388

IMPACTS OF HVDC LINES

ON

THE ECONOMICS OF HVDC PROJECTS

Joint Working Group
B2/B4/C1.17

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cigré

Impacts of HVDC Lines
on
the Economics of HVDC Projects

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TABLE OF CONTENTS

Executive Summary

Introduction

In 2005, Committees B2, B4 and C1 decided to create a Joint Working Group, aimed at studying the impact of overhead lines related cost inside the Economics of HVDC Systems. For materializing this objective, they established the new JWG-B2/B4/C1.17, having the following terms of reference.
"The use of HVDC technology is increasing with the use of IGBT's and other such high speed, relatively low cost technology equipment. This has made DC technology an option for lower voltages as well as for higher voltages. The issues such as T-offs (intermediate substations for supplying loads or AC systems) and fault level requirements as well as cost of terminal equipment have been addressed to a certain extent in many cases. The economics of a point-to-point HVDC project is determined by two major components, namely the DC lines and the converter stations (the eventual supply of intermediate loads can also be considered). In determining the technology (AC or DC) to be used for different power transfer operations, it is necessary to evaluate the cost of the terminal equipment as well as the line linking the terminals. The cost of a HVDC project shall than include both the converter stations and the transmission line".

Therefore, JWG-B2/B4/C1.17 would review the related works already performed inside B4 and B2.09 (Former WG of B2) and develop models for evaluating the cost of DC lines. HVDC (High Voltage Direct Current) is a technology suitable for long distance transmission. The decision of using AC (Alternating Current) or DC (Direct Current) system involves an economic analysis where the line, stations costs and losses have to be considered.

For the same power rating, DC lines are less expensive than AC lines because they need two phases (poles) compared to three phases for AC lines; however the DC station cost must be added to the DC system cost. As the DC stations are more expensive, it means that for short distances AC is more economical, however, as the length increases, DC transmission becomes more economical than AC because the savings in the line cost offset the increase in station cost. The break even cost depends on the local conditions but is generally around 800-1,200 km.

Due to the importance of the HVDC line cost, the Joint Working Group JWG-B2/B4/C1.17 was settled in order to analyze the economics of the whole system and the share represented by the line.

Aspects considered

To understand the economics of DC systems, DC line designs were done and the costs were established. Voltages from ±300 to ±800 kV, powers from 700 to 6,000 MW and line lengths from 750 to 3,000 km were taken into account. For the DC line design 10 (ten) basic alternatives were established. Electrical aspects as overvoltages, insulation coordination, corona effect, and current carrying capacity were evaluated in order to define tower geometries. This was done considering mainly the line crossing a region without ice; however, the cost sensitivity was evaluated for a region with ice.

Mechanical designs were done considering sag and tension calculation, tower loading, and tower and foundation weight estimation for the selected basic designs.

The line budgets broken down into the important items (tower, foundation, conductor, erection, etc) were established and a cost equation was defined as function of voltage and pole conductor configuration (number of conductors and size).

The costs of converter station alternatives were searched in the literature and manufacturer information in order to define a cost equation as function of the power and voltage.

The price of commodities and US$/Euro exchange rate at the date of the study were included for cost updates in the future, if necessary.

The system economical analysis was then carried out by adding the yearly costs of line, converter station, and line and station losses. As result the most favorable voltage and conductor configuration for several ranges of power and line length was defined.

A procedure to compare alternatives based on Present Worth evaluation of a set of yearly parcel was established to compare alternatives taking into consideration the staging of the system construction and different design.

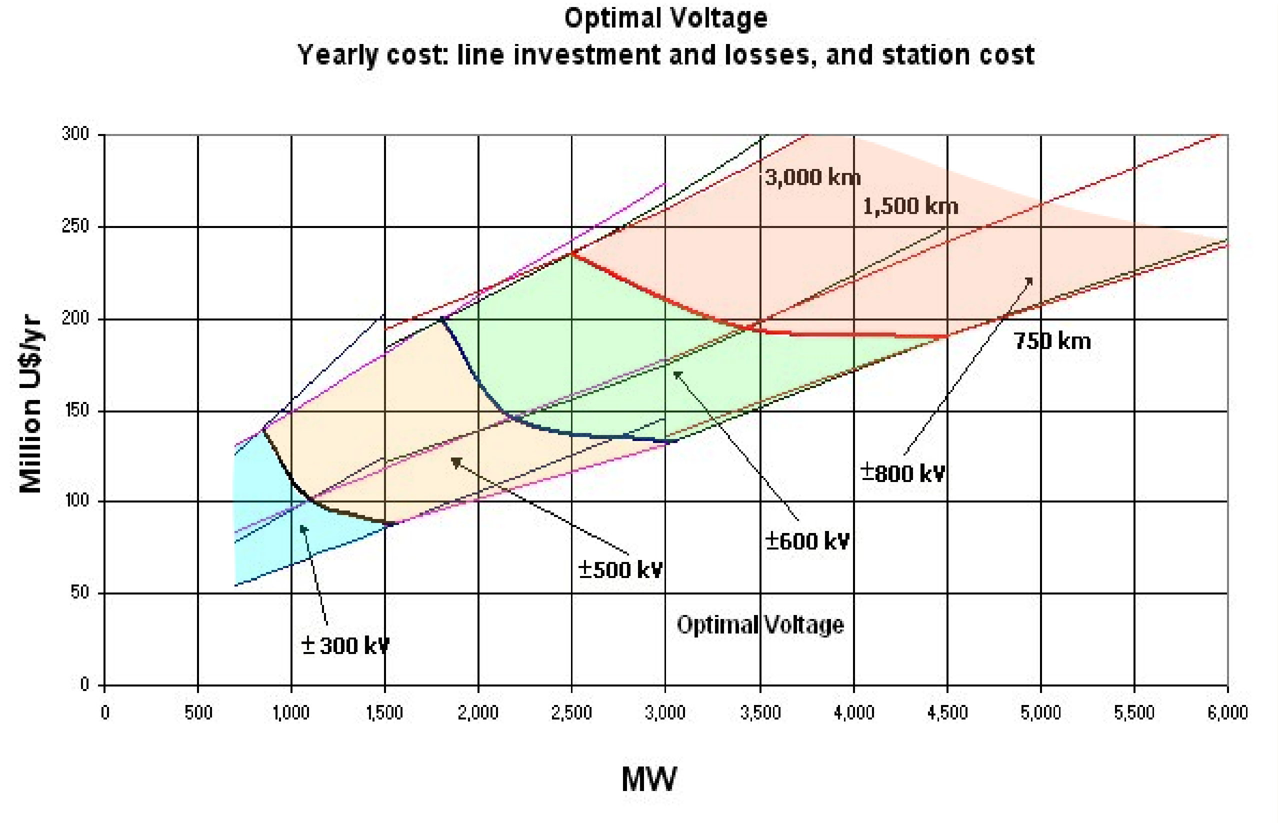
Results

As result, line geometries, tower and foundation evaluation, line budgets, and graphical representation of system cost as function of voltage, power and length are reported. A sensitivity of line cost as function of the basic design assumptions is also included.

The line cost C_L (U$/ km) was obtained based on the cost budget of ten alternatives of line chosen to cover adequate range of voltages (V), of total aluminum section (S) with N subconductors per pole.

$$C_L = a + b\,V + S\,(c\,N + d)$$

By adding the line cost, the corona and Joule losses, and the station cost and it losses cost, the system cost is obtained for any combination of parameters. Then, the optimum voltage and conductor cross section can be obtained. The figure 1 bellow shows the results.



Legend: Red → ±800 kV; green → ±600 kV; pink → ±500 kV; blue → ±300 kV
* station losses cost not included (equal for same station power and different voltage)

Figure 1: Optimal voltage as function of converter station power and line length

On the figure 1 above, three sets of line length are indicated namely 750; 1,500; 3,000 km; for each length a set of curves of the costs for the voltages alternatives are indicated. From them the frontier of changing optimal voltage are identified. For instance, for 1,500 km bellow 3,500 MW the voltage ±600 kV is the most economic whereas above is the ±800 kV. These frontiers are also shown on table 1.

Table 1: Optimal voltage as a function of station power and line length

Voltage (kV)	For 750 km	For 1,500 km	For 3,000 km
±300	<1,550 MW	<1,100 MW	<850 MW
±500	1,550 – 3,050 MW	1,100 – 2,200 MW	850 – 1,800 MW
±600	3,050 – 4,500 MW	2,200 – 3,400 MW	1,800 – 2,500 MW
±800	>4,500	>3,400 MW	>2,500 MW

After comparing direct costs and present worth costs of different alternatives, impact of both line and converter station on the whole system cost are evaluated as exampled bellow(figure 2).

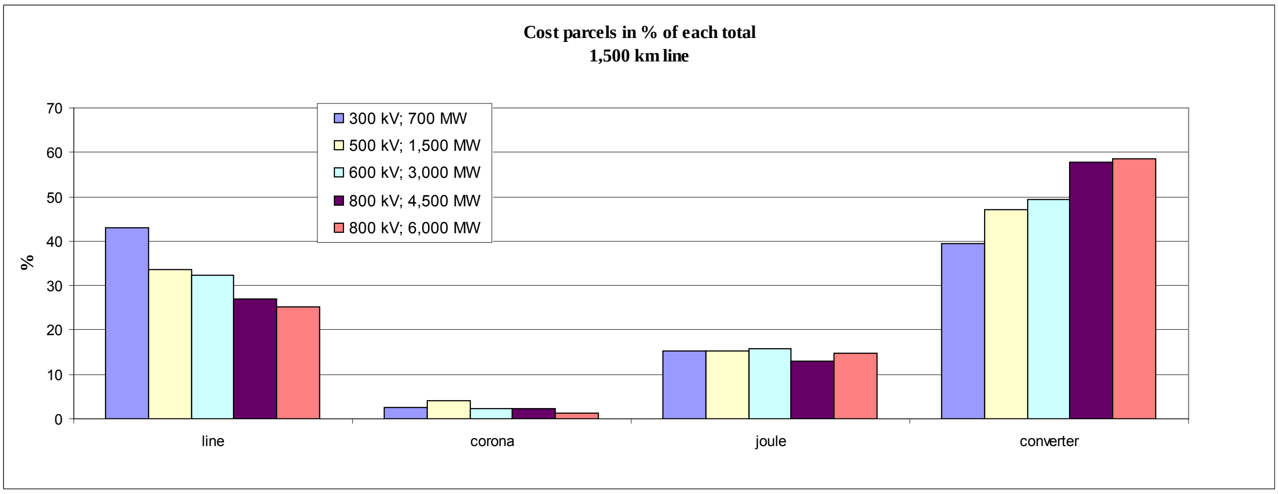


Figure 2: Cost Parcels for 1,500 km line

MW	700		1,500		3,000		4,500		6,000	
kV	+300		+500		+600		+800		+800	
conductor/pole	2		2		4		4		5	
Aluminum area mm^2 (MCM)*	1,155 (2,280)		1,274 (2,515)		1,136 (2,242)		1,274 (2,515)		1,274 (2,515)	
	Million U$/yr	%	Million U$/yr	%	Million U$/yr	%	Million U$/yr	%	Million U$/yr	%
line	33,7	42,9	39,7	33,7	56,9	32,4	65,1	26,9	76,0	25,2
corona	1,9	2,4	4,7	4,0	4,1	2,3	5,4	2,2	4,2	1,4
joule	12,0	15,2	17,9	15,2	27,9	15,9	31,5	13,0	44,8	14,8
converter	30,9	39,4	55,6	47,1	86,7	49,4	140,1	57,9	177,0	58,6
U$/ year/ MW	78,5	100,0	118,0	100,0	175,6	100,0	242,0	100,0	302,0	100,0

* 1MCM=0.5067 mm^2

In this table and figure the broken down costs of the most economical alternatives for a line 1,500 km long, for a set (MW, kV) are shown. The cost are also expressed in percent of the total cost in order to evaluate the impact of the various parcels.

In figure 3 these parcels of cost are shown as function of the station power, and line length. These parcels are in % of the total cost (investment plus losses). To get the losses parcels subtract from 100% the line plus station investment cost.

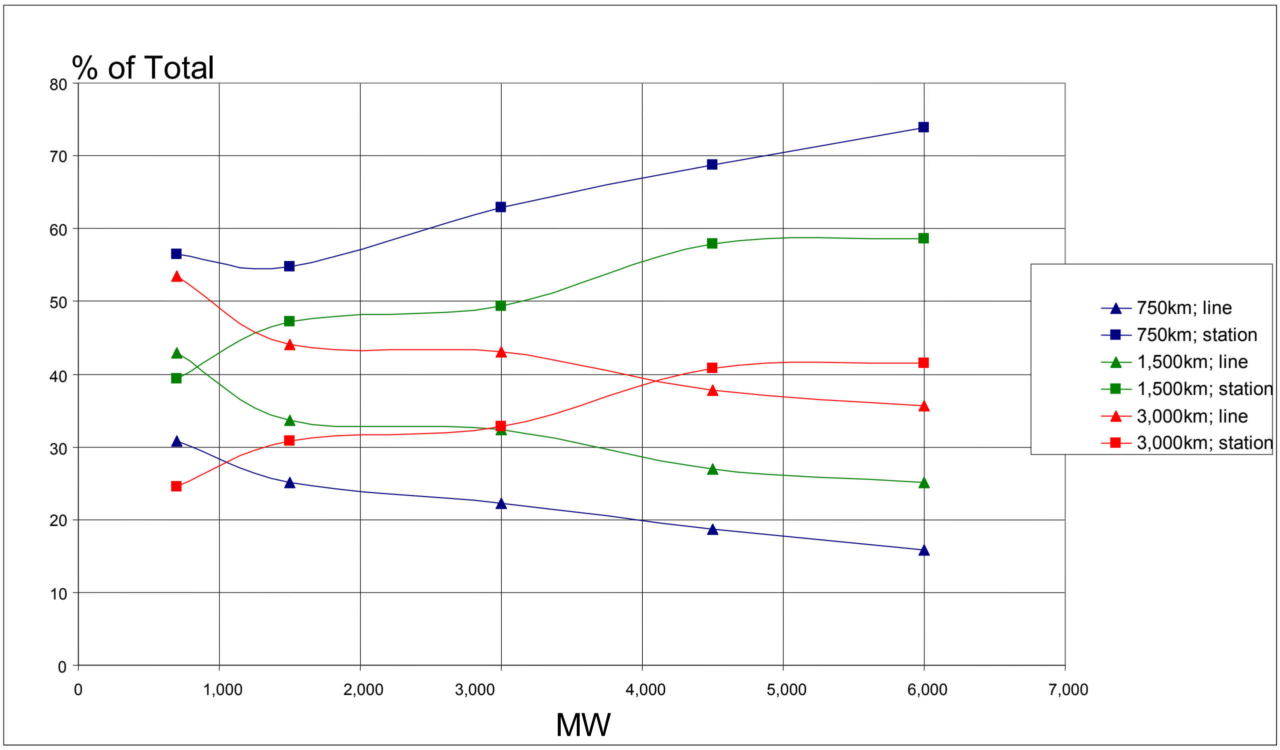


Figure 3: Cost parcels (line and converter station investment) as function of power and line length

ABSTRACT

Impacts of HVDC Lines on the Economics of HVDC Projects.

This technical brochure presents the results of the development of basic electrical and mechanical studies required for the design of HVDC lines; the economical aspects play an important role in this context, comprising the estimates of line and converter station costs; the overall HVDC system economics are included, considering the direct investment (lines and stations), the losses for a given time period, operation and maintenance costs and interest during construction.

The most economically favorable voltages and conductor configurations are studied for several HVDC system alternatives in the following ranges: voltages: ±300 to ±800 kV; power transfers: from 700 to 7,200 MW and line lengths from 750 to 3,000 km.

Basic designs and most economical alternatives are evaluated for a range of towers, voltages and line lengths above. Directives are therefore presented on the "best-solutions" solution for every set of transmission parameters. This study shows the HVDC line and the converter stations selection impact every combination and directives were established for the best selection.

Keywords

HVDC systems; HVDC lines; HVDC system economics; converter station, HVDC line design, electrode line; electrode

1 Introduction

The HVDC Transmission development and investigations have undergone some important milestones along the last 50 years, in which such technology overcame several challenges and showed up itself as a valid, reliable and economic alternative for carrying high blocks of electric energy, especially over long distances. Some big and special projects were constructed representing relevant milestones in this kind of transmission. The James Bay Project in Canada (± 450 kV) and the Itaipu Project in Brazil (± 600 kV) can be mentioned, among others, because of their relevance, having been built and put into operation in the eighties. Several other significant projects were implemented in between.

Regarding technology development, the big manufacturers through a sound and outstanding research now control the last difficulties resulting from the AC/HVDC/AC conversion. In the field of studies, analytical treatment and tests of the different variables involved in the process, key technical reports and books were issued on the subject in the last decade, namely: the HVDC Transmission Line Reference Book to ± 600 kV, by EPRI, in 1977, as a complete manual on transmission line technology, and the CIGRÉ Technical Brochure 186: "Economical Assessment of HVDC links", in June 2001, among others.

The complete domain of the Power Electronics by the present technology places the HVDC Transmission as a real and valid alternative to HVAC option for Transmission Systems, both technically and economically.

Inside the CIGRÉ organization, during the last 20 years, Study Committee B4 (former SC14) – HVDC and Power Electronics – has studied, developed and detailed the main aspects of the HVDC Systems, especially the different types of Converter Stations and the respective equipment and their applicability to real projects. Meanwhile, Study Committee B2 (former SC22) – Overhead Power Lines – have studied and detailed the electrical and mechanical aspects of overhead lines. However, despite the relatively small differences between AC and DC lines, the latter ones have not received special treatment so far.

Aiming at integrating the activities of B2 and B4 Committees regarding HVDC Systems, comprising lines and converter stations, the CIGRÉ Technical Committee decided, through a common action of these SC's bodies to launch a Joint Working Group for studying the impacts of HVDC Lines on the global Economics of HVDC Systems. The Study Committee C1 – System Development and Economy – joined the WG for studying the planned aspects associated therewith. Then, it was created the JWG-B2/B4/C1, which was so named: "*Impacts of HVDC Lines on the Economics of HVDC Projects*", having a 3-year time for developing its activities.

The final results of JWG-B2/B4/C1.17 Group are detailed and presented in this Technical Brochure.

2 Objectives

At the time of its creation, it was established for JWG-B2/B4/C1.17 an expected duration of three years, so that it would be extended from March 2005 until the Paris Session of 2008. The basic objective as established by the Technical Committee, with the approval of the relevant Study Committees B2, B4 and C1, stated that: (sic) "*The use of HVDC technology is increasing with the use of IGBT's (Insulated Gate Bipolar Transistor) and other such high speed, relatively low cost technology equipment. This has made DC technology an option for lower voltages as well as for higher voltages. The issues such as T-offs (Intermediate substations for supplying loads or AC systems) and fault level requirements as well as cost of terminal equipment have been addressed to a certain extent in many cases. In determining the technology to be used for different power transfer operations, it is necessary to determine the cost of the terminal equipment as well as the line linking the terminals. The determination of the HVDC system as a whole (Converter Stations plus Transmission Line) may prove more adequate than the investigation of the terminal equipment only*".

JWG-B2/B4/C1.17 studied deeply the electrical phenomena associated with HVDC transmission and prepared a comprehensive guide especially for designing the line, but showed also the basic schemes of converter stations required. All these steps were finally presented in this Technical Brochure, although there were initially some difficulties to pinpoint the essential points to be developed. However, with the progress of the discussions, the scope of the group became clearer, considering that the classical optimization of lines/stations would be what was really wanted to address. This was where a real economy of scale and technical advances could be achieved through the use of large power ratings over long distances. In recent years there was a certain trend to use ±500 kV, beside the ±600 kV of Itaipu since early 1980's. Viability of a renewed progress to higher voltages, and higher powers, with projects at ±800 kV currently being designed in China and India led the Group to establish a set of voltages, powers and line lengths, to be examined by JWG-B2/B4/C1.17 along the three years of its projected existence. It was decided to establish bipole voltages ±300, ±500 ±600 and ±800 kV, combined with powers from 750 MW to 6,000 MW and with line lengths from 800 km to 3,000 km, and subsequently optimizing the main sets with such combinations, as references.

In view of that, JWG-B2/B4/C1.17 would review the work of B4 and B2.09 (Former WG of B2) and develop models for evaluating the cost of DC lines, optimizing them and combining them with the corresponding Converter Stations. Three Task Forces have been defined for achieving such objectives.

