor

The AC power supplied to the converter is given by

$$P_{ac} = \sqrt{3}E_{LL}I_1\cos\phi$$

where ϕ is the (fundamental frequency) power factor.

The DC power must match the AC power ignoring the losses in the converter. Thus, we get

$$P_{ac} = P_{dc} = V_d I_d = \sqrt{3} E_{LL} I_1 \cos\phi \tag{2.9}$$

Substituting for V_d and I_1 from equations (2.3) and (2.6) in the above equation we obtain

$$\cos\phi = \cos\alpha \tag{2.10}$$

The reactive power requirements are increased as α is increased from 0 (or reduced from 180°). When $\alpha = 90°$, the power factor is zero and only reactive power is consumed.

2.2.2 Choice of Converter Configuration for any Pulse Number

We mentioned earlier that Graetz bridge is a six pulse converter for which the lowest DC voltage harmonic is sixth. Correspondingly, lowest AC current harmonics are 5th and 7th. To reduce the harmonic content in the AC current and DC voltage, it is desirable to use higher pulse numbers. In general, it can be stated that the characteristic harmonics (under ideal conditions) are of the order

$$h_{dc} = np,\ h_{ac} = np \pm 1 \tag{2.11}$$

where 'n' is an integer, 'p' is the pulse number.

There are several configurations for a converter of a specified pulse number. For $p = 6$, we have in addition to the Graetz bridge, six-phase diametral connection, cascade of three single phase full wave converters, cascade of two three phase converter, parallel connection with interphase transformer etc.

It is convenient to consider a 'p' pulse converter made up of series and parallel connections of a basic valve (commutation) group of 'q' valves or switches as shown in Fig. 2.7. Here, the switch is a thyristor valve whose firing can be delayed (from the instant when the valve voltage becomes positive). The voltage sources are actually obtained from the converter transformer windings. Neglecting overlap, only one valve conducts in a commutation group of 'q' valves.

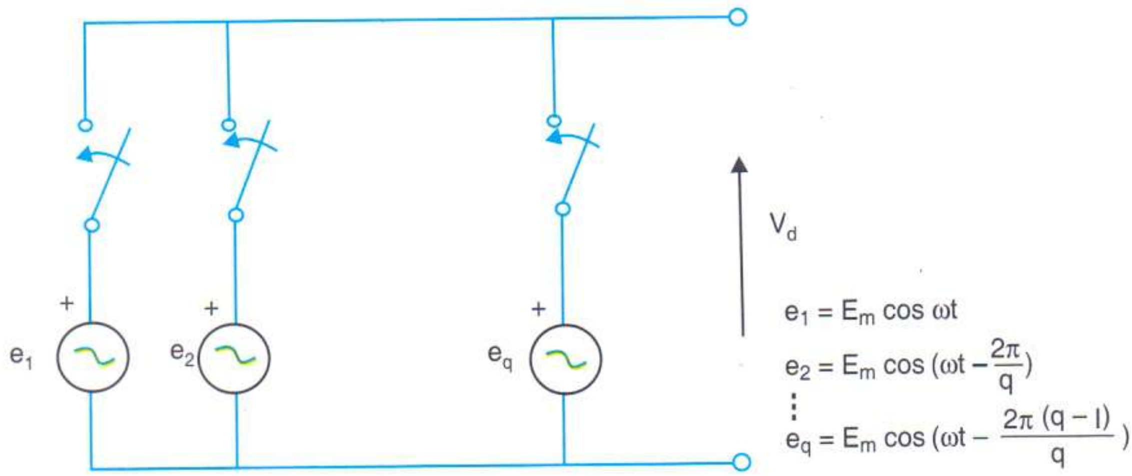


Fig. 2.7: A valve group with 'q' valves

If the converter is made up of a matrix of 's' valve groups in series and 'r' valve groups in parallel, then,

$$p = qrs \tag{2.12}$$

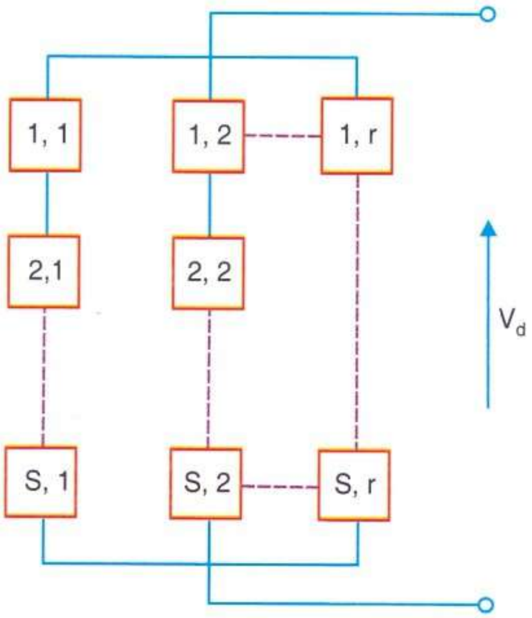


Fig. 2.8: Converter made up of series and parallel connection of communication groups

See Fig. 2.8 for the converter configuration. In general, there are '*p*' transformer windings. It will be shown later that sometimes windings can be combined (in particular for $q = 3$, $r = 1$, $s = 2$).

Valve rating

The valve voltage rating is specified in terms of peak inverse voltage (PIV) it has to withstand. The ratio of PIV to the average DC voltage is an index of the valve utilization. The average maximum DC voltage across the converter is given by

$$V_{do} = s\frac{q}{2\pi}\int_{\frac{-\pi}{q}}^{\frac{\pi}{q}} E_m \cos\omega t \, d\omega t$$

$$= \frac{sq}{\pi} E_m \sin\frac{\pi}{q} \qquad (2.13)$$

The peak inverse voltage (PIV) across a valve can be obtained as follows:

If '*q*' is even, then the maximum inverse voltage occurs when the valve with a phase displacement of π radian (180°) is conducting and this is given by

$$PIV = 2E_m$$

If '*q*' is odd, maximum inverse voltage occurs when the valve with a phase shift of $\pi \pm \pi/q$ is conducting. In this case,

$$PIV = 2E_m \cos\frac{\pi}{2q} \qquad (2.14)$$

The valve utilization factor is given by

$$\frac{PIV}{V_{do}} = \frac{2\pi}{sq \sin \frac{\pi}{q}} \text{ for } q \text{ even}$$

$$= \frac{\pi}{sq \sin \frac{\pi}{2q}} \text{ for } q \text{ odd}$$

Table 2.3 shows the valve utilization factor for different six pulse converter configurations. The best valve utilization is obtained for configurations 1 and 3.

Table 2.3: Valve Utilization Factor

Sl. No.	q	r	s	$\frac{PIV}{V_{do}}$
1	2	1	3	1.047
2	2	3	1	3.142
3	3	1	2	1.047
4	3	2	1	2.094
5	6	1	1	2.094

Transformer rating

The current rating of a valve (as well as transformer winding supplying it) is given by

$$I_v = \frac{I_d}{r\sqrt{q}} \tag{2.15}$$

where I_d is the DC current which is assumed to be a constant. The transformer rating on the valve side (in volt amperes) is given by

$$S_{tv} = p \frac{E_m}{\sqrt{2}} I_v$$

$$= p \frac{V_{do}\pi}{\sqrt{2} sq \sin \frac{\pi}{q}} \frac{I_d}{r\sqrt{q}}$$

$$= \frac{\pi}{\sqrt{2}} \frac{V_{do} I_d}{\sqrt{q} \sin \frac{\pi}{q}} \tag{2.16}$$

The transformer utilization factor $\frac{S_{tv}}{V_{do} I_d}$ is only a function of 'q'. The optimum value of q which results in maximum utilization is equal to 3. It is a fortunate coincidence that the AC power supply is 3 phase and the commutation group of 3 valves is easily arranged.

For $q = 3$,

$$\frac{S_{tv}}{V_{do} I_d} = 1.481 \tag{2.17}$$

The transformer utilization can be improved further if two valve groups can share a single transformer winding. In this case, the current (rms) rating of the winding can be increased by a factor of $\sqrt{2}$ while decreasing the number of windings by a factor of 2. For this case,

$$\frac{S_{tv}}{V_{do} I_d} = 1.047 \tag{2.18}$$

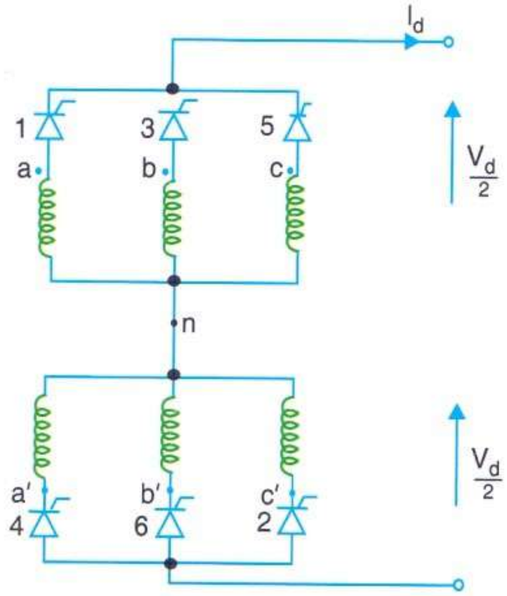


Fig. 2.9: Six pulse converter

For a 6 pulse converter, this can be easily arranged. The Graetz circuit shown in Fig. 2.1 is obtained when the two winding (shown in Fig. 2.9) are combined into one. This is possible since the terminals a and a' are at the same potential (with respect to the supply neutral point n). Thus, it is shown that both from valve and transformer utilization considerations, Graetz circuit is the best circuit for a six pulse converter.

Twelve pulse converter

In HVDC transmission, the series conduction of converter groups has been preferred because of the ease of control and protection as well as the requirements of high voltage rating. Thus a 12 pulse converter is obtained by the series connection of two bridges. The 30° phase displacement between the two sets of source voltages is achieved by the transformer connections, Y/Y for feeding one bridge and Y/Δ for feeding the second bridge.

The use of 12 pulse converter is preferable over the six pulse converter because of the reduced filtering requirements. However, increase in pulse number beyond 12 is not practical because the non-characteristic harmonics (which arise due to asymmetry in firing, imbalance in supply etc.) are not eliminated.

Example 1

For a 12 pulse converter with $q = 4$, $s = 3$, $r = 1$, calculate the maximum DC power and transformer ratings (valve windings) if PIV rating of the valve is V and the rms current rating is I. Rework the problem if $q = 3$, $s = 4$, $r = 1$.

Solution

With even value of q, $PIV = 2E_m$

$$V_{do} = \frac{q}{\pi} sE_m \sin\frac{\pi}{q} = \frac{12}{\pi}\frac{V}{2}\sin\frac{\pi}{4} = \frac{3\sqrt{2}}{\pi}V = 1.35V$$

$$I = \frac{I_d}{r\sqrt{q}} = \frac{I_d}{2} \Rightarrow I_d = 2I$$

$$P_{d\max} = V_{do}I_d = 2.70VI$$

$$S_{tv} = p\frac{E_m}{\sqrt{2}}I = \frac{12V}{2\sqrt{2}}I = 4.243VI$$

with $q = 3$, $s = 4$, $r = 1$

$$PIV = 2E_m \cos\frac{\pi}{2q} = 2E_m \cos 30^o = \sqrt{3}E_m$$

$$V_{do} = \frac{qs}{\pi}E_m \sin\frac{\pi}{q} = \frac{12}{\pi}\frac{V}{\sqrt{3}}\sin 60^o = \frac{6V}{\pi} = 1.91V$$

$$I_d = \sqrt{q}rI = \sqrt{3}I,\ P_{d\max} = V_{do}I_d = 1.91 \times \sqrt{3}VI = 3.31\,VI$$

$$S_{tv} = 12\frac{E_m}{\sqrt{2}}I = \frac{12VI}{\sqrt{6}} = 4.9VI$$

with only six windings on the valve side

$$S_{tv} = \frac{4.9}{\sqrt{2}}VI = 3.465VI$$

2.2.3 Analysis of a 12 Pulse Converters

To analyze the operation of a 12 pulse converter, consider the converter circuit diagram shown in Fig. 2.10. This shows two transformers with primary windings connected in star and connected to the common supply voltage. The currents supplied by the supply are the sums of the currents flowing in the two primary windings. Thus,

$$\left.\begin{aligned} i_A &= i_{AS} + i_{AD} \\ i_B &= i_{BS} + i_{BD} \\ i_C &= i_{CS} + i_{CD} \end{aligned}\right\} \tag{2.19}$$

In determining the voltage and current waveforms, there is no loss of generality, in assuming that the turns ratio of the transformer feeding bridge 1 as 1:1 and the turns ratio of the transformer feeding the second bridge as $1 : \sqrt{3}$. Assuming ideal transformers, we will get the identical magnitude of the AC voltages applied to the two bridges. Assuming e_A, e_B and e_C are defined as follows:

$$e_A = e_{aS} = \sqrt{\frac{2}{3}}E_{LL}\sin(\omega t + 150^\circ)$$

$$e_B = e_{bS} = \sqrt{\frac{2}{3}}E_{LL}\sin(\omega t + 30^\circ)$$

$$e_C = e_{cS} = \sqrt{\frac{2}{3}}E_{LL}\sin(\omega t - 90^\circ)$$

We get the line to line voltages applied to the second bridge as

$$e_{baD} = -\sqrt{3}e_A = \sqrt{2}E_{LL}\sin(\omega t - 30^\circ) \tag{2.20}$$

Comparing the above equation with the Eq. (2.1) we note that the voltages applied to bridge 2 lag the voltages applied to the bridge 1 by 30°. Assuming the identical delay angle for both the bridges, valve 3 in the second bridge will be fired 30° after firing the valve 3 in bridge 1.

Thus, in a 12 pulse converter, there are 12 intervals in a cycle, each of duration 30°. In each interval, 4 valves (2 each from the two bridges) conduct. Table 2.4 shows the conducting valves from each bridge for all the intervals (note that the subscripts S and D denote the bridges with star connected and delta connected windings respectively).

Table 2.4: Bridge Voltages in Each Interval

<table>
<tr><td>Interval</td><td>I (a)</td><td>I (b)</td><td>II (a)</td><td>II (b)</td><td>III (a)</td><td>III (b)</td><td>IV (a)</td><td>IV (b)</td><td>V (a)</td><td>V (b)</td><td>VI (a)</td><td>VI (b)</td></tr>
<tr><td>Conducting Valves Bridge 1</td><td colspan="2">2, 3</td><td colspan="2">3, 4</td><td colspan="2">4, 5</td><td colspan="2">5, 6</td><td colspan="2">6, 1</td><td colspan="2">1, 2</td></tr>
<tr><td>v_{d1}</td><td colspan="2">e_{bcS}</td><td colspan="2">e_{baS}</td><td colspan="2">e_{caS}</td><td colspan="2">e_{cbS}</td><td colspan="2">e_{abS}</td><td colspan="2">e_{acS}</td></tr>
<tr><td>Conducting Valves Bridge 2</td><td>1, 2</td><td colspan="2">2, 3</td><td colspan="2">3, 4</td><td colspan="2">4, 5</td><td colspan="2">5, 6</td><td colspan="2">6, 1</td><td>1, 2</td></tr>
<tr><td>v_{d2}</td><td>e_{acD}</td><td colspan="2">e_{bcD}</td><td colspan="2">e_{baD}</td><td colspan="2">e_{caD}</td><td colspan="2">e_{cbD}</td><td colspan="2">e_{abD}</td><td>e_{acD}</td></tr>
</table>

The DC voltage V_{dc} for a 12 pulse converter is the sum of the DC voltages for the individual bridges. Thus,

$$v_d = v_{d1} + v_{d2} \tag{2.21}$$

For the interval I(a), the R.H.S. can be expressed as (see Table 2.1)

$$\begin{aligned} v_d &= e_{bcS} + e_{acD} \\ &= \sqrt{2}E_{LL}\sin(\omega t + 60^\circ) - \sqrt{2}E_{LL}\sin(\omega t - 270^\circ) \\ &= \sqrt{2}E_{LL}\left[\sin(\omega t + 60^\circ) + \cos\omega t\right] \\ &= E_m\sin(\omega t + 75^\circ) \end{aligned} \tag{2.22}$$

where E_m is defined as

$$E_m = \sqrt{2}E_{LL}(2\cos 15^\circ) = \sqrt{2}E_{LL}(1.93185) \tag{2.23}$$

The average DC voltage (V_{dc}) is given by

$$V_{dc} = \frac{6}{\pi}\left[\int_{\alpha}^{\alpha+30^\circ} E_m \sin(\omega t + 75^\circ)\, d\omega t\right]$$
$$= 2V_{do}\cos\alpha \tag{2.24}$$

where $V_{do} = \frac{3}{\pi}\sqrt{2}E_{LL}$ (see Eq. 2.3)

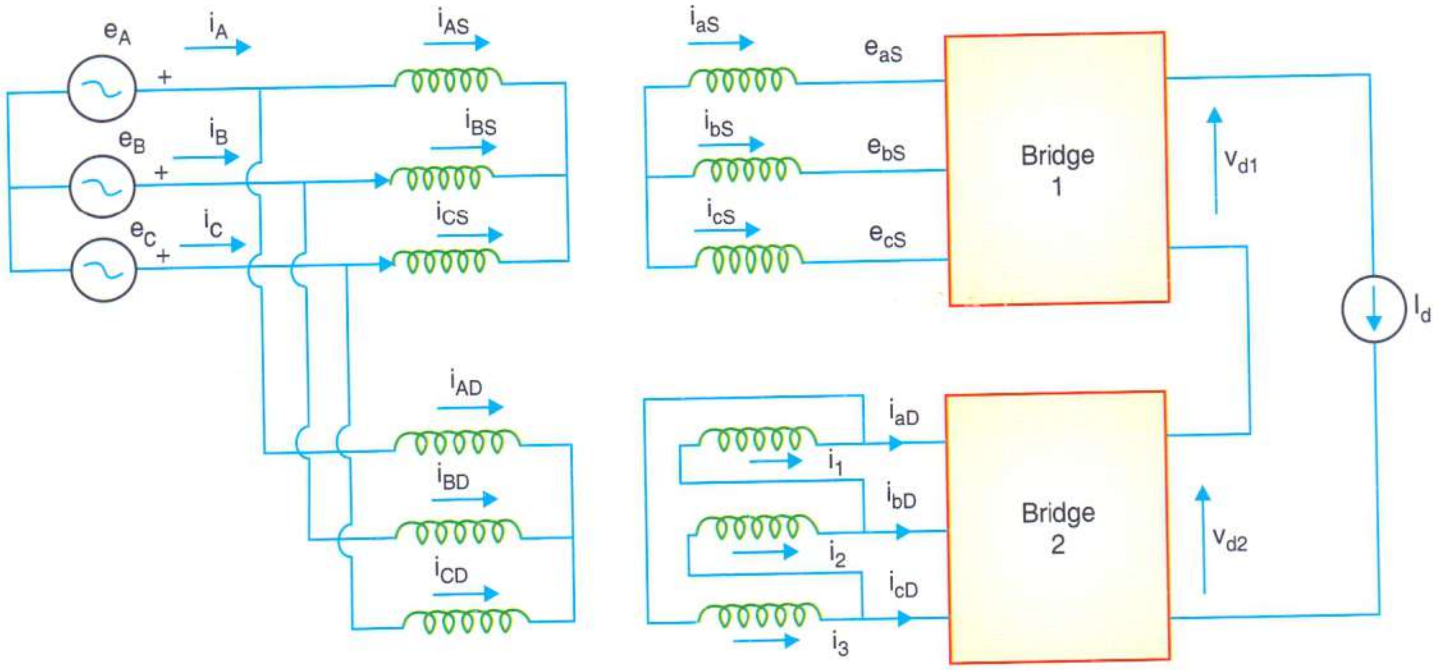


Fig. 2.10: A 12 pulse converter

The current i_{BD} flowing in the primary winding of the star/delta connected transformer (feeding bridge 2 in Fig. 2.10) is given by

$$i_{BD} = \sqrt{3}i_2 \tag{2.25}$$

where i_2 is the current flowing in the secondary winding that is coupled with phase B. Assuming that $i_1 + i_2 + i_3 = 0$, we can show that

$$i_{BD} = \frac{1}{\sqrt{3}}(i_{bD} - i_{cD}) \tag{2.26}$$

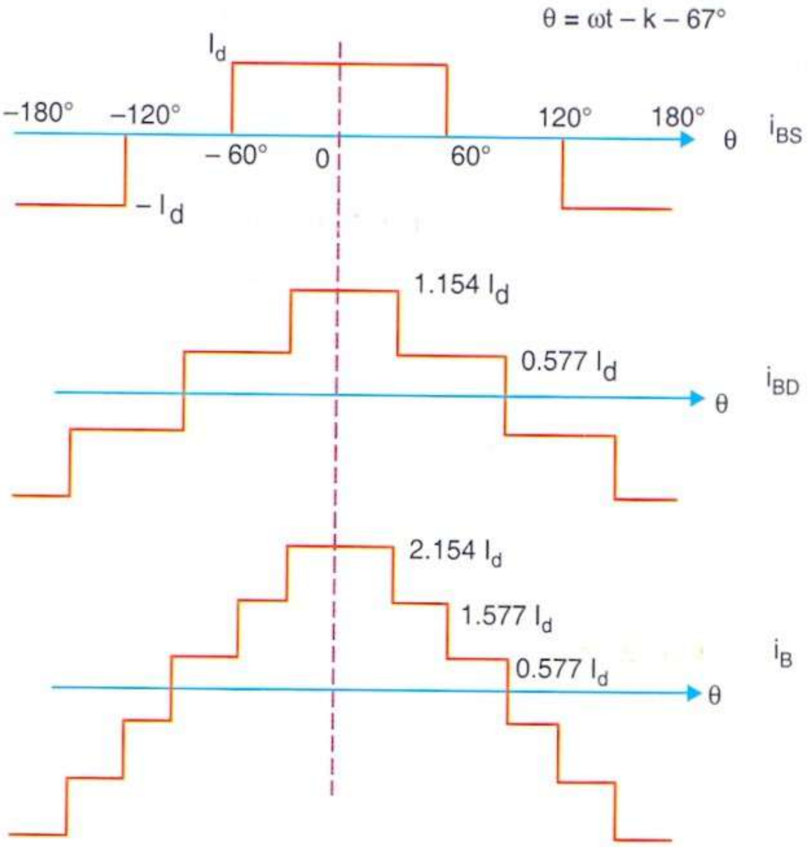


Fig. 2.11: Waveforms of current in 12 pulse converter

The waveform of i_{BS}, i_{BD} and i_B are shown in Fig. 2.11. In deriving the waveform of i_{BD}, it is to be noted that i_{bD} lags i_{bS} by 30° and i_{cD} lags i_{bD} by 120°.

It can be shown that the rms value of the fundamental component of the supply current in a 12 pulse converter is given by

$$I_1 = 2.\frac{\sqrt{6}}{\pi} I_d \tag{2.27}$$

The harmonic current I_h is given by

$$I_h = \frac{I_1}{h}$$

where $h = 12n \pm 1$, n is an integer

$= 6m \pm 1$, m is an even integer.

In comparing with the harmonic currents of a six pulse converter, it is obvious that the fifth and seventh harmonics flowing in the two transformers cancel each other. This can be generalized to the case whenever m is an odd integer.

2.2.4 Effect of Finite Smoothing Reactor

In the previous sections, it was assumed that I_d is constant which implies that the reactance of the smoothing reactor is very high (theoretically infinite). If the smoothing reactor is finite, then we cannot neglect the ripple in the DC current. The average DC current (I_d) should be above a minimum value, (corresponding to the peak value of the ripple) such that the current

3.7 ANALYSIS OF A VOLTAGE SOURCE CONVERTER

A VSC based HVDC converter is similar to a STATic COMpensator (STATCOM), a shunt connected FACTS controller. Here, we consider three phase VSC using six switches made up of six GTO or IGBTs with antiparallel diodes connected as a six pulse, Graetz bridge (see Fig. 3.20). Following assumptions are made in the analysis.