The Technical Brochure starts with the presentation of the main HVDC System configurations, around of which the Group will develop its activities. The lines are then treated by presenting the main calculations and technical basis for the definition of towers, conductors, insulation of the lines, covering the principal electrical effects associated therewith. Finally it follows with the economic evaluation of the lines first, of the Converter Stations separately, and finally of the whole system. The three Task Forces created in JWG-B2/B4/C1.17 developed their works in a consistent way and the Technical Brochure tries to summarize the results as below.

Task Force TF01: Economics of DC Lines, led by José A. Jardini -Brazil

The main studies and calculations carried out are described in the Technical Brochure, namely:

a. Selection of sets of triple combinations of the representative voltages for HVDC lines (bipoles), as stated above, with powers to be transmitted and with line lengths;

b. Cost of components for HVDC typical lines and optimization of every selected option, comprising towers, foundations, conductors, insulators and fittings, grounding system and electrode lines, construction costs, costs of losses.
c. Overvoltages and insulation coordination in DC Lines – Insulation of DC lines
d. Corona calculation and economic impact of corona on conductor selection; and electric field calculation;
e. Towers: determination of regression formulae for tower weights as a function of the conductor, pole spacing, heights and loads, for regions with ice and without ice;
f. Composition of investment costs for HVDC typical lines;
g. Definition of parameters for economical evaluation: cost of losses, number of years of analysis, interest rates, power transmitted along line life;
h. Electrode line and metallic return
i. Economical evaluation of different alternatives of conductor bundles, using yearly cost of losses plus yearly cost of line investment methodology;
j. Selection of economical range of conductor alternatives to be studied in detail for alternatives of transmitted power and voltage;
k. Sensitivity analysis to select the optimum choice for every line under consideration, thus permitting the final choice for the different options;

TF02: Economics of Converter stations, led by Günter Bruske -Germany

a. Cost survey as supplied by the manufacturers, supplemented by other means as in the items below;
b. Establishment of converter station cost equation;
c. Converter station basic component requirements;
d. Costs estimates provided by the empirical formulae
e. Evaluation of world wide cost differences for materials and services and selection of the most appropriate ones for study purposes.

Based on one or more of the above criteria, JWG-B2/B4/C1.17 proceeded to the determination of costs of the Converter Stations (rectifier and inverter stations) for every of the HVDC system options previously selected.

TF03: Optimization of HVDC Project Options – Systems Economics led by João F. Nolasco and José A. Jardini, with the strict collaboration of John Graham and Günter Bruske

a. Development of the system economics evaluation. Herein the joint economical evaluation of the DC lines and Converter Stations (CS) was carried out, showing the interesting aspects of how the choice of the CS voltage is dependent on the line voltage as well, and vice-versa;
b. Composition of the cost split, both installation costs and Present Worth costs, between DC lines and converter stations, including losses along line life;
c. Set of the impact evaluation of the Lines and Converter Stations as related to total system costs, for the different alternatives, varying bipole voltages, powers and line lengths.

Finalizing, it is shortly emphasized how the Technical Brochure can help those initiating study and development of a transmission system, making it possible to consider the following evaluations:

a. To determine the optimum HVDC voltage to be chosen for the transmission of a certain power over a certain distance;
b. To compare, both technically and economically, an HVDC system alternative with a corresponding AC one apt to perform the same work, at equal reliability conditions.

3 Overview of Configurations Studied

3.1 Overview

Two basic converter technologies are used in modern HVDC transmission systems. These are conventional line-commutated current source converters and self-commutated voltage source converters.

The invention of mercury arc rectifiers in the nineteen-thirties made the design of line-commutated current source converters (LCCs/CSCs) possible and commercial use became word-wide from the nineteen-fifties. In the late nineteen-seventies the development of thyristors further improved the reliability and maintenance requirements of the converter stations. The first large utility application thyristor converter valves were outdoor oil insulated and oil cooled valves, followed by indoor air insulated and air cooled valves. Finally the air insulated, water cooled valve was developed installed in containers or buildings. The air-insulated water-cooled converter valve design is still the state of the art. Today schemes are in operation with bipolar powers above 3,000 MW, while projects are under construction for over 7,200 MW.

More recently development of new high power semiconductors, especially IGBT's, has led to the emergence of self-commutated voltage source converters (VSCs) which by their nature have even faster response times than LCCs, as well as independent control of reactive power and the ability to feed a passive load. Today there are projects with power ratings of up to 350 MW in operation and some of over 1,000 MW are being proposed.

These technological advances, particularly increased power in LCCs and increased flexibility in VSCs, need to be matched to the rather more established practice of overhead line design over the range of considered voltages, that is ±300 kV to ±800 kV.

Note that converters in back-to-back configuration that is with the rectifier and inverter at the same location, as used for asynchronous connection, are not considered here. The types of converter station considered particularly related to overhead transmission, although many of the characteristics may apply to cable transmission configurations.

3.2 Configuration

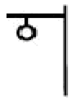
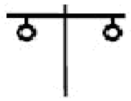
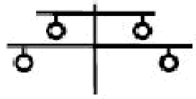
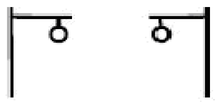
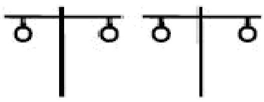
For long distance overhead transmission bipolar mode that is with both positive and negative conductors, has been the de facto standard. This is due to increased reliability and reduced losses. However as monopolar mode is often used as a stage in the development of a project, as well as during outages of one pole, it is discussed here.

3.2.1 Transmission Line Configurations

Consideration must be given to the basic configuration of the transmission line and the cost versus reliability factors for the project, in addition to the design criteria to be used. HVDC overhead transmission systems often have large power ratings and are therefore planned to be in bipolar configuration, then in most cases it is logical that a bipolar transmission line be used. However, the use of two monopolar lines should also be considered as reliability issues may make their use attractive, despite the increase of line cost versus bipolar line. Converter configurations are discussed below where it can be seen that many arrangements are possible. However for overhead transmission the studied cases are bipolar and are used with one bipolar transmission line, although use of two monopolar lines is possible as mentioned above.

The reliability of various transmission line configurations are given in the Table 3.1, taken from Cigré report 186 from WG 14.20 [41]. the variants differ as related to transmission capacity after permanent line fault.

Table 3.1 Transmission line configuration capacities

Variant	Tower Configuration	Remaining Transmission Capacity		
		Loss of one pole		Tower breakage
		Ground return permitted	Ground return not permitted	
Single monopolar line		0	0	0
single bipolar line		50 (100)	0	0
double bipolar line		100	100	0
Two monopolar lines		50 (100)	0	50 (100)
two lines (bipolar or homopolar)		100	100	100

In the above table the remaining capacity may be 0; 50; or 100% of the normal condition. Values between brackets refer to the assumption that the converter can be paralleled in the station and that the remaining pole has adequate current carrying capacity.

Unless otherwise mentioned, this report assumes a single bipolar line.

3.2.2 Converter Configurations

For overhead transmission lines bipolar converter configurations only have been studied, with thyristor valve converters used in the majority of cases studied. In this item we discuss such thyristor LCCs, with VSCs using IGBT valves being handled separately in clause 5. In a LCC station the most costly items are the thyristor valves and the converter transformers. Further the transformers are quite likely subject to restrictions in size and weight due to transportation limits. These two items therefore are most likely to determine the configurations of the converter station.

For the converter transformers an upper transport weight of 400 tons was taken, although this may be high for some countries. This is further discussed in clause 5; however for the moment it is important to note that due to this restriction the station arrangement uses two converters per pole above 3,000 MW. The 3,000 MW stations, and those of lower ratings, use one converter per pole, while the 6,000 MW stations in this study use two converters per pole, in either series or parallel connection. There are exceptions for the 750 MW rating which are discussed below.

The development of thyristors with higher current and voltage ratings has eliminated the need for parallel connection and reduced the number of series-connected thyristors per valve. While parallel thyristors have been used in converter valves in the past, for the purpose of this study in cases where the line current exceeds the capacity of valves using 6” thyristors, the parallel converter configuration has been used. This can be seen below in the case of 6,000 MW at ±600 kV, where parallel converters only are studied. The development of high power IGBT’s has led to the emergence of self-commutated voltage source converters (VSCs) which are further discussed in clause 5. Today there is one project under construction [37] utilizing an overhead line, all other VSC transmission projects use underground or submarine cables. As powers are lower than for LCCs using thyristors, one case was studied with a 750 MW rating.

In order to explore the lowest cost solution at 750 MW, the lowest rating studied, a LCC station using a centre-tapped twelve-pulse bridge with thyristors was included. Here it should be noted that although the transmission is bipolar in that there are positive and negative poles, operation is permitted only in this mode, that is monopolar transmission for line pole faults or station maintenance is not possible

3.2.3 System Configurations

As noted above, all configurations are bipolar in that there are positive and negative poles, but in most cases monopolar operation is permitted either in cases of maintenance or during the staged construction of the project. The most basic bipolar configuration is shown below in figure 3.1.

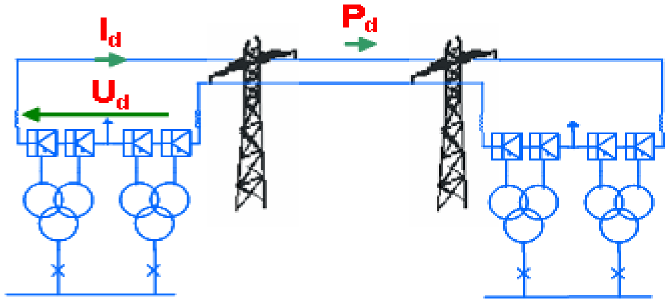


Figure 3.1 Bipolar transmission

This bipolar arrangement uses ground electrodes connected to the neutral point at each station. As can be seen in figure 3.2, a bipolar scheme can easily be divided into two stages, first constructing one station pole in each location. The question then arises as to whether to use ground return or metallic return during this period.

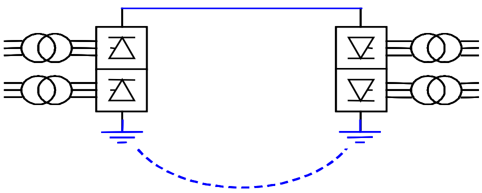


Figure 3.2.a Ground Return

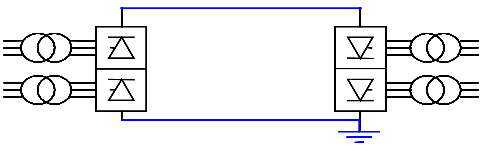


Figure 3.2.b Metallic Return

Ground return has the advantages of lower losses and in the case of a long construction interval the second line conductor need not be strung. Alternatively the two poles conductors can be used in parallel to reduce losses further, a technique used in some projects.

Ground return has been successful in many projects and for considerable periods of operation. However in some cases, especially in densely populated areas metallic return is used to avoid ground currents. When using metallic return in a bipolar scheme a switching arrangement is used to connect the neutral point of one station to the line pole, keeping the ground electrode connected in the second. This way ground current is avoided for extended periods, including station maintenance.

3.3 Cases Studied

In order to rationalize the cases to be investigated, a study matrix was agreed upon in the early stages of the JWG and this is given in Table 3.2 below.

Table 3.2 Cases studied

Bipole	750 MW	1,500 MW	3,000 MW	6,000 MW
750 km	± 300 kV	± 300 kV ± 500 kV	± 500 kV	± 600 kV
1,500 km	± 300 kV ± 500 kV	± 500kV	± 500 kV ± 600 kV ± 800 kV	± 600 kV ± 800 kV
3,000 km			± 500 kV ± 600 kV ± 800 kV	± 600 kV ± 800 kV

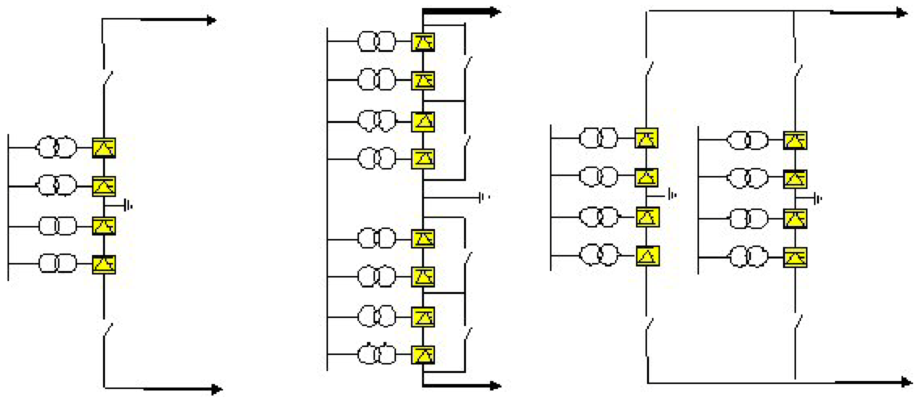
Note: for better interpolation 2,250 km are also evaluated

This matrix, together with the considerations enumerated above, led to the choice of the following converter configurations to be analyzed given in Table 3.3.

Table 3.3 Converter configurations studied

	1	2	3	4	5	6	7	8	9	10	11	12
Bipolar	750 MW	750 MW	750 MW	750 MW	1,500 MW	1,500 MW	3,000 MW	3,000 MW	3,000 MW	6,000 MW	6,000 MW	6,000 MW
Rating	±300 kV	±300 kV	±300 kV	±500 kV	±300 kV	±500 kV	±500 kV	±600 kV	±800 kV	±600 kV	±800 kV	±800 kV
Conv/pole	VSC	1x6 pulse	1	1	1	1	1	1	1	2 parallel	2 series	2 parallel

The main converter configurations are shown in Figure 3.3:



One per pole - 3,000 MW   Two Series - 6,000 MW   Two Parallel - 6,000 MW

Figure 3.3 Basic converter station configurations

Figure 3.3 covers cases 3 to 12 of the converter arrangements studied. The two special cases, 1-VSC converter and 2-mid-point grounded 12-pulse converter are covered separately in clause 5.

4 Transmission Line Considerations

The selection of the optimum transmission line (bipole) alternatives encompasses the different components of the line, so that a global optimization can be achieved. The optimum choice only has a real meaning when electrical, mechanical, civil and environmental aspects are taken into account as a whole set, for which a satisfactory performance and reasonable costs are simultaneously looked for.

Regarding the transmission line itself, its design includes at first the electrical requirements such as power transfer capability and voltage are specified from which the tower-top geometry, the electric field effects, the corona effects, the overvoltage and insulation coordination and the required right of way are established. Then the mechanical design of the towers and foundations, the determination of conductors and shield wires stresses are carried out; finally the economics including direct costs, cost of losses, operation and maintenance cost along line life, is evaluated.
The design process is iterative as the electrical parameters can be met with a variety of solutions. The optimum solution is derived from interaction with planners and designers.

4.1 Overvoltages

4.1.1 Types of Overvoltages

The definition of the insulation levels is dependant on different voltage stresses that reach the air gaps and are so chosen as to result in the best compromise between a satisfactory electrical performance and reasonable costs.

To define the tower top geometry of the towers, in the case of a DC line, the following voltage stresses are considered: sustained due to operating voltage, and transient due to lightning and switching surge overvoltages. Therefore, the scope of this clause is an evaluation of the overvoltages in the HVDC system aiming at the DC line insulation design required.

The switching surge overvoltages in a HVDC system occur in the DC as well as in the AC part of the system.

In the latter one, overvoltages are the result of the following switching operations: line energization; line reclosing, load rejection, fault application, fault clearing and reactive load switching, and all should be evaluated.

As related to HVDC system, the above mentioned overvoltages are also considered for the converter station insulation design; by the use of surge arresters, the overvoltages are limited to values corresponding to the arrester Maximum Switching and Lightning Surge Sparkover Voltages Level. The surge discharge capability of the arrester needs to be verified as part of the overvoltage studies for equipment specification.

Regarding switching surges fault application is the only one type of overvoltage to be considered because of the intrinsic process of the HVDC system. For line energization and reclosing the DC voltage is ramped up smoothly from zero, and in the reclosing process the line de-energization process eliminates the trapped charge.

As for load rejection, it generally does not transfer overvoltages to the DC side. DC filter switching does not cause overvoltages.

Lightning overvoltages may start a fault in the DC line, however its effect is smaller as compared with AC system faults due to the fact that the fault current will be limited by HVDC station controls, the line voltage is ramped down and after a sufficient time for the trapped charge discharge, the voltage is ramped up to the nominal value or to a reduced voltage value (around 80% for example).

Shield wires are normally installed in the lines for reducing the number of faults, by providing appropriate shielding. The major point in the design is then to locate the shield wires in the right position. . Shield wires may also be used as a communication medium for control of thyristors, their design needs to take both functions into account.

Sustained overvoltages in the DC side of HVDC systems do not occur due to the intrinsic control process of the HVDC operation. It should be noted that overvoltages in the DC side may appear due to harmonic/filter/smoothing reactor resonance. It is considered here that this is a problem to be solved by the design of appropriate elements, and so such kind of stresses will not be considered herein for the insulation design of the DC line.

4.1.2 Determination of Switching Surge Overvoltage (Fault Application)

Switching surge due to fault application in a DC line, being the most important voltage stresses to be applied to its insulation, will be evaluated hereafter.

4.1.2.1 Modeling

The overvoltages hereinafter are calculated with ATP (Alternative Transient Program) using models such as the one shown on Figure 4.1. The data of the Base Case are here also represented.

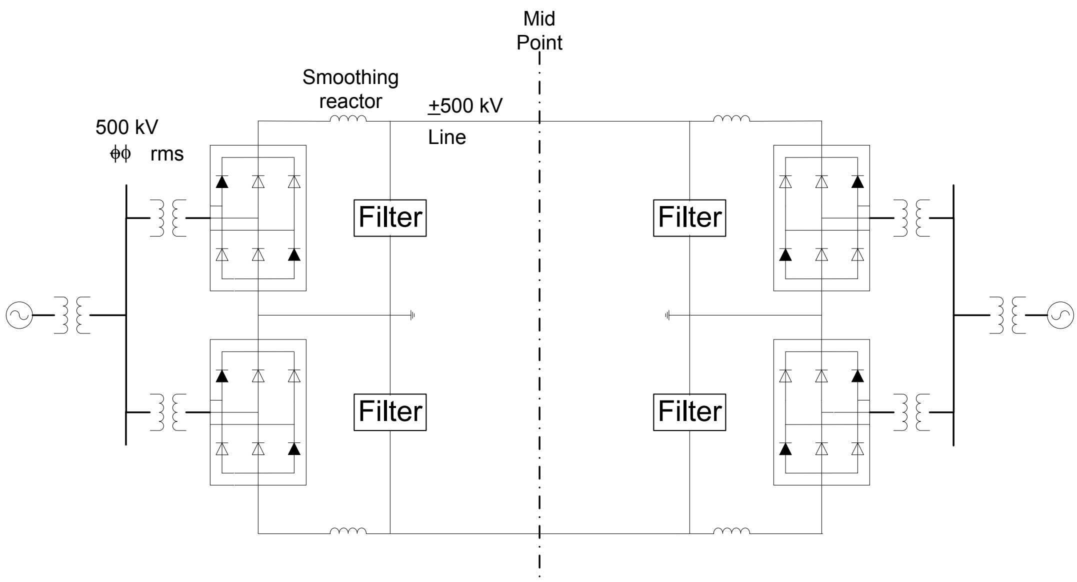


Figure 4.1: HVDC system modeling for fault application calculation

a. Generator/ receiving system
   They are modeled as a short circuit power, providing enough power as required. In one of the models as used for the present case, the short-circuit capacities are: 23,000 MVA for single-phase short-circuit and 20,000 MVA for three-phase short-circuit.

b. The converter transformers of both terminals are specified in this model as:
   One transformer per pole herein modeled with the following characteristics:

Power	→	1,500 MVA per pole
Reactance x_{cc}	→	18%
Turn ratio	→	500 / 370.2 kV

c. DC filters
   The values from reference [1] or the ones used in Itaipu System [2] are used.
   Smoothing reactor of 200 mH;
   DC filter equal in both line terminals composed by two branches:
   One series filter with → L = 489 mH, C = 0.1 μF;
   One filter in parallel with → L = 51.7 mH, C = 0.3 μF, R = 467 Ω.

d. Converter stations
   Always two thyristors are fired and the DC current flows through the transformer windings. Therefore two phases of the transformer are represented. An AC low frequency voltage of 1 Hz is set in the sources to model the DC voltage.

e. DC line
   The line model is composed of eight sections, each one modeled as lossless line traveling wave equations. Line losses (resistance) are represented in the model at section end. Electrical parameters (resistance and inductance) are modeled as frequency dependant or constant. The line parameters are indicated below.
   - Positive sequence
     R = 0.0094 Ohms/ km
     L = 0.98 mH/ km
     C = 12.0 nF/ km
   - zero sequence
     R_o = 0.011 Ohms/ km
     L_o = 3.61 mH/ km
     C_o = 10.5 nF/ km

4.1.2.2 Fault Application Phenomena

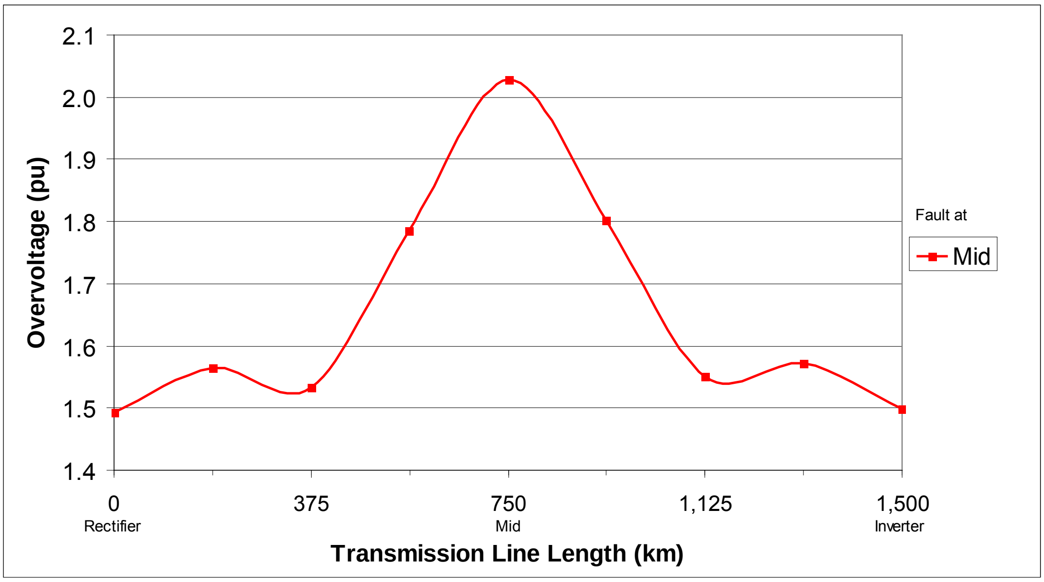
For the initiation of the fault in the negative pole, a positive surge of value equal to the pre-fault voltage is injected in the fault point, and the resulting surge travels in both line directions, reflecting in the line end and coming back to the fault point. The traveling wave is coupled to the positive pole resulting in an overvoltage which values are due to the composition of the forwarded and of the reflected waves.

The maximum overvoltage occurs for a fault initiated in the middle of the line, within a time close to the travel time to the line end and back to the mid point of the first reflections. Faults in other locations produce smaller overvoltages. Due to this, the overvoltage profiles down the line are similar for every line length, as will be shown later. Line end equipments (filters, smoothing reactor and source) play an important role, as they define the traveling wave reflection coefficients.

4.1.2.3 Calculation Results

For the Base Case calculation, the following points were taken into account: a line 1,500 km long; equal sources at both ends (rectifier and inverter) and line parameters not variable with the frequency (Bergeron Model).

Figure 4.2 (over) shows the maximum overvoltage profile in the sound pole for a fault initiated at mid point of the other pole, and (under) the voltage X time in the mid/end point of the sound pole.



red middle, green end; of the sound pole (1,500 km line)
Figure 4.2: Fault at mid point of the line, base case, overvoltage profile.

The maximum overvoltage reaches 2.03 pu, however the overvoltages are above 1.8 pu (10% lower) at 1/4 of the line only. Standard deviation for insulation switching surge withstand is 6%, this means that the overvoltage in the major part of the line does not contribute to the risk of failure and therefore the line is designed considering mainly the maximum value (2.03 pu in this case).

From here on, the line is split in several segments, identified as a fraction of its length (1/8, 1/4, 3/8 and so on). Figure 4.3 shows the overvoltage profile for fault initiated at other line positions. It can be seen that very few values are above 1.8 pu (faults at 3/8 and 5/8 positions have some points above this) and so do not contribute so much to the risk of failure.

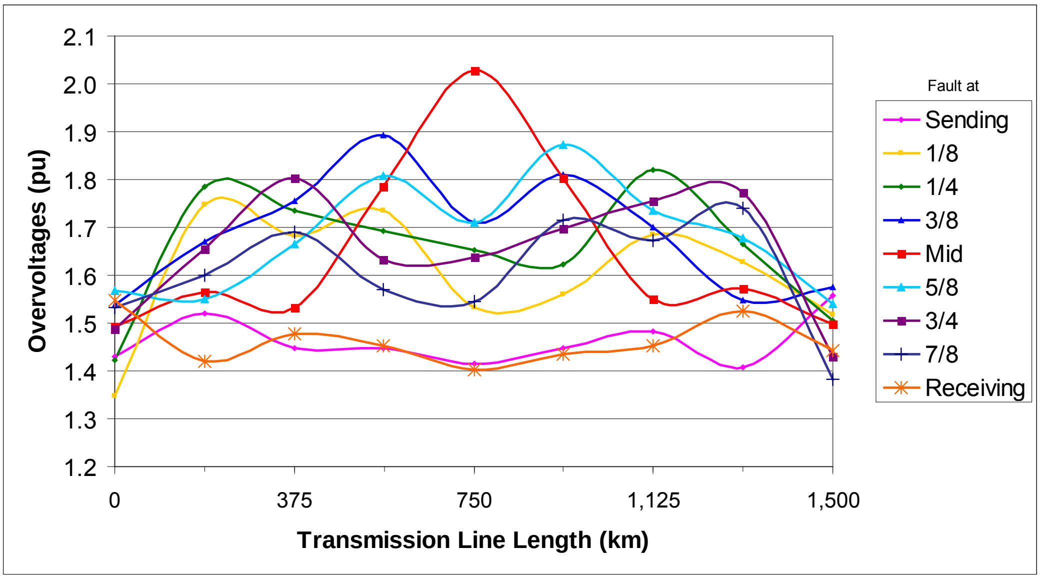


Figure 4.3: Overvoltage profiles, Base Case, fault in different positions.

In order to evaluate the sensitivity of the results to the modeling under utilization here, the following alternatives to the Base Case were analyzed:

- only the capacitor of the DC filters were represented at both ends; it should be noted that in the Base Case a voltage source is connected at the receiving end;
- only DC filter capacitors are represented, but no receiving end source is used;
- only DC filter capacitors are represented, keeping the line opened at receiving end;
- no DC filters are installed at line ends;
- the filters are represented at both ends but they are not equal.

Figure 4.4 shows the results when the line parameters are represented as frequency dependent (J. Marti model).

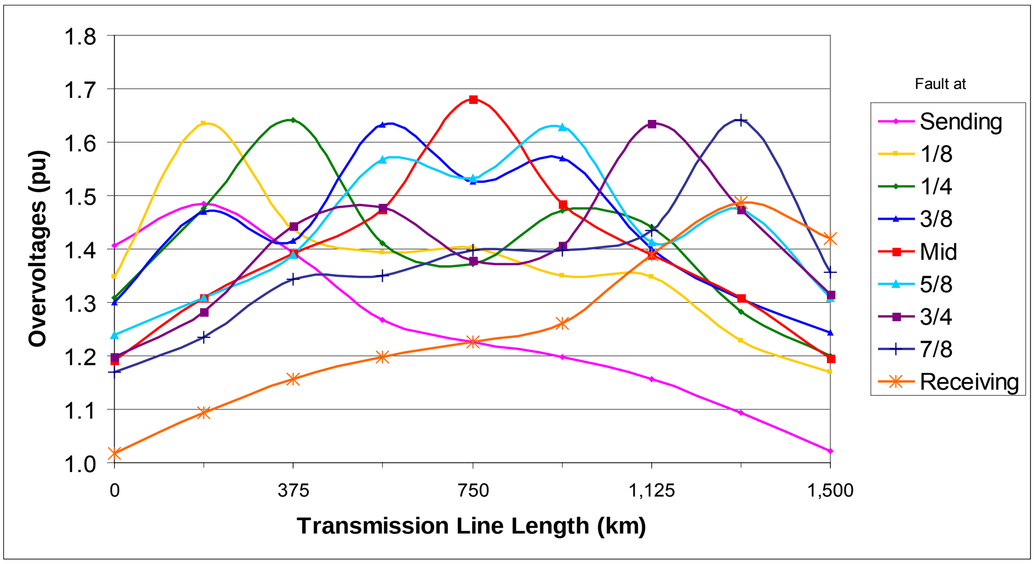


Figure 4.4: Base Case: line model with frequency dependant parameters.

It should be noted from Figure 4.4 that the overvoltages are considerably low (< 1.7 pu) when line is modeled as frequency dependant parameters.

Table 4.1 shows the maximum values of the overvoltages in one pole obtained when a fault is applied in the middle of the other pole.

Table 4.1: Sensitivity of the results. maximum overvoltage at mid point of one pole, fault at mid point of the other pole.

Case	Overvoltage (pu)
Base Case (Bergeron model)	2.03
DC Filter capacitor only in the filter model	2.19
DC Filter capacitor only; no receiving system represented	2.03
No DC filter represented	2.70
Unequal DC Filters at ends	1.98
Base Case - Line model with frequency dependant parameters (J. Marti model)	1.68

Figures 4.5 to 4.8 show the overvoltage profiles for the different line lengths under consideration, namely: 750 km, 1,500 km, 2,250 and 3,000 km for the Base Case (with frequency-dependant parameter model).

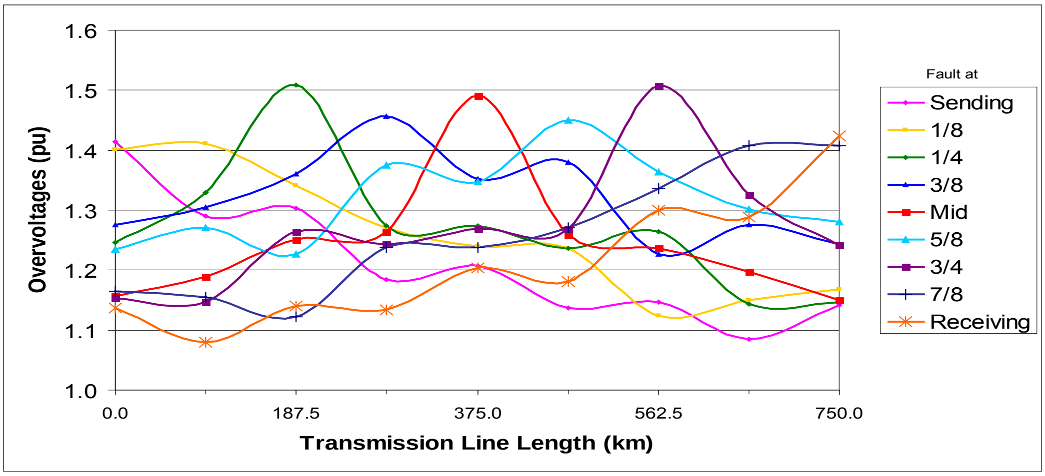


Figure 4.5: 750 km Transmission Line.

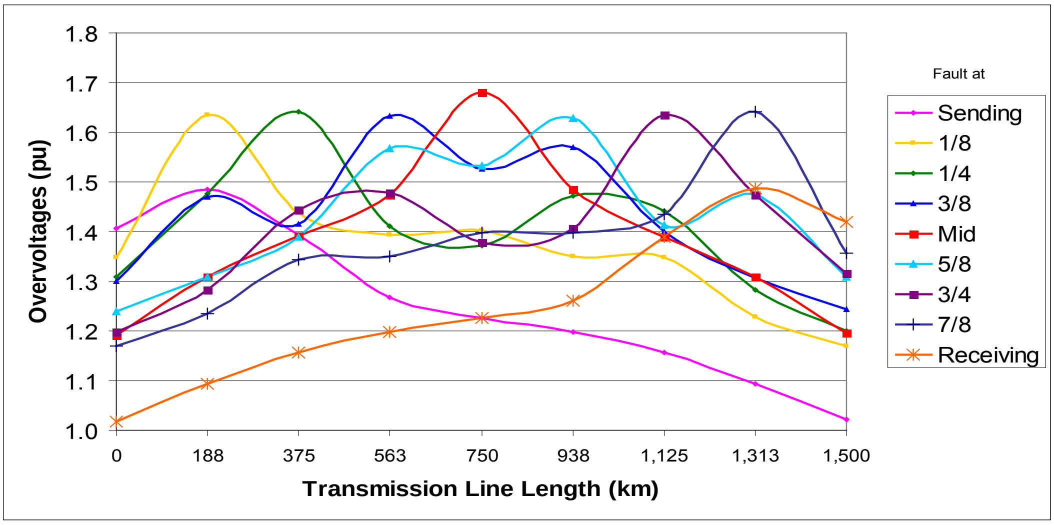


Figure 4.6: 1,500 km Transmission Line.

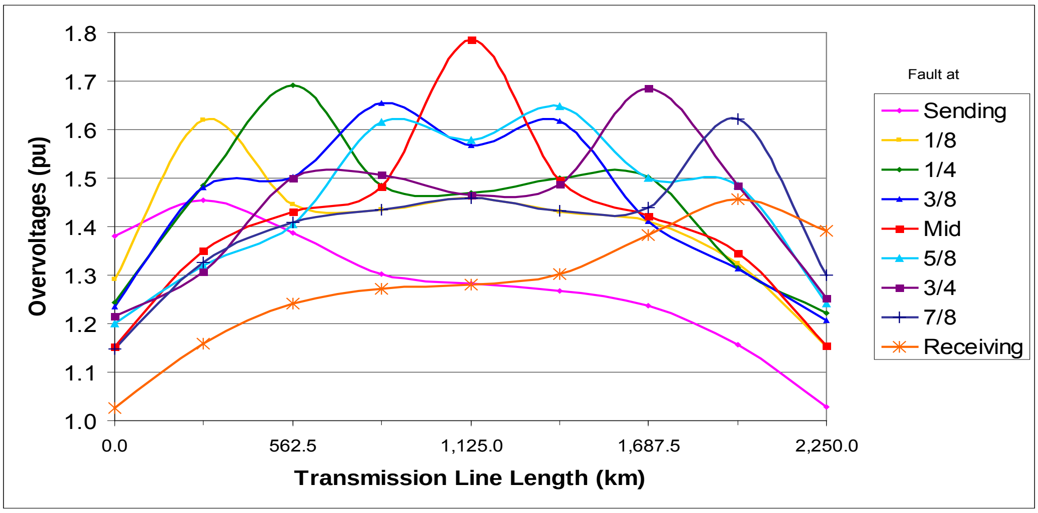


Figure 4.7: 2,250 km Transmission Line.

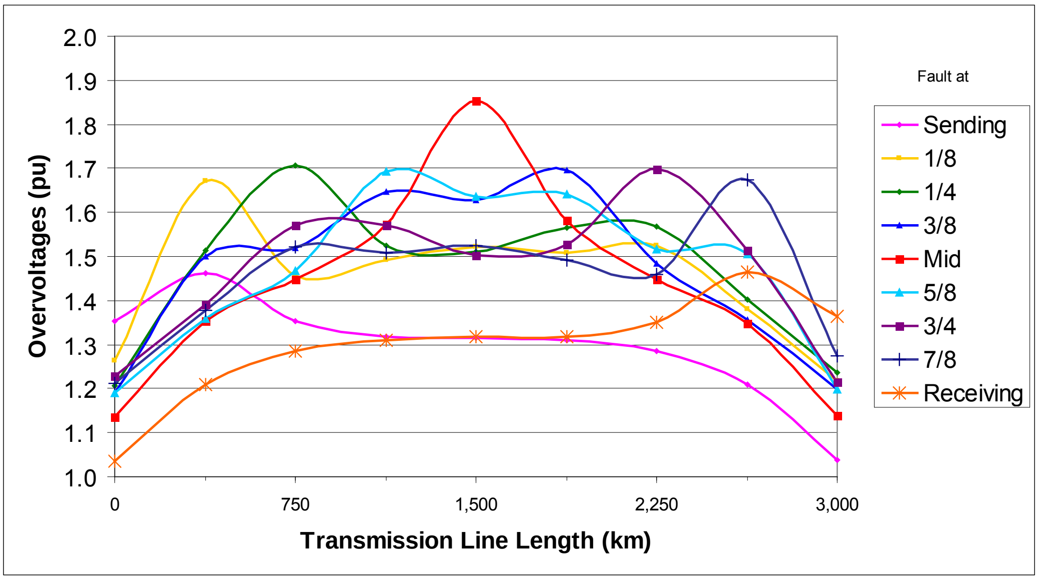


Figure 4.8: 3,000 km Transmission Line.

A summary of results obtained for the maximum overvoltages is presented here below in Table 4.2 for comparison purposes.

Table 4.2: Maximum values (pu) from figures 4.5 to 4.8.

Distance (km)	Bergeron model	J. Marti model
750	1.82	1.5
1,500	2.03	1.68
2,250	1.98	1.78
3,000	2.0	1.85

The overvoltage profiles presented in Figures 4.5 to 4.8 will be considered in the insulation design to be carried out, as the J Marti model is more accurate.

4.2 Insulation Coordination

This section aims at designing the clearances and at defining the number and type of insulators to be used in the insulator strings.

The number of insulators is initially selected based on the maximum DC voltage withstand and on the assumption of a certain pollution level. The number of insulators obtained by these criteria is then verified by considering the overvoltage values. The clearances to be determined are: conductor-to-tower cross arm, conductor-to-tower or objects (lateral), conductor-to-ground or objects (at the ground), and conductor to guy wires.

They are calculated for switching surge overvoltage withstand. However, the clearance to tower and guy wires as well as to edge of right-of-way shall be verified in the condition of insulation string swing due to wind in order to prevent flashovers and the touch of objects (such as trees) at the border of the right-of-way.

4.2.1 Operating Voltage

4.2.1.1 Air Clearances

For determining the minimum necessary conductor-structure clearances for operating voltage insulation, the following premises are considered:

- Withstand voltage regarding the most unfavorable condition: positive polarity, conductor-to-structure;
- Maximum operating voltage and correction for the atmospheric conditions: 1.15 pu.

The distances conductor-to-structure were obtained according [5] (Green Book) and are shown on Table 4.3.

Table 4.3: Clearances for operating voltages (m).

Operating Voltage (kV)	Clearance (m)
±300	0.70
±500	1.20
±600	1.50
±800	1.90

4.2.1.2 Number of Insulators

By using a creepage distance (pole-to-ground) equal 30 mm/kV [7], the number of insulators and the respective insulator string lengths are determined and shown in Table 4.4. The creepage distances adopted are adequate with a good safety margin to zones with a pollution level classified as “light to moderate contamination”.

For agricultural areas and woodlands 23 mm/ kV is recommended [7], and for outskirts of industrial areas 40 mm/ kV is recommended. Some references recommend as acceptable even lower creepage distances down to 20 mm/kV (for area classified as with “ very light pollution”); however a higher figure is here considered as more appropriate.

As a reference, the Itaipu lines (“ light pollution - agricultural area”) were designed for 27 mm/kV and have shown adequate performance in more than 20 years of operation.

Table 4.4: Number of Insulator and String Length.

Operating Voltage (kV)	Creepage distance 30 mm/kV	
	Number of Insulators	String Length (m) (*)
± 300	18	3.22
± 500	30	5.20
± 600	36	6.20
± 800	48	8.17

Notes: (*)

The following type of insulator was considered:

- Anti-fog insulator, pitch of 165 mm and leakage distance of 508 mm;
- Hardware length: 0.25m
- Porcelain type; or glass. Composite can be used in any area and is robust against vandalism and pollution.

It should be noted that the insulator string length suitability is also verified considering switching surge and the gap conductor cross arm).

4.2.1.3 Insulator String Swing Angle

The swing angle of the conductor due to wind was calculated according CIGRE/ IEC [8] recommendation, using the following data:

- Line altitude: 300 to 1,000 m;
- Average temperature: 16 ºC;
- Minimum ratio of vertical/horizontal span : 0.7;
- Wind return period: 50 years;
- Alfa parameter of Gumbel distribution $(m/s)^{-1}$: 0.30
- Beta parameter of Gumbel distribution (m/s): 16.62
- Wind distribution with 30 years of measurements.