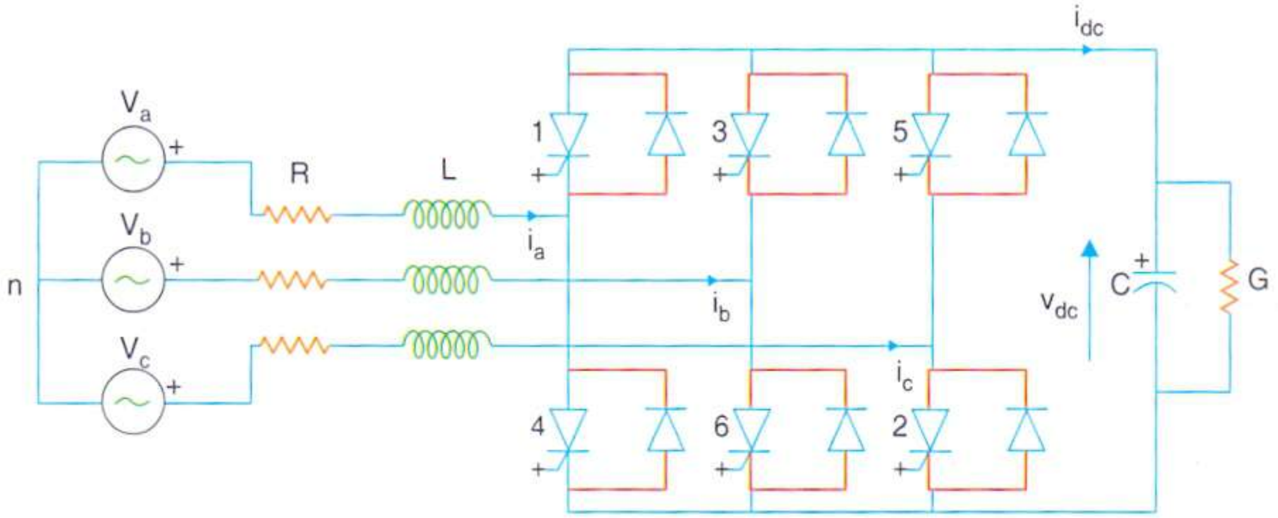


Fig. 3.20: A six pulse VSC circuit

CONVERTER AND HVDC SYSTEM CONTROL

4

$\left(\frac{3\sqrt{2}}{\pi}\right) n_b E_{vr} \cos\alpha_r$ $\left(\frac{3\sqrt{2}}{\pi}\right) n_b E_{vi} \cos$

4.1 GENERAL

One of the major advantages of a HVDC link is the rapid controllability of transmitted power through the control of firing angles of the converters. Modern converter controls are not only fast, but also very reliable and they are used for the protection against line and converter faults.

The system control in a HVDC link tends to be quite complex with a hierarchy of controllers. High speed microprocessors are being used for many of the control functions including monitoring and supervisory control.

In this chapter, the basic principles and functions of the system and converter control are presented.

LCC based HVDC transmission systems using thyristor valves is considered first. At the end, the control in a VSC based HVDC link is described.

4.2 PRINCIPLES OF DC LINK CONTROL

In what follows, a two terminal DC link is assumed. The control in multiterminal DC systems is similar and is described in a separate chapter.

The control of power in a DC link can be achieved through the control of current or voltage. From minimization of loss considerations, it is important to maintain constant voltage in the link and adjust the current to meet the required power. This strategy is also helpful for voltage regulation in the system from the considerations of the optimal utilization of the insulation. It is to be noted that the voltage drop along a DC line is small compared to the AC line, mainly because of the absence of the reactive voltage drop.

Consider the steady state equivalent circuit of a two terminal DC link shown in Fig. 4.1(a). This is based on the assumption that all the series connected bridges in both poles of a converter station are identical and have same delay angles. Also, the numbers of series connected bridges (n_b) in both stations (rectifier and inverter) are the same. The voltage sources E_{dr} and E_{di} are defined by

$$E_{dr} = (3\sqrt{2}/\pi) n_b E_{vr} \cos\alpha_r \tag{4.1}$$

$$E_{di} = (3\sqrt{2}/\pi) n_b E_{vi} \cos\gamma_i \tag{4.2}$$

where E_{vr} and E_{vi} are the line to line voltages in the valve side windings of the rectifier and inverter transformer respectively. From Fig. 4.1(b), these voltages can be obtained as

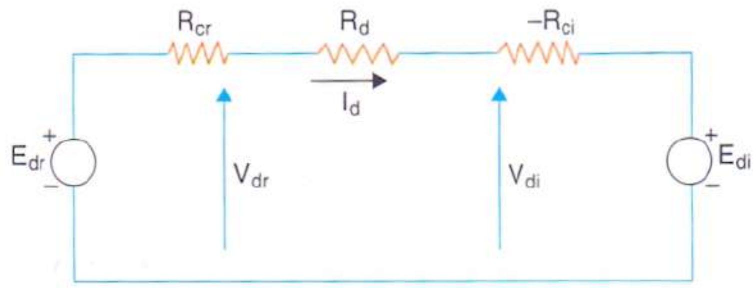


Fig. 4.1: (a) Steady-state equivalent circuit of a 2-terminal DC link

Fig. 4.1: (b) Schematic of a DC link showing transformer ratios

$$E_{vr} = \frac{N_{sr}E_r}{N_{pr}T_r}, E_{vi} = \frac{N_{si}E_i}{N_{pi}T_i} \tag{4.3}$$

where E_r and E_i are the AC (line to line) voltages of the converter buses on the rectifier and the inverter side. T_r and T_i are the off-nominal tap ratios on the rectifier and inverter side.

Combining (4.1), (4.2) and (4.3), we can write

$$E_{dr} = (A_rE_r/T_r)\cos\alpha_r \tag{4.4}$$

$$E_{di} = (A_iE_i/T_i)\cos\gamma_i \tag{4.5}$$

where A_r and A_i are constants.

It is to be noted E_{di} is defined in terms of the extinction angle γ_i rather than β_i (the angle of advance in the inverter). E_{di} can also be written as

$$E_{di} = (A_iE_i/T_i)\cos\beta_i + 2R_{ci}I_d \tag{4.6}$$

where

$$R_{ci} = (3n_b/\pi)X_{ci}, R_{cr} = (3n_b/\pi)X_{cr} \tag{4.7}$$

X_{cr} and X_{ci} are the leakage reactances of the converter transformers in the rectifier and inverter station respectively.

The steady-state current I_d in the DC link is obtained as

$$I_d = \frac{(E_{dr} - E_{di})}{R_{cr} + R_d - R_{ci}} \tag{4.8}$$

Substituting (4.4) and (4.5) in (4.8), we get,

$$I_d = \frac{(A_rE_r/T_r)\cos\alpha_r - (A_iE_i/T_i)\cos\gamma_i}{R_{cr} + R_d - R_{ci}} \tag{4.9}$$

It is to be noted that the control variables are T_r, T_i and α_r, β_i. However, for maintaining safe commutation margin it is convenient to consider γ_i as control variable instead of β_i.

As the denominator in equation (4.9) is small, even small changes in the voltage magnitudes E_r or E_i can result in large changes in the DC current, if the control variables are held constant. As the voltage changes can be sudden it is obvious that manual control of converter angles is not feasible. Hence direct and fast control of current by varying α_r, and/or γ_i in response to a feedback signal is essential. The direct and fast control over the current is also desirable from the viewpoint of limiting the overcurrents in thyristor valves which have limited short term overload capability. It is to be noted that although current and power can be controlled by changing transformer taps T_r and T_i, this can be achieved only by slow control of mechanical switches.

As mentioned in the beginning, it is desirable to control the current and regulate the voltage simultaneously in the link. The question that can be posed now is, which terminal should be assigned the task of current control, while the other terminal regulates the DC voltage? From considerations given below, it is desirable to have current control at the rectifier station under normal conditions.

1. The increase of power in the link is achieved by reducing α_r which improves the power factor at the rectifier, for higher loadings and minimizes the reactive power consumption.
2. The inverter can now be operated at minimum γ thereby minimizing the reactive power consumption at the inverter also.

It is to be noted that the current control at the inverter worsens power factor at the higher loadings as γ has to be increased. Increased γ also implies higher losses in the valve snubber circuits.

3. The operation at minimum extinction angle at the inverter and current control at the rectifier results in better voltage regulation than the operation with minimum delay angle at the rectifier and current control at the inverter (This is valid for similar values of R_{cr} and R_{ci}).
4. The currents during line faults are automatically limited with rectifier station in current control.

While there is a need to maintain a minimum extinction angle of the inverter to avoid commutation failure, it is economical to operate the inverter at constant extinction angle (CEA) which is slightly above the absolute minimum required for the commutation margin. This results in reduced costs of the inverter stations, reduced converter losses and reactive power consumption. However, the main drawback of CEA control is the negative resistance characteristic of the converter which makes it difficult to operate stably when the AC system is weak (low short circuit ratios). Constant DC voltage (CDCV) control or constant AC voltage (CACV) control are the alternatives that could be used at the inverter.

Under normal conditions, the rectifier operates at constant current (CC) control and inverter at the CEA control. Under conditions of reduced AC voltage at the rectifier it is necessary to shift the current control to the inverter to avoid run down of the DC link when the rectifier control hits the minimum α limit. This implies that current controller must also be provided at the inverter in addition to the CEA controller. A smooth transition from CEA to CC takes place whenever the link current starts falling. To avoid the clash of two current controllers, the current reference at the inverter is kept below that at the rectifier by an amount called the 'current margin'. This is typically about 10% of the rated current.

The power reversal in the link can take place by the reversal of the DC voltage. This is done easily by increasing the delay angle at the station initially operating as the rectifier, while reducing the delay angle at the station initially operating as the inverter. Thus, it is necessary to provide both CEA and CC controllers at both terminals. The on-load tap changer control at the inverter is used mainly to maintain a constant DC voltage (when the inverter is in CEA control). The tap changer control at the rectifier is designed to maintain the delay angle within certain limits (say 10° to 20°) in order to maintain certain voltage margin for the purposes of current control. A voltage margin of 3% is generally considered to be adequate to meet any sudden demand for the increase in the link current.

The feedback control of power in a DC link is not desirable for the following reasons:

1. At low DC voltages, the current required is excessive to maintain the required level of power. This can be counter productive because of the excessive requirements on the reactive power, which depresses the voltage further.
2. The constant power characteristic contributes to negative damping and degrades dynamic stability.

4.3 CONVERTER CONTROL CHARACTERISTICS

4.3.1 Basic Characteristics

The basic principles of the control of DC link have been stated in the previous section. The control characteristics of both stations are illustrated in Fig. 4.2 which shows the DC voltage at the station II versus DC current. Each station characteristic has three parts as given below

Station I	Station II	Type
ab	*hg*	minimum (α)
bc	*gf*	constant current
cd	*fe*	minimum (γ)

The intersection of the two characteristics (point A) determines the mode of operation—Station I operating as rectifier with constant current control and station II operating at constant (minimum) extinction angle.

There can be three modes of operation of the link (for the same direction of power flow) depending on the ceiling voltage of the rectifier which determines the point of intersection of the two characteristics. These are defined below:

1. CC at rectifier and CEA at inverter (operating point A) which is the normal mode of operation.
2. With slight dip in the AC voltage, the point of intersection drifts to C which implies minimum α at rectifier and minimum γ at the inverter.
3. With lower AC voltage at the rectifier, the mode of operation shifts to point B which implies CC at the inverter with minimum α at the rectifier.

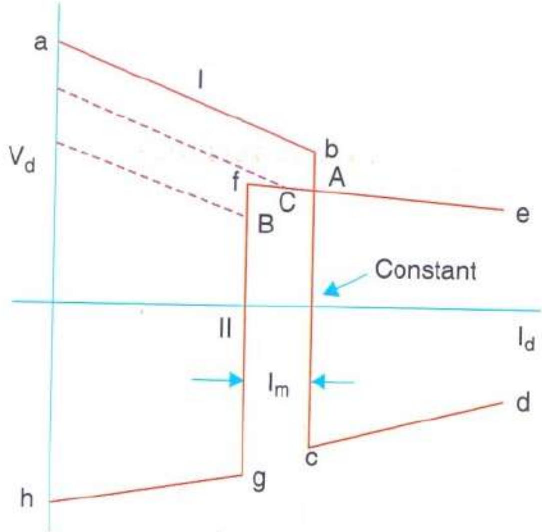


Fig. 4.2: Converter controller characteristic

The characteristic ab has generally more negative slope than characteristic fe for similar values of R_{cr} and R_{ci}. This is because of the fact that the slope of ab is due to the combined resistance $(R_d + R_{cr})$ while the slope of fe is due to R_{ci}. However, for low SCR at the inverter, the slope of fe could be more negative than that of ab.

Figure 4.3 shows the control characteristics for negative current margin I_m (or where the current reference of station II is larger than that at station I). The operating point shifts now to 'D' which implies power reversal with station I (now acting as inverter) operating with minimum CEA control while station II operating with CC control.

This shows the importance of maintaining the correct sign of the current margin to avoid inadvertent power reversal. The maintenance of proper current margin requires adequate telecommunication channel for rapid transmission of the current or power order from one station (Master) to the other (Slave) station.

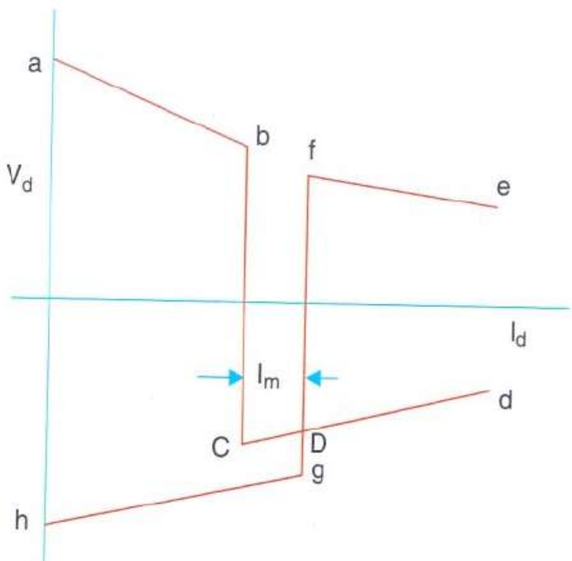


Fig. 4.3: Control characteristic for negative current margin

In order to prevent inadvertent power reversal in the link due to failure of telecommunication channels, it is necessary to prevent the inverter from transition to the rectifier operation. This can be easily done by putting minimum limits on the delay angle of the inverter (100° to 110°).

4.3.2 Modification of the Control Characteristics

The previous discussion has outlined the need to restrict the control region to the first quadrant of the $V_d - I_d$ plane to avoid unwanted reversal of power. In addition, there are two other requirements which necessitate the modification of the control characteristics.

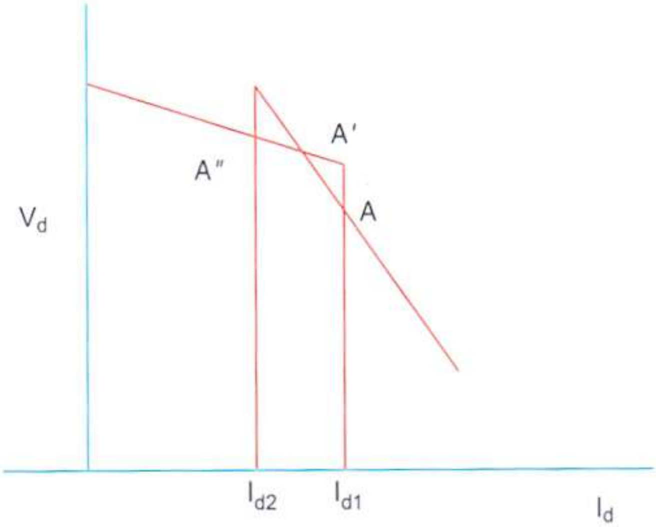


Fig. 4.4: Illustration of 3-point instability

Mode stabilization

The slope of *ab* and *fe* are nearly equal which can lead to poor definition of the intersection of point '*C*'. Further, if the slope of *fe* exceeds that of *ab* (see Fig. 4.4), there will be three possible operating points *A*, *A'* and *A"*. This implies instability of the control which will result in hunting between different modes of operation. To eliminate this problem, the inverter characteristics are modified and given a positive slope when the current is between I_{d1} and I_{d2} [see Fig. 4.5 (*a*)]. This is achieved by current error dependent γ control. Alternate solution is to modify the inverter control to maintain a constant DC voltage with back-up control of minimum CEA [see Fig. 4.5 (*b*)]. This requires the normal operating value of extinction angle to be greater than the minimum value.

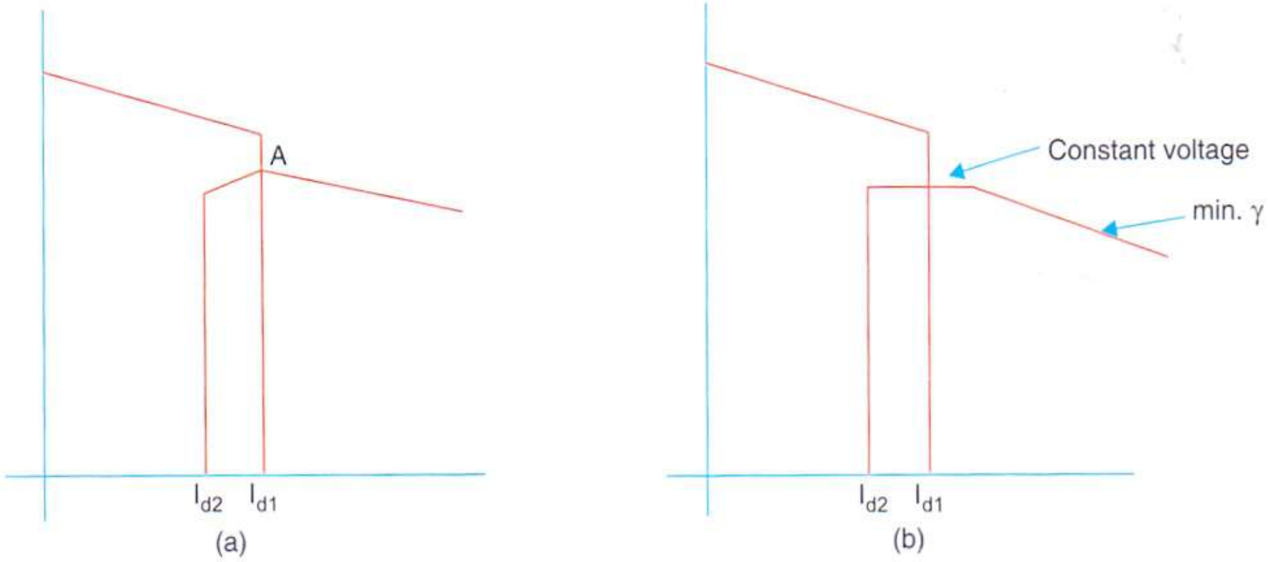


Fig. 4.5: Modification of inverter characteristics

4.4 SYSTEM CONTROL HIERARCHY

The control functions required for the HVDC link are performed using the hierarchical control structure shown in Fig. 4.7. The master controller for a bipole is located at one of the terminals and is provided with the power order (P_{ref}) from the system controller (from energy control centre). It also has other information such as AC voltage at the converter bus, DC voltage, etc. The master controller transmits the current order (I_{ref}) to the pole units which in turn provide a firing angle order to the individual valve groups (converters). The valve group or converter control also oversees valve monitoring and firing logic through the optical interface. It also includes bypass pair selection logic, commutation failure protection, tap changer control, converter start/stop sequences, margin switching and valve protection circuits.

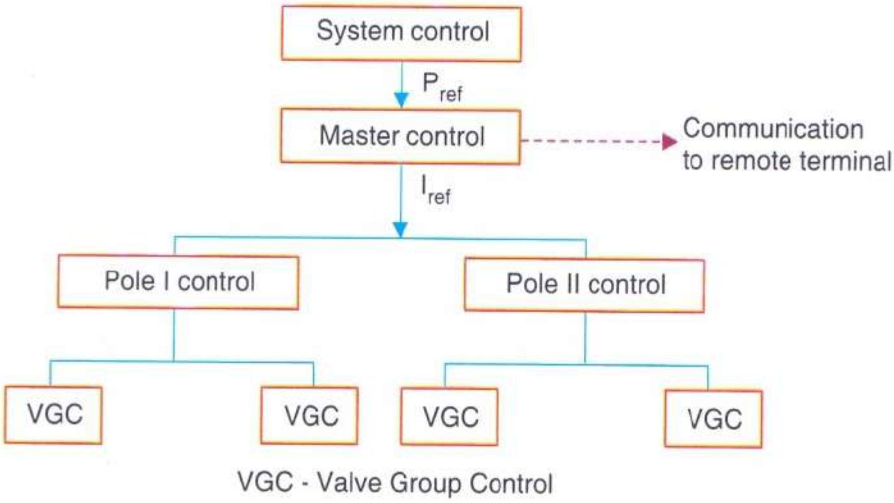


Fig. 4.7: Hierarchical control structure for a DC link

The pole control also incorporates pole protection, DC line protection and optional converter paralleling and deparalleling sequences. The master controller which oversees the complete bipole includes the functions of frequency control, power modulation, AC voltage and reactive power control and torsional frequency damping control. It also oversees pole paralleling sequences, transient pole current increases for outage of a pole, balancing of pole currents and communication of the power/current order to the remote terminal.

The block diagram of the pole and converter controls is shown in Fig. 4.8. This shows the basic control functions. The current or extinction angle controller generates a control signal V_c which is related to the firing angle required. The firing angle controller generates gate pulses in response to the control signal V_c. The selector picks the smaller of the α determined by the current and CEA controllers. In digitally based firing-pulse controller, the output of the primary regulator can be firing angle reference which is used as input to the continuously acting synchronization control with feedback from the measurement of the firing angle and the system frequency [21].

4.5 FIRING ANGLE CONTROL

The operation of CC and CEA controllers is closely linked with the method of generation of gate pulses for the valves in a converter. The following are the two basic requirements for the firing pulse generation of HVDC valves.

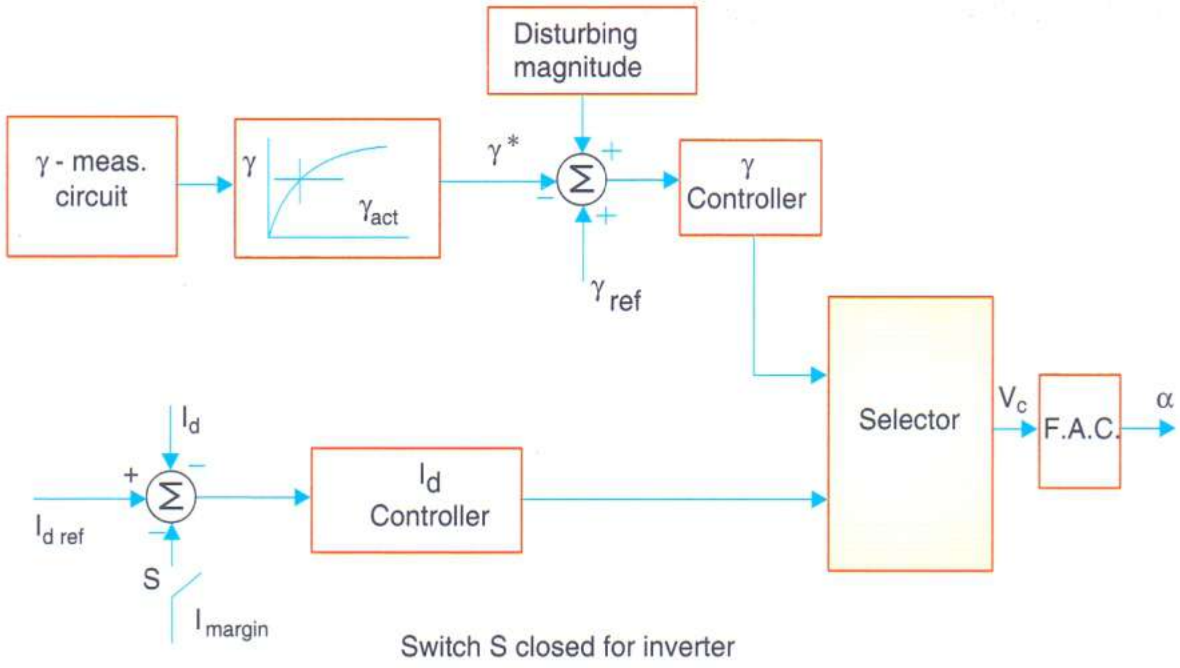


Fig. 4.8: Block diagram of pole and converter controllers

1. The firing instant for all the valves are determined at ground potential and the firing signals sent to individual thyristors by light signals through fiber-optic cables. The required gate power is made available at the potential of individual thyristor for electrically triggered thyristor (ETT) valves. However, for light triggered thyristor (LTT) valves, the light signal can be used to directly fire individual thyristors.
2. While the single pulse is adequate to turn-on a thyristor, the gate pulse generator must send a pulse whenever required, if the particular valve is to be kept in a conducting state. This is of importance when operating at low DC currents and a transient might reduce the current below the holding current.