Note: It means that in the calculation, the mean wind intensity, 10 min, is 18.39 m/s with a standard deviation of 3.68 m/s. The design wind intensity is then 29.52 m/s for 50 year return period.

- Terrain classification: B

The calculations were done based on [8] CIGRE Brochure 48, for a set of ACSR- Aluminum Conductor Steel Reinforced conductors; the results are shown on Table 4.5.

Table 4.5: Swing Angle to be used together with the respective Clearances for the Operating Voltage.

Conductor code	**Aluminum/steel mm^2/mm^2**	**Aluminum MCM***	**Swing Angle (°)**
Joree	1,274/70	2,515	44.5
Thrasher	1,171/64	2,312	45.6
Kiwi	1,098/49	2,167	46.9
2,034	1,031/45	2,034	47.7
Chukar	902/75	1,78	47.5
Lapwing	806/57	1,59	49.5
Bobolink	725/50	1,431	50.7
Dipper	684/47	1,351.5	51.4
Bittern	645/45	1,272	52.0
Bluejay	564/40	1,113	53.4
Rail	483/34	954	55.0
Tern	403/29	795	56.7

* 1 MCM=0.5067 mm^2

Note: The conductor types and stranding taken as examples in this report can be further optimized in the case of a real project. In lines where there is no significant ice, the steel percentage of the ACSR conductor can be reduced. There are cases were others conductor types (ASC Aluminum Conductor; AAC- Aluminum-Alloy Conductor, ACAR – Aluminum Conductor Aluminum-Alloy Reinforced; AACSR- Aluminum-Alloy Steel Reinforced) may be more adequate, however will not be covered here but the whole methodology applies to them.

4.2.2 Clearances for Switching Surge Withstand

Once known the switching surge overvoltages as determined in 4.1.2, the clearances are calculated based on the risk of failure considering the withstand capability of the gaps estimated by:

$$V_{50} = k \ 500 \ d^{0.6}$$

Where:

V_{50} → Insulation critical flashover (50% probability), in kV

$d \rightarrow$ gap distance (m)
$k \rightarrow$ gap factor:

k = 1.15 conductor – plane
k = 1.30 conductor – structure under
k = 1.35 conductor – structure (lateral or above)
k = 1.40 conductor – guy wires
k = 1.50 conductor – cross arms (with insulator string)

The latter equation applies to Extra High Voltage System when $2 < d < 5$ m.

An alternative equation when $5 < d < 15$m, is:

$$V_{50} = k \ \frac{3400}{1+ 8/d}$$

The clearances are determined based on the fault application overvoltage profiles, aiming at a certain flashover failure risk target (design criteria). It is proposed here a failure rate of 1 in 50 or 1 in 100 years. It will also be assumed, as design criteria, that 1 fault per 100 km per year (mainly due to lightning) can occur. The overvoltages shown on Figures 4.5 to 4.8 are used for this purpose. The following steps are carried out:

I - Select one line length and one rated voltage;
II - Select one gap type and size;
III - Select the overvoltage profiles in the sound pole for fault in the middle of the other pole;
IV - Calculate the risk of flashover failure for the tower in the mid point of the line (1 gap);
V - Calculate the flashover risk of failure in the central section (gaps in parallel subjected to the same overvoltage of the tower in the mid point of the line);
VI - Extend the flashover risk calculation for parallel gaps (towers) for the whole overvoltage profile;
VII - Repeat calculation of the flashover risks of failure for the gap, for fault at other points (or sending, or 1/8, or 1/4, or 3/8, or 5/8, or 3/4, or 7/8, or receiving end of the line);
VIII - Calculate the weighted flashover average risk of failure, considering that each profile represents fault occurring in a section of (1/8) of the length of the line except seeding/receiving end profiles that correspond to (1/2)*(1/8) of the length. The total flashover risk R is then determined;
IX - Consider the number of occurrences (faults) and determine the probability of flashover. Check against 1 in 50 - 100 years; if the flashover risk is different, then select another gap size and go to step III above;
X - Repeat for all gaps.

It should be noted that, if the line is designed with I insulator strings, then it is recommended to consider in the risk calculation the effect of possible winds simultaneously with the overvoltages.

There are two approaches for taking this point into account: first, by calculating the clearances for an established risk and admitting that such clearances shall be maintained with a certain swing due to wind; or second, considering the simultaneous occurrence of wind and overvoltage, and finally calculating the composite risk.

4.2.2.1 Clearances for an Established Flashover Risk of Failure

The following Figures (4.9 to 4.13) show the clearances for the gaps above mentioned as a function of the line voltage. They were designed for a flashover risk of failure of 1/50 yr, and the overvoltages were calculated using J. Marti line model.

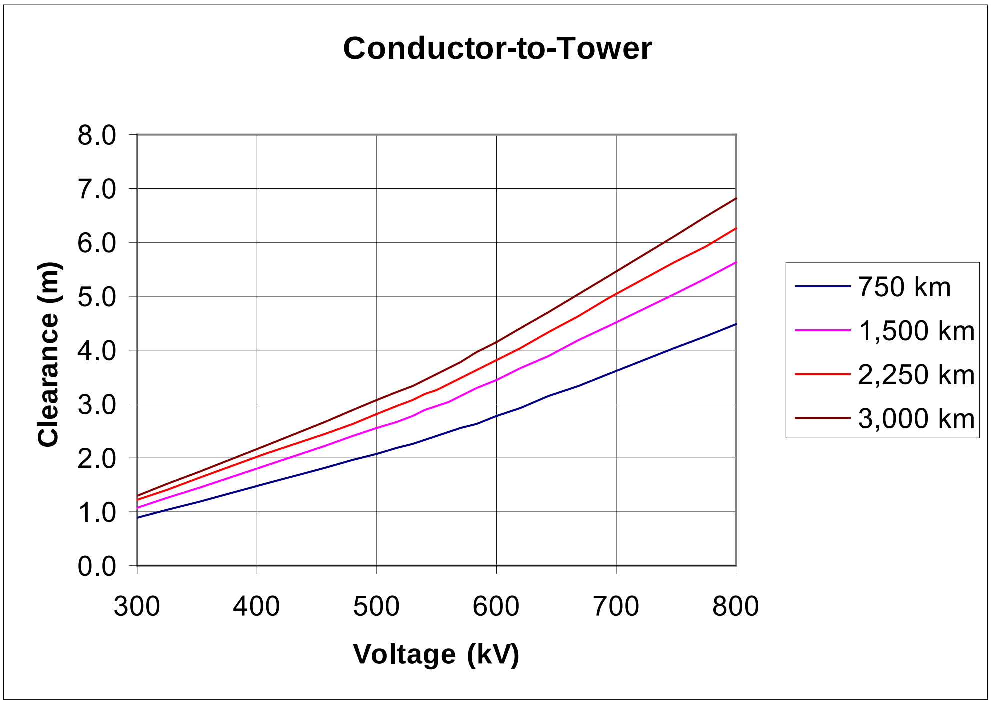


Figure 4.9: Conductor to tower clearances.

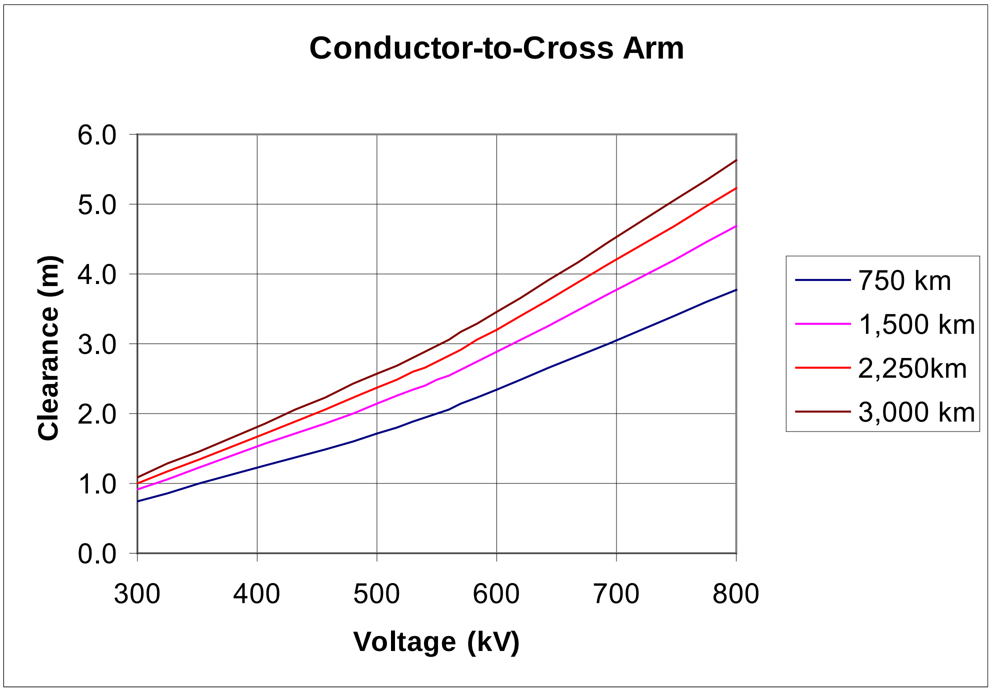


Figure 4.10: Conductor to cross-arm clearance.

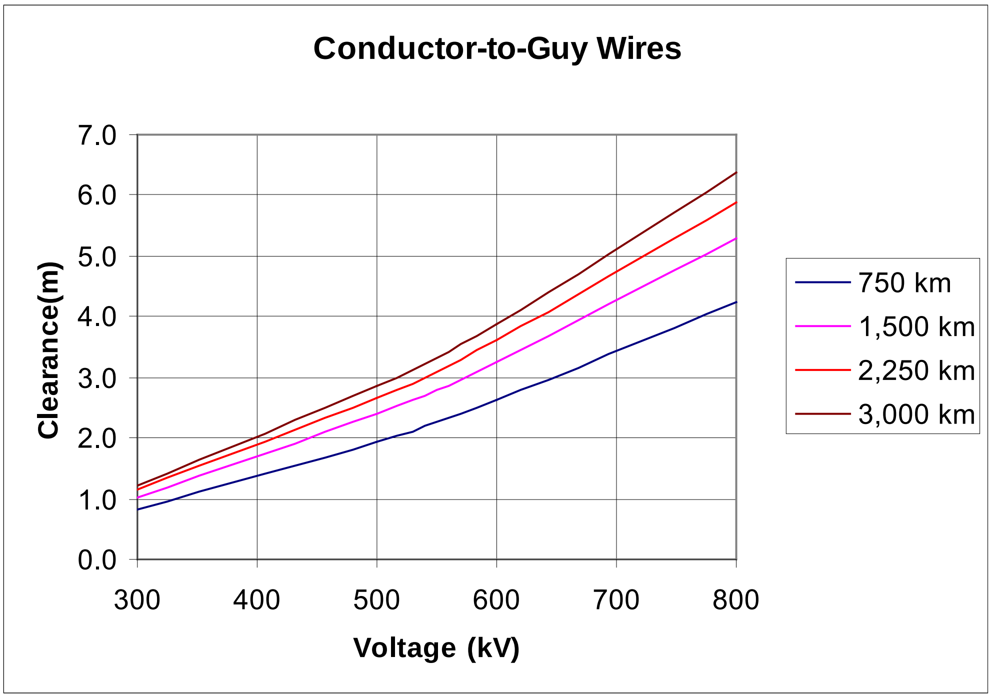


Figure 4.11: Conductor to guy wires clearance.

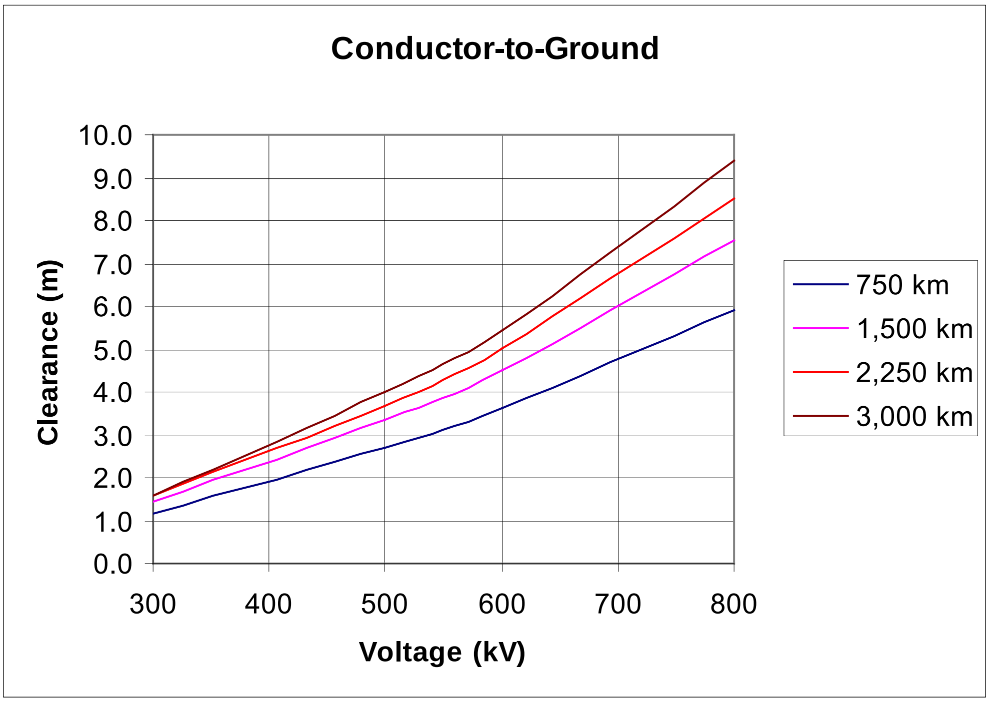


Figure 4.12: Conductor to ground clearance.

Note: The clearances to ground may be overruled by minimum distances to ground for others requirements.

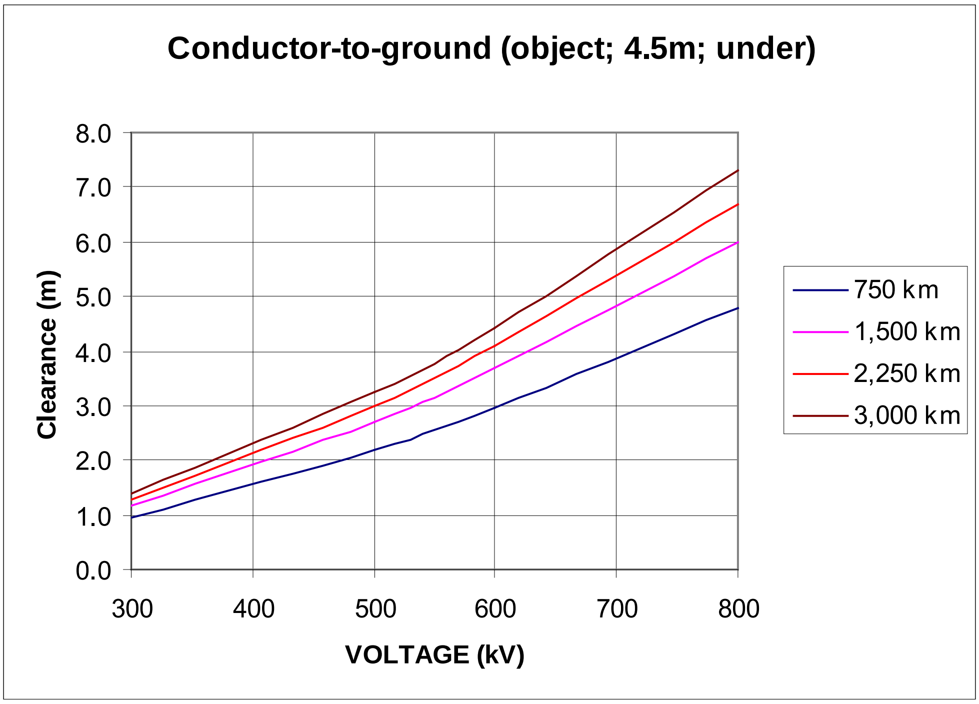


Figure 4.13: Conductor to object clearance (add 4.5 m to get conductor to ground distance).

4.2.2.2 Switching Overvoltages with Conductor Displacement due to Wind

CIGRE Brochure 48 [8] recommends the adoption of a swing angle caused by a wind intensity corresponding to 1% probability of being exceeded in a year together with the occurrence of switching surge overvoltages. Using the wind distribution as per item 4.2.1.3, the wind intensity is 13.54 m/s.

The swing angles caused by this wind are shown on Table 4.6.

Table 4.6: Swing angle to be used together with Switching Surge Clearances

ACSR Conductor code	MCM*	Swing Angle (°)
Joree	2,515	13.4
Thrasher	2,312	13.8
Kiwi	2,167	14.3
2,034	2,034	14.6
Chukar	1,780	14.5
Lapwing	1,590	15.3
Bobolink	1,431	15.8
Dipper	1,351.5	16.1
Bittern	1,272	16.4
Bluejay	1,113	17.0
Rail	954	17.7
Tern	795	18.6

* 1 MCM=0.5067 mm^2

It should be noted that considering simultaneously: the conductor swing due to the wind with 1% probability of being exceeded in one year, and the clearances corresponding to a risk of 1/50 years; the final flashover risk will be much smaller than 1/50, therefore the stated criteria is conservative.

An alternative approach is to find a clearance considering the composite risk for overvoltage distribution and a swing due to the wind distribution.

Note: It should be alerted here that the results obtained in this example and others are applicable only to the parameters used, i.e. wind speed, probability functions, etc.

4.2.2.3 Composite Risk Calculation

In order to define a wind to be used together with the overvoltage occurrence, an example of composite calculation will follow.

i - Data used for the example:
- ± 500 kV and ± 600 kV, 1,500 km long lines;
- Conductor: ACSR 1,351.5 MCM (Dipper)

ii - Wind intensity distribution

A Weibull distribution (Fig 4.14) is assumed, characterized by the following parameters [8]:
- $V\eta = 6.31$
- $\beta = 2$

These values are compatible with the wind characteristic values mentioned before.

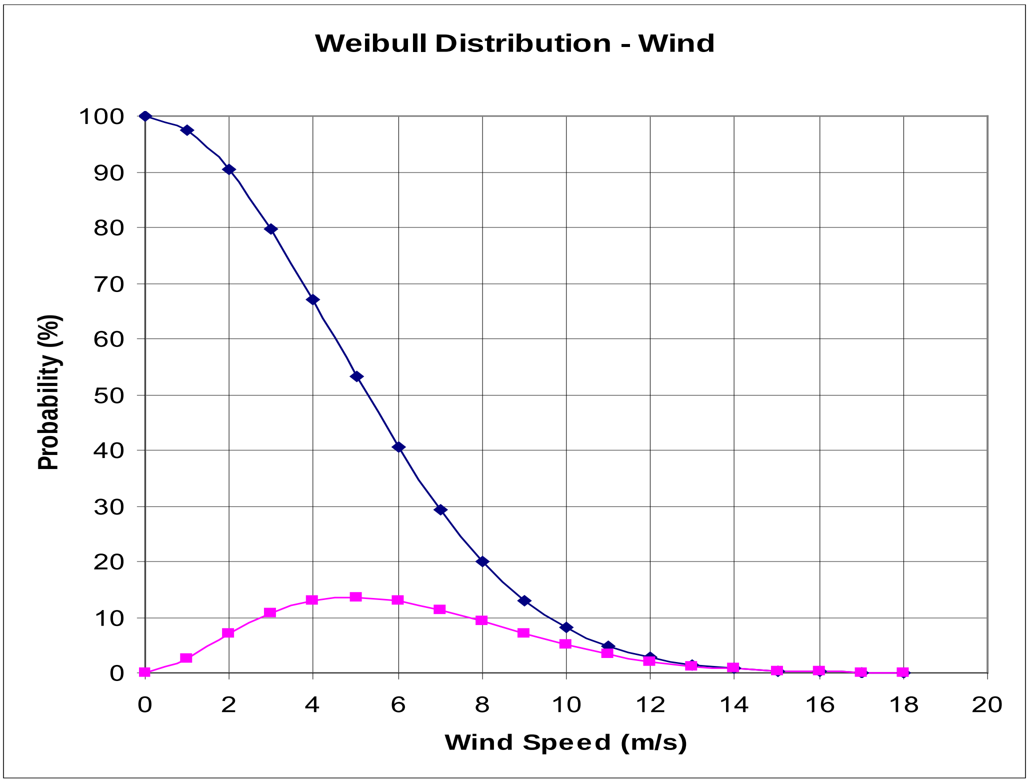


Figure 4.14: Wind distribution

The composite flashover risk was calculated by the following procedure:

- It was started with the clearances called "switching surge distance" as per item 4.2.2 equations.
- Then an additional distance was added, this one corresponding to the insulator string displacement due to the wind with 50%, 15%, 1% (named %VT) probability of being exceeded when ±500 kV is used, or 50%, 20%, 1% when ±600 kV is used. The resulting distance will be called here as "in no wind distance".
- Next step consists in splitting the wind frequency distribution into intervals defined by the value marked with a square (Figure 4.14); then evaluating the density probability of every interval (Pi).
- Then, pick up one wind interval (i), evaluate the displacement caused by this wind, subtract it from the no-wind distance, so obtaining a reduced clearance; set its critical flashover value Vi and the risk Ri; and then calculate Ri * Pi.
- Repeat the steps above for all wind intervals and calculate the weighted average, as follows:

$$R = \frac{\sum Ri * Pi}{\sum Pi}$$

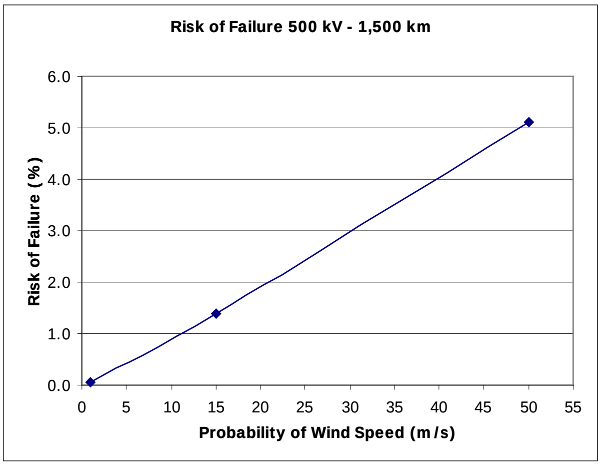
Where: R is the composite risk.