   There are two basic firing schemes, namely:

   Individual Phase Control (IPC)

   Equidistant Pulse Control (EPC)

IPC was used in the past and has now been replaced by EPC for reasons that will be explained.

4.5.1 Individual Phase Control

This was used in early HVDC projects. The main feature of this scheme is that the firing pulse generation for each phase (or valve) is independent of each other and the firing pulses are rigidly synchronized with the commutation voltages.

There are two ways in which this can be achieved—constant α control and inverse cosine control.

Constant α control

In this scheme (see Fig. 4.9) six timing (commutation) voltages are derived from the converter AC bus via voltage transformers and the six gate pulses are generated at nominally identical delay times subsequent to the respective voltage zero crossings. The instant of zero-crossing of a particular commutation voltage corresponds to $\alpha = 0$ for that valve. The delays are produced by independent delay circuits and controlled by a common control voltage V_c derived from the current/extinction angle controllers.

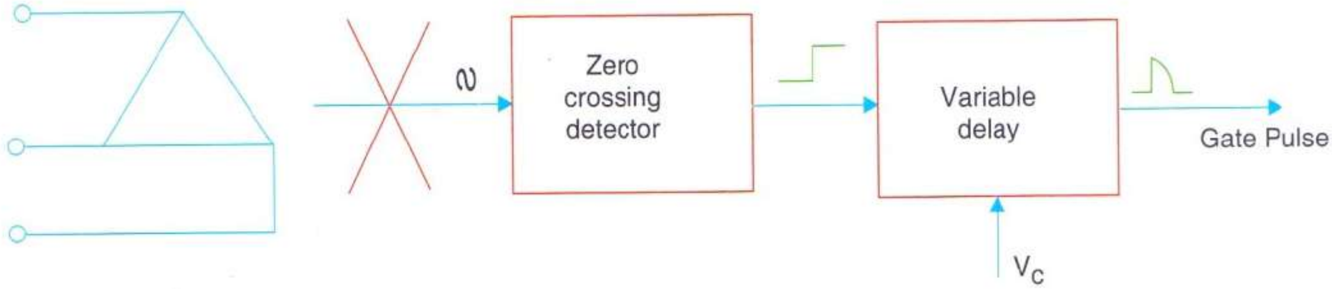


Fig. 4.9: Constant alpha control

Inverse cosine control

There are several variations of this, but in one common arrangement (see Fig. 4.10(a)), six timing voltages, (obtained as in constant α control) are each phase shifted by 90° and added separately to a common control voltage V_c. The zero crossing of the sum of the two voltages initiates the firing pulse for the particular valve considered (see Fig. 4.10(b)). The delay angle α is nominally proportional to the inverse cosine of the control voltage. It also depends on the AC system voltage amplitude and shape. The main advantage of this control scheme is that the average DC voltage across the bridge varies linearly with the control voltage V_c. It is essential in this scheme to maintain the phase shift at 90° for variations in the supply frequency.

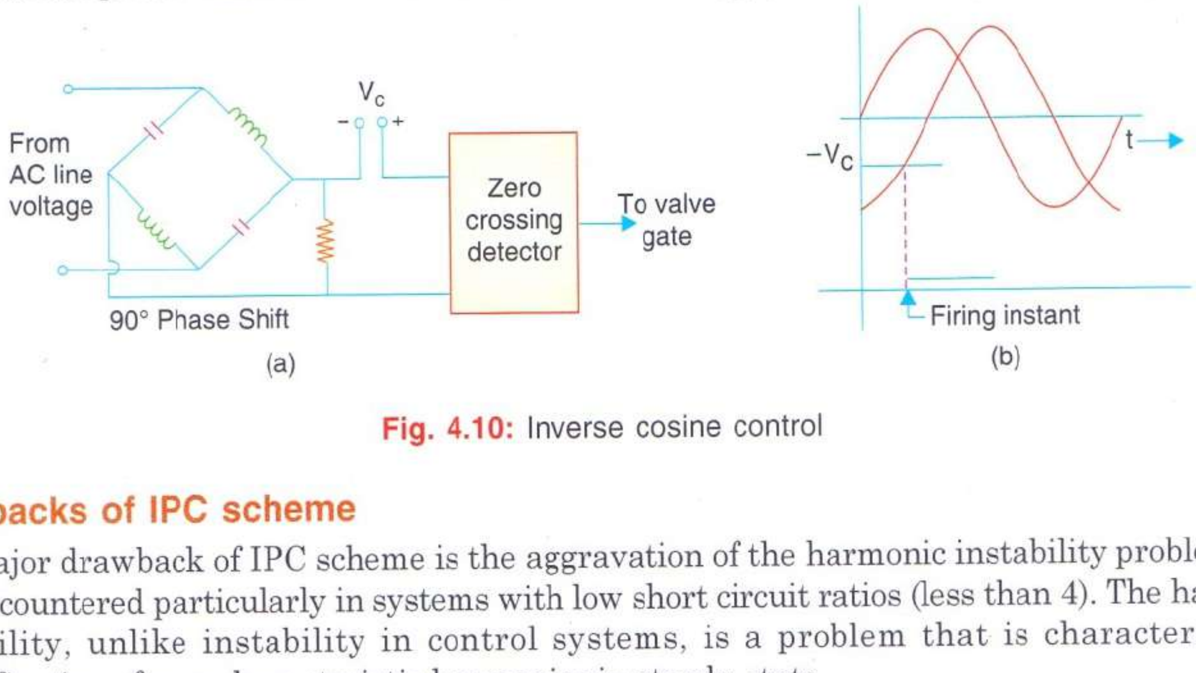


Fig. 4.10: Inverse cosine control

Drawbacks of IPC scheme

The major drawback of IPC scheme is the aggravation of the harmonic instability problem that was encountered particularly in systems with low short circuit ratios (less than 4). The harmonic instability, unlike instability in control systems, is a problem that is characterised by magnification of non-characteristic harmonics in steady-state.

This is mainly due to the fact that any distortion in the system voltage leads to perturbations in the zero crossings which affect the instants of firing pulses in IPC scheme. This implies that even when the fundamental frequency voltage components are balanced, the firing pulses are not equidistant in steady-state.

This in turn leads to the generation of non-characteristic harmonics (harmonics of order $h \neq np \pm 1$) in the AC current which can amplify the harmonic content of the AC voltage at the converter bus. The problem is aggravated at the frequencies for which the filter impedance and the system impedance are in parallel resonance.

The problem of harmonic instability can be overcome by the following measures:

1. Influencing the harmonic behaviour of AC network impedance seen by the converter (through the provision of synchronous condensers or additional filters for filtering out non-characteristic harmonics).
2. Use of filters in control circuit to filter out non-characteristic harmonics in the commutation voltages. This can, however, be problematic due to variations in the supply frequency and will add to the control delays.
3. The use of firing angle control independent of the zero crossings of the AC voltages. This is the most attractive solution and leads to the equidistant pulse firing scheme described next.

4.5.2 Equidistant Pulse Control (EPC)

In this scheme, the firing pulses are generated in steady state at equal intervals of $1/pf$, through a ring counter. This control scheme was first suggested by Ainsworth[3] using a phase locked oscillator to generate the firing pulses. There are three variations of the EPC scheme

Pulse Frequency Control (PFC)

Pulse Period Control

Pulse Phase Control (PPC)

Pulse frequency control (PFC)

In this scheme, a voltage controlled oscillator (VCO) is used, the frequency of which is determined by the control voltage V_c which is related to the error in the quantity (current, extinction angle or DC voltage) being regulated. The frequency in steady-state operation is equal of pf_0 where f_0 is the nominal frequency of the AC system. PFC system has an integral characteristic and has to be used along with a feedback control system for stabilization.

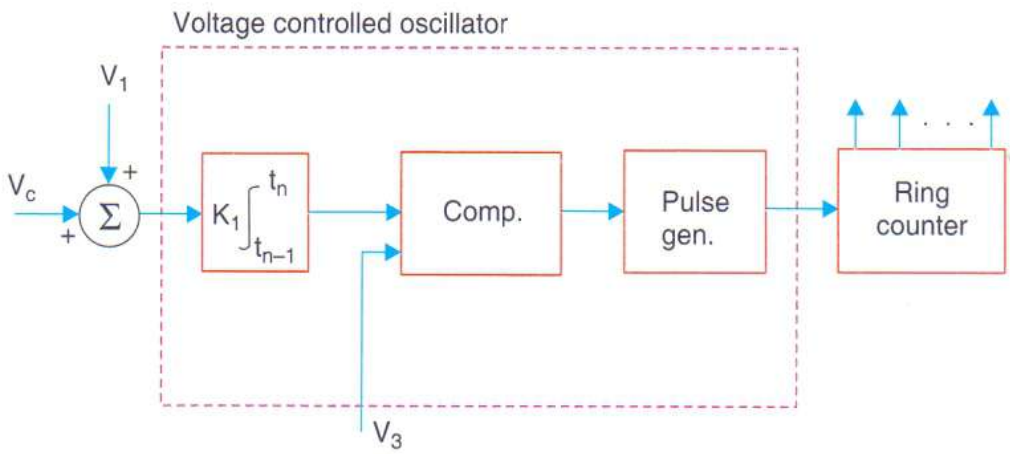


Fig. 4.11: Block diagram of PFC system

Figure 4.11 shows a simplified block diagram of the PFC system [10]. The voltage controlled oscillator (VCO) consists of an integrator, comparator and a pulse generator. The output pulses of the generator drive the ring counter and also reset the integrator. The instant (t_n) of the firing pulse is determined from the following equations

$$\int_{t_{n-1}}^{t_n} K_1(V_c + V_1)dt = V_3 \tag{4.10}$$

where V_1 is a bias (constant) voltage and V_3 is proportional to the system period. In steady state, $V_c = 0$, and from Eq. (4.10) we get

$$K_1V_1(t_n - t_{n-1}) = V_3 \tag{4.11}$$

Since

$$t_n - t_{n-1} = 1/pf_0 \tag{4.12}$$

in steady-state, the gain K_1 of the integrator is chosen as

$$K_1 = pf_0V_3/V_1 \tag{4.13}$$

The circuit shown in Fig. 4.11 does not incorporate frequency correction (when the system frequency deviates from f_o). The frequency correction according to Ainsworth is obtained by deriving V_3 as shown in Fig. 4.12. From Fig. 4.12, we have

$$V_3 = V_2/(1 + sT_1), V_2 = K_1V_1(t_{n-1} - t_{n-2})$$

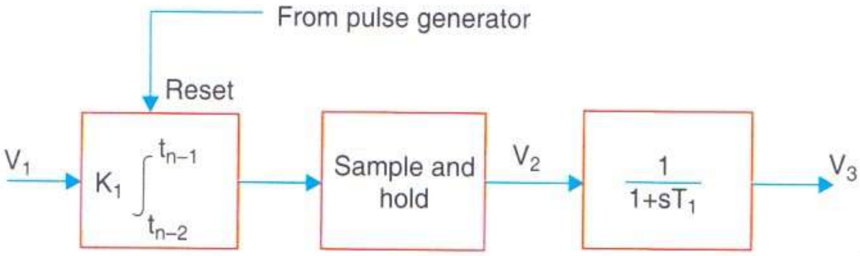


Fig. 4.12: Frequency correction for PFC

Pulse period control [4]

This is similar of PFC except for the way in which the control voltage V_c is handled. The structure of the controller is the same as that in Fig. 4.11, however, V_c is now summed with V_3 instead of V_1. Thus, the instant t_n of the pulse generation is given by

$$\int_{t_{n-1}}^{t_n} K_1V_1dt = V_3 + V_c \tag{4.14}$$

From Eq. (4.14), we get

$$K_1V_1(t_n - t_{n-1}) = V_3 + V_c \tag{4.15}$$

With $V_c = 0$, the interval between consecutive pulses, in steady state, is exactly equal to $1/pf_o$. Figure 4.13 shows how an exponentially decaying V_c which appears at $t = t_1$ shifts the delay angle by decreasing the pulse frequency between t_1 and t_2.

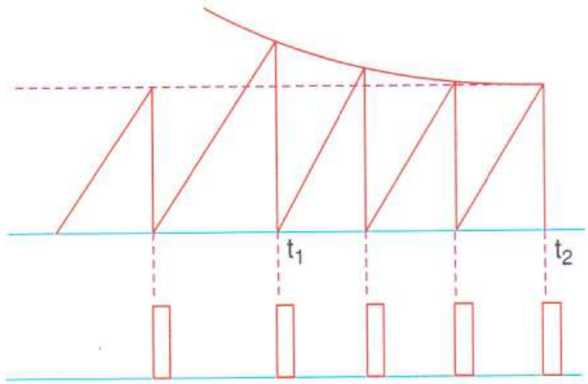


Fig. 4.13: Firing pulse train

The frequency correction in this scheme is obtained by either updating V_1 in response to the system frequency variation or including another integrator in the CC or CEA controller.

It can be seen that conceptually, the pulse period control is similar to PFC and both have integral characteristics. Ainsworth [10] claims that PFC gives better stability because the control voltage V_c is averaged in this scheme, unlike in pulse period control. However, if the ripple in control voltage V_c has harmonic components of frequency less than pf_o they are bound to affect the operation of PFC also.

Pulse phase control (PPC)

This has been suggested by Rumpf and Ranade [5], Reeve and Sevenco [6]. As suggested in [5] an analog circuit is configured to generate firing pulses according to the following equation

$$\int_{t_{n-1}}^{t_n} K_1 V_1 dt = V_{cn} - V_{c(n-1)} + V_3 \tag{4.16}$$

where V_{cn} and $V_{c(n-1)}$ are the control voltages at the instants t_n and t_{n-1} respectively. For proportional current control, the steady state can be reached when the error or V_c is constant. To reduce the error to zero, the authors of reference [5] recommend a slow α control with feedback signal taken from the measured delay angle. This signal in addition to a signal derived from frequency error (to compensate for variation in frequency) is used to control the voltage V_1.

The major advantages claimed for PPC over PFC are (*i*) easy inclusion of α limits by limiting V_c as in IPC and (ii) linearization of control characteristic by including an inverse cosine function block after the current controller. Actually, limits can also be incorporated into PFC or pulse period control system. In any case, the constraints of limits give rise to generation of nonequidistant pulses, unless special symmetrizing controls are included. This basically involves firing the subsequent $(p-1)$ valves at equal intervals once a valve is fired at, say, minimum limit, unless an increase in the firing angle is called for.

Drawbacks of EPC scheme

Although EPC scheme has replaced IPC scheme in modern HVDC projects, it has certain limitations. The first drawback is that under unbalanced voltage conditions, EPC results in less DC voltage compared to IPC. Unbalance in the voltage results from single phase to ground fault in the AC system which may persist for over 10 cycles due to stuck breakers. Under such conditions, it is desirable to maximise DC power transfer in the link which calls for IPC. However, transition from EPC to IPC under the fault conditions has to be evaluated carefully.

EPC scheme also results in higher negative damping contribution to torsional oscillations when HVDC is the major transmission link from a thermal station. However, this problem is not so serious as the problem of non-characteristic harmonics associated with IPC.

4.5.3 Control Hardware

The implementation of the controls can be achieved using analog or digital circuits. In the latter case, micro-processor based controls can be used. μP based controls were initially used where speed of control was not critical, but flexibility was an advantage. However, with the availability of high speed programmable controllers using bit-slice architecture, converter control using these devices is now feasible. μP based controllers, in general, are more reliable than analog controllers and permit redundancy. The control channel not in use operates in a hot standby mode.

4.6 CURRENT AND EXTINCTION ANGLE CONTROL

The current controller (see Fig. 4.8) is invariably of feedback type. A typical block diagram of the controller which is of PI type is shown in Fig. 4.14.

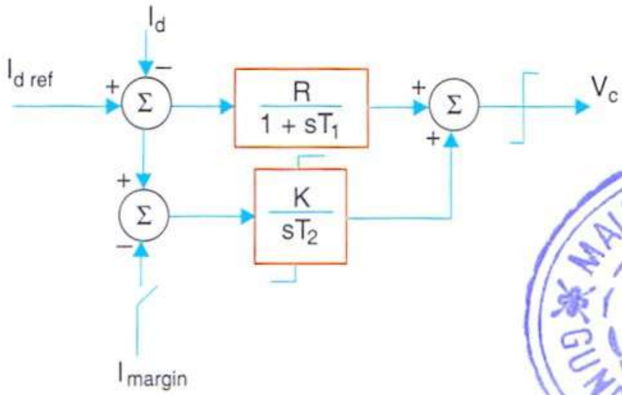


Fig. 4.14: Block diagram of current controller

The extinction angle controller can be of predictive type or feedback type with EPC control. The predictive controller is considered to be less prone to commutation failure and was invariably used in the early schemes. The feedback control with PFC type of equidistant pulse control overcomes the problems associated with IPC.

The extinction angle, as opposed to current, is a discrete variable and it was felt that feedback control of gamma is slower than the predictive type. In one of the predictive schemes proposed by Hingorani [17], the firing pulse generation is based on the following equation

$$0 = \int_{-\pi+\delta_{n-1}}^{\omega t_n} e_{cj} d(\omega t) + 2X_c I_d \tag{4.17}$$

where e_{cj} is the commutation voltage across valve j and t_n is the instant of its firing.

In general, the prediction of firing angle is based on the equation

$$\beta_j = \gamma_{ref} + u_j \tag{4.18}$$

where u_j is the overlap angle of valve j, which is to be predicted based on the current knowledge of the commutation voltage and DC current.

In feedback control of extinction angle shown in Fig. 4.8 the measured value of γ passes through a non-linear block. The control is made faster when $\gamma < \gamma_1$ and slower when $\gamma > \gamma_2$. In the former case, the fast control reduces the incidence of commutation failure while in the latter case, the instability due to the negative resistance characteristic of fast γ control is avoided. Under large disturbances such as sudden dip in the AC voltage, signals derived from the derivative of voltage or DC current aid the advancing of delay angle for fast recovery from commutation failures.

Ekstrom and Liss [4] describe a predictive control scheme in conjunction with EPC.

4.7 STARTING AND STOPPING OF DC LINK

4.7.1 Energization and Deenergization of a Bridge

Consider N series connected bridges at a converter station. If one of the bridges is to be taken out of service, there is need to not only block, but bypass the bridge. This is because of the fact that just blocking the pulses does not extinguish the current in the pair of valves that are left conducting at the time of blocking. The continued conduction of this pair injects AC voltage into the link which can give rise to current and voltage oscillations due to lightly damped oscillatory circuit in the link formed by smoothing reactor and the line capacitance. The transformer feeding the bridge is also subjected to DC magnetization when DC current continues to flow through the secondary windings. The bypassing of the bridge can be done with the help of a separate bypass valve or by activating a bypass pair in the bridge (two valves in the same arm of the bridge). The bypass valve was used with mercury arc valves where the possibility of arc backs makes it impractical to use bypass pairs. With thyristor valves, the use of bypass pair is the practice as it saves the cost of an extra valve.

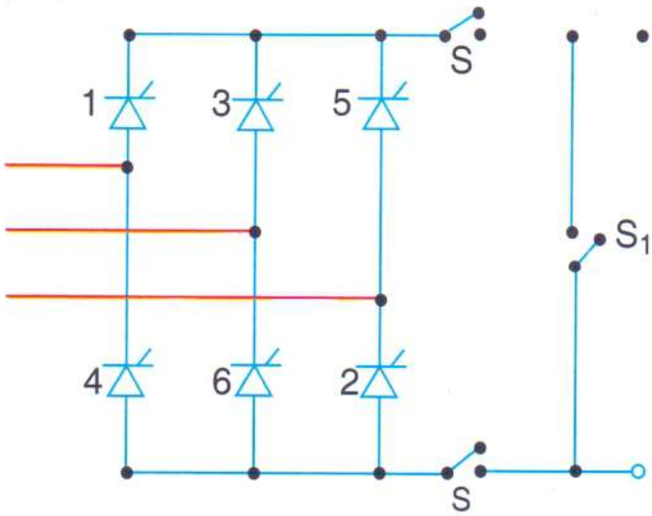


Fig. 4.15: A converter bridge with isolators

The process of deenergization of a bridge is explained with reference to Fig. 4.15. The valves 2 and 3 are assumed to be conducting initially when the blocking command is given. With the selection of bypass pair 1 and 4, the commutation from valve 2 to 4 is in the usual manner, but the commutation from valve 3 to valve 5 is prevented. In the case of a predetermined choice of the bypass path, the time lapse between the blocking command and the current transfer to bypass path can vary from 60° to 180° for a rectifier bridge. This time can be reduced (from 60°

to 120°) if the bypass pair is chosen such that the valve with the lower valve number carrying current at the instant of blocking is included in the bypass pair. In the inverter, there is no time lag involved in the activation of the bypass pair. The voltage waveforms for the rectifier and the inverter are shown in Fig. 4.16 (*a*) and (*b*) respectively. The overlap is neglected here.

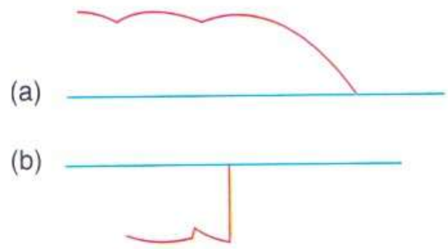


Fig. 4.16: Voltage waveforms during de-energisation for rectifier and inverter

The current from the bypass pair is shunted to a mechanical switch S_1. With the aid of the isolators S the bridge can now be isolated. The isolator pair S and switch S_1 are interlocked such that one or both are always closed.

The energization of a blocked bridge is done in two stages. The current is first diverted from S_1 to the bypass pair. For this to happen, S_1 must generate the required arc voltage and to minimize this voltage, the circuit inductance must be small. In case the bypass pair fails to take over the current, S_1 must close automatically if the current in that does not become zero after a predetermined time interval. AC breakers with sufficient arc voltage, but with reduced breaking capacity are used as switch S_1.

In the second state of energization, the current is diverted from the bypass pair. For the rectifier, this can take place instantaneously neglecting overlap. However, for the inverter, the transition requires some time lag. The voltage waveforms for this case are shown in Fig. 4.17(*a*) and (*b*).

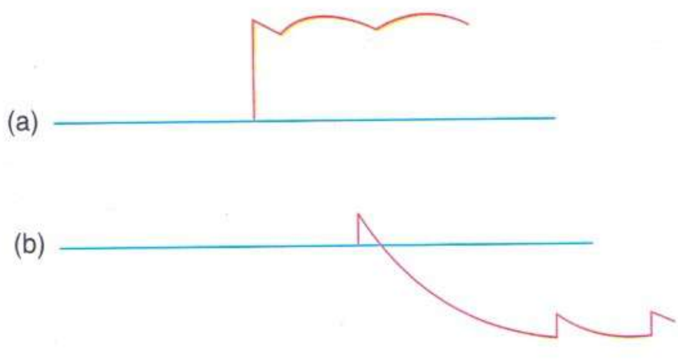


Fig. 4.17: Voltage waveforms during energisation for rectifier and inverter

It is to be noted that to avoid operation at high delay or extinction angles, the deenergization of a bridge at the rectifier (or inverter) station is accompanied by the deenergization of a bridge at the inverter (or rectifier) station.

4.7.2 Start-up of DC Link

There are two different start-up procedures depending upon whether the converter firing controller provides a short gate pulse or a long gate pulse. The long gate pulse lasts nearly 120°, the average conduction period of a valve.

Start-up with long-pulse firing

In this case, the current extinction during the start-up is not a problem. The starting sequence in this case is as follows:

1. Deblock inverter at about $\gamma = 90°$
2. Deblock rectifier at $\alpha = 85°$ to establish low direct current
3. Ramp up voltage by inverter control and the current by rectifier control

Start-up with short pulse firing

In this case, the problem of current extinction during start-up is present as the valve with forward bias is not put into conduction when the current in that falls transiently below holding current.

The starting sequence for this case is as follows:

1. Open bypass switch at one terminal
2. Deblock that terminal and load to minimum current in the rectifier mode
3. Open bypass switch at the second terminal and commutate current to the bypass pair
4. Start the second terminal also in the rectifier mode
5. The inverter terminal is put into the inversion mode
6. Ramp up voltage and current

The voltage is normally raised before raising the current. This permits the insulation of the line to be checked before raising the power. The ramping of power avoids stresses on the generator shaft. The switching surges in the line are also reduced.