The results are shown on Table 4.7 for ±500 kV and ±600 kV bipole lines.

Table 4.7: Composite risk calculation

±500 kV bipole line		**±600 kV bipole line**	
%VT	RISK %	%VT	RISK %
50	5,12	50	3,84
15	1,40	20	1,47
1	0,06	1	0,04

Figure 4.15 shows also the values obtained and can be used to find the wind probability that leads to a composite flashover risk of 1% or 1/100 year.



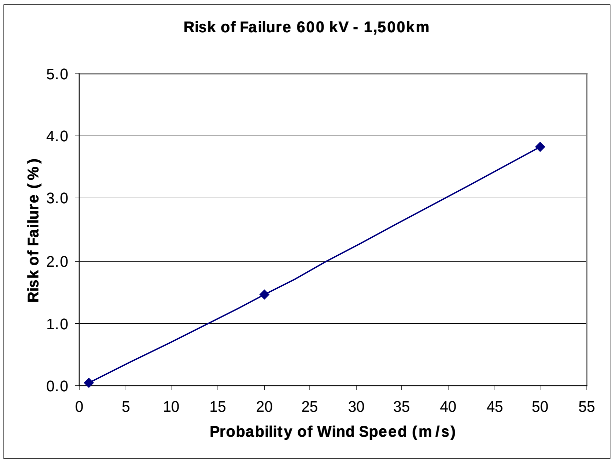


Figure 4.15: Composite risk

It shall be noted that the displacement with the wind having 11% probability of being exceeded (±500 kV) and 14 % (±600 kV) are the values to be used. The displacement due to this wind distribution added to the "switching surge clearance" leads to a final risk of 1/100 years. As a matter of simplification, the 10% wind will be used in the next calculations.

The swing angles for 10% probability of occurrence are shown on Table 4.8.

Table 4.8: Swing Angle for Switching Surges

ACSR Conductor code	MCM*	Swing Angle (°)
Joree	2,515	6.5
Thrasher	2,312	6.7
Kiwi	2,167	7
2,034	2,034	7.1
Chukar	1,780	7.1
Lapwing	1,590	7.5
Bobolink	1,431	7.8
Dipper	1,351.5	7.9
Bittern	1,272	8.1
Bluejay	1,113	8.4
Rail	954	8.8
Tern	795	9.2

* 1 MCM=0.5067 mm^2

4.3 Pole Spacing Determination

The pole spacing requirements will be determined considering the use of I or V strings.

4.3.1 Case of I Strings

For the pole spacing evaluation, the swing angles of the insulator strings as determined before will be used.

A) Pole Spacing Required for Operating Voltage

The minimum pole spacing DP_{TO} is:

$$DP_{TO} = (R + dmin + (L + R)\sin\theta) * 2 + w$$

Where:

dmin → Operating voltage clearance, as per Table 4.3;

R → bundle radius $R = \dfrac{a}{2\,\mathrm{sen}(\pi / N)}$

a → subconductor spacing (as general rule, 45cm is adopted);

N → number of subconductors in the bundle (N = 4 is adopted for all calculations here), leading to R = 0.32 m;
L → insulator string length, as per Table 4.5;
θ → swing angle for the maximum wind speed with 50 year return period, as per Table 4.6;
w → tower width at conductor level, as per Table 4.9.

Table 4.9: Assumed Tower Widths

Operating Voltage (kV)	Tower Width (m)
±300	1.2
±500	1.7
±600	2.0
±800	2.5

The pole spacing values are shown on Table 4.10.

Table 4.10 - Pole Spacing (m) for Operating Voltage I strings

ACSR Conductor	Cross Section (MCM)*	Pole Spacing (m)			
		±300 kV	±500 kV	±600 kV	±800 kV
Joree	2,515	8.2	12.5	14.6	18.8
Thrasher	2,312	8.3	12.6	14.8	19.1
Kiwi	2,167	8.4	12.8	15.0	19.3
2,034	2,034	8.5	12.9	15.1	19.5
Chukar	1,780	8.5	12.9	15.1	19.5
Lapwing	1,590	8.6	13.1	15.4	19.8
Bobolink	1,431	8.7	13.3	15.6	20.1
Dipper	1,351.5	8.8	13.4	15.7	20.2
Bittern	1,272	8.8	13.4	15.8	20.3
Bluejay	1,113	8.9	13.6	16.0	20.6
Rail	954	9.0	13.8	16.2	20.8
Tern	795	9.2	14.0	16.4	21.1

*1 MCM=0.5067 mm^2

B) Pole Spacing Required for Switching Surges

The minimum pole spacings required for switching surges is calculated in a similar manner as before, except that the swing angles are those from Table 4.8. The results for ±800 kV bipole lines are shown on Figure 4.16.

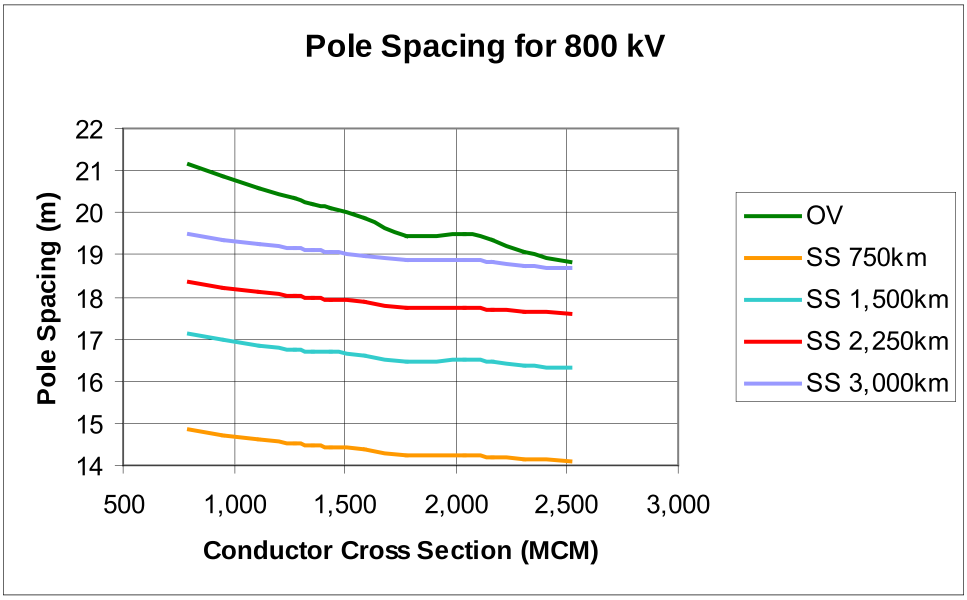


Figure 4.16: Pole Spacing (±800 kV, 750 to 3,000 km)

Nomenclature: OV Operating Voltage; SS Switching Surge

It can be seen that the operating voltage criteria governs the pole spacing for ±800 kV voltages and of course for the other voltages as well.

Therefore, the values of Table 4.10 shall be used as pole spacing for I string configurations.

4.3.2 Case of V strings

In this case there will be no swing angles due to wind at the towers and the clearance requirements for switching surges will determine the pole spacing. However, the V strings having length (L) shall be inserted in the tower, meaning that the minimum pole spacing (PSmin) for installation will be:

$$PSmin = 2*L* \cos(45^{o}) + w$$

Where:
w $\rightarrow$ tower width;

It is assumed here that the V string angle is 90 degrees, however this opening can be reduced.

The pole spacing requirement is otherwise calculated by:

$$DP_{TO} = (dmin + R) * 2 + w \qquad \text{(provided that } DP_{TO} > PSmin)$$

The results are shown on Table 4.11.

Table 4.11: Pole spacing requirements

Operating Voltage (kV)	Clearance Conductor Structure (m)				Bundle Radius (m)	Tower Width (m)	Pole Spacing (m)				
	750 km	1,500 km	2,250 km	3,000 km			750 km	1,500 km	2,250 km	3,000 km	PSmin
±300	0.88	1.09	1.21	1.30	0.32	1.20	3.6	4.0	4.3	4.4	6.0
±500	2.06	2.55	2.83	3.06	0.32	1.70	6.5	7.4	8.0	8.5	9.3
±600	2.78	3.46	3.83	4.14	0.32	2.00	8.2	9.6	10.3	10.9	11.0
±800	4.50	5.62	6.25	6.81	0.32	2.50	12.1	14.4	15.6	16.8	14.3

In summary the pole spacing distances are:

- ±300 kV => 6 m
- ±500 kV => 9.3 m
- ±600 kV => 11 m
- ±800 kV => 14.4 m for line length < 2,250 km
  15.6 for line length equal to 2,250 km
  16.8 for line length equal to 3,000 km

It should be noted that clearances for insulation is not the only criteria to choose between I or V strings, for instance I sting offer less surface for pollution from birds excretion, the corona protection rings are simpler, and of course is less expensive as they have less insulators.

4.4 Conductor Current Carrying Capability and Sags

4.4.1 Current Capability

The current carrying capability of ACSR conductors were calculated based on CIGRE recommendation [10] “Brochure 207: Thermal Behavior of Overhead Conductors (August/2002)”, that relates to AC current. It should be noted that the DC current has a lower heating effect than AC current due to the absence of the transformer and eddy current effects, however this will not be considered here.

The following assumptions are made:

- Wind speed (lowest) 1 m/s
- Wind angle related to the line 45 degree
- Ambient temperature 35ºC
- Height above sea level 300 to 1,000 m
- Solar emissivity of surface 0.5
- Cond. solar absorption coefficient 0.5
- Global solar radiation 1,000 W/ m^2

The maximum temperature of the conductor will be limited here to 90ºC (as design criteria commonly used in many countries) for steady state and in emergency or short duration conditions, although it could be accepted temperatures even above 100 ºC for non special conductors (thermal resistant conductor may withstand much more in steady state condition) . However, the conductor is selected based on economic criteria (cost of line plus losses) leading to a maximum operating temperature in normal conditions much lower (~55 to 60 ºC). Therefore 90 ºC will eventually apply to pole conductors at abnormal conditions as well as to electrode lines and metallic return conductors. Figure 4.17 shows the current capability for some conductors, so that the corresponding values for intermediate sizes can be interpolated.

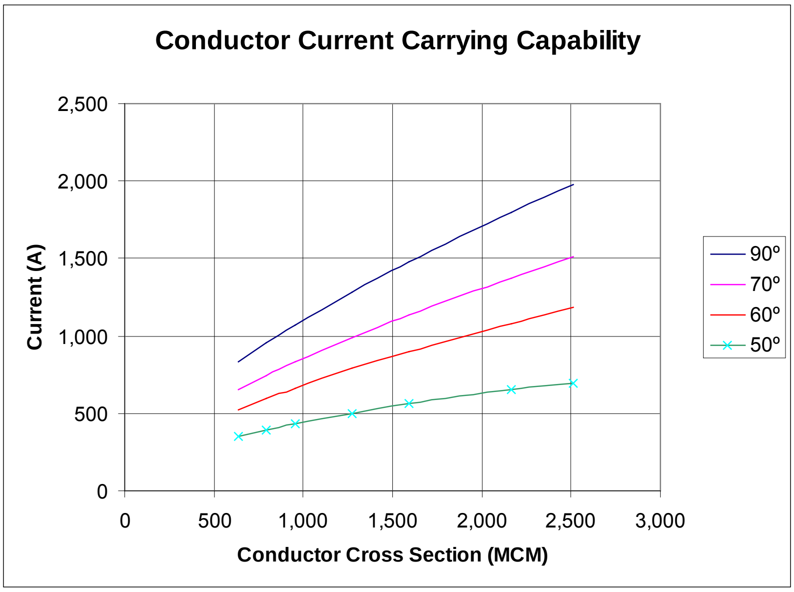


Figure 4.17: Conductor Current Carrying Capability for alternatives maximum temperature criteria

4.4.2 Sag for Conductor Maximum Temperature

The sags are presented on Figure 4.18 for conductor temperatures in the range from 50 to 90 ºC. The sag calculation was based on the following conditions:

- Span → 450 m
- EDS → Every Day Stress condition

  • Tension of 20% of the RTS (this is a simplification - ideally the EDS should be selected based on fixed H/w horizontal-tension/ weight, the catenary's parameter) ;

  • Temperature: 20 ºC

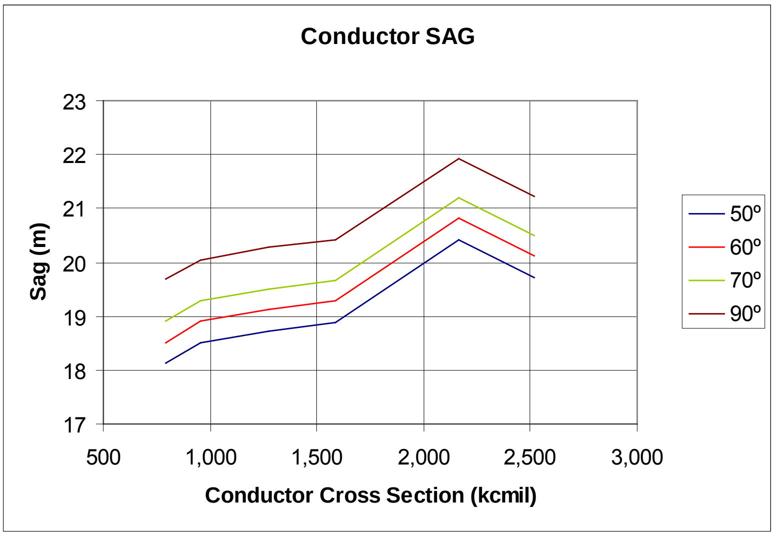


Figure 4.18: Conductor sags

It can be seen that the sags vary from 18 to 22 meters, depending on the conductor temperature and type of conductor. It should be noted that the conductors considered in this graph are those of the tables shown before (table 4.10 for instance). Conductor with the same aluminum but different steel content will have different sag.

4.5 Tower Height

The following distances are defined hereunder.

The conductor height at the tower (h_p) is:

$$h_p = C_S + sg + Ext + R$$

Where:
h_p → distance from the center of the bundle to ground at tower;
C_S → clearance to ground at mid-span 8; 12.5; 14.5; 19.5 m for ±300; ±500; ±600; ±800 kV, respectively, determined by electric field criteria (see clause 4.9);
sg → conductor sag at 90º C (criteria adopted) , as per Figure 4.18 (22 m adopted for all conductors in this clause);
R → bundle radius;
Ext → tower extensions up to 3 x 3 m = 9 m

The shield wire height (h_g) at the tower is:

$$h_g = h_p + R + dis + D_G$$

Where:
dis → insulator string and hardware length: 3.22; 5.2; 6.2 and 8.17 m for ±300; ±500; ±600 and ±800kV, respectively;
The assumed values for shield wire to cross arm distance DG are:

D_G = 2.5 m (for the case of two shield wires), or
D_G = 5 m (for the case of only one shield wire).

Table 4.12 shows the values to be used in the calculations which follow.

Table 4.12: Conductor and shield wire heights at tallest tower
(Two shield wires - for one, add 2.5 m to h_g)

Voltage (kV)	h_p (m)	h_g (m)
±300	38.3	44.3
±500	42.8	50.8
±600	44.8	53.8
±800	50.8	61.8

4.6 Lightning Performance

In order to get a good performance under lightning strokes, the design of HVDC lines should include the use of shield wires (one or two).

The shield wires reduce the direct strokes to the conductors. For the strokes that hit the shield wires, there will be an overvoltage that is coupled to the pole conductors and can cause flashovers or not.

To set a good design, some conditions shall be considered:

a) The current of the stroke that hit the pole conductors should not produce an overvoltage greater than the insulation withstand of the line.
b) The closer are the shield wires to the pole conductor, the better will be the performance due to strokes hitting the shield wires.
c) The tower footing resistance and the corresponding tower footing surge impedance should be low, therefore requiring the use of an adequate grounding system, generally counterpoises at the towers.

In regions with ice, the second condition may be conflicting with the requirements of keeping a safety distance from the shield wire to the pole conductors during icing events.

The clearances at the tower are designed to withstand switching overvoltages with a pre-established risk of failure, or the operating voltage.

Once defined the required clearances, the Critical Impulse Flashover Capability (E) of the insulation (50% probability) for lightning surges (fast front overvoltages) are known.

With E and the conductor surge impedance Z, the critical "threshold current" I_{oc}, into the conductor for which a flashover will start is determined [11] by:

$$Ioc = \frac{2\ E}{Z}$$

The striking distance r_{sc} is a function of I_{oc} and is calculated by:

$$r_{sc} = k\ 6.7\ I_{oc}^{0.8}$$

Where:
r_{sc} → in (m)
I_{oc} → in (kA)
k is a factor different from 1 eventually adopted for shield wires or ground.

The horizontal distance "X" between conductor and shield wire is:

$$X = rsc\left(\sqrt{1-(k-T)^2} - \sqrt{1-(k-R)^2}\right)$$

Where:
r_{sc} → striking distance (m)
k → factor
T → $T = h_g^* / r_{sc}$
R → $R = h_p^* / r_{sc}$
h_g^* → average shield wire height (m)
h_p^* → average conductor height (m)

Three types of terrain may be considered, namely:

a) Flat: in this case the following parameters are used in the equations above.
$h_p^* = h_p – S_c$ (2/3)
$h_g^* = h_g – S_g$ (2/3)
h_p, h_g are conductor or shield wires heights at tower; and S_c, S_g are the conductors and shield wires sags.
b) Rolling: in this case:
$h_p^* = h_p$
$b^* = (h_g - h_p) + (S_c - S_g)$ (2/3)
$h_g^* = h_p^* + b^*$
c) Mountainous
hp* = 2 hp
h_p^*, h_g^* as in the rolling case.

In this report the evaluations will be done considering rolling terrain, average tower (no extensions) and k = 1.
The protection angle θ is then:

$$\theta = \arctan \frac{X}{(T - R)S}$$

The line surge impedance Z is assumed here as 350 ohms.

When the lightning activities are low (and on icing regions where it is desired that the shield wires should not be in the same vertical line as the conductors), one shield wire may be a preferable design for economical reasons. For such cases, in this work, the shield wires are positioned 5 m above the tower cross arm, and the X value is determined, as well as the maximum pole spacing - PSM (X, PSM values for effective protection for direct striking).

$$PSM = 2\,X + w$$

Where:
w → tower width (see Table 4.9)

When the required pole spacing (see Table 4.9 for I and Table 4.10 for V insulator strings) is bigger than PSM, the line is not effectively protected for direct striking. Table 4.13 presents the results considering one and two shield wires.