The required power ramping rate depends on the strength of the AC system. Weaker systems require fast restoration of DC power for maintaining transient stability. Unfortunately, high ramping rates in such cases can give rise to large voltage drops due to the requirement of reactive power at the converter. Such voltage drops can lead to commutation failure at the inverter. The permissible ramping rates may vary from 2 to 10 p.u. per second, implying a start-up time of more than 100 to 500 msec.

4.8 POWER CONTROL

Figure 4.18 shows the block diagram of basic power and auxiliary controller used. The current order is obtained as the quantity derived from the power order by dividing it by the direct voltage.

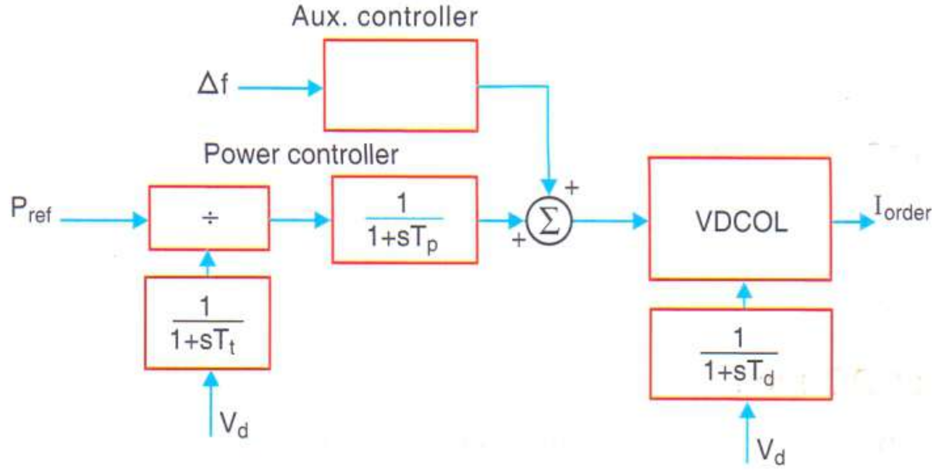


Fig. 4.18: Power and auxiliary controller block diagram

The limits on the current order are modified by the voltage dependent current order limiter (VDCOL). The objective of VDCOL is to prevent individual thyristors from carrying full current for long periods during commutation failures. However, sufficient time delay is given to prevent the action of VDCOL during normal AC system faults, which would otherwise drastically reduce DC power. The generic model of a VDCOL is shown in Fig. 4.19. G_1 (s) and G_2 (s) are simple transfer functions given by

$$G_1(s) = \frac{1}{1 + sT_{\text{down}}}$$

$$G_2(s) = \frac{1}{1 + sT_{\text{up}}}$$

By providing both converter stations with dividing circuits and transmitting the power order from the leading station in which the power order is set to the trailing station, the fastest response to DC line voltage changes is obtained without undue communication requirements. To get equal calculated current orders in the two stations, the measured DC line voltage must be referred to the same point on the DC line by compensation for DC line voltage drop. This is done by adding the term $\pm RI_d$ to the measured voltage, thus referring the voltage to a common reference point.

When the DC line resistance is large and varies considerably, e.g., when the overhead line is very long and exposed to large temperature variations, the DC line voltage drop cannot be compensated individually in the two stations. This problem can be solved by using a current order calculated in one substation only and transmitting it to the other substation.

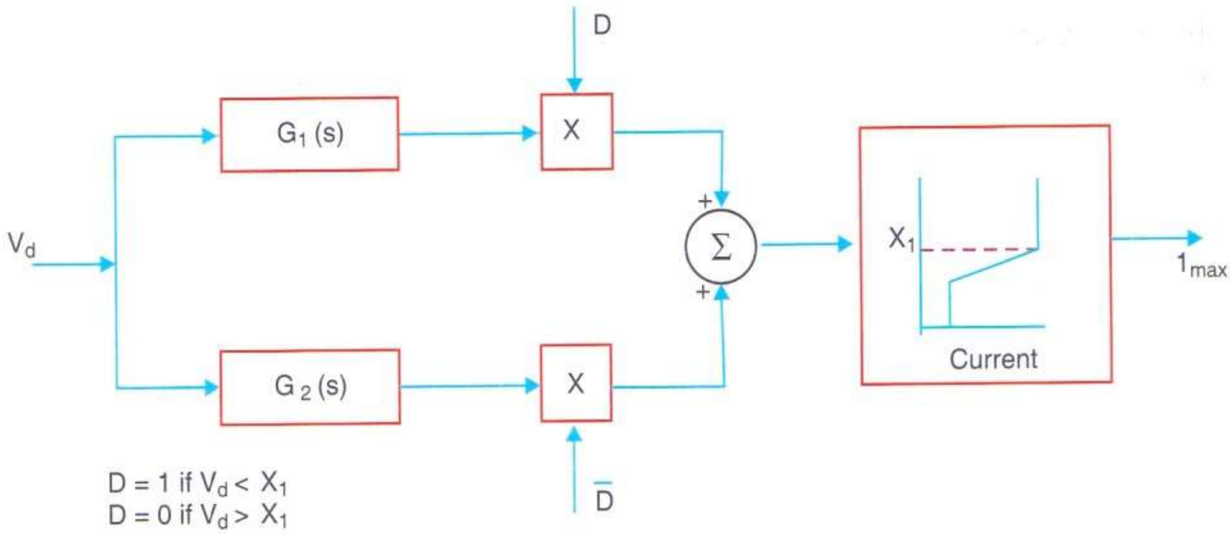


Fig. 4.19: Generic model of VDCOL (Source: Reference 18)

The power order and the corresponding rate of change or order are set with thumb wheels by the operator in one of the stations, the lead station, which may be the inverter or rectifier station. The order setting may also be transmitted there by a remote control link from the energy control centre. The order setting unit which is a digital unit based on integrated logic circuitry is intended mainly for performing power stepping and synchronization of order stepping in the two stations with the help of the communication link. The order setting unit in the trail station accepts a power order from the telecommunication system and has a supervisory function for the power order transmission. The received power is both parity checked and checked with regard to allowed change from one order message to the next. If the received order message is accepted, a receipt signal is sent back to the lead station to allow transmission of new order messages. If the receipt signal is not generated and accordingly not received in the lead station, order stepping is interrupted and the latest power order is repeatedly transmitted until accepted in the trail station at which, order stepping can start again. Thus, power transmission interruptions as a consequence of telecommunication failures are avoided.

The use of programmable logic for realization of power flow control function seems to be most appropriate solution for future applications. Standardized computer hardware equipment can be used and the functions may be adapted to individual requirement.

The auxiliary controller is designed to provide power modulation for frequency control or stabilization of AC systems. The input signal is derived from frequency or other signals.

HVDC and FACTS

By

Dr. A. V. Sudhakara Reddy

MODULE IV: Power Flow and Dynamic Stability

4.1 Transmission interconnections

4.2 Power flow in an AC System

4.3 Loading capability limits

4.4 Power flow and dynamic stability considerations

4.5 Importance of controllable parameters

4.6 Opportunities for FACTS

4.7 Basic types of FACTS controllers

4.8 Benefits from FACTS controllers

4.9 Requirements and characteristics of high power devices Voltage and current rating, losses and speed of switching, parameter trade - off of devices

4.1 Transmission interconnections:

The electric power supply systems of whole world are interconnected, involving connections inside the utilities, own territories with external to inter-utility, internationals to inter regional and then international connections. This is done for economic reasons, to reduce the cost of electricity and to improve reliability of power supply.

We need these interconnections to pool power plants and load centers in order to minimize the total power generation capacity and fuel cost. Transmission lines interconnections enable taking advantage of diversity of loads, availability of sources and fuel price in order to supply electricity to the loads at minimized cost with a required reliability.

In general, power system made up of radial lines from individual generators without part of grid system, many more generation resources would be needed to serve the load with the same reliability and cost of electricity would be much higher. With that perspective, transmission is often an alternative to a new generation resource. Less transmission capability means that more generation resources would be required regardless of whether the system is made up of large or small power plants.

In fact, small distributed generation becomes more economically viable if there is a backbone of a transmission grid. One cannot be really sure about what the optimum balance between generation and transmission unless the system planners use advanced methods of analysis which integrate transmission planning into an integrated value-based transmission/generation planning scenario. The cost of transmission lines and losses, as well as difficulties encountered in building new transmission lines, would often limit the available transmission capacity. It seems that there are many cases where economic considerations or reserve sharing is constrained by transmission capacity and the situation is not getting any better. In a deregulated electric service environment, an effective electric grid is vital to the competitive environment of reliable electric service.

On the other hand, as power transmission grows, the power system becomes increasingly more complex to operate and the system can become less secure for riding through the major outages. It may lead to large power flows with inadequate control, excessive reactive power in various parts of the system, large dynamic swings (disturbances) between various parts of the system, thus the full potential of transmission interconnections cannot be utilized.

The power systems of today, by and large, are mechanically controlled. There is a widespread use of microelectronics, computers and high-speed communications for control and protection of present transmission systems; however, when operating signals are sent to the power circuits, where the final power control action is taken, the switching devices are mechanical and there is little high-speed control. Another problem with mechanical devices is that control cannot be initiated frequently, because these mechanical devices tend to wear out very quickly compared to static devices. In effect, from the point of view of both dynamic and steady-state operation, the system is really uncontrolled. Power system planners, operators, and engineers have learned to live with this limitation by using a variety of ingenious techniques to make the system work effectively, but at a price of providing greater operating margins and redundancies. These represent an asset that can be effectively utilized with prudent use of FACTS technology on a selective, as needed basis.

In recent years, greater demands have been placed on the transmission network, and these demands will continue to increase because of the increasing number of nonutility generators and heightened competition among utilities themselves. Added to this is the problem that it is very difficult to acquire new rights of way. Increased demands on transmission, absence of long-term planning, and the need to provide open access to generating companies and customers, all together have created tendencies toward less security and reduced quality of supply. The FACTS technology is essential to alleviate some but not all of these difficulties by enabling utilities to get the most service from their transmission facilities and enhance grid reliability. It must be stressed, however, that for many of the capacity expansion needs, building of new lines or upgrading current and voltage capability of existing lines and corridors will be necessary.

The FACTS Technology is adopted in the transmissions to enhance grid reliability and to overcome the practical difficulties which occur in mechanical devises used as controllers of the transmission network.

4.2 Power flow in an AC System:

At present, many transmission facilities confront one or more limiting network parameters plus the inability to direct power flow at will.

In ac power systems, given the insignificant electrical storage, the electrical generation and load must balance at all times. To some extent, the electrical system is self-regulating. If generation is less than load, the voltage and frequency drop, and thereby the load, goes down to equal the generation minus the transmission losses. However, there is only a few percent margin for such a self-regulation. If voltage is propped up with reactive power support, then the load will go up, and consequently frequency will keep dropping, and the system will collapse. Alternately, if there is inadequate reactive power, the system can have voltage collapse.

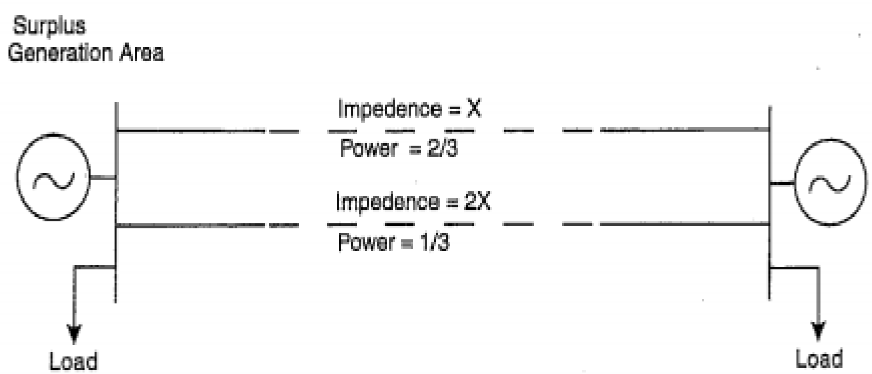
When adequate generation is available, active power flows from the surplus generation areas to the deficit areas, and it flows through all parallel paths available which frequently involves extra high-voltage and medium-voltage lines. Often, long distances are involved with loads and generators along the way. An often cited example is that much of the power scheduled from Ontario Hydro Canada to the North East United States flows via the PJM system over a long loop, because of the presence of a large number of powerful low impedance lines along that loop. There are in fact some major and a large number of minor loop flows and uneven power flows in any power transmission system.

4.2.1 Power flow in parallel paths:

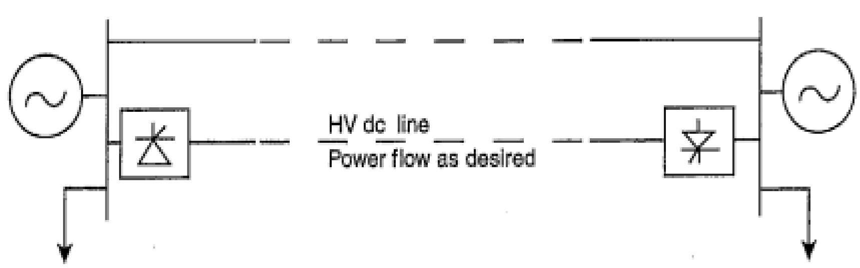
Consider a very simple case of power flow [Figure 1.1(a)], through two parallel paths (possibly corridors of several lines) from a surplus generation area, shown as an equivalent generator on the left, to a deficit generation area on the right. Without any control, power flow is based on the inverse of the various transmission line impedances. Apart from ownership and contractual issues over which lines carry how much power, it is likely that the lower impedance line may become overloaded and thereby limit the loading on both paths even though the higher impedance path is not fully loaded. There would not be an incentive to upgrade current capacity of the overloaded path, because this would further decrease the impedance and the investment would be self-defeating particularly if the higher impedance path already has enough capacity.

Figure 1.1(b) shows the same two paths, but one of these has HVDC transmission. With HVDC, power flows as ordered by the operator, because with HVDC power electronics converters power is electronically controlled. Also, because power is electronically controlled, the HVDC line can be used to its full thermal capacity if adequate converter capacity is provided. Furthermore, an HVDC line, because of its high-speed control, can also help the parallel ac transmission line to maintain stability. However, HVDC is expensive for general use, and is usually considered when long distances are involved, such as the Pacific DC Intertie on which power flows as ordered by the operator.

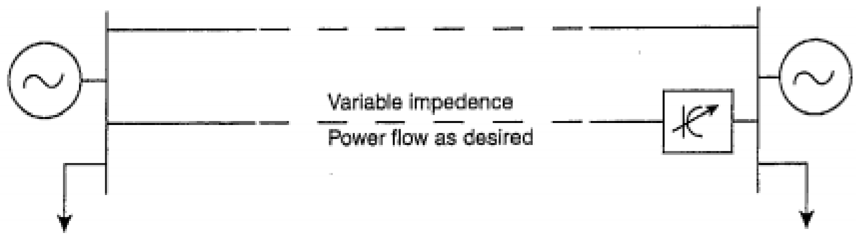
As alternative FACTS Controllers, Figures 1.1(c) and 1.1(d) show one of the transmission lines with different types of series type FACTS Controllers. By means of controlling impedance [Figure 1.1(c)] or phase angle [Figure 1.1(d)], or series injection of appropriate voltage (not shown) a FACTS Controller can control the power flow as required. Maximum power flow can in fact be limited to its rated limit under contingency conditions when this line is expected to carry more power due to the loss of a parallel line.



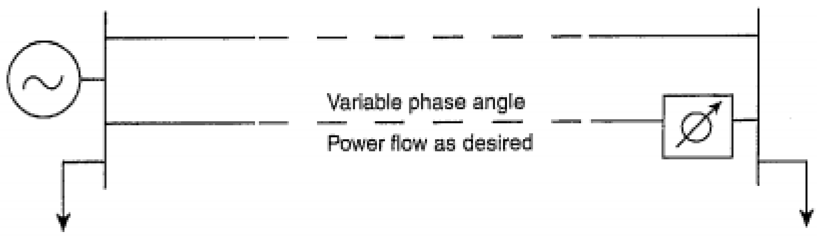
(a) Power flow with parallel paths



(b) Power flow control with HVDC



(c) Power flow control with variable impedance



(d) Power flow control with variable phase angle

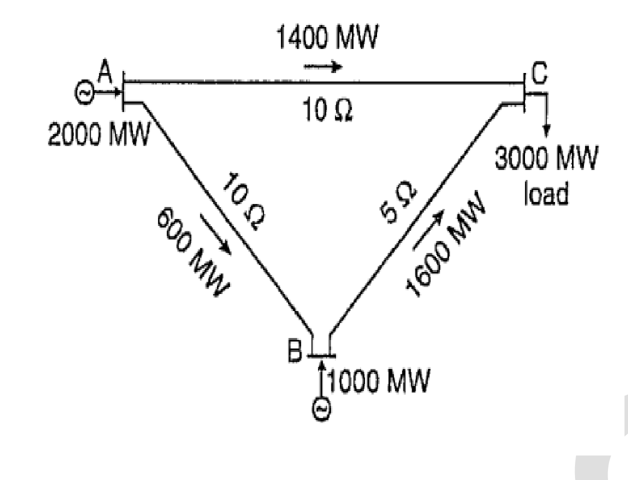
4.2.2 Power flow in a mesh network:

For understanding free flow of power, consider a simplified case in which two generators are sending power to load center from different sites. The Mesh network has the lines AB, BC and AC having continuous rating of 1000 MW, 1250 MW respectively. If one of the generators is generating 2000 MW and the other 1000 MW, a total power of 3000 MW would be delivered to the load center. In Fig 2.1 (a) the three impedances 10Ω, 5Ω and 10Ω, carry the powers 600 MW, 1600 MW and 1400 MW respectively. Such a situation would overload line BC and therefore generation would have to be decreased at „B" and increased at „A" in order to meet the load without overloading the line BC.

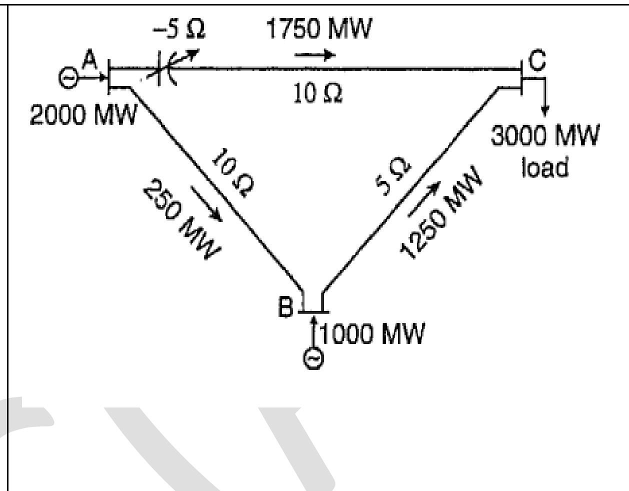
If a capacitor of reactance (-5Ω) at the synchronous frequency is inserted in the line AC as in Fig 2.1 (b), it reduces the line impedance from 10Ω to 5Ω so that the power flow through the lines AB, BC and AC are 250 MW, 1250 MW and 1750 MW respectively. It is clear that if the series capacitor is adjusted the power flow level may be realized. The complication is if the series capacitor is mechanically controlled it may lead to sub synchronous resonance. This resonance occurs when one of the mechanical resonance frequencies of the shaft of a multiple-turbine generator unit coincides with normal frequency by subtracting the electrical resonance frequency of the capacitor with the inductive load impedance of the line. Then the shaft will be damaged.

If the series capacitor is thyristor controlled, it can be varied whenever required. It can be modulated to rapidly damped and sub synchronous conditions. Also can be modulated at damped low frequency oscillations. The transmission system to go from one steady-state condition to another without the risk of damaging the shaft, the system collapse. In other words thyristor controlled series capacitor can enhance the stability of network similarly as in Fig 2.1(c). The impedance of line BC is increased by inserting an inductor of reactance in series with the line AB, the series inductor which is controlled by thyristor could serve to adjust the steady-state power flow and damped unwanted oscillations.

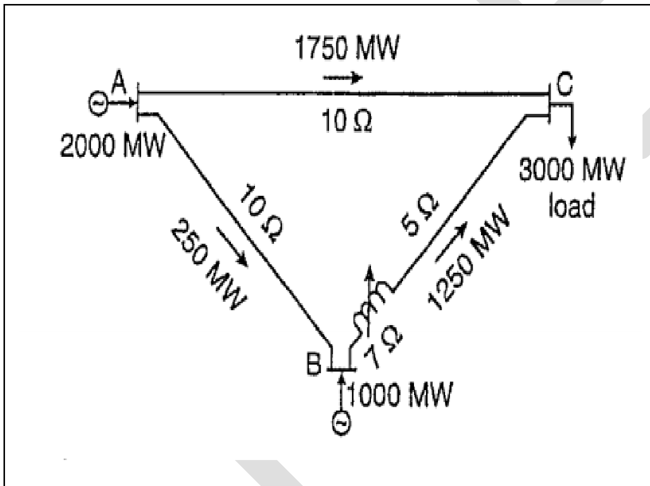
Another option of thyristor controlled method is, phase angle regulator could be installed instead of series capacitor in the line as in Fig 2.1(d). The regulator is installed in line AC to reduce the total phase angle difference along the line from 8.5 degree to 4.26 degrees. Thus the combination of Mesh and thyristor control of the phase angle regulator may reduce the cost. The same result could be achieved by injecting a variable voltage in one of the lines. Balancing of power flow in the line is carried out by the use of FACTS controller in the line.



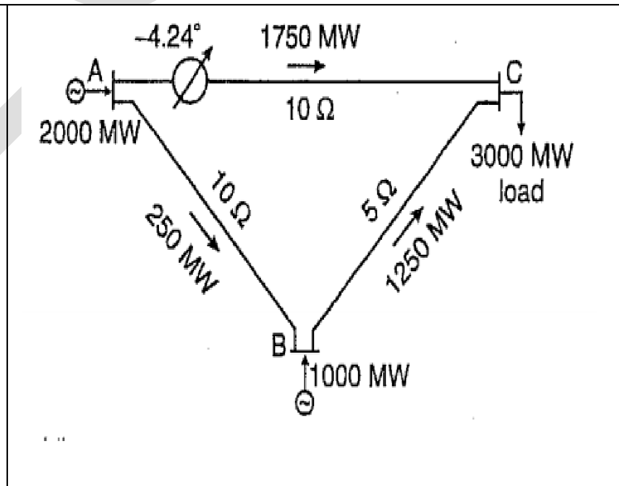
(a) Original system diagram



(b) system diagram with thyristor controlled series capacitor in line AC



(c) system diagram with thyristor controlled series reactor in line BC



(d) system diagram with thyristor controlled phase angle regulator in line AC

4.3 Loading capability limits

For the best use of the transmission and to improve the loading capability of the system one has to over come the following three kinds of limitations.

- Thermal Limitations
- Dielectric Limitations
- Limitations of Stability

Thermal Limitations

Thermal capability of an overhead lines is a function of the ambient temperature, wind conditions, conductors condition and ground clearance. It varies by a factor of 2 to 1 due to variable environment and the loading history. It needs to find out the nature of environment and other loading parameters. For this, off-line computer programs are made use to calculate a line loading capability based on available ambient environment and present loading history. The over load line monitoring devices are also used to know the on line loading capability of the line. The normal loading of the line is also decided on a loss evaluation basis which may vary for many reasons. The increase of the rating of transmission line involves the consideration of the real time rating of a transformer which is a function of ambient temperature, aging of transformer and present loading history of off-line and on-line monitoring.

The loading capability of transformer is also used to obtain real time loading capability. Enhancement of cooling of transformer is also a factor of increase of load on transmission line. From the above discussion it is necessary of upgrading line loading capability which can be done by changing the conductor of higher current rating which requires the structural upgrading. The loading capability of line is also achieved by converting a single circuit to double circuit line. If the higher current capability is available then the question arises, how to control this high current in the line, also, the acceptance of sudden voltage drop with such high current etc. The FACTS technology helps in making an effective use of the above technique of upgrading the loading capability of line.

Dielectric Limitations

From insulation point of view, many transmission lines are designed very conservatively. For a normal voltage rating, it is rarely possible to increase normal operation by +10% voltages, e.g. 500 kV, - 550 kV or even higher. Care must be taken such that the dynamic and transient over voltages are within the limit. Modern type of gapless arresters, or line insulators with internal gapless arresters or powerful Thyristor-controlled over voltage suppressors at the sub-stations are used to increase the line and sub station voltage capability. The FACTS technology could be used to ensure acceptable over-voltage and power conditions.