Table 4.13 - Protection for direct strokes

Voltage (kV)	**E (kV)**	**hg* (m)**	**hp* (m)**	**2 shield wires**				**1 shield wire**	
				I_{oc} (kA)	**r_{sc} (m)**	**X (m)**	**θ (º)**	**X (m)**	**PSM (m)**
±300	1,900	43.1	32.3	11.9	48.7	2.5	13	2.0	5.2
±500	3,000	49.6	36.8	18.9	70.2	5.4	22	5.0	11.7
±600	3,600	52.6	38.8	22.6	81.2	6.8	26	6.4	14.8
±800	4,850	60.6	44.8	30.5	103.1	8.9	29	8.4	21.3

From Table 4.13 it can be seen that the minimum protection angle θ can be set at values from 13 to 29 degrees. The closer are shield wires to the conductors, the better is the lightning performance for back flashovers due the higher coupling factor.

As a consequence, the protection angle can be adopted as 10 degrees, when using two shield wires.

If one shield wire is used, then the protection is practically satisfactory for towers with V strings (compare PSM with the values from Table 4.10). If I strings are used, there is no effective protection for voltages below ±800 kV (compare PSM with values from Table 4.11).

Note: Only EHS steel wire is considered for shielding purpose. However other material or characteristics may be used if one intend for instance to provide dual function: lightning shielding and communication (carrier or fiber optics)

4.7 Right-of-Way Requirements for Insulation

The Right-of-Way width (ROW) is defined considering the following aspects: Conductor swing and clearances to objects at the border of ROW, corona and field effects.

At this point, only the first condition is examined and so the results will be partial.

In the ROW determination, clearances for operating voltage and I insulator string length are used.

The swing angles are calculated using the same parameters of clause 4.2.1.3, except that the ratio vertical to horizontal span is equal 1.0, and the span length should not exceed 600 m. It should be reminded that the wind intensity corresponds to 50 year return period. The swing angles are shown on Table 4.14.

Table 4.14: Swing angles for ROW width definition

Conductor		Swing Angle (degree)
ACSR Code	**Section (MCM)***	
Joree	2,515	34.1
Thrasher	2,312	35.1
Kiwi	2,167	36.4
2,034	2,034	37.2
Chukar	1,780	37.0
Lapwing	1,590	39.1
Bobolink	1,431	40.4
Dipper	1,351.5	41.1
Bittern	1,272	41.9
Bluejay	1,113	43.5
Rail	954	45.4
Tern	795	47.5

* 1 MCM=0.5067 mm^2

The conductor sags (Table 4.15) were obtained by starting from EDS conditions and considering the wind load with the coincident temperature.

Table 4.15: Sags for ROW width definition

Conductor		Sag (m)
ACSR Code	Section (MCM)*	
Joree	2,515	36.5
Thrasher	2,312	36.6
Kiwi	2,167	38.0
2,034	2,034	37.9
Chukar	1,780	33.2
Lapwing	1,590	34.9
Bobolink	1,431	34.5
Dipper	1,351.5	34.5
Bittern	1272	34.5
Bluejay	1,113	34.5
Rail	954	33.8
Tern	795	33.6

*1 MCM=0.5067 mm^2

4.7.1 Line with I Strings

The minimum ROW when using “I strings” is determined by:

$$ROW = [(R + L + S) \sin\theta + d_{min}] * 2 + PS$$

Where:

d_{min} → operating voltage clearance
R → bundle’s radius (m)
L → insulators string length
S → conductor sag
θ → swing angle due to wind (50 year return period)
PS → pole spacing

Table 4.16 shows the ROW width as function of the conductor type.

Table 4.16: Right Of Way (I strings) in (m)

Conductor		±300 kV	±500 kV	±600 kV	±800 kV
ACSR Code	Section (MCM)*				
Joree	2,515	54.7	62.1	65.9	73.2
Thrasher	2,312	56.0	63.6	67.4	74.9
Kiwi	2,167	59.3	67.0	70.9	78.5
2,034	2,034	60.1	67.9	71.8	79.5
Chuckar	1,780	54.3	62.1	66.0	73.7
Lapwing	1,590	58.7	66.7	70.7	78.5
Bobolink	1,431	59.6	67.7	71.8	79.8
Dipper	1,351	60.4	68.6	72.7	80.8
Bittern	1,272	61.1	69.4	73.5	81.6
Bluejay	1,113	62.9	71.3	75.5	83.8
Rail	954	63.8	72.4	76.7	85.1
Tern	795	65.5	74.3	78.6	87.2

*1 MCM=0.5067 mm^2

4.7.2 Line with V Strings

The minimum ROW widths ("V strings") are calculated according to the same equation before but disregarding insulator string length. The results are shown in Table 4.17.

Table 4.17: Right Of Way (V Strings)

ACSR Conductor		±300 kV	±500 kV	±600 kV	±800 kV		
CODE	**SECTION (MCM)***	**750 to 3,000 km**	**750 to 3,000 km**	**750 to 3,000 km**	**<2,250 km**	**2,250 km**	**3,000 km**
Joree	2.515	48.9	53.2	55.3	59.6	60.7	61.8
Thrasher	2,312	50.0	54.3	56.5	60.7	61.8	63.0
Kiwi	2,167	53.1	57.4	59.5	63.8	64.9	66.0
2.034	2.034	53.7	58.0	60.5	64.4	65.6	66.7
Chuckar	1,780	48.0	52.3	54.4	58.7	59.8	61.0
Lapwing	1,590	52.0	56.3	58.4	62.7	63.8	65.0
Bobolink	1,431	52.7	57.0	59.2	63.4	64.5	65.7
Dipper	1,351	53.4	57.7	59.9	64.1	65.3	66.4
Bittern	1,272	54.0	58.3	60.5	64.7	65.9	67.0
Bluejay	1,113	55.6	59.9	62.0	66.3	67.4	68.5
Rail	954	56.2	60.5	62.7	66.9	68.1	69.2
Tern	795	57.7	61.9	64.1	68.4	69.5	70.6

*1 MCM=0.5067 mm^2

Note that the results (for I or V strings) are partial as corona effects were not yet considered. Also note that only horizontal design is considered (vertical design will led to smaller ROW)

4.8 Corona effects

4.8.1 Concepts

Corona considerations in the design of HVDC transmission lines have been discussed in the CIGRÉ Publication 61 [12]. This publication includes discussion of corona losses (CL), radio interference (RI) and audible noise (AN).

Factors influencing the choice of conductor bundles are discussed below. This section provides the basis for selection of the conductor bundle. It can be used, however, to evaluate the cost sensitivity of HVDC transmission lines to corona performance considerations.

4.8.1.1 Conductor Surface Gradient

A) Equations

The parameter that has the most important influence on corona performance is the conductor surface electric field or what is commonly known as conductor surface gradient. Electrostatic principles are used to calculate the electric field on the conductors of a transmission line [13]. If a single conductor is used on each pole of the line, the electric field is distributed almost uniformly around the conductor surface. For a bipolar HVDC transmission line with a single conductor, the average and maximum conductor surface gradients E_a and E_m, respectively, in kV/m, are given as:

$$E_m = E_a = \frac{V}{r \ln \dfrac{2H}{r * \sqrt{\left(\dfrac{2H}{S}\right)^2 + 1}}}$$

Where:
V → voltage applied (actually ± V) to the conductors of the line, kV
r → conductor radius, cm
H → conductor height, cm
S → pole spacing, cm

When bundled conductors are used, the electric field around the sub-conductors of the bundle is distributed non-uniformly, with maximum and minimum gradients occurring at diametrically opposite points and the average gradient at a point in between. The degree of non-uniformity increases as the number of sub-conductors in the bundle as well as the ratio of the sub-conductor radius to the bundle radius increase. Using the method known as Markt and Mengele's method, the average and maximum bundle gradients [14] of a bipolar HVDC line, with n-conductor bundles on each pole, are given as [13].

$$E_a = \frac{V}{n\ r\ \ln \dfrac{2H}{r_{eq} * \sqrt{\left(\dfrac{2H}{S}\right)^2 + 1}}}$$

$$E_m = E_a \left[1 + (n-1)\frac{r}{R}\right]$$

Where:
r → sub-conductor radius, cm
R → bundle radius, cm
r_{eq} → equivalent bundle radius, cm

$$R = \frac{a}{2\,\mathrm{sen}(\pi / N)}$$

$$r_{eq} = R \cdot \left[\frac{nr}{R}\right]^{1/n}$$

a → distance between adjacent subconductors, cm

Equations above give reasonably accurate results for the maximum bundle gradient, with errors not exceeding 2%, for $n \leq 4$ and for normal values of H and S. More accurate methods, such as the method of successive images [14, 15], are required for $n > 4$. For purposes of design and economic evaluations considered in this report, these equations are sufficiently accurate.

B) Corona Onset Gradient

When the electric field at the surface of a transmission line conductor exceeds a certain value, partial electrical breakdown of the surrounding air takes place, giving rise to corona discharges.

The occurrence of corona discharges in the immediate vicinity of conductors leads to a number of corona effects that have important influence on transmission line design. Corona effects that are generally taken into account in the design of both AC and DC transmission lines are CL, RI, AN and visual effects. In the case of HVDC transmission lines, the combined effect of DC electric fields and corona-generated ion currents at ground level have also to be taken into account as design considerations. Although corona on transmission lines also generates ozone, studies on experimental as well as operating transmission lines have shown that contribution to ambient ozone levels is almost negligible [16].

The conductor surface electric field at which the onset of corona discharges occurs is defined as the corona onset gradient of the conductor. The corona onset gradient of a given conductor depends on many factors, the most important being the conductor radius, surface conditions and ambient air density. It depends also on the type of voltage applied to the conductor, AC or dc, and in the case of direct voltages, also on the polarity.

Corona onset gradients of cylindrical conductors have been determined experimentally in laboratory studies. While Peek studied the corona onset of conductors under alternating voltages, Whitehead [17] studied it under the application of direct voltages of both positive and negative polarity. Based on test results obtained on a number of smooth cylindrical conductors of small diameter, Whitehead derived the following empirical formula for the corona onset gradient:

$$E_c = mE_0\delta\left[1 + \frac{K}{\sqrt{\delta r}}\right]$$

Where:
E_c → corona onset gradient, kV/cm
r → conductor radius, cm
m → conductor surface irregularity factor
E_0 and K → empirical constants. According to Whitehead, E_0 = 33.7 and K = 0.24 for positive DC and E_0 = 31.0 and K = 0.308 for negative dc.

δ → relative air density, given as:

$$\delta = \left(\frac{273 + t_0}{273 + t}\right).\left(\frac{p}{p_0}\right)$$

Where t is the temperature and p is the pressure of ambient air and t_0 = 25 °C and p_0 = 760 torr.

Since no significant differences have been observed between the corona onset gradients at positive and negative polarities for practical conductors, the following formula, applicable at both polarities, is generally used:

$$E_c = 30m\delta\left[1 + \frac{0.301}{\sqrt{\delta r}}\right]$$

Although other empirical formulas have been proposed [18], for practical conductor sizes (2–5 cm diameter) they do not differ significantly from the results obtained using the above equation. In fact, for practical transmission line conductors, the parameters m and δ have a much greater impact on corona performance than the form of empirical formula used to calculate corona onset gradients. Practical transmission line conductors are generally of stranded construction and may also have surface irregularities such as nicks, scratches etc. produced during the handling and installation of conductors. In addition, organic (leaves, insects etc.) and inorganic (dust, smoke and other atmospheric pollutants) matter may be deposited on conductors during the course of normal operation of a transmission line.

Experimental studies show that for reasonably clean stranded conductors, m varies in the range of 0.75 to 0.85, depending on the relative diameters of the conductor and strands. Surface irregularities may reduce m to values in the range of 0.6 to 0.8, while conductor surface deposits and precipitation (rain, snow etc.) may further reduce it to values in the range of 0.3 to 0.6 [13].

The relative air density δ varies as a function of the temperature and pressure of the ambient air. Thus, at the same location (i.e. the pressure variations are small), seasonal ambient temperature variations may cause δ to vary by as much as 15% to 25%. However, the altitude above sea level of the location can potentially have a much larger influence on δ. Since atmospheric pressure decreases rapidly with altitude, δ may reach values as low as 0.5 in mountainous regions.

The corona onset gradient of a clean conductor, determined in the laboratory by detecting light, radio or acoustic emissions, has very little direct application to the evaluation of corona performance of a transmission line with the same conductor. The factors m and δ, which depend very much on the operating conditions and location of the line, have a much larger influence on the corona performance of the line. Consequently, although corona onset gradient may serve as a rough guideline, the selection of conductor bundles for HVDC transmission lines is based mainly on criteria for corona performance defined in terms of CL, RI, AN and visual effects.

4.8.1.2 Corona Loss

Corona losses on both AC and DC transmission lines occur due to the movement of both positive and negative ions created by corona. However, there are basic differences between the physical mechanisms involved in AC and DC corona loss [13]. On AC lines, the positive and negative ions created by corona are subject to an oscillatory movement in the alternating electric field present near the conductors and are, therefore, confined to a very narrow region around the conductors. On DC lines, however, ions having the same polarity as the conductor move away from it, while ions of opposite polarity are attracted towards the conductor and are neutralized on contact with it. Thus, the positive conductor in corona acts as a source of positive ions which fill the entire space between the conductor and ground, and vice-versa, for the negative conductor.

The case more widely used is the bipolar HVDC transmission line. The positive and negative conductors in corona emissions having the same polarity as the respective conductor. Unipolar space charges fill the space between each pole and ground while ions of both polarities mix in the bipolar region between the two poles and are subject to some amount of recombination.

Theoretical calculation of corona losses from HVDC transmission lines requires analysis of the complex electric field and space charge environment in the unipolar and bipolar regions [13]. Such an analysis determines in the first step the electric field and ion current distributions on the surface of the conductors and ground plane and then evaluating corona losses of the line. Ambient weather conditions have a large influence on corona losses from the line. The losses are lower under fair weather conditions than under foul weather conditions such as rain, snow etc. However, the ratio of foul weather to fair weather CL on a DC line is much lower than in the case of an AC line.

Because of the complexity of theoretical calculations and the large number of factors influencing corona on practical HVDC transmission lines, it is often preferable to obtain empirical formulas derived from a large amount of data on long-term corona loss measurements made on experimental lines with different conductor bundles and under different weather conditions [19-21]. However, the amount of data available for CL from DC lines is much more limited than in the case of AC lines and, consequently, the accuracy and applicability of empirical formulas may be limited.

For unipolar DC lines, corona losses may be calculated using an empirical formula derived from measurements made on an experimental line in Sweden [19], which is given as:

$$P = V_u \cdot k_c \cdot n \cdot r_c \cdot 2^{0.25(g - g_0)} \times 10^{-3}$$

Where:
P → corona loss, kW/km
V_u → line voltage, kV
n → number of sub-conductors in the bundle
r_c → sub-conductor radius, cm
g → maximum bundle gradient, kV/cm
g_0 → reference value of g, and kc is an empirical constant

The reference value is given as g_0 = 22 δ kV/cm, where *δ* is the relative air density. The empirical constant is given as k_c = 0.15 for clean and smooth conductors, k_c = 0.35 for conductors with surface irregularities and k_c = 2.5 for the calculation of all-weather corona losses.
For bipolar DC transmission lines, some empirical formulas have been developed [21] for corona losses in different seasons of the year and under different weather conditions. However, the following empirical formulas are recommended since they are derived using available experimental data from a number of different studies [22], for evaluating fair and foul weather corona losses of bipolar HVDC transmission lines:

$$P_{fair} = P_0 + 50\log\left(\frac{g}{g_0}\right) + 30\log\left(\frac{d}{d_0}\right) + 20\log\left(\frac{n}{n_0}\right) - 10\log\left(\frac{H\ S}{H_0\ S_0}\right)$$

$$P_{foul} = P_0 + 40\log\left(\frac{g}{g_0}\right) + 20\log\left(\frac{d}{d_0}\right) + 15\log\left(\frac{n}{n_0}\right) - 10\log\left(\frac{H\ S}{H_0\ S_0}\right)$$

Where P is the bipole corona loss in dB above 1W/m, d is conductor diameter in centimeter and the line parameters g (conductor surface gradient), n (number of conductors), H (height) and S (pole spacing) have the same significance as described above. The reference values assumed are g_0 = 25 kV/cm, d_0 = 3.05 cm, n_0 = 3, H_0 = 15 m and S_0 = 15 m. The corresponding reference values of P_0 were obtained by regression analysis to minimize the arithmetic average of the differences between the calculated and measured losses. The values obtained are P_0 = 2.9 dB for fair weather and P_0 = 11 dB for foul weather.

$$P\,(W/m) = 10^{P(dB)/10} \quad \text{bipole losses in watt per meter}$$

In the economic evaluation it will be considered 80% of time fair-weather and 20% as foul-weather.

4.8.1.3 Radio Interference and Audible Noise

While corona losses occur due to the creation and movement of ions by corona on conductors, radio interference and audible noise are generated by the pulse modes of corona discharges. The current pulses induced in the conductors and propagating along the line produce RI, while the acoustic pulses generated by these modes of corona and propagating in ambient air produce AN [13].

The characteristics of corona-generated RI and AN on DC transmission lines differ significantly from those on AC lines. Firstly, while all three phases of an AC line contribute to the overall RI and AN of the line, only the positive pole of a DC line contributes to the RI and AN level. Secondly, the RI and AN levels of DC transmission lines under foul weather conditions such as rain etc., which produce rain drops on conductors, are lower than those under fair weather conditions. This is contrary to the case of AC lines on which foul weather conditions produce the highest levels of RI and AN, much higher than in fair weather. These two distinguishing features play important roles in predicting the RI and AN performance of DC transmission lines and in establishing the design criteria necessary for conductor selection.

A) Radio Interference

Both analytical and empirical methods may be used for calculating the RI level of DC transmission lines. Analytical methods require, however, knowledge of the RI excitation function for the conductor bundle used on the line under different weather conditions [13].

This information can be obtained through studies on experimental lines. Unfortunately, not many experimental studies have been carried out to enable prediction of the RI Excitation Function as a function of bundled conductor parameters of practical interest, particularly for transmission voltages above ± 500 to ±600 kV.

Some empirical methods have been developed for predicting the RI level of DC transmission lines under different weather conditions [21]. Their applicability is somewhat limited, however, because of the limited experimental data on which they are based. Based on data obtained on experimental as well as operating lines, a simple empirical formula has been developed [12,23] for predicting the average fair weather RI level for bipolar HVDC transmission lines as:

$$RI = 51.7 + 86\log\frac{g}{g_0} + 40\log\frac{d}{d_0} + 10\{1-[\log(10f)]^2\} + 40\log\frac{19.9}{D} + \frac{q}{300}$$

Where:
RI → radio interference level measured at a distance D from the positive pole with a CISPR instrument, dB above 1 μV/m
g → maximum bundle gradient, kV/cm
d → conductor diameter, cm
f → frequency, MHz
D → radial distance from positive pole, m
q → altitude, m

The reference values are g_0 = 25.6 kV/cm and d_0 = 4.62 cm.

Adequate statistical information is not presently available to determine the difference in the RI level between the average and maximum fair weather values or between the fair and foul weather values. However, based on the results of some long-term studies [21], the maximum fair weather RI may be obtained by adding 6 dB [24] and the average foul weather RI may be obtained by subtracting 5 dB from the average fair weather value.

Design criteria for RI from transmission lines are generally based on signal to noise ratios (SNR) for acceptable AM radio reception. Studies carried out on corona-generated RI from AC and DC transmission lines [21], [5] indicate that the SNRs for acceptable radio reception are:

a) background not detectable	SNR >30 dB
b) background detectable	20 dB
c) background evident	8 dB

Minimum radio station signal requirement in Brazil is 66 dB for cities with population from 2,500 to 10,000 inhabitants. Similar condition probably applies to other countries and is used here as part of the criteria.

At present, there are no established design criteria for RI from DC transmission lines; so the tentative guidelines are for limiting the RI at the edge of the right of way to (66-20) = 46 dB or to keep a reception quality b) at the reception. The equation for calculating noise above gives the average fair weather noise. For more stringent criteria, the noise shall be below 46-4= 42 dB [24] for 90% probability of not being exceeded, meaning that in 10% of the time the reception will be classified as between the criteria b) and c) above. The reference frequency is considered here as 1 MHz, and the line is at an average altitude of 600 m.

B) Audible Noise

As in the case of RI, analytical treatment of AN from transmission lines requires knowledge of a quantity known as generated acoustic power density, which can be obtained only through extensive measurements on an experimental line using a number of conductor bundles and carried out in different weather conditions. However, as in the case of RI, not enough data is available to develop accurate prediction methods for DC lines, particularly for transmission voltages above ± 500 to ±600 kV.