Limitations of Stability

There are a number of stability issues that limit the transmission capability. They are

- Transient Stability
- Dynamic Stability
- Steady-state Stability
- Frequency Collapse
- Voltage Collapse
- Sub synchronous Resonance

4.4 Power flow and dynamic stability considerations

Figure 1.3(a) shows a simplified case of power flow on a transmission line. Locations 1 and 2 could be any transmission substations connected by a transmission line. Substations may have loads, generation, or may be interconnecting points on the system and for simplicity they are assumed to be stiff busses. E_1 and E_2 are the magnitudes of the bus voltages with an angle δ between the two. The line is assumed to have inductive impedance X, and the line resistance and capacitance are ignored.

As shown in the phasor diagram [Figure 1.3(b)] the driving voltage drop in the line is the phasor difference $\boldsymbol{E}_L$ between the two line voltage phasors, $\boldsymbol{E}_1$ and $\boldsymbol{E}_2$. The line current magnitude is given by:

$$I = E_L/X, \text{ and lags } E_L \text{ by } 90°$$

Nevertheless the point of this very simple example is that generally speaking the rating of series FACTS Controllers would be a fraction of the throughput rating of a line.

Figure 1.3(b) shows that the current flow phasor is perpendicular to the driving voltage (90° phase lag). If the angle between the two bus voltages is small, the current flow largely represents the active power. Increasing or decreasing the inductive impedance of a line will greatly affect the active power flow. Thus impedance control, which in reality provides current control, can be the most cost-effective means of controlling the power flow. With appropriate control loops, it can be used for power flow control and/or angle control for stability.

Figure 1.3(c), corresponding to Figure 1.3(b), shows a phasor diagram of the relationship between the active and reactive currents with reference to the voltages at the two ends.

Active component of the current flow at E_1 is:

$$I_{p1} = (E_2 \sin \delta)/X$$

Reactive component of the current flow at E_1 is:

$$I_{q1} = (E_1 - E_2 \cos \delta)/X$$

Thus, active power at the E_1 end:

$$P_1 = E_1 (E_2 \sin \delta)/X$$

Reactive power at the E_1 end:

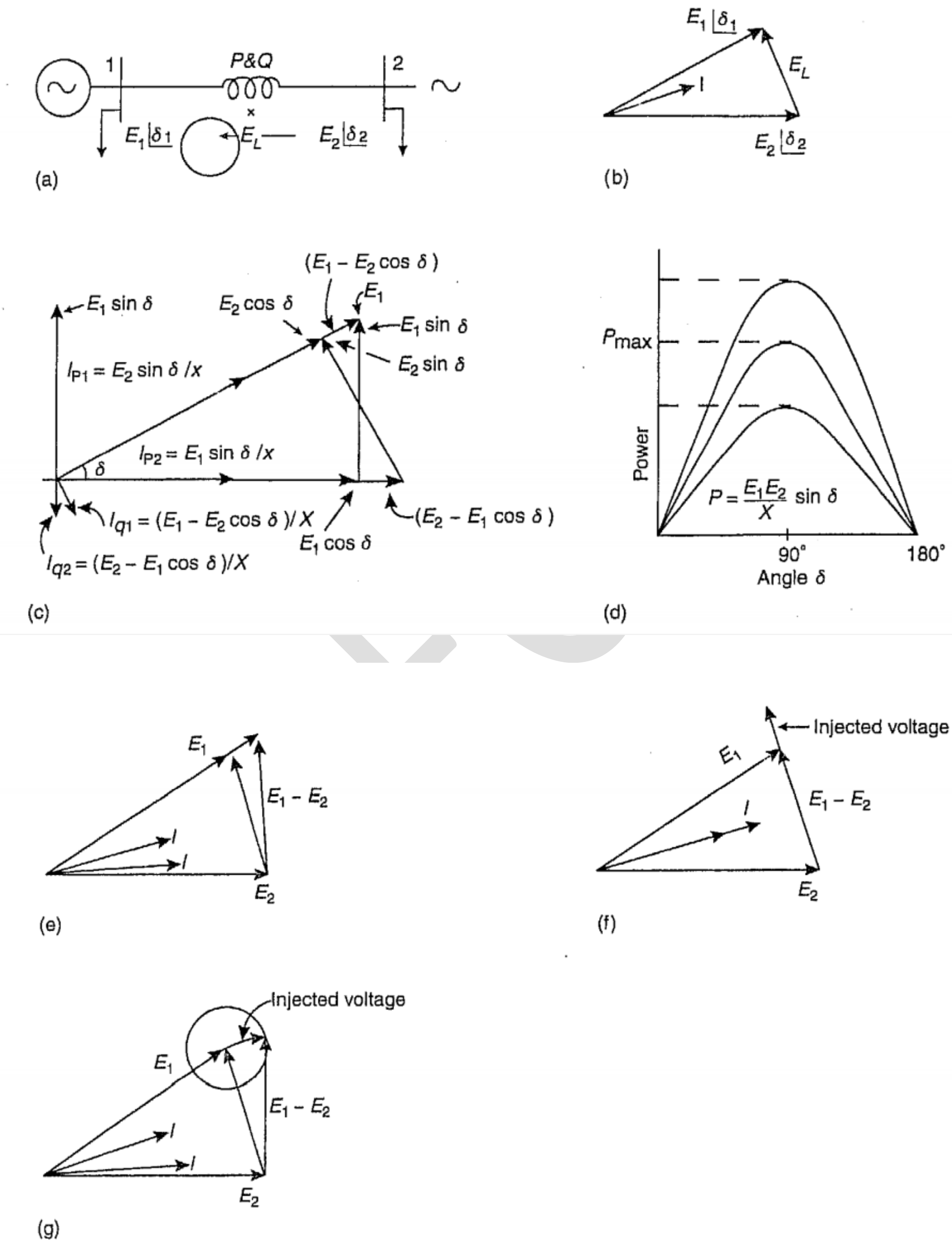
$$Q_1 = E_1 (E_1 - E_2 \cos \delta)/X \tag{1.1}$$

Similarly, active component of the current flow at E_2 is:

$$I_{p2} = (E_1 \sin \delta)/X$$

Reactive component of the current flow at E_2 is:

$$I_{q2} = (E_2 - E_1 \cos \delta)/X$$



1
P&Q
2
x
$E_1\angle\delta_1$
E_L
$E_2\angle\delta_2$
(a)
$E_1\angle\delta_1$
E_L
I
$E_2\angle\delta_2$
(b)
$(E_1 - E_2\cos\delta)$
$E_1\sin\delta$
$E_2\cos\delta$
E_1
$E_1\sin\delta$
$E_2\sin\delta$
$I_{P1} = E_2\sin\delta/x$
$I_{P2} = E_1\sin\delta/x$
δ
$I_{q1} = (E_1 - E_2\cos\delta)/X$
$E_1\cos\delta$
$(E_2 - E_1\cos\delta)$
$I_{q2} = (E_2 - E_1\cos\delta)/X$
(c)
P_{max}
Power
$P = \frac{E_1E_2}{X}\sin\delta$
90°
180°
Angle δ
(d)
E_1
$E_1 - E_2$
I
I
E_2
(e)
Injected voltage
E_1
$E_1 - E_2$
I
E_2
(f)
Injected voltage
E_1
$E_1 - E_2$
I
I
E_2
(g)

Figure 1.3 Ac power flow control of a transmission line: (a) simple two-machine system; (b) current flow perpendicular to the driving voltage; (c) active and reactive power flow phasor diagram; (d) power angle curves for different values of X; (e) regulating voltage magnitude mostly changes reactive power; (f) injecting voltage perpendicular to the line current mostly changes active power; (f) injecting voltage phasor in series with the line. (Note that for clarity the phasors are identified by their magnitudes in this figure.)

Thus, active power at the E_2 end:

$$P_2 = E_2\,(E_1 \sin \delta)/X$$

Reactive power at the E_2 end:

$$Q_2 = E_2\,(E_2 - E_1 \cos \delta)/X \tag{1.2}$$

Naturally P_1 and P_2 are the same:

$$P = E_1\,(E_2 \sin \delta)/X \tag{1.3}$$

because it is assumed that there are no active power losses in the line. Thus, varying the value of X will vary P, Q_1, and Q_2 in accordance with (1.1), (1.2), and (1.3), respectively.

Assuming that E_1 and E_2 are the magnitudes of the internal voltages of the two equivalent machines representing the two systems, and the impedance X includes the internal impedance of the two equivalent machines, Figure 1.3(d) shows the half sine-wave curve of active power increasing to a peak with an increase in δ to 90 degrees. Power then falls with further increase in angle, and finally to zero at $\delta = 180°$. It is easy to appreciate that without high-speed control of any of the parameters E_1, E_2, $E_1 - E_2$, X and δ, the transmission line can be utilized only to a level well below that corresponding to 90 degrees. This is necessary, in order to maintain an adequate margin needed for transient and dynamic stability and to ensure that the system does not collapse following the outage of the largest generator and/or a line.

Increase and decrease of the value of X will increase and decrease the height of the curves, respectively, as shown in Figure 1.3(d). For a given power flow, varying of X will correspondingly vary the angle between the two ends.

4.5 Importance of controllable parameters

- Control of line impedance „X" with a Thyristor controlled series capacitor can provide a powerful means of current control.
- When the angle is not large in some cases the control of „X" or the angle provides the control of active power.
- Control of angle with a phase angle regulator controls the driving voltage, which provides the powerful means of controlling the current flow and hence active power flow when the angle is not large.
- Injecting a voltage in series with the line, which is perpendicular to the current flow can increase or decrease the magnitude of current flow. Since the current flow lags the driving voltage by 90º, this means injection of reactive power in series compensation can provide a powerful means of controlling the line current and hence the active power when the angle is not large.
- Injecting voltage in series with line with any phase angle with respect to the driving voltage can control the magnitude and the phase of the line current. This means that injecting a voltage phasor with variable phase angle can provide a powerful means of controlling the active and reactive power flow. This requires injection if both active and reactive power are in series.
- When the angle is not-large, controlling the magnitude of one or the other line voltages with a Thyristor-controlled voltage regularly can very cost-effective means for the control of reactive power flow through the inter connection.
- Combination of the line impedance with a series controller and voltage regulation with shunt controller can also provide a cost effective means to control both the active and reactive power flow between the two systems.

4.6 Opportunities for FACTS

The FACTS Technology has opened a new opportunity to the transmission planner for controlling power and enhancing the useable capacity presently, also to upgrade the transmission lines. The current through the line can be controlled at a reasonable cost which enables a large potential of increasing the capacity of existing lines with large conductors and by the use of FACTS controllers the power flow through the lines is maintained stable. The FACTS controllers control the parameters governing the operation of transmission systems, such as series impedance, shunt impedance, current, voltage, phase angle and damping of oscillations at various frequencies below the rated frequency. These constraints cannot be overcome, while maintaining the required system reliability, by mechanical means without lowering the useable transmission capacity. By providing added flexibility, FACTS controllers can enable a line to carry power closer to its thermal rating. Mechanical switching needs to be supplemented by rapid response power electronics. It must be emphasized that FACT is an enabling technology, and not a one-to- one substitute for mechanical switches.

The FACTS technology is not a single high-power Controller, but rather a collection of Controllers, which can be applied individually or in coordination with others to control one or more of the interrelated system parameters mentioned above. A well-chosen FACTS Controller can overcome the specific limitations of a designated transmission line or a corridor. Because all FACTS Controllers represent applications of the same basic technology, their production can eventually take advantage of technologies of scale. Just as the transistor is the basic element for a whole variety of microelectronic chips and circuits, the thyristor or high-power transistor is the basic element for a variety of high-power electronic Controllers.

FACTS technology also lends itself to extending usable transmission limits in a step-by-step manner with incremental investment as and when required. A planner could foresee a progressive scenario of mechanical switching means and enabling FACTS Controllers such that the transmission lines will involve a combination of mechanical and FACTS Controllers to achieve the objective in an appropriate, staged investment scenario.

Some of the Power Electronics Controllers, now folded into the FACTS concept predate the introduction of the FACTS concept by co-author Hingorani to the technical community. Notable among these is the shunt-connected Static VAR Compensator (SVC) for voltage control which was first demonstrated in Nebraska and commercialized by GE in 1974 and by Westinghouse in Minnesota in 1975. The first series-connected Controller, NGH-SSR Damping Scheme, invented by co-author Hingorani, a low power series capacitor impedance control scheme, was demonstrated in California by Siemens in 1984. It showed that with an active Controller there is no limit to series capacitor compensation. Even prior to SVCs, there were two versions of static saturable reactors for limiting overvoltages and also powerful gapless metal oxide arresters for limiting dynamic overvoltages. Research had also been undertaken on solid-state tap changers and phase shifters. However, the unique aspect of FACTS technology is that this umbrella concept revealed the large potential opportunity for power electronics technology to greatly enhance the value of power systems, and thereby unleashed an array of new and advanced ideas to make it a reality. Co-author Gyugyi has been at the forefront of such advanced ideas. FACTS technology has also provided an impetus and excitement perceived by the younger generation of engineers, who will rethink and re-engineer the future power systems throughout the world.

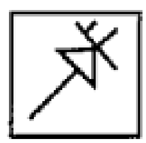
It is also worth pointing out that, in the implementation of FACTS technology, we are dealing with a base technology, proven through HVDC and high-power industrial drives. Nevertheless, as power semiconductor devices continue to improve, particularly the devices with turn-off capability, and as FACTS Controller concepts advance, the cost of FACTS Controllers will continue to decrease. Large-scale use of FACTS technology is an assured scenario.

4.7 Basic types of FACTS controllers

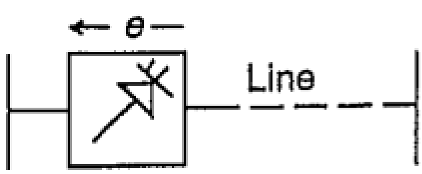
In general FACTS controllers can be classified into four categories.

- Series controllers
- Shunt controllers
- Combined series-series controllers
- Combined series-shunt controllers

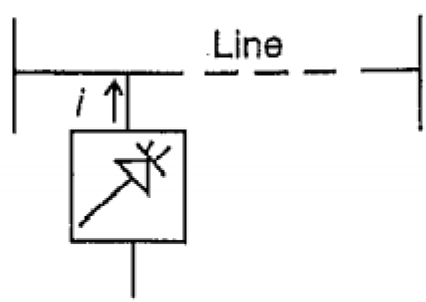
Fig 4.7 (a) shows the general symbol for FACTS controller; with a thyristor arrow inside a box. Fig 4.7 (b) shows the series controller could be variable impedance, such as capacitor, reactor etc. or it is a power electronics based variable source of main frequency sub- synchronous frequency and harmonics frequencies or combination of all to serve the desired need. The principle of series controller is to inject the voltage in series with the line. Even variable impedance multiplied by the current flow through it, represents an injected series voltage in the line. So long as the voltage is in phase quadrature with the line current, the series controller supplies or consumes variable reactive power. If any other phase relation involves it will handle the real power also.



(a) general symbol for FACTS controller



(b) series controller

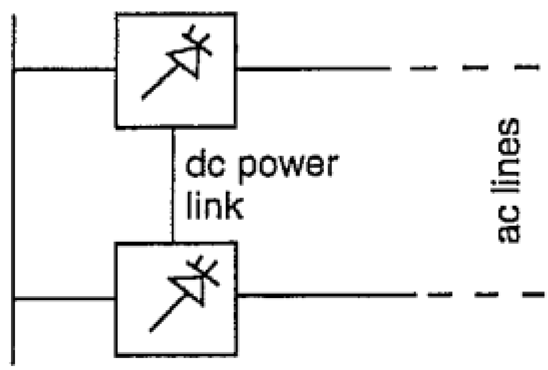


(c) shunt controllers

Fig 4.7 (c) shows the shunt controllers. As series controller, the shunt controller also has variable impedance, variable source, or a combination of all. The principle of shunt controller is to inject current into the system at the point of connection. Even variable shunt impedance connected to the line voltage causes a variable current flow and hence represents injection of current into the line. As long as the injected current is in phase quadrature with the line voltage.

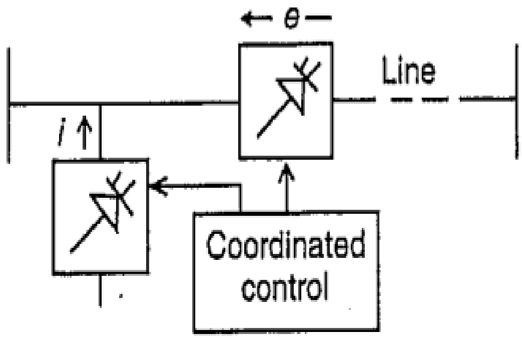
The shunt controller supplies or consumes variable reactive power. If any other phase relationship involves, it will also handle real power.

Fig 4.7 (d) shows the combination of two separate series controllers, which are controlled in a coordinated manner, in a multi line transmission system. Otherwise, it could be unified controller. As shown in Fig 2.2 (d) the series controllers provide independent series reactive compensation for each line and also transfer the real power among the lines via the unified series-series controller, referred to as inter-line power flow controller, which makes it possible to balance both the real and reactive power flow in the lines and thereby maximizing the utilization of transmission system. Note that the term "unified" here means that the D.C terminals of all controller converters are connected together for real power transfer.

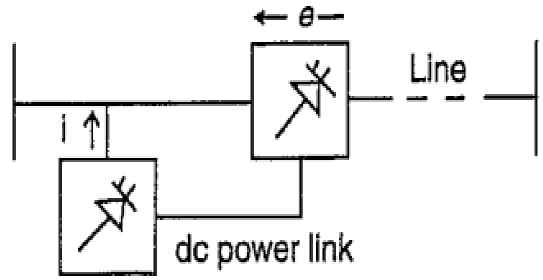


4.7 (d) Unified series- series controller

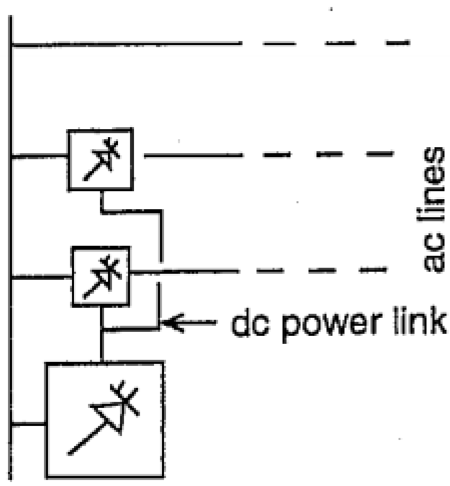
Fig 4.7 (e & f) shows the combined series-shunt controllers. This could be a combination of separate shunt and series controllers, which are controlled in coordinated manner in Fig 4.7 (e) or a unified power flow controller with series and shunt elements in Fig 4.7 (f). The principle of combined shunt and series controllers is, it injects current into the system with the shunt part of the controller and voltage through series part. However, when the shunt and series controllers are unified, there can be a real power exchange between the series and shunt controllers via the power link.



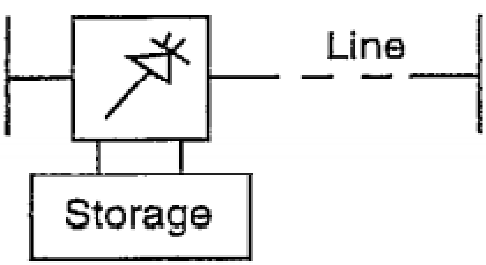
(e) Coordinated series- shunt controller



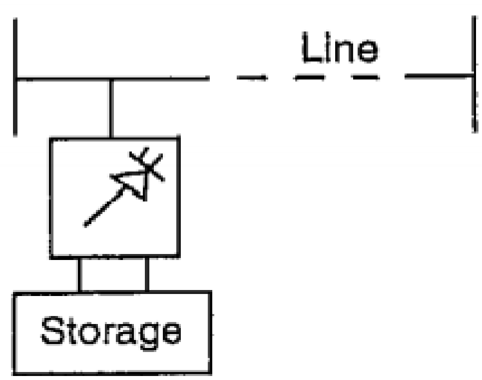
(f) Unified series- shunt controller



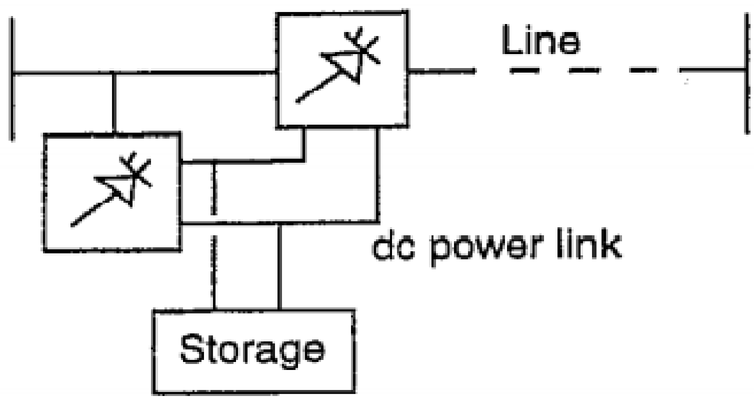
(g) Unified controller for multiple lines



(h) Series controller with storage



(i) Shunt controller with storage



(j) Unified series- shunt controller with storage

4.8 Benefits from FACTS controllers

- Control of power flow is in order, meet the utilities, own needs, ensure optimum power flow, and ride through emergency conditions or a combination of all.
- Increase the loading capability of lines to their thermal capabilities, including short term and seasonal, this can be done by overcoming other limitations and sharing of power among lines according to their capability.
- Increase the system security through raising the transient stability limit, limiting short circuit currents and over loads, managing cascading black-outs and damping electro-mechanical oscillations of power systems and machines.
- Provide secure tie-line connections to neighboring utilities and regions thereby decreasing overall generation reserve requirements both sides.
- Provide greater flexibility in setting new generation.
- Provide upgrade of lines.
- Reduce the reactive power flow, thus allowing the lines to carry more active power.
- Reduce power flows in a loop.
- Increase utilization of lowest cost generation.

4.9 Requirements and characteristics of high power devices Voltage and current rating, losses and speed of switching, parameter trade - off of devices

UNIT-III

STATIC SHUNT COMPENSATORS

Objectives of shunt compensation –methods of controllable VAR generation-static VAR compensators, SVC and STATCOM, comparison

****

OBJECTIVES OF SHUNT COMPENSATION:

Shunt compensation is used to influence the natural characteristics of the transmission line to “ steady-state transmittable power and to control voltage profile along the line” shunt connected fixed or mechanically switched reactors are used to minimize line over-voltage under light load conditions. Shunt connected fixed or mechanically switched capacitors are applied to maintain voltage levels under heavy load conditions.

Var compensation is used for voltage regulation.

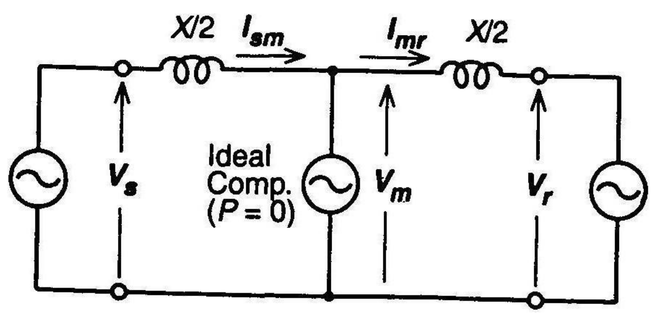
i. At the midpoint to segment the transmission line and
ii. At the end of the line

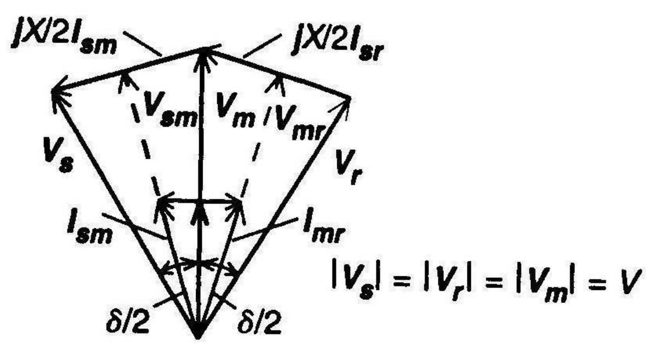
To prevent “voltage intangibility as well as for dynamic voltage control to increase transient stability and to damp out power oscillations”.