Based on measurements made on experimental as well as operating DC lines and the general characteristics of corona-generated AN, an empirical formula has been developed [26] for the mean fair weather AN, in dBA, from a DC line as:

$$AN = AN_0 + 86\ \log(g) + k\ \log(n) + 40\ \log(d) - 11.4\ \log(R) + \frac{q}{300}$$

Where:

g $\rightarrow$ average maximum bundle gradient, kV/cm
n $\rightarrow$ number of sub-conductors
d $\rightarrow$ conductor diameter, cm
R $\rightarrow$ radial distance from the positive conductor to the point of observation

The empirical constants k and AN_0 are given as:

k = 25.6 for n > 2
k = 0 for n = 1,2

AN_0 = -100.62 for n > 2
AN_0 = -93.4 for n = 1, 2

The maximum fair weather AN (probability 10% of not being exceeded [24]) is calculated by adding 5 dBA to the mean fair weather value obtained above, while the mean AN during rain is calculated by subtracting 6 dBA from the mean fair weather AN.

As in the case of RI, there are presently no regulations for AN from HVDC transmission lines. The Environmental Protection Agency (EPA) in the US recommends that the day-night average sound level L_{dn} [27] be limited to 55 dBA outdoors. The level L_{dn} is defined as:

$$L_{dn} = 10\log\left\{\frac{1}{24}\left[15{\cdot}10^{\frac{L_d}{10}} + 9{\cdot}10^{\frac{L_n+10}{10}}\right]\right\}$$

Where L_d and L_n are the day and night time sound levels, respectively. However, since the highest level of AN from DC lines occurs in fair weather, it may be prudent to limit the L_{dn} (10%) of AN from HVDC transmission lines to 55 dBA, and this correspond to 50 dBA for L_{dn}(50%). Reference [24] indicates that the night, and the all time distribution are close together by 1.5 dBA. Therefore assuming $L_d = L_n$ = 42 to 44 dBA results L_{dn}~50 dBA.

As a conclusion, the AN calculated by the equation above (average value) shall be limited to ~42 dBA at the edge of the right-of-way.

4.8.2 Calculation Results

The results of calculation based on the concepts and the equation described in item 4.8.1 are shown in this clause.

4.8.2.1 Conductor and Shield Wires Surface Gradient

A) Conductor Surface Gradient

In order to establish the mentioned guideline, calculations were made on the basis described below.

- DC voltages: ±300, ±500, ±600 and ±800 kV
- a → 45 cm or optimized to get the lowest maximum surface gradient
- N → 1 to 6
- H → 8; 12.5; 14.5; 19.5 m, for the above voltages
- S → as determined in the insulation coordination section
- r → from 1 to 2.4 cm
- E_c →calculated with equation of the clause 4.8.1.1 B taking δ = 0.92 and m = 0.82. Also a margin of 5% will be considered, therefore E_m (maximum conductor surface gradient) shall be lower than (0.95 E_c) in the analysis.

Figures 4.19 to 4.22 show the limits for towers with “I Insulator strings“, the results being summarized on Table 4.18. The same calculations were made for a tower with “V Insulator strings“ (lower pole spacing) and the results are also shown on Table 4.18.

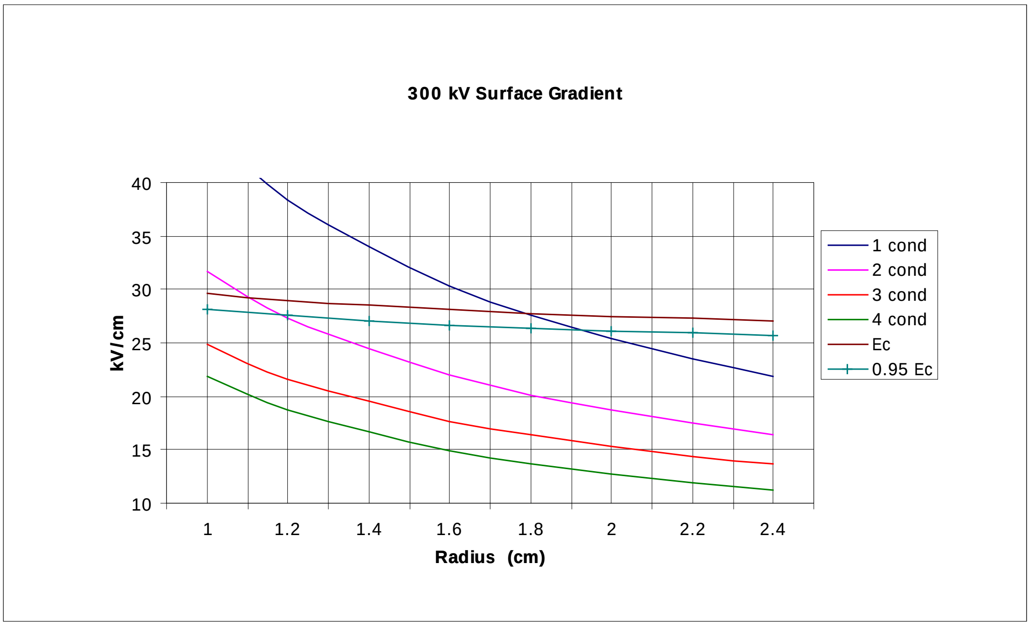


Figure 4.19: Conductor Surface Gradients ±300 kV

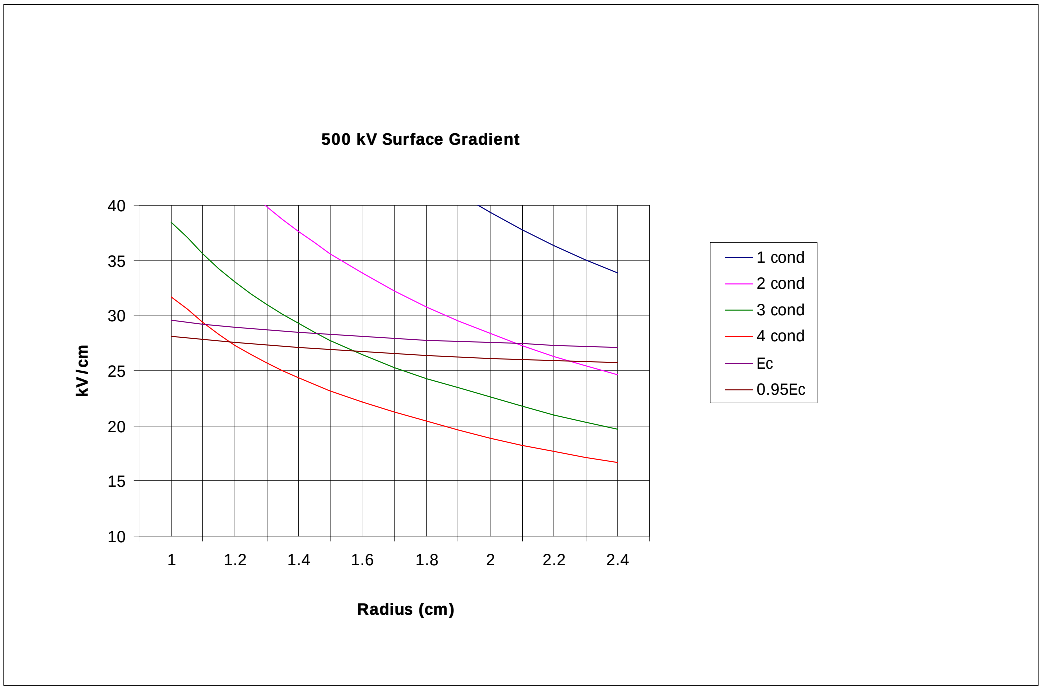


Figure 4.20: Conductor Surface Gradients ±500 kV

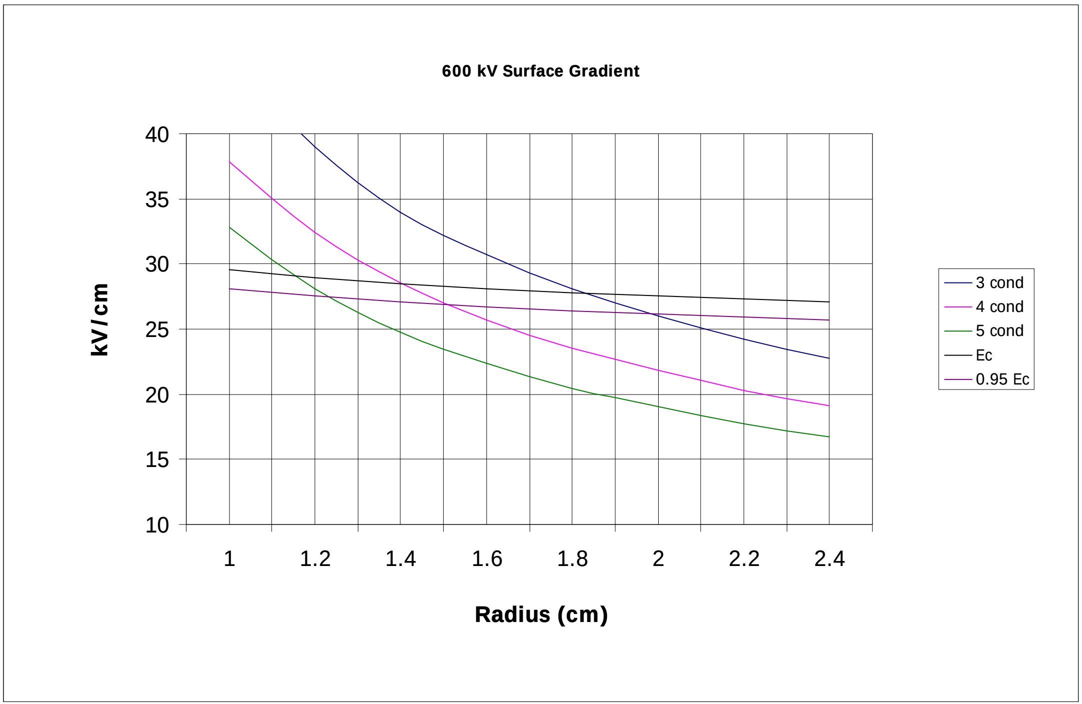


Figure 4.21: Conductor Surface Gradients ±600 kV

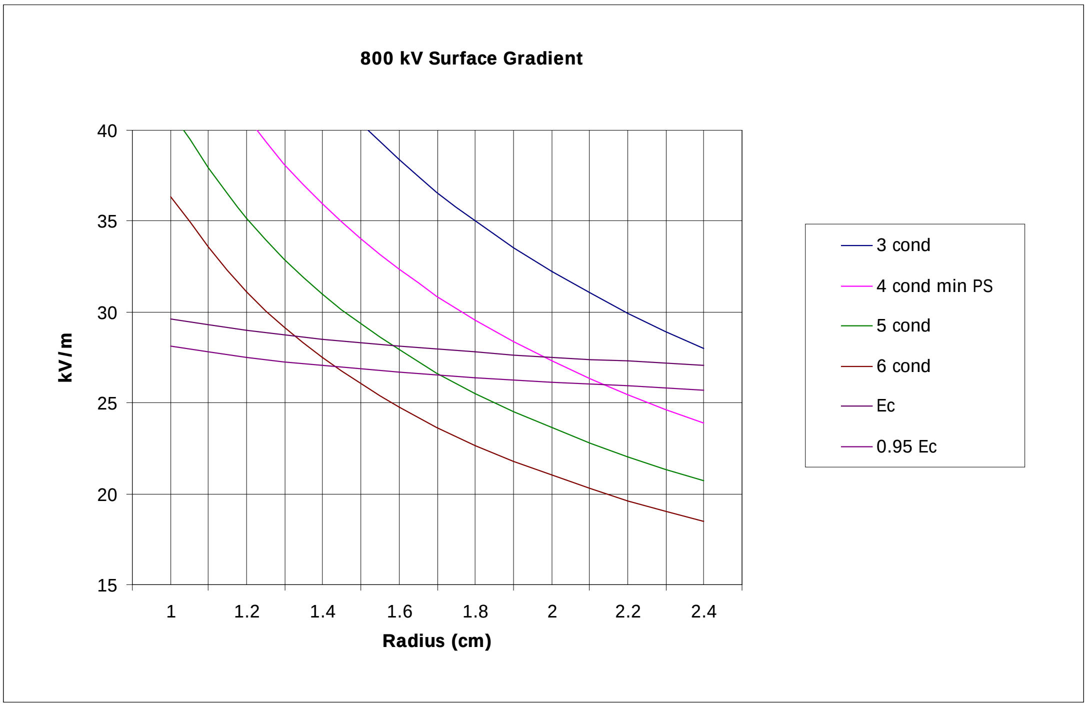


Figure 4.22: Conductor Surface Gradients ±800 kV

Based on the figures above, the minimum bundle configuration shown on Table 4.18 is recommended for next calculations.

Table 4.18: Minimum bundle configuration ($E_m = 0.95*E_c$)

kV	Subcond.	I Strings radius (cm)	I Strings (MCM)*	V Strings radius (cm)	V Strings (MCM)*
±300	1	1.94	1,590*	2.08	2,034
	2	1.18	605	1.33	715.5
	3	All		All	
±500	2	2.29	2,312	None	
	3	1.60	1,113	1.76	1,351.5
	4	1.2	605	1.33	715.5
	5	All		1.05	477
±600	3	2.01	1,780	2.23	2,156
	4	1.51	954	1.72	1,272
	5	1.22	605	1.35	715.5
±800	3	None		None	
	4	2.18	2,167	2.388	2,515
	5	1.71	1,272	1.92	1,590
	6	1.4	954	1.58	1,113

*1 MCM=0.5067 mm^2

Note: If smaller conductors should be of interest, then a convenient alternative is to increase the pole spacing.

Figure 4.23 shows the range of bundle configuration that meets the defined criteria, and the total conductor cross section considered for I insulator strings.

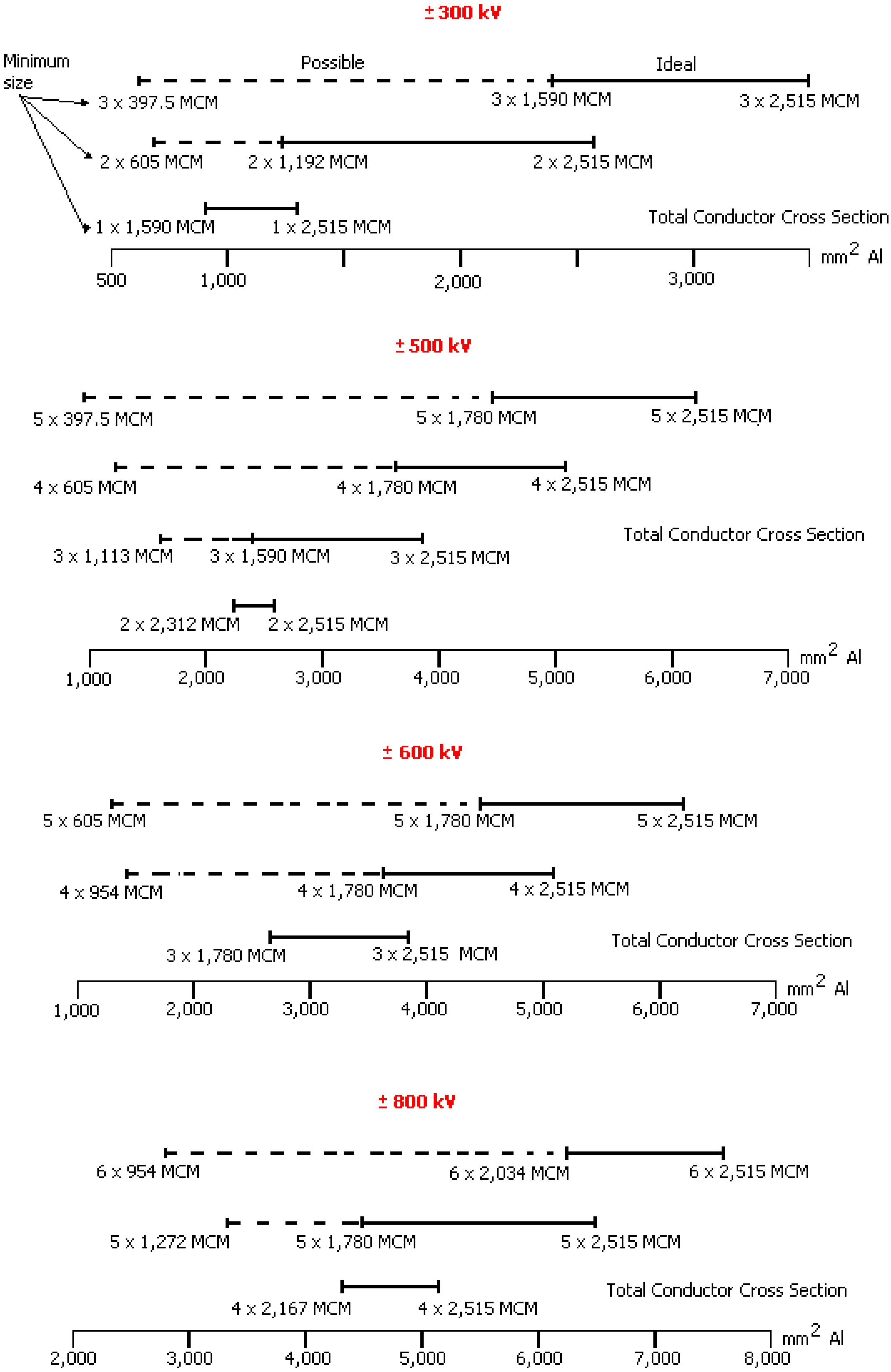


Figure 4.23: Conductor cross-sections for towers with I strings.

B) Shield Wire Gradient

As an extension of the concept described in 4.8.1, the shield wires surface gradient is analyzed.

The charge-voltage equation in the matrix form is:

$$[V] = [H][Q]$$

Where:
V → voltages on the conductors and shield wires [kV]
Q → charges $[kV * F/km]$
H → Maxwell's potential coefficients $[km/F]$

The inverse equation is:

$$[Q] = [C][V]$$

Where:
C → the admittance coefficient (F/km).

When the shield wires are grounded at the towers, their voltages are zero and their charges are calculated by:

$$Q_{Sw1} = C_{SW1-C1}\ V_{+} + C_{SW1-C2}\ V_{-}$$

For instance, the sub-index $_{Sw1-C1}$ is the mutual coefficient between shield wire 1 and conductor 1.
The electric field in the shield wire surface is:

$$E_{SW1} = \frac{Q_{SW1}}{2\ \pi\ \varepsilon\ r}$$

Where:
r → shield wire radius

$$\varepsilon = \frac{1}{36\pi}10^{-9} \quad F/m \quad or \quad \frac{1}{36\pi}10^{-6} \quad F/km$$

The calculation examples hereinafter will consider:

- Conductor configuration: 4 X ACSR, diameter 4 cm, bundle spacing: 45 cm
- V = $\pm$800 kV
- Shield wire EHS steel 3/4 ”
- Wire coordinates (x; y): consider (0;0) at the center of the tower at ground
  - Conductor coordinates (- 12 m; 44 m) ; (+ 12 m; 44 m)
    Conductor sag → 24 m
  - Shield wires coordinates (-10.5m; 55 m) (+10.5; 55 m)
    Shield wire sag → 20 m

The calculation with the wires at tower position leads to the following results:

$$Q_{cond} = 9815\ 10^{-9} \qquad [kV][F/km]$$

$$Q_{sw} = 723 \quad 10^{-9} \qquad [kV][F/km]$$

$$E_{SW} = 13.7 \qquad kV/cm$$

This value is considerably below the corona limit. The same calculation with the wires at mid-span position leads to lower values as the distance from conductor to shield wires are bigger due to the smaller sag of the shield wire.

$$E_{SW} = 8.9 \quad kV/cm$$

A verification should be made regarding to staging of valve groups or pole emergency, when there will be a voltage of 1 pu on one pole and 0.5 pu or zero on the other.
The result for V = +800 kV and -400 kV, wires at tower, are:

$$E = 18.9 \text{ kV/ cm}$$

The result for V = +800 kV in one pole and zero in the other are:

$$E = 24.1 \text{ kV/ cm}$$

The surface gradients on the shield wires are below the critical value. It can be concluded that no problem is expected as related to corona effect on shield wires.

It should be noted that 3/4" shield wires were taken into account. If 3/8" shield wires are used instead, then the gradients will be too high; in this case the shield wire position has to be changed to stay farther from the poles, if shield wire corona free is desired.