MID-POINT VOLTAGE REGULATION FOR LINE SEGMENTATION:

Consider simple two-machine(two-bus)transmission model in which an ideal var compensator is shunt connected at the midpoint of the transmission line

FIG:





The line is represented by the series line inductance. The compensator is represented by a "sinusoidal ac voltage source". The mid-point compensator in effect segments the transmission line into two independent parts

i. The first segment, with an impedance of $\left(\frac{X}{2}\right)$ carries power from the sending end to mid-point.

ii. The second segment also with an impedance of $\left(\frac{X}{2}\right)$ carries power from midpoint to the receiving end

The relationship between voltages V_s, V_r and V_m line currents I_{sm} and I_{mr} is shown

For the loss-less system, the real power is same at each terminal (ie, sending and, midpoint and receiving end" of the line. From the vector diagram,

$$V_{sm} = V_{mr} = V cos\left(\frac{\delta}{4}\right);$$

$$I_{sm} = I_{mr} = I = \frac{V}{\left(\frac{X}{4}\right)} sin\left(\frac{\delta}{4}\right) = \frac{4V}{X} sin\left(\frac{\delta}{4}\right)$$

The transmitted power is, $\quad$ P=$V_{sm} I_{sm} = V_{mr} I_{mr}$

$$P=\left[v_M . cos\left(\frac{\delta}{4}\right)\right].I = VIcos\left(\frac{\delta}{4}\right)$$

$$=V.\left[\frac{4V}{X} sin\left(\frac{\delta}{4}\right)\right] cos\left(\frac{\delta}{4}\right)$$

$$=\frac{2V^2}{X} 2sin\left(\frac{\delta}{4}\right) cos\left(\frac{\delta}{4}\right)$$

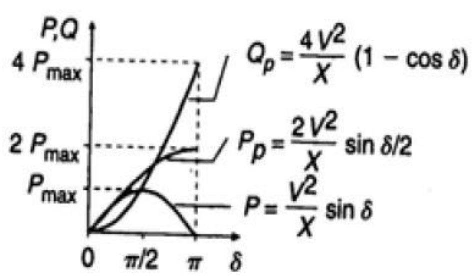
$$=\frac{2V^2}{X} sin\left(2.\frac{\delta}{4}\right)$$

$$=\frac{2V^2}{X} sin\left(\frac{\delta}{2}\right)$$

$$\text{Active power, Q=VI } sin\left(\frac{\delta}{2}\right)$$

$$=\frac{4V^2}{X}\left[1 - cos\left(\frac{\delta}{2}\right)\right]$$

The relationship between real power (P), reactive power(Q) and 'δ' for ideal shunt compensation is shown in fig

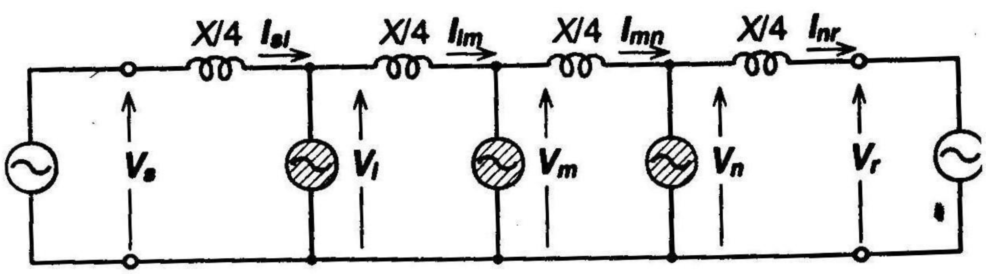


It can be observed that the midpoint shunt compensation can increase transmittable power significantly (doubling maximum value).

NOTE:

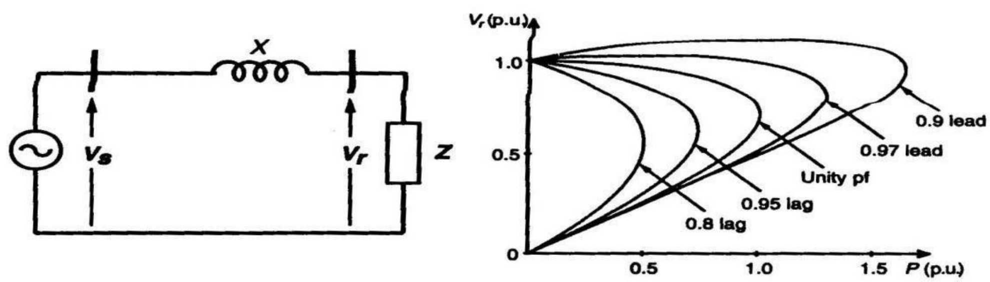
i. The midpoint of the transmission line is the best location for compensator because the voltage sage along the uncompensated transmission line is the longest at the midpoint

ii. The concept of transmission line segmentation can be expanded to use of multiple compensators, located at equal segments of the transmission line as shown in fig.



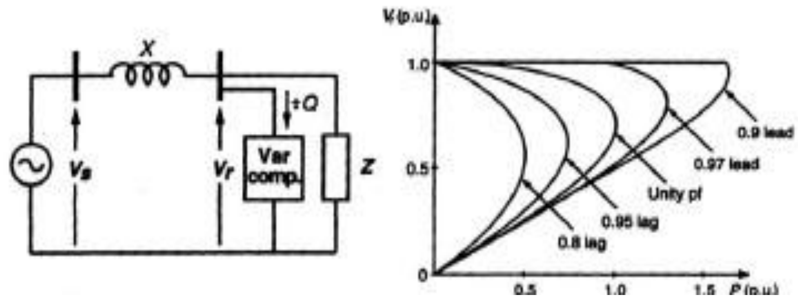
END OF LINE VOLTAGE TO SUPPORT TO PREVENT VOLTAGE INSTABILITY:

A simple radial system with feeder line reactance X and load impedance Z is shown.



The plot shows variation of normalized voltage(V_r) ,(V_s) power at different power factors ranging from 0.8 lag to 0.9 lo9ad. It should be that noted that voltage stability limit decreases with inductive loads and increases with capacitive loads.

i. The shunt compensation can effectively increase the voltage stability by supplying reactive load neglecting terminal voltage as shown in fig:



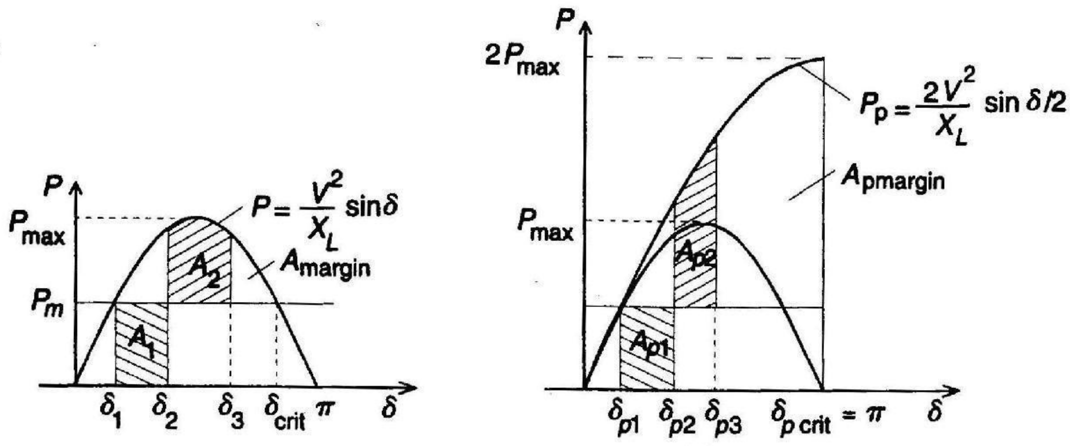
NOTE:

1. For a radial line , the end of the line, where the largest voltage variation is experienced, is the best location for the compensator.
2. Reactive shunt compensation is often used too regulate voltage support for the load when capacity of sending –end system becomes impaired.

IMPROVEMENT OF TRANSIENT STABILITY:

The shunt compensation will be able to change the power flow in the system during and following disturbances. So as to increase the transient stability limit. The potential effectiveness of shunt on transient stability improvement can be conveniently evaluated by "EQUAL AREA CRITERION".

Assume that both the uncompensated and compensated systems are subjected to the same fault for the same period of time. The dynamic behavior of these systems is illustrated in the following figures.



METHODS OF CONTROLLABLE VAR GENERATION:

Capacitors generate and inductors (reactors)absorb reactive power when connected to an ac power source. They have been used with mechanical switches for controlled var generation and absorption. Continuously variable var generation or absorption for dynamic system compensation as originally provided by

- over or under-excited rotating synchronous machines
- saturating reactors in conjunction with fixed capacitors

Using appropriate switch control, the var output can be controlled continuously from maximum capacitive to maximum inductive output at a given bus voltage.

More recently gate turn-off thyristors and other power semiconductors with internal turn off capacity have been use of ac capacitors or reactors.

Variable Impedance Type Static Var Generators

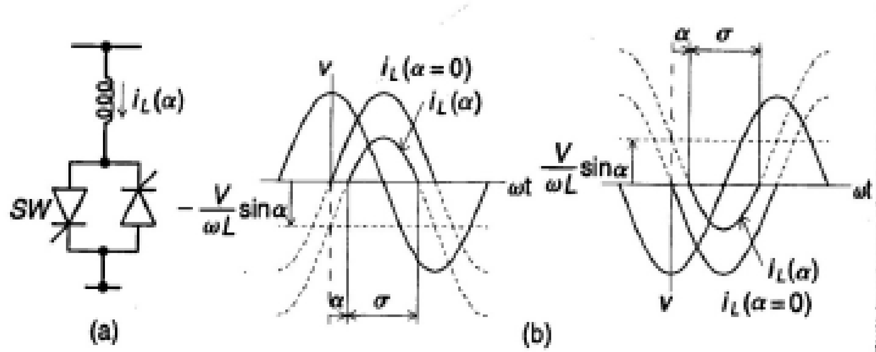
The performance and operating characteristics of the impedance type var generators are determined by their major thyristors-controlled constituents:

(i)Thyristor Controlled Reactor(TCR)

(ii)Thyristor Switched Capacitor(TSC)

Thyristor Controlled Reactor:

An elementary single-phase thyristors-controlled reactor is shown in fig.



It consists of a fixed (usually air-core) reactor of inductance L, and a bidirectional thyristors valve(or switch). Currently available large thyristors can block voltage up to 4000 to 9000 volts and conduct current up to 3000 to 6000 amperes. Thus, in practical many thyristors are connected in series to meet the required blocking voltage levels at a given power rating.

A thyristors valve can be brought into conduction by simultaneous application of a gate pulse to all thyristors of the same polarity. The valve will automatically block immediately after the a.c current crosses zero, unless the gate signal is reapplied.

The current in the reactor can be controlled from maximum(thyristor valve closed) to zero(thyristor valve open) by the method of firing delay angle control. That is, the closure of the thyristors valve is delayed w.r.t. the peak of the applied voltage in each half cycle, and thus the duration of the current conduction intervals is controlled.

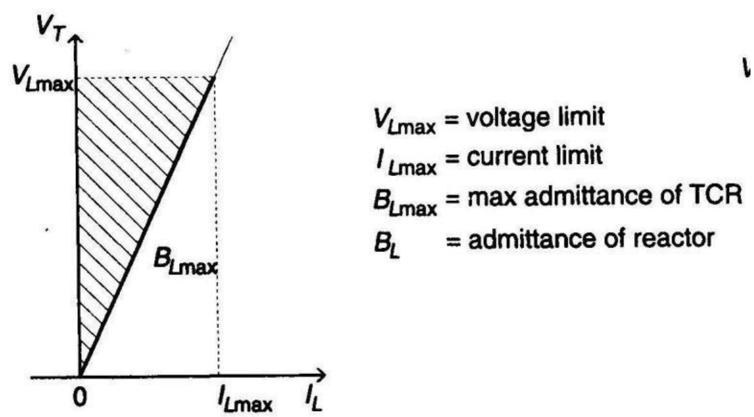
The method of current control is illustrated separately for the positive and negative current half cycles in fig.(b). where applied voltage υ and the reactor current $i_L(\alpha)$ at zero delay angle and at arbitrary α delay angle are shown.

- When α=0, the valve closes at the crest of the applied voltage and evidently the resulting current in the reactor will be the same as that obtained in steady state with a permanently closed switch.
- When the gating of the valve is delayed by an angle α(0≤ α≤90) with respect to the crest of the voltage, The current in the reactor can be expressed with υ(t)= V cos ωt as follows:

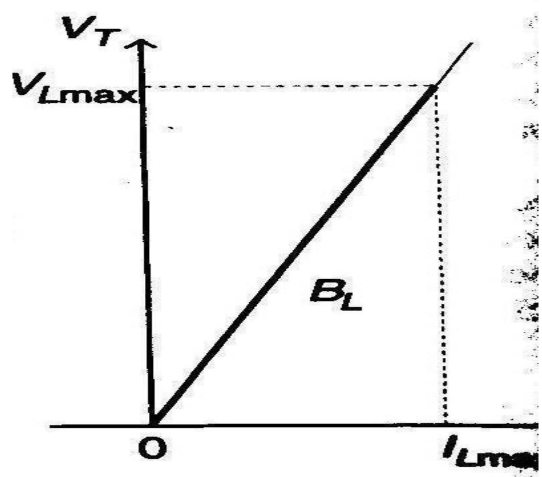
$$i_L(t) = \frac{1}{L}\int_{\alpha}^{wt} v(t)dt = \frac{V}{\omega L}(\sin \omega t - \sin \alpha)$$

It is evident that the magnitude of current in the reactor can be varied continuously by the method of delay angle control from maximum (α=0) to zero (α=90).

In practice, the maximum magnitude of the applied voltage and that of the corresponding current will be limited by the ratings of the power components(reactor and thyristor valve)used. Thus, a practical TCR can be operated anywhere in a defined V-I area ,the boundaries of which are determined by its maximum attainable admittance, voltage and current ratings are shown in fig.



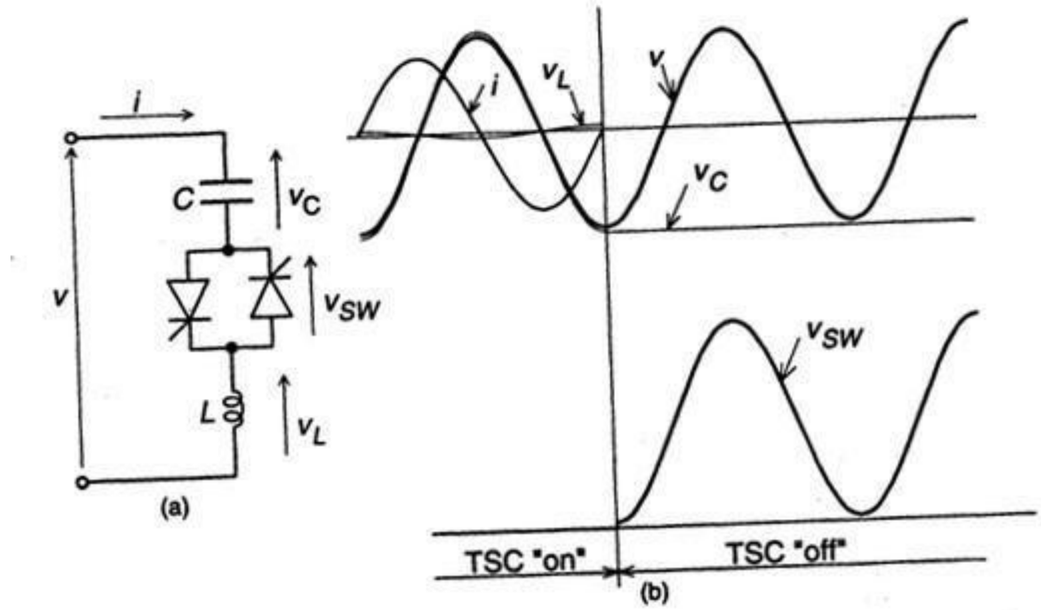
Note: If Thyristor Controlled Reactor(TCR) switching is restricted to a fixed delay angle, usually α=0, then it becomes a thyristors – switched reactor (TSR). The TSR provides a fixed inductive admittance. Thus, when connected to the a.c. system, the reactive current in it will be proportional to the applied voltage as shown in fig.



TSRs can provide at α=0, the resultant steady-state current will be sinusoidal.

THYRISTOR SWITCHED CAPACITOR(TSC):

A single-phase thyristors switched capacitor (TSC) is shown in fig.



It consists of a capacitor, a bi-directional thyristors valve, and a relatively small surge current limiting reactor. This reactor is needed primarily

To limit the surge current in the thyristors valve under abnormal operating conditions To avoid

resonances with the a.c. system impedance at particular frequencies

Under steady state conditions, when the thyristor valve is closed and the TSC branch is connected to a sinusoidal a.c. voltage source, υ=Vsin ωt, the current in the branch is given by

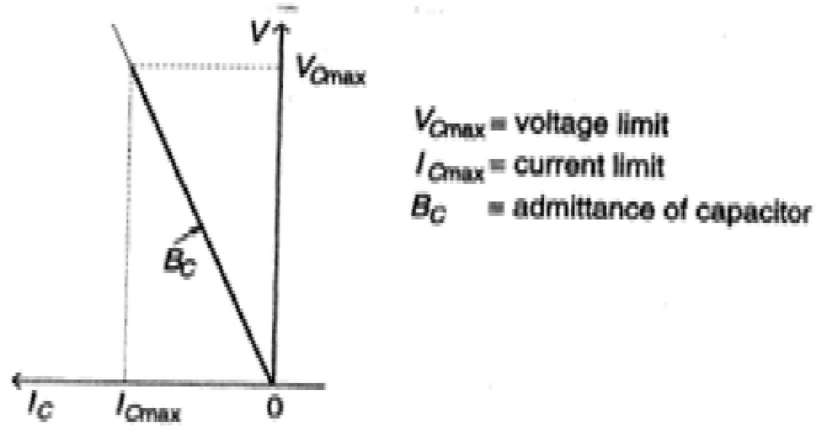
$$i(\omega t) = V\frac{n^2}{n^2-1}\ \omega C\ cos\omega t$$

$$\text{where } n = \frac{1}{\sqrt{\omega^2 LC}} = \sqrt{\frac{X_c}{X_L}}$$

The amplitude of voltage across capacitor is given by $V_c = \frac{n^2}{n^2-1}V$

The TSC branch can be disconnected ("switched out") at any current zero by prior removal of the gate drive to the thyristor valve. At the current zero crossing, the capacitor voltage is at its peak valve. The disconnected capacitor stays charged to this voltage, and consequently the voltage across the non-conducting thyristors valve varied between zero and the peak-to-peak value of the applied a.c. voltage as shown in fig.(b).

The TSC branch represents a single capacitive admittance which is either connected to, or disconnected from the a.c. system. The current in the TSC branch varies linearly with the applied voltage according to the admittance of the capacitor as illustrated by the V-I plot in the following fig.



It is observed that , maximum applicable voltage and the corresponding current are limited by the ratings of the TSC components(capacitor and thyristor valve).To approximate continuous current variation, several TSC branches in parallel may be employed, which would increase in a step-like manner the capacitive admittance.

STATIC VAR COMPENSATOR:

The *static compensator term is used in a general sense to refer to an SVC as well as to a STATCOM.*

The static compensators are used in a power system to increase the power transmission capacity with a given network, from the generators to the loads. Since static compensators cannot generate or absorb real power, the power transmission of the system is affected indirectly by ***voltage control***. That is, the reactive output power (capacitive or inductive) of compensator is varied to control the voltage at given terminals of the transmission network so as to maintain the desired power flow under possible system disturbances and contingencies.

Static Var Compensator(SVC) and Static Synchronous Compensator(STATCOM) are var generators, whose output is varied so as to maintain to control specific parameters of the electric power system.

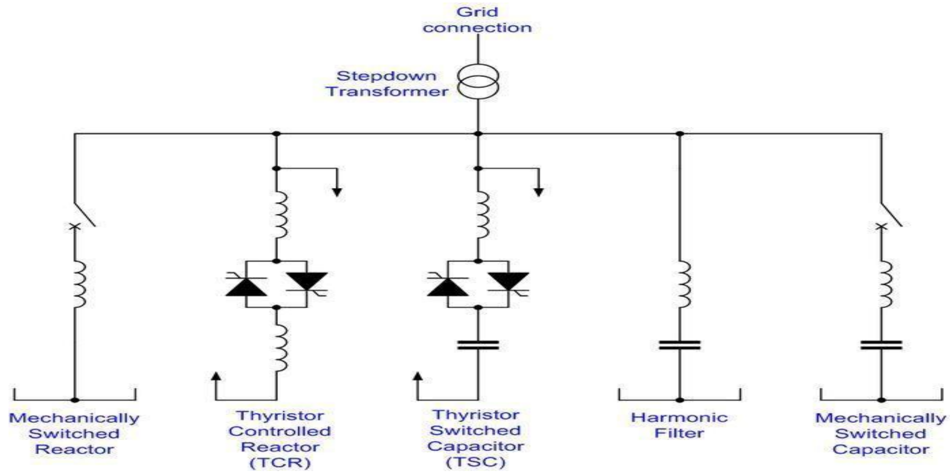
The basic compensation needs fall into one of the following two main categories

- Direct voltage support to maintain sufficient line voltage for facilitating increased power flow under heavy loads and for preventing voltage instability.
- Transient and dynamic stability improvements to improve the first swing stability margin and provide power oscillation damping.

SVC:

SVCs are part of the Flexible AC transmission system device family, regulating voltage and stabilizing the system. Unlike a synchronous condenser which is a rotating electrical machine, a "static" VAR compensator has no significant moving parts (other than internal switchgear). Prior to the invention of the SVC, power factor compensation was the preserve of large rotating machines such as synchronous condensers or switched capacitor banks.

Fig.shows Static Var Compensator(SVC).



An SVC comprises one or more banks of fixed or switched shunt capacitors or reactors, of which at least one bank is switched by thyristors. Elements which may be used to make an SVC typically include:

Thyristor controlled reactor (TCR), where the reactor may be air- or iron-cored Thyristor

switched capacitor (TSC)

Harmonic filter(s)

Mechanically switched capacitors or reactors (switched by a circuit breaker)

The SVC is an automated impedance matching device, designed to bring the system closer to unity power factor. SVCs are used in two main situations:

Connected to the power system, to regulate the transmission voltage ("Transmission SVC") Connected near

large industrial loads, to improve power quality ("Industrial SVC")

Fig.shows V-I Characteristics of SVC.

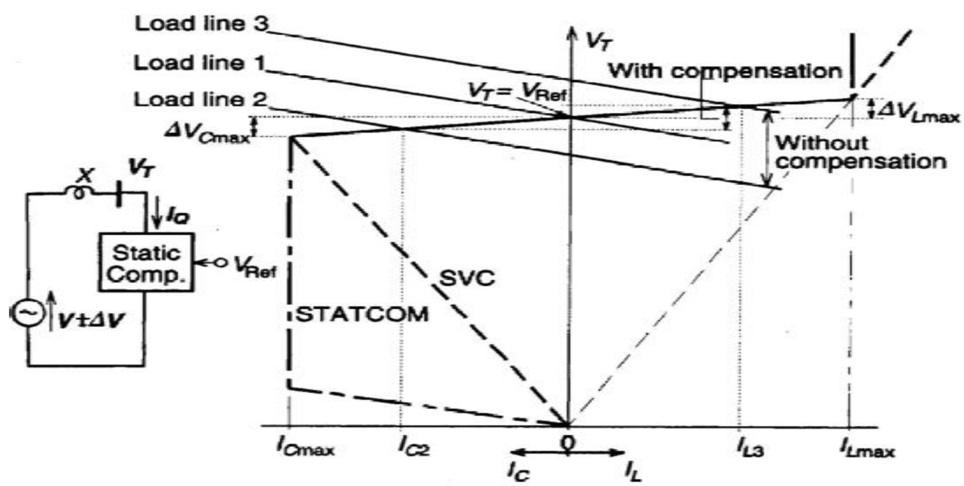
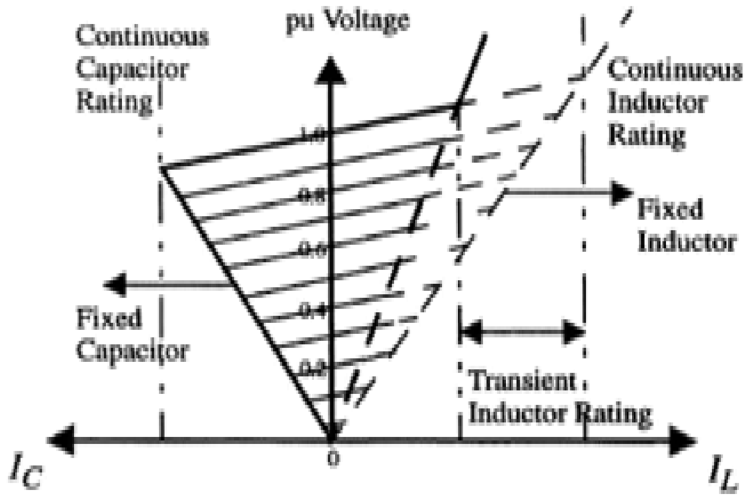


Figure 5.45 *V-I* characteristic of the SVC and the STATCOM.



(b)

In transmission applications, the SVC is used to regulate the grid voltage. If the power system's reactive load is capacitive (leading), the SVC will use thyristor controlled reactors to consume vars from the system, lowering the system voltage. Under inductive (lagging) conditions, the capacitor banks are automatically switched in, thus providing a higher system voltage. By connecting the thyristor-controlled reactor, which is continuously variable, along with a capacitor bank step, the net result is continuously-variable leading or lagging power.

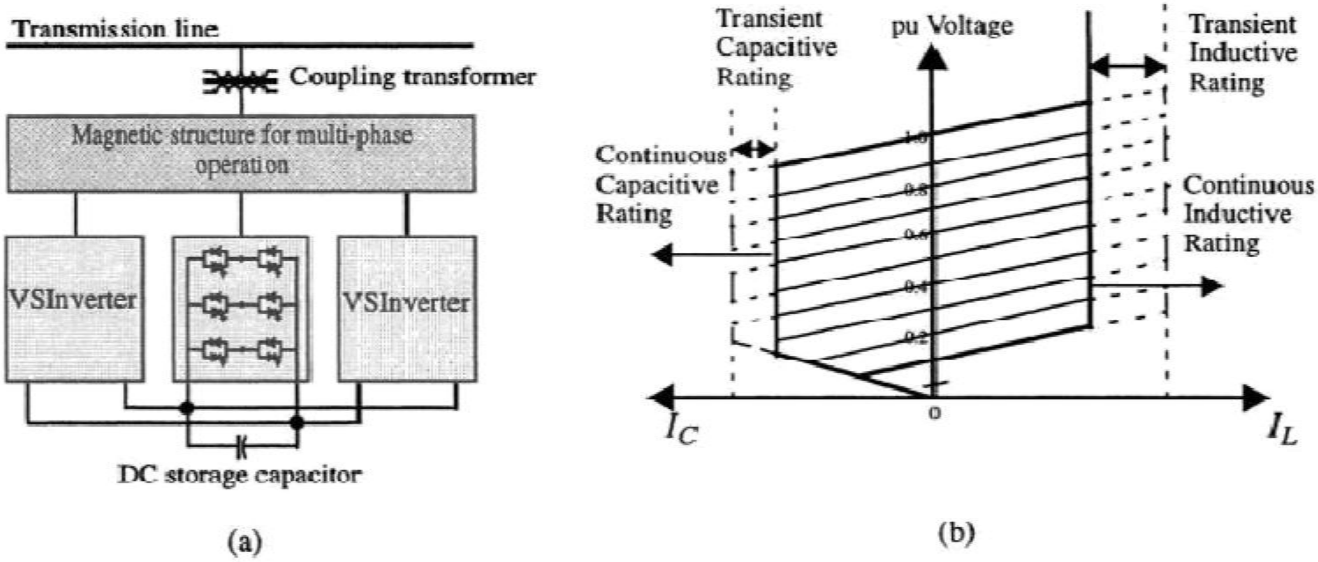
In industrial applications, SVCs are typically placed near high and rapidly varying loads, such as arc furnaces, where they can smooth flicker voltage.

STATCOM:

A **static synchronous compensator** (**STATCOM**), also known as a "static synchronous condenser" ("STATCON"), is a regulating device used on alternating current electricity transmission networks. It is based on a power electronics voltage-source converter and can act as either a source or sink of reactive AC power to an electricity network. If connected to a source of power it can also provide active AC power. It is a member of the FACTS family of devices.

The STATCOM generates a 3-phase voltage source with controllable amplitude and phase angle behind reactance. When the a.c. output voltage from the inverter is higher(lower) than the bus voltage, current flow is caused to lead(lag) and the difference in the voltage amplitudes determines how much current flows. This allows the control of reactive power.

Fig. shows block diagram representation of STATCOM and V-I characteristics.



The STATCOM is implemented by a 6-pulse Voltage Source Inverter(VSI) comprising GTO thyristors fed from a d.c.storage capacitor.The STATCOM is able to control its output current over the rated maximum capacitive or inductive range independently of a.c. system voltage, in contrast to the SVC that varies with the ac system voltage. Thus STATCOM is more effective than the SVC in providing voltage support and stability improvements. The STATCOM can continue to produce capacitive current independent of voltage.The amount and duration of the overload capability is dependent upon the thermal capacity of the GTO.

Note : Multi-pulse circuit configurations are employed to reduce the harmonic generation and to produce practically sinusoidal current.

Comparison between STATCOM and SVC:

S.No.	STATCOM	SVC
1	Acts as a voltage source behind a reactance	Acts as a variable susceptance
2	Insensitive to transmission system harmonic resonance	Sensitive to transmission system harmonic resonance
3	Has a larger dynamic range .	Has a smaller dynamic voltage
4	Lower generation of harmonics .	Higher generation of harmonics
5	Faster response and better performance during transients	Somewhat slower response
6	Both inductive and capacitive regions of operation is possible	Mostly capacitive region of operation
7	Can maintain a stable voltage even with a very weak a.c. system	Has difficulty operating with a very weak a.c. system

STATIC SYNCHRONOUS SERIES COMPENSATOR

INTRODUCTION

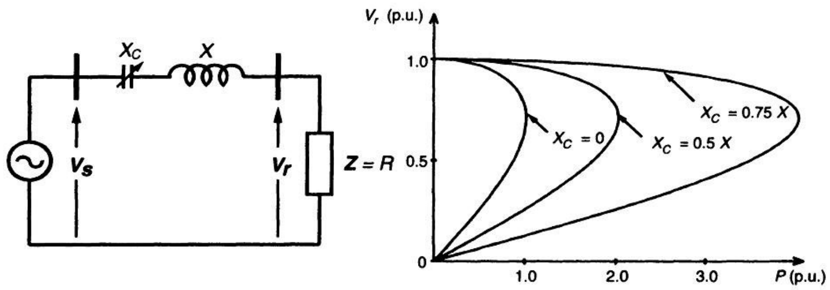
Series compensation is a means of controlling the power transmitted across transmission lines by altering or changing the characteristic impedance of the line. The power flow problem may be related to the length of the transmission line. The transmission line may be compensated by a fixed capacitor or inductor to meet the requirements of the transmission system. When the structure of the transmission network is considered, power flow imbalance problems arise. Inadvertent interchange occurs when the power system tie line becomes corrupted. This is because of unexpected change in load on a distribution feeder due to which the demand for power on that feeder increases or decreases. The generators are to be turned on or off to compensate for this change in load. If the generators are not activated very quickly, voltage sags or surges can occur. In such cases, controlled series compensation helps effectively.

SERIES COMPENSATOR

Series compensation, if properly controlled, provides voltage stability and transient stability improvements significantly for post-fault systems. It is also very effective in damping out power oscillations and mitigation of sub-synchronous resonance (Hingorani 2000).

Voltage Stability

Series capacitive compensation reduces the series reactive impedance to minimize the receiving end voltage variation and the possibility of voltage collapse. Figure 3.1 (a) shows a simple radial system with feeder line reactance X, series compensating reactance X_c and load impedance Z. The corresponding normalized terminal voltage V_r versus power P plots, with unity power factor load and 0, 50, and 75% series capacitive compensation, are shown in Figure 3.1(b). The "nose point" at each plot for a specific compensation level represents the corresponding voltage instability. So by cancelling a portion of the line reactance, a "stiff" voltage source for the load is given by the compensator.



(a) (b)

Figure 3.1 Transmittable power and voltage stability limit of a radial transmission line as a function of series capacitive compensation

Transient Stability Enhancement

The transient stability limit is increased with series compensation. The equal area criterion is used to investigate the capability of the ideal series compensator to improve the transient stability.

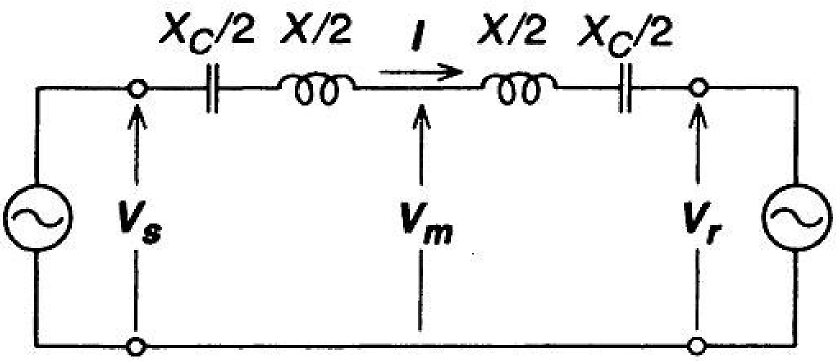


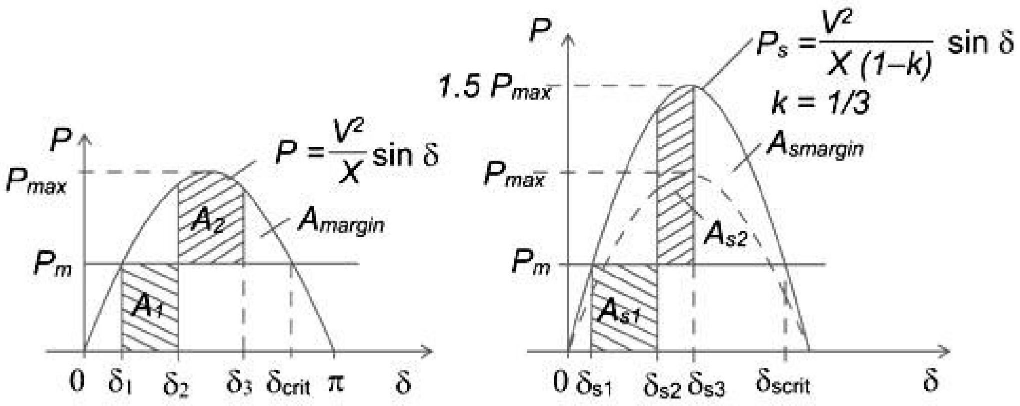
Figure 3.2 Two machine system with series capacitive compensation

Figure 3.2 shows the simple system with the series compensated line. Assumptions that are made here are as follows:

- The pre-fault and post-fault systems remain the same for the series compensated system.
- The system, with and without series capacitive compensation, transmits the same power P_m.
- Both the uncompensated and the series compensated systems are subjected to the same fault for the same period of time.

Figures 3.3 (a) and (b) show the equal area criterion for a simple two machine system without and with series compensator for a three phase to ground fault in the transmission line. From the figures, the dynamic behaviour of these systems are discussed.

Prior to the fault, both of them transmit power P_m at angles 6_1 and 6_{s1} respectively. During the fault, the transmitted electric power becomes zero, while the mechanical input power to the generators remains constant (P_m). Hence, the sending end generator accelerates from the steady-state angles 6_1 and 6_{s1} to 6_2 and 6_{s2} respectively, when the fault clears. In the figures, the accelerating energies are represented by areas A_1 and A_{s1}. After fault clearing, the transmitted electric power exceeds the mechanical input power and therefore the sending end machine decelerates. However, the accumulated kinetic energy further increases until a balance between the accelerating and decelerating energies, represented by the areas A_1, A_{s1} and A_2, A_{s2}, respectively, are reached at the maximum angular swings, 6_3 and 6_{s3} respectively. The areas between the P versus 6 curve and the constant P_m line over the intervals defined by angles 6_3 and 6_{crit}, and 6_{s1} and 6_{scrit}, respectively, determine the margin of transient stability represented by areas A_{margin} and $A_{smargin}$ for the system without and with compensation.



(a) (b)

Figure 3.3 Equal area criterion to illustrate the transient stability margin for a simple two-machine system (a) without compensation and (b) with a series capacitor

Comparing figures 3.3(a) and (b), it is clear that there is an increase in the transient stability margin with the series capacitive compensation by partial cancellation of the series impedance of the transmission line. The increase of transient stability margin is proportional to the degree of series compensation.

Power Oscillation Damping

Power oscillations are damped out effectively with controlled series compensation. The degree of compensation is varied to counteract the accelerating and decelerating swings of the disturbed machine(s) for damping out power oscillations. When the rotationally oscillating generator accelerates and angle 6 increases (d6/dt > 0), the electric power transmitted must be increased to compensate for the excess mechanical input power and conversely, when the generator decelerates and angle 6 decreases (d6/dt < 0), the electric power must be decreased to balance the insufficient mechanical input power.

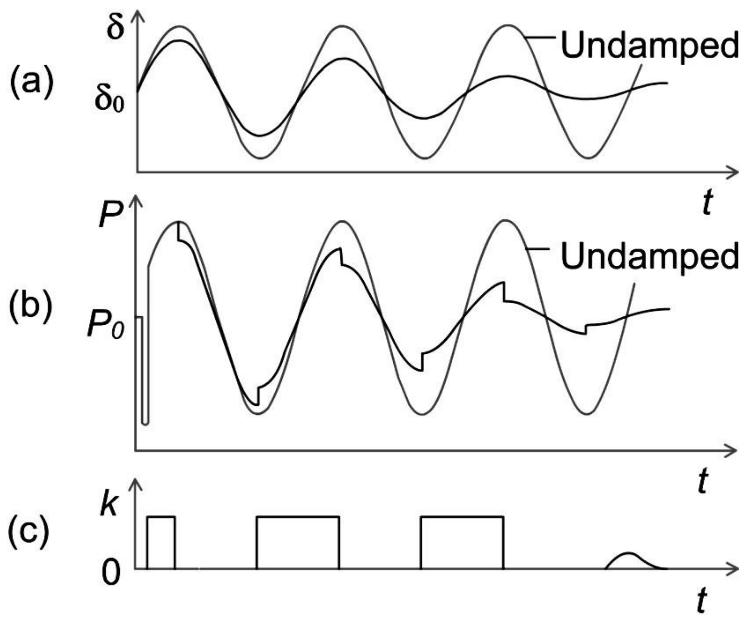


Figure 3.4 Waveforms illustrating power oscillation damping by controllable series compensation (a) generator angle (b) transmitted power and (c) degree of series compensation

Figure 3.4 shows the waveforms describing the power oscillation damping by controllable series compensation. Waveforms in figure 3.4(a) show the undamped and damped oscillations of angle 6 around the steady state value 6_0. The corresponding undamped and damped oscillations of the electric power P around the steady state value P_0, following an assumed fault (sudden drop in P) that initiated the oscillation are shown by the waveforms in figure 3.4(b). Waveform 3.4 (c) shows the applied variation of the degree of series compensation, k applied. ‘k’ is maximum when $d6/dt > 0$, and it is zero when $d6/dt < 0$.

Immunity to Sub-synchronous Resonance

The sub-synchronous resonance is known as an electric power system condition where the electric network exchanges energy with a turbine generator at one or more of the natural frequencies of the combined system below the synchronous frequency of the system. With controlled series compensation, the resonance zone is prohibited for operation and the control system is designed in such a way that the compensator does not enter that area. Also, an SSSC is an ac voltage source operating only at the fundamental output frequency and its output impedance at any other frequency should be zero. The SSSC is unable to form a series resonant circuit with the inductive line impedance to initiate sub-synchronous system oscillations.

Types of Series Compensators

Series compensation is accomplished either using a variable impedance type series compensators or a switching converter type series compensator.

Variable impedance type series compensators

The thyristor controlled series compensators are the variable type of compensators. The type of thyristor used for the variable type series compensators has an impact on their performance. The types of thyristors used in FACTS devices are Silicon Controller Rectifier (SCR), Gate Turn-Off Thyristor (GTO), MOS Turn-Off Thyristor (MTO), Integrated Gate Commutated Thyristor (GCT or IGCT), MOS Controlled Thyristor (MCT) and Emitter Turn-Off Thyristor (ETO). Each of these types of thyristors has several important device parameters that are needed for the design of FACT devices. These parameters are di/dt capability, dv/dt capability, turn-on time and turn-off time, Safe Operating Area (SOA), forward drop voltage, switching speed, switching losses, and gate drive power.

The variable impedance type series compensators are GTO thyristor controlled series compensator (GCSC), Thyristor Switched Series Capacitor (TSSC) and Thyristor Controlled Series Capacitor (TCSC).

GTO Thyristor Controlled Series Capacitor (GCSC)

A GCSC consists of a fixed capacitor in parallel with a GTO Thyristor as in figure 3.5which has the ability to be turned on or off. The GCSC controls the voltage across the capacitor (V_c) for a given line current. In other words, when the GTO is closed the voltage across the capacitor is zero and when the GTO is open the voltage across the capacitor is at its maximum value. The magnitude of the capacitor voltage can be varied continuously by the method of delayed angle control (max y = 0, zero y = n/2). For practical applications, the GCSC compensates either the voltage or reactance.

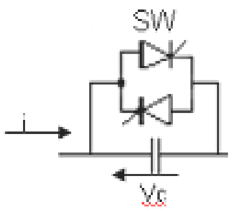


Figure 3.5 GTO Controlled Series Capacitor

Thyristor Switched Series Capacitor (TSSC)

Thyristor Switched Series Capacitor (TSSC) is another type of variable impedance type series compensators shown in Figure 3.6. The TSSC consists of several capacitors shunted by a reverse connected thyristor bypass switch.

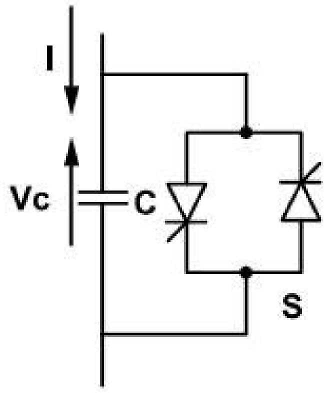


Figure 3.6 Thyristor Switched Series Capacitor

In TSSC, the amount of series compensation is controlled in a step-like manner by increasing or decreasing the number of series capacitors inserted into the line. The thyristor turns off when the line current crosses the zero point. As a result, capacitors can only be inserted or deleted from the string at the zero crossing. Due to this, a dc offset voltage arises which is equal to the amplitude of the ac capacitor voltage. In order to keep the initial surge current at a minimum, the thyristor is turned on when the capacitor voltage is zero.

The TSSC controls the degree of compensating voltage by either inserting or bypassing series capacitors. There are several limitations to the TSSC. A high degree of TSSC compensation can cause sub-synchronous resonance in the transmission line just like a traditional series capacitor. The TSSC is most commonly used for power flow control and for damping power flow oscillations where the response time required is moderate. There are two modes of operation for the TSSC-voltage compensating mode and impedance compensating mode.

Thyristor Controlled Series Capacitor (TCSC)

Figure 3.7 shows the basic Thyristor Controlled Series Capacitor (TCSC) scheme. The TCSC is composed of a series-compensating capacitor in parallel with a thyristor-controlled reactor. The TCSC provides a continuously variable capacitive or inductive reactance by means of thyristor firing angle control. The parallel LC circuit determines the steady-state impedance of the TCSC.

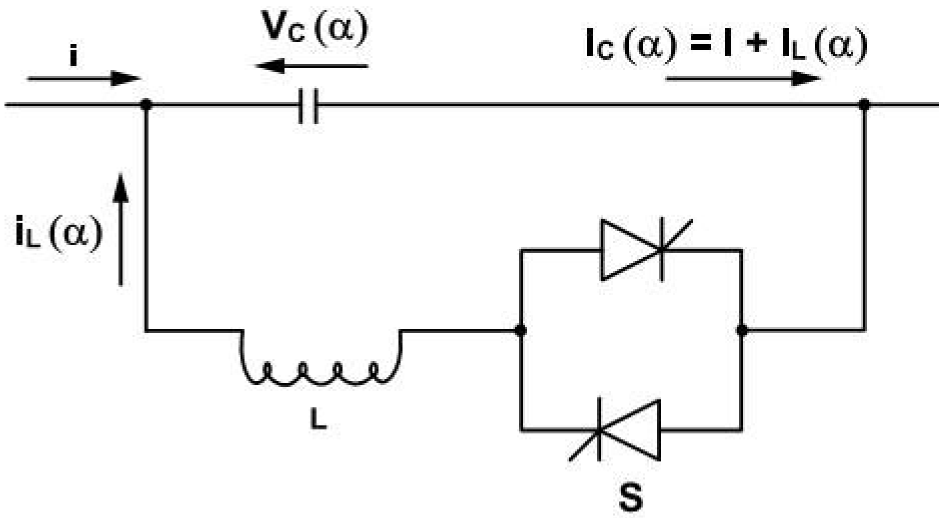


Figure 3.7 Thyristor Controlled Series Capacitor

The impedance of the controllable reactor is varied from its maximum (infinity) to its minimum (mL). The TCSC has two operating ranges; one is when $a_{Clim} \leq a \leq n/2$, where the TCSC is in capacitive mode. The other range of operation is $0 \leq a \leq a_{Llim}$, where the TCSC is in inductive mode. TCSC can be operated in impedance compensation mode or voltage compensation mode.

Switching converter type compensator

With the high power forced-commutated valves such as the GTO and ETO, the converter-based FACTS controllers have become true. The advantages of converter-based FACTS controllers are continuous and precise power control, cost reduction of the associated relative components and a reduction in size and weight of the overall system.

An SSSC is an example of a FACTS device that has its primary function to change the characteristic impedance of the transmission line and thus change the power flow. The impedance of the transmission line is changed by injecting a voltage which leads or lags the transmission line current by 90°.

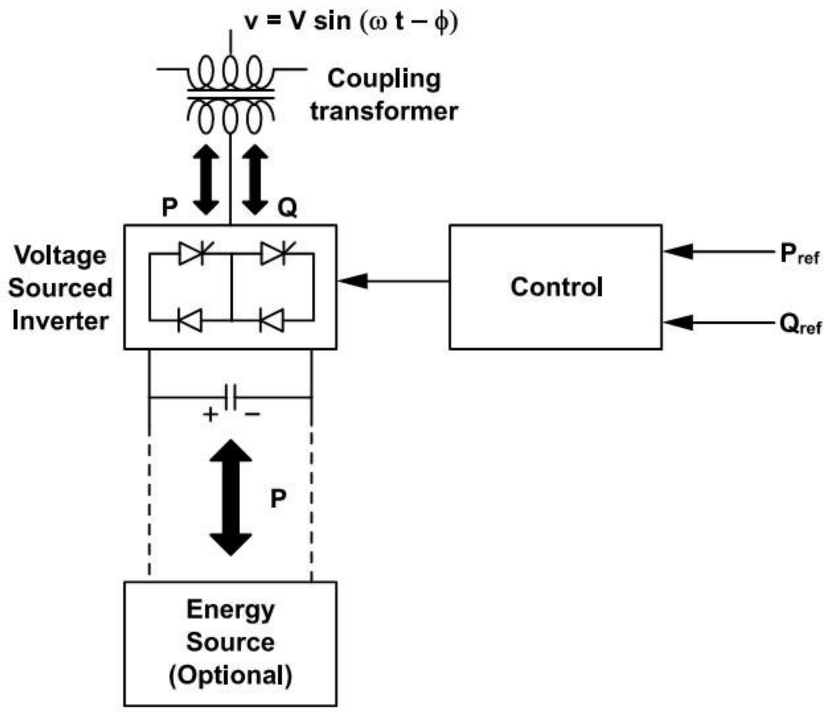


Figure 3.8 Schematic diagram of SSSC

If the SSSC is equipped with an energy storage system, the SSSC gets an added advantage of real and reactive power compensation in the power system. By controlling the angular position of the injected voltage with respect to the line current, the real power is provided by the SSSC with energy storage element. Figure 3.8 shows a schematic diagram of SSSC with energy storage system for real and reactive power exchange.

The applications for an SSSC are the same as for traditional controllable series capacitors. The SSSC is used for power flow control, voltage stability and phase angle stability. The benefit of the SSSC over the conventional controllable series capacitor is that the SSSC induces both capacitive and inductive series compensating voltages on a line. Hence, the SSSC has a wider range of operation compared with the traditional series capacitors.

The primary objective of this thesis is to examine the possible uses of the SSSC with energy storage system with state-of-the-art power semiconductor devices in order to provide a more cost effective solution.

Comparison of Series Compensator Types

Figure 3.9 shows a comparison of VI and loss characteristics of variable type series compensators and the converter based series compensator.

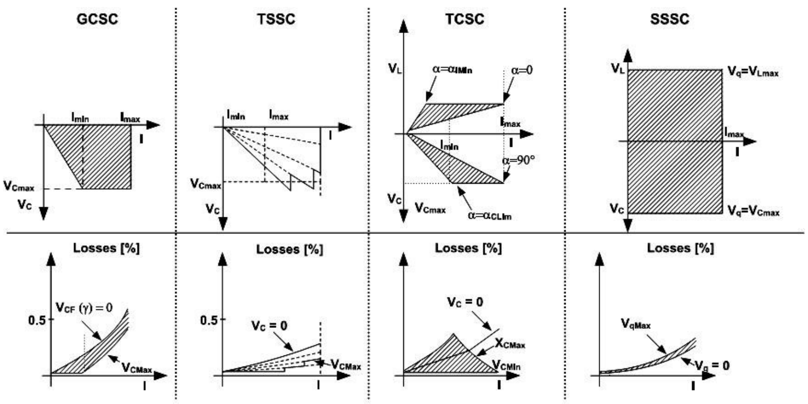


Figure 3.9 Comparison of Variable Type Series Compensators to Converter Type Series Compensator

From the figure the following conclusions can be made.

- The SSSC is capable of internally generating a controllable compensating voltage over any capacitive or inductive range independent of the magnitude of the line current. The GCSC and the TSSC generate a compensating voltage that is proportional to the line current. The TCSC maintains the maximum compensating voltage with decreasing line current but the control range of the compensating voltage is determined by the current boosting capability of the thyristor controlled reactor.
- The SSSC has the ability to be interfaced with an external dc power supply. The external dc power supply is used to provide compensation for the line resistance. This is accomplished by the injection of real power as well as for the line reactance by the injection of reactive power. The variable impedance type series compensators cannot inject real power into the transmission line. They can only provide reactive power compensation.
- The SSSC with energy storage can increase the effectiveness of the power oscillation damping by modulating the amount of series compensation in order to increase or decrease the transmitted power. The SSSC increases or decreases the amount of transmitted power by injecting positive and negative real impedances into the transmission line. The variable-type series compensators can damp the power oscillations by modulating the reactive compensation.

STATIC SYNCHRONOUS SERIES COMPENSATOR (SSSC)

The Voltage Sourced Converter (VSC) based series compensators - Static Synchronous Series Compensator (SSSC) was proposed by Gyugyi in 1989. The single line diagram of a two machine system with SSSC is shown in Figure 3.10. The SSSC injects a compensating voltage in series with the line irrespective of the line current. From the phasor diagram, it can be stated that at a given line current, the voltage injected by the SSSC forces the opposite polarity voltage across the series line reactance. It works by increasing the voltage across the transmission line and thus increases the corresponding line current and transmitted power.

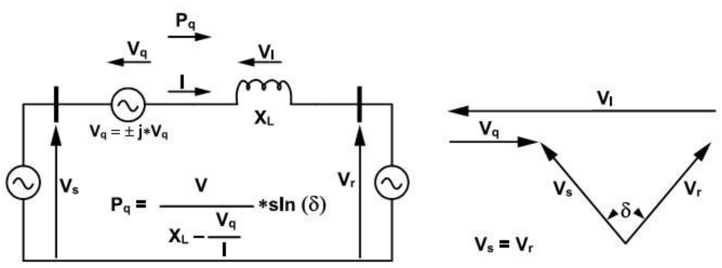


Figure 3.10 Simplified diagram of series compensation with the phasor diagram.

The compensating reactance is defined to be negative when the SSSC is operated in an inductive mode and positive when operated in capacitive mode. The voltage source converter can be controlled in such a way that the output voltage can either lead or lag the line current by 90^o. During normal capacitive compensation, the output voltage lags the line current by 90^o. The SSSC can increase or decrease the power flow to the same degree in either direction simply by changing the polarity of the injected ac voltage. The reversed (180^o) phase shifted voltage adds directly to the reactive voltage drop of the line. The reactive line impedance appears as if it were increased. If the amplitude of the reversed polarity voltage is large enough, the power flow will be reversed. The transmitted power verses transmitted phase angle relationship is shown in Equation (3.1) and the transmitted power verses transmitted angle as a function of the degree of series compensation is shown in Figure 3.11.

$$P = \frac{V^2}{X} \sin \delta + \frac{V}{X} V_q \cos \frac{\delta}{2} \qquad (3.1)$$

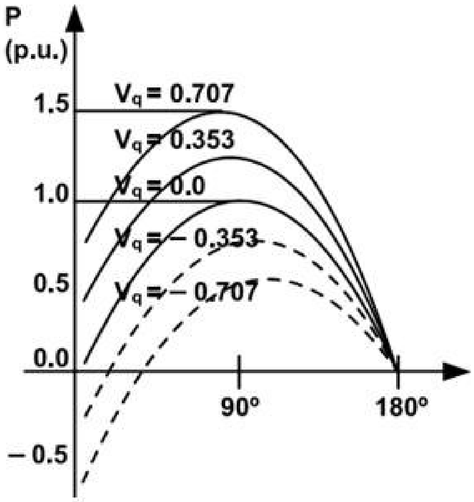


Figure 3.11 Transmitted power verses transmitted angle as a function of series compensation

CONVERTERS

Basic Concept

The conventional thyristor device has only the turn on control and its turn off depends on the natural current zero. Devices such as the Gate Turn Off Thyristor (GTO), Integrated Gate Bipolar Transistor (IGBT), MOS Turn Off Thyristor (MTO) and Integrated Gate Commutated Thyristor (IGCT) and similar devices have turn on and turn off capability. These devices are more expensive and have higher losses than the thyristors without turn off capability; however, turn off devices enable converter concepts that can have significant overall system cost and performance advantages. These advantages in principle result from the converter, which are self commutating as against the line commutating converters. The line commutating converter consumes reactive power and suffers from occasional commutation failures in the inverter mode of operation. Hence, the converters applicable for FACTS controllers are of self commutating type (Hingorani and Gyugyi, 2000). There are two basic categories of self commutating converters:

UNIT-V

POWER FLOW CONTROLLERS

THE UNIFIED POWER FLOW CONTROLLER

The Unified Power Flow Controller (UPFC) concept was proposed by Gyugyi in 1991. The UPFC was devised for the real-time control and dynamic compensation of ac transmission systems, providing multifunctional flexibility required to solve many of the problems facing the power delivery industry. Within the framework of traditional power transmission concepts, the UPFC is able to control, simultaneously or selectively, all the parameters affecting power flow in the transmission line (i.e., voltage, impedance, and phase angle), and this unique capability is signified by the adjective "unified"
in its name. Alternatively, it can independently control both the real and .reactive power flow in the line. The reader should recall that, for all the Controllers discussed in the previous chapters, the control of real power is associated with similar change in reactive power, i.e., increased real power flow also resulted in increased reactive line power.

Basic Operating Principles of UPFC

From the conceptual viewpoint, the UPFC is a generalized synchronous voltage source (SVS), represented at the fundamental (power system) frequency by voltage phasor $\boldsymbol{V}_{pq}$ with controllable magnitude V_{pq} ($0 \leq V_{pq} \leq V_{pq\max}$) and angle ρ ($0 \leq \rho \leq 2\pi$), in series with the transmission line, as illustrated for the usual elementary two-machine system (or for two independent systems with a transmission link intertie) in Figure 8.3. In this functionally unrestricted operation, which clearly includes voltage and angle regulation, the SVS generally exchanges both reactive and real power with the transmission system. Since, as established previously, an SVS is able to generate only the reactive power exchanged, the real power must be supplied to it, or absorbed from it, by a suitable power supply or sink. In the UPFC arrangement the real power exchanged is provided by one of the end buses (e.g., the sending-end bus), as indicated in Figure 8.3.

In the presently used practical implementation, the UPFC consists of two voltage-sourced converters, as illustrated in Figure 8.4. These back-to-back converters, labeled "Converter 1" and "Converter 2" in the figure, are operated from a common dc link provided by a dc storage capacitor. As indicated before, this arrangement functions as an ideal ac-to-ac power converter in which the real power can freely flow in either direction between the ac terminals of the two converters, and each converter can independently generate (or absorb) reactive power at its own ac output terminal.

Converter 2 provides the main function of the UPFC by injecting a voltage $\boldsymbol{V}_{pq}$ with controllable magnitude V_{pq} and phase angle ρ in series with the line via an insertion transformer. This injected voltage acts essentially as a synchronous ac voltage

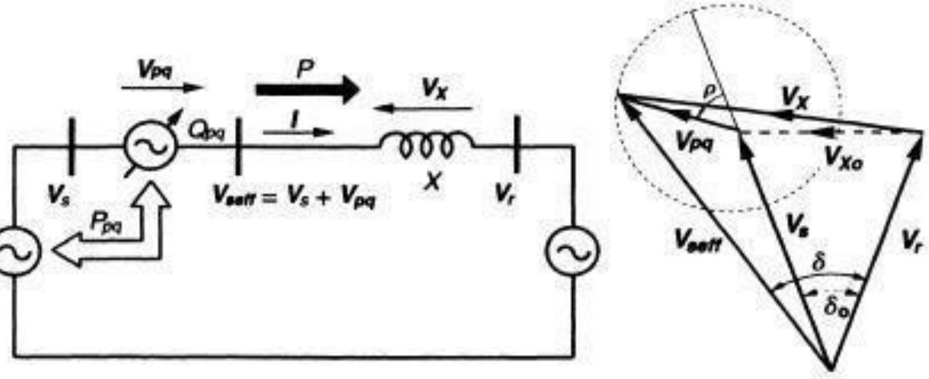


Figure 8.3 Conceptual representation of the UPFC in a two-machine power system.

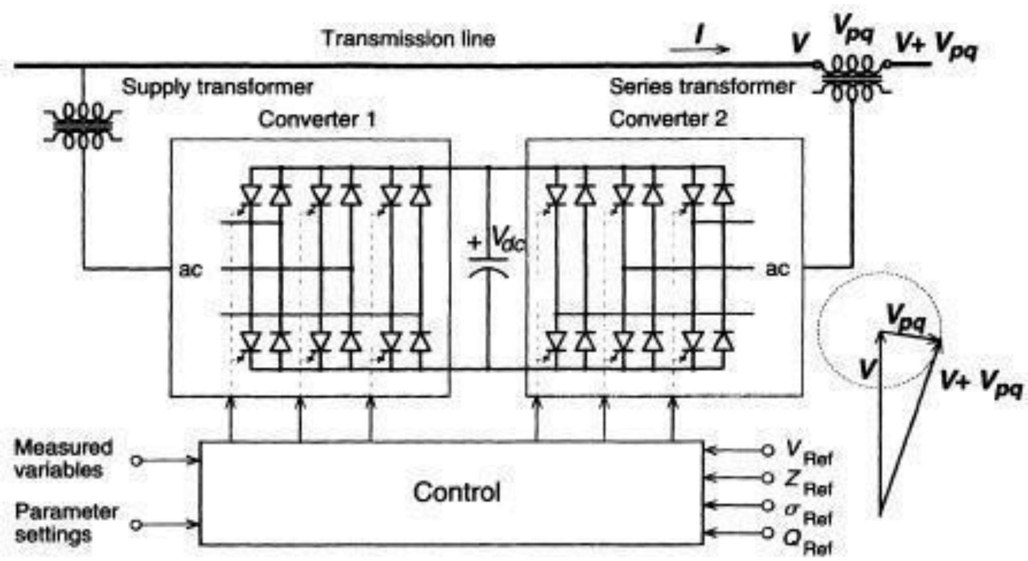


Figure 8.4 Implementation of the UPFC by two back-to-back voltage-sourced converters.

source. The transmission line current flows through this voltage source resulting in reactive and real power exchange between it and the ac system. The reactive power exchanged at the ac terminal (Le., at the terminal of the series insertion transformer) is generated internally by the converter. The real power exchanged at the ac terminal is converted into de power which appears at the de link as a positive or negative real power demand. The basic function of Converter 1 is to supply or absorb the real power demanded by Converter 2 at the common de link to support the real power exchange resulting from the series voltage injection. This de link power demand of Converter 2 is converted back to ac by Converter 1 and coupled to the transmission line bus via a shuntconnected transformer. In addition to the real power need of Converter 2, Converter 1 can also generate or absorb controllable reactive power, if it is desired, and thereby provide independent shunt reactive compensation for the line. It is important to note that whereas there is a closed direct path for the real power negotiated by the action of series voltage injection through Converters 1 and 2 back to the line, the corresponding reactive power exchanged is supplied or absorbed locally by Converter 2 and therefore does not have to be transmitted by the line. Thus, Converter 1 can be operated at a unity power factor or be controlled to have a reactive power exchange with the line independent of the reactive power exchanged by Converter 2. Obviously, there can be no reactive power flow through the UPFC de link.

INDEPENDENT REAL AND REACTIVE POWER FLOW CONTROL:

In order to investigate the capability of the UPFC to control real and reactive power flow in the transmission line, refer to Figure 8.7(a). Let it first be assumed that the injected compensating voltage, V_{pq}, is zero. Then the original elementary two-machine (or two-bus ac intertie) system with sending-end voltage V_s, receiving-end voltage V_r, transmission angle δ, and line impedance X is restored. With these, the normalized transmitted power, $P_0(\delta) = \{V^2/X\} \sin \delta = \sin \delta$, and the normalized reactive power, $Q_0(\delta) = Q_{0s}(\delta) = -Q_{0r}(\delta) = \{V^2/X\}\{1-\cos \delta\} = 1-\cos \delta$, supplied at the ends of the line, are shown plotted against angle (δ) in Figure 8.8(a). The relationship between real power $P_0(\delta)$ and reactive power $Q_{0r}(\delta)$ can readily be expressed with $V^2/X = 1$ in the following form:

$$Q_{0r}(\delta) = -1 - \sqrt{1 - \{P_0(\delta)\}^2} \tag{8.13}$$

or

$$\{Q_{0r}(\delta) + 1\}^2 + \{P_0(\delta)\}^2 = 1 \tag{8.14}$$

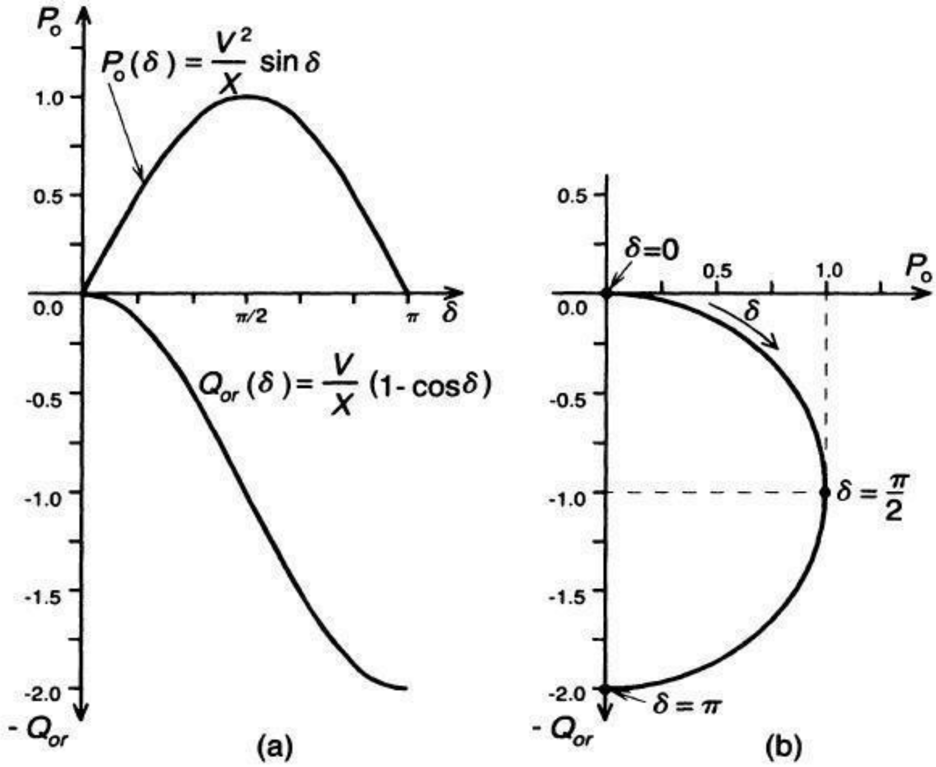


Figure 8.8 Transmittable real power P_0 and receiving-end reactive power demand Q_{or} vs. transmission angle δ of a two-machine system (a) and the corresponding Q_{or} vs. P_0 loci (b).

Equation (8.14) describes a circle with a radius of 1.0 around the center defined by coordinates $P = 0$ and $Q_r = -1$ in a $\{Q_r, P\}$ plane, as illustrated for positive values of P in Figure 8.8(b). Each point of this circle gives the corresponding P_0 and Q_{0r} values of the uncompensated system at a specific transmission angle δ. For example, at $\delta = 0$, $P_0 = 0$ and $Q_{0r} = 0$; at $\delta = 30°$, $P_0 = 0.5$ and $Q_{0r} = -0.134$; at $\delta = 90°$, $P_0 = 1.0$ and $Q_{0r} = -1.0$; etc.

Refer again to Figure 8.7(a) and assume now that $\boldsymbol{V_{pq}} \neq 0$. It follows from (8.3), or (8.7) and (8.8), and from Figure 8.7(b), that the real and reactive power change from their uncompensated values, $P_0(\delta)$ and $Q_{0r}(\delta)$, as functions of the magnitude V_{pq} and angle ρ of the injected voltage phasor $\boldsymbol{V_{pq}}$. Since angle ρ is an unrestricted variable ($0 \leq \rho \leq 2\pi$), the boundary of the attainable control region for $P(\delta, \rho)$ and $Q_r(\delta, \rho)$ is obtained from a complete rotation of phasor $\boldsymbol{V_{pq}}$ with its maximum magnitude $V_{pq\max}$. It follows from the above equations that this control region is a circle with a center defined by coordinates $P_0(\delta)$ and $Q_{0r}(\delta)$ and a radius of V_rV_{pq}/X. With $V_s = V_r = V$, the boundary circle can be described by the following equation:

$$\{P(\delta, \rho) - P_0(\delta)\}^2 + \{Q_r(\delta, \rho) - Q_{0r}(\delta)\}^2 = \left\{\frac{VV_{pq\max}}{X}\right\}^2 \qquad (8.15)$$

The circular control regions defined by (8.15) are shown in Figures 8.9(a) through (d) for $V = 1.0$, $V_{pq\max} = 0.5$, and $X = 1.0$ (per unit or p.u. values) with their centers on the circular arc characterizing the uncompensated system (8.14) at transmission angles $\delta = 0°$, 30°, 60°, and 90°. In other words, the centers of the control regions are defined

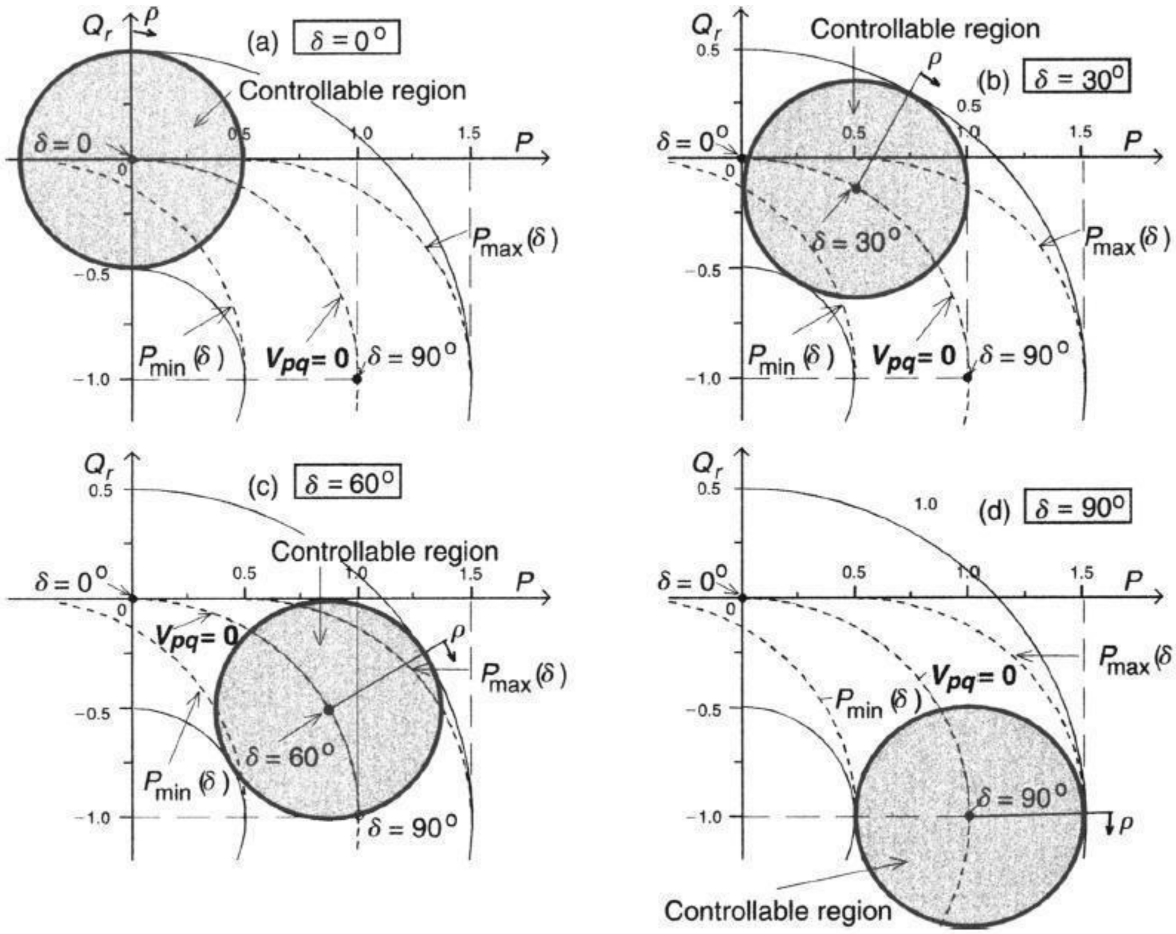


Figure 8.9 Control region of the attainable real power P and receiving-end reactive power demand Q_r with a UPFC-controlled transmission line at $\delta = 0°$ (a), $\delta = 30°$ (b), $\delta = 60°$ (c), and $\delta = 90°$ (d).

by the corresponding $P_0(\delta)$, $Q_{0r}(\delta)$ coordinates at angles $\delta = 0$, 30°, 60°, and 90° in the $\{Q_r, P\}$ plane.

Consider first Figure 8.9(a), which illustrates the case when the transmission angle is zero ($\delta = 0$). With $V_{pq} = 0$, P, Q_r, (and Q_s) are all zero, i.e., the system is at standstill at the origin of the Q_r, P coordinates. The circle around the origin of the $\{Q_r, P\}$ plane is the loci of the corresponding Q_r and P values, obtained as the voltage phasor V_{pq} is rotated a full revolution ($0 \le \rho \le 360°$) with its maximum magnitude $V_{pq\max}$. The area within this circle defines all P and Q_r values obtainable by controlling the magnitude V_{pq} and angle ρ of phasor V_{pq}. In other words, the circle in the $\{Q_r, P\}$ plane defines all P and Q_r values attainable with the UPFC of a given rating. It can be observed, for example, that the UPFC with the stipulated voltage rating of 0.5 p.u. is able to establish 0.5 p.u. power flow, in either direction, without imposing any reactive power demand on either the sending-end or the receiving-end generator. (This statement tacitly assumes that the sending-end and receiving-end voltages are provided by independent power systems which are able to supply and absorb real power without any internal angular change.) Of course, the UPFC, as illustrated, can force the system at one end to supply reactive power for, or absorb that from, the system at the other end. Similar control characteristics for real power P and the reactive power Q_r can be observed at angles $\delta = 30°, 60°$, and $90°$ in Figures 8.9(b), (c), and (d).

In general, at any given transmission angle δ, the transmitted real power P, as well as the reactive power demand at the receiving end Q_r, can be controlled freely by the UPFC within the boundary circle obtained in the $\{Q_r, P\}$ plane by rotating the injected voltage phasor V_{pq} with its maximum magnitude a full revolution. Furthermore, it should be noted that, although the above presentation focuses on the receiving-end reactive power, Q_r, the reactive component of the line current, and the corresponding reactive power can actually be controlled with respect to the voltage selected at any point of the line.

Figures 8.9(a) through (d) clearly demonstrate that the UPFC, with its unique capability to control independently the real and reactive power flow at any transmission angle, provides a powerful, hitherto unattainable, new tool for transmission system control.