4.8.2.2 Corona Losses

Below, it is shown the calculation results for two line configurations (Base Cases 1 and 2) with the following characteristics:

	Base case 1	Base case 2
Voltage	±800 kV	± 500 kV
conductor MCM	5x1272	3x1590
code	(Bittern)	(Lapwing)
diameter	3.417 cm	3.822 cm
bundle spacing	45 cm	45 cm
pole spacing	20.3 m	13.1 m
minimum conductor-ground clearance	19.5m	12.5 m
maximum conductor surface gradient	26.45 kV/cm	23.25 kV/cm
Bipole Corona losses		
Pfair	5.9 kW/km	3.7 kW/km
Pfoul	24.8 kW/km	20.3 kW/km

4.8.2.3 Radio Interference and Audible Noise

A) Radio Interference

Figure 4.24 is an example of the right of way requirement as a function of the conductor size for ±500 kV lines (applying the equation and the adopted criteria see 4.8.1.3 A).

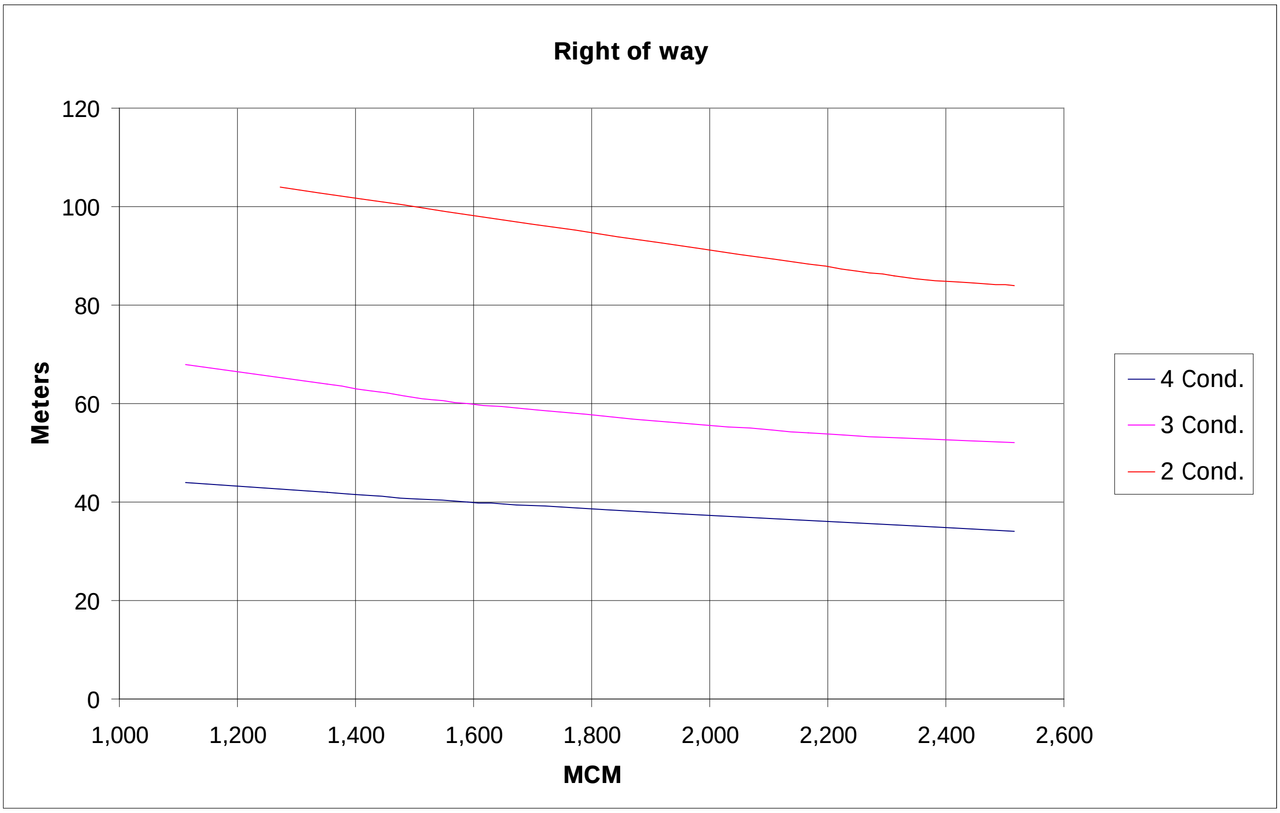


Figure 4.24: Right of way width, ±500 kV lines (for RI)

B) Audible Noise

Figure 4.25 shows the right-of-way requirements for ±500 kV lines, in order to meet the criteria proposed (applying methodology and criteria adopted, see 4.8.1.3 B).

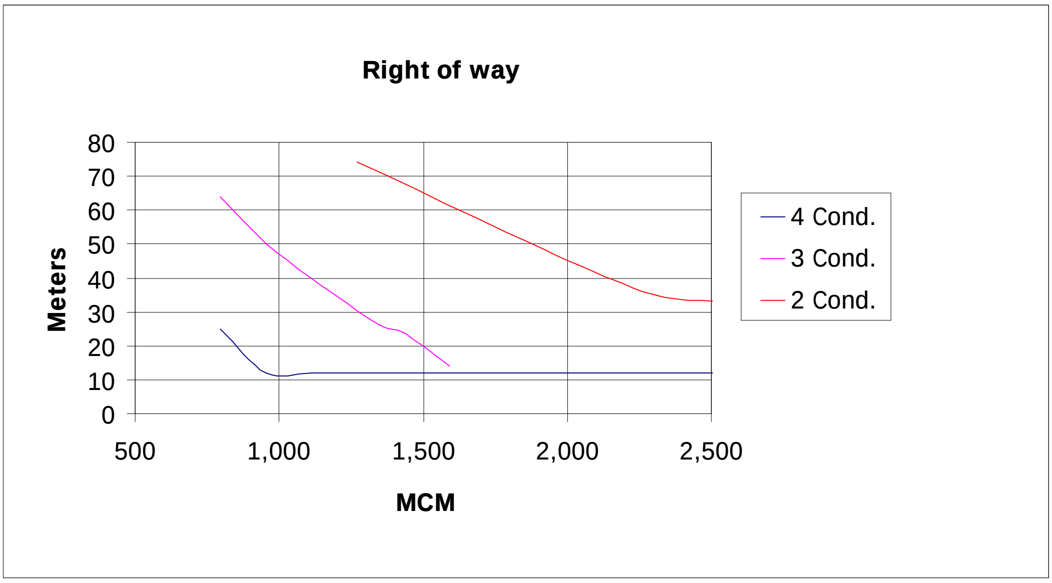


Figure 4.25: Right-of-way width, ±500 kV line (for AN)

C) Right-of-way Width to Comply with RI and AN Criteria

Figure 4.26 shows examples of comparative results of right-of-way requirements, considering RI and AN for ±500 kV lines, having three conductors per pole.

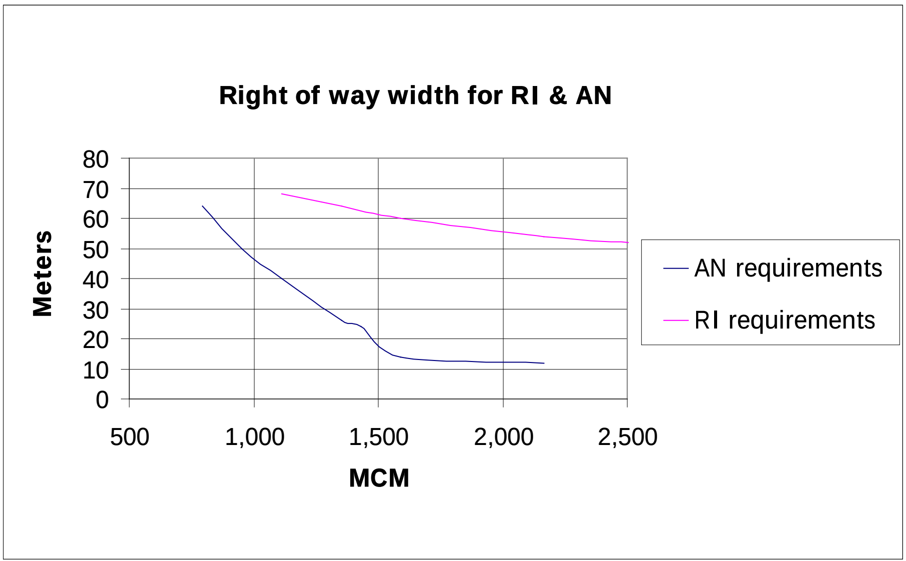


Figure 4.26: Right-of-way width (RI and AN), ± 500 kV, 3 cond. /pole

In this case RI criteria govern the choice of the right-of-way width, however it should be noted that for smaller conductors (larger surface gradient) the AN criteria increase in importance.
Tables 4.19 to 4.22 show the ROW requirements to meet both RI and AN criteria, as a function of the voltage (kV), number of conductor per pole (n) and conductor size.

Table 4.19: ROW (m) requirements for ±300 kV lines, I strings.

kV	n	MCM*	ROW RI	ROW AN
±300	1	2,515	64	10
		2,167	64	10
		1,590	72	22
±300	2	2,515	34	10
		1,590	40	10
		795	60	10
±300	3	2,515	20	10
		1,590	24	10
		795	36	10

*1 MCM=0.5067 mm^2

Table 4.20: ROW (m) requirements for ±500 kV lines, I strings.

kV	n	MCM*	ROW RI	ROW AN
±500	2	2,515	84	33
		2,312	86	35
		1,272	104	74
±500	3	2,515	52	12
		1590	60	14
		1,113	68	40
±500	4	2,515	34	12
		1,590	40	12
		1,113	44	12

Table 4.21: ROW (m) requirements for ±600 kV lines, I strings.

kV	n	MCM*	ROW RI	ROW AN
±600	3	2,515	70	52
		2,167	76	62
		1,780	80	78
±600	4	2,515	48	16
		1,780	52	30
		1,113	62	60
±600	5	2,515	30	16
		1,780	34	16
		795	50	44

Table 4.22: ROW (m) requirements for ±800 kV lines, I strings.

kV	n	MCM*	ROW RI	ROW AN
±800	4	2,515	76	144 *
		2,167	76	144 *
		1,590	88	-
±800	5	2,515	50	80
		2,167	54	96
		1,272	64	136**
±800	6	2,515	20	34
		1,590	40	74
		1,272	46	94

Notes: * If the criteria are relaxed by 2 dB, then the right of way can be reduced to 90 and 100 m,
** If the criteria are relaxed by 2 dB, then the right of way can be reduced to 100 m.

For a final definition of the ROW width, it is necessary to compare the results with the insulation coordination requirements. On Table 4.23 the ROW for ±800 kV and 4 conductors/pole, when using V string and the minimum pole spacing, are shown.

Table 4.23: ROW (m) requirements for ±800 kV lines, V strings, 4 conductors//pole

MCM	ROW RI	ROW AN
2,515	84	210 *
2,167	90	250 *

Note: If the criteria are relaxed by 2 dB, then the right of way reduces to 150 and 170 m.

This happens because of the increase in the conductor surface gradient, meaning that the possible reduction in pole spacing may not be useful.

D) Final ROW Width

The final right of way is chosen as the largest requirements for insulation coordination (item 4.7). Figure 4.27 illustrates what defines the (1/2 ROW) for ±500 kV, 3 conductors per pole. In this case, RI governs for conductors larger than 1,400 MCM (insulation requirements are always smaller in this case).

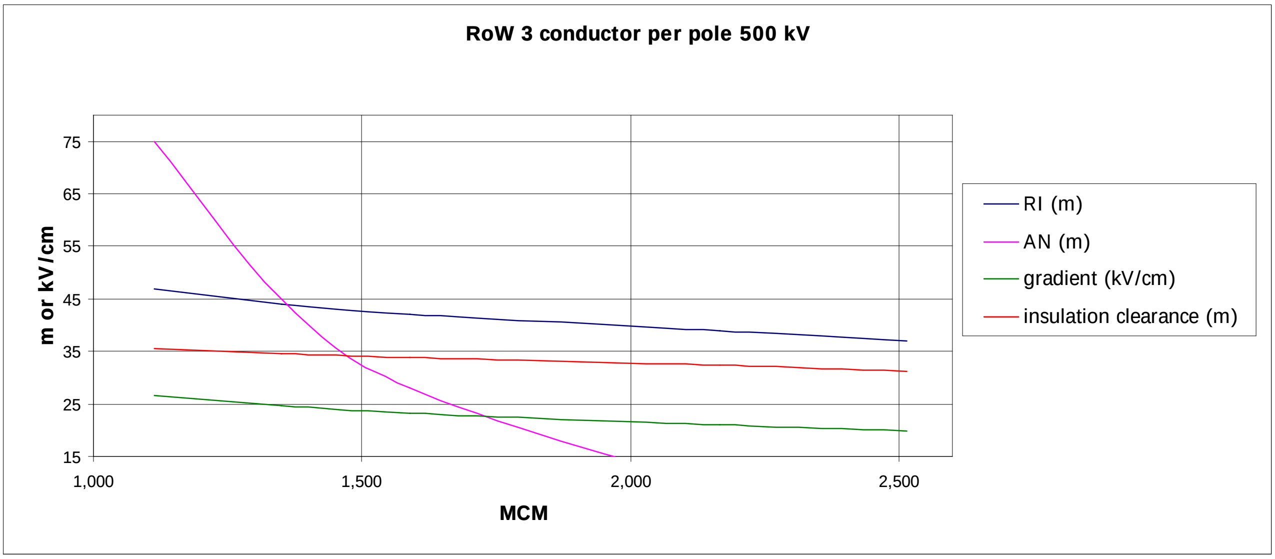


Figure 4.27: Half ROW and gradient for ±500 kV bipole having three conductors per pole.

Tables 4.24 to 4.27 show the final results.

Note: For large conductor configurations the ROW values shall be also checked for electric field criteria (see clause 4.9).

Table 4.24: ROW width (m) for ± 300 kV

kV	n	MCM**	I string ROW	V string ROW
±300	1	2,515	70	76
		2,167	130	140
		1,590	155	N (not calculated)
±300	2	2,515	54.7*	48.9*
		1,590	58.7*	56
		795	120	150
±300	3	2,515	54.7*	48.9*
		1,590	58.7*	52*
		795	65.5*	57.7*

** 1 MCM=0.5067 mm^2

* governed by insulation and conductor swing due to wind at mid span.

Table 4.25: ROW width (m) for ±500 kV

kV	n	MCM	I string ROW	V string ROW
±500	2	2,515	150	138
		2,312	170	176
±500	3	2,515	74	80
		1,590	84	104
		1,351.5	88	160
		1,113	150	N
±500	4	2,515	62.2*	60
		1,590	66.7*	70
		795	108	180

* governed by insulation and conductor swing due to wind at mid span.

Table 4.26: ROW width (m) for ±600 kV

kV	n	MCM	I string ROW	V string ROW
±600	3	2,515	124	130
		2,312	160	190
±600	4	2,515	76	82
		1,590	90	100
		1,351.5	104	170
		1,113	190	N
±600	5	2,515	65.9*	65
		1,590	70.7*	70
		795	130	240

* governed by insulation and conductor swing due to wind at mid span.

Table 4.27: ROW width (m) ±800 kV

kV	n	MCM	I string ROW	V string ROW
±800	4	2,515	180	280
		2,167	220	N
		2,034	280	N
±800	5	2,515	94	110
		2,167	98	166
		1,780	144	240
		1,272	300	N
±800	6	2,515	74	82
		1,590	86	150
		1,272	140	N
		954	250	N

4.9 Ground-Level Electric Field and Ion Current

4.9.1 Preliminary Design

Induction effects under AC transmission lines are defined mainly in terms of the magnitude and frequency of the alternating electric fields at the ground level. In the case of DC transmission lines, however, the magnitudes of both the electric field and the corona-generated ion currents at ground level are required to characterize any induction effects.

Corona-generated ion space charge fills the entire space between the conductors and the ground plane. In the cases of both unipolar and bipolar DC transmission lines, only positive or negative unipolar space charge exists at ground level. The combined presence of DC electric field and ion space charge is generally known as *space charge field* [13].

Both unipolar and bipolar space charge fields are defined in terms of a set of coupled non-linear partial differential equations. Solution of these equations, with appropriate boundary conditions, provides a description of the electric field, space charge density and ion current density at every point and, consequently, at the surface of the ground plane.

A numerical method has been developed [28] to solve the unipolar space charge field, necessary to determine the ground-level electric field and ion current distributions under either unipolar or bipolar DC transmission lines. Although some improved methods of calculation have subsequently been developed [29, 30], for practical transmission line configurations and taking into account the uncertainties in the input parameters such as corona onset gradient, conductor surface irregularity factor, ion mobility etc., all the methods described in references [28] to [29] provide results of acceptable accuracy.

An empirical method [31], called the degree of corona saturation method, has been proposed for calculating ground-level electric fields and ion currents. The method is based on assumptions that contradict basic corona physics and require a number of arbitrarily chosen empirical constants, many experts believe it is not appropriate for determining ground-level electric fields and ion currents.

Considering the gaps in the current state of knowledge, it would be prudent to carry out long-term measurements on experimental lines to obtain an accurate statistical description of the electric field and ion current environment for any new transmission line designs, particularly for transmission voltages above ± 500 to ± 600 kV. If calculations are required, however, it is recommended to use one of the numerical methods [28-30] based on correct physical and mathematical models of unipolar space charge fields.

In the absence of availability of experimental data for the proposed line design or access to numerical calculation methods, a simplified method, based on the physics of space charge fields and published experimental data, is proposed.

In the absence of corona on the conductors, no space charges are created and the electric field under a DC line may be calculated using principles of electrostatics. The space-charge-free electric field $E'_g(x)$ at any point P on the ground plane is obtained as:

$$E'_g(x) = \frac{V}{\ln \dfrac{2H}{r_{eq}\sqrt{\left(\dfrac{2H}{S}\right)^2 + 1}}} \cdot \left[\frac{2H}{\left(x - \dfrac{S}{2}\right)^2 + H^2} - \frac{2H}{\left(x + \dfrac{S}{2}\right)^2 + H^2} \right]$$

Where:
$V \rightarrow$ voltage applied to the bipolar line, kV
$H \rightarrow$ conductor height, m
$S \rightarrow$ pole spacing, m
$r_{eq} \rightarrow$ equivalent radius of the conductor bundle, m
$x \rightarrow$ lateral distance of P from the center of the line, m

The above equation can be used to obtain the lateral profile of the ground-level space-charge-free electric field, i.e. E'_g as a function of x. At a certain distance $x = x_m$, the electric field will reach a maximum value of E'_{gm}. Since it is rather difficult to derive them analytically, x_m and E'_{gm} should be determined using numerical calculations.

The presence of corona-generated space charge maintains the conductor surface electric field at the corona onset value, but enhances the electric field at points away from the conductors, with maximum enhancement occurring at ground level [13].

The electric field $E_g(x)$ at P in the presence of corona-generated space charge may, therefore, be expressed as:

$$E_g(x) = k_c(x) \cdot E'_g(x)$$

Where $k_c(x)$ is the field enhancement factor which depends on the intensity of corona on the sub-conductors of the bundle used and on the line geometry, i.e. the values of H and S. The field enhancement factor at ground level is one of the results obtained from numerical solution of equations defining unipolar space charge fields. In general, k_c and therefore E_g increase non-linearly with the voltage applied to the line. The enhancement factor k_{cm} corresponding to the maximum electric field at ground level is defined as:

$$E_{gm} = k_{cm} E'_{gm}$$

Electric field measurements carried out at ground level under a bipolar DC experimental line for different conductor bundles, line geometries and voltages up to ± 1,200 kV [21, 32] indicate that the enhancement factor k_{cm} varies in the range $1 \le k_{cm} \le 3$ under practical operating conditions. A value of $k_{cm} = 2$ may be used for the purpose of preliminary evaluation of E and selection of conductor height H. Accurate determination of k_{cm} requires calculations based on the proper physical model of unipolar space charge fields or, preferably, long-term measurements on an experimental line.

For the ion current density at ground level, however, no simplified but valid method of calculation is available. It can be determined only through complex calculations based on a proper physical model or through experimental studies or both. It is therefore recommended to base preliminary design for the purpose of economic evaluation mainly on the ground-level electric fields at the present time.

On the question of design criteria for ground-level electric fields and ion current densities, not many studies with the necessary scientific rigor have been carried out. One study [33], in which human subjects were exposed to electric fields and ion currents in a carefully controlled exposure chamber [34], was carried out using psychophysical principles. The results of this study clearly show that human perception is a function of both the electric field E and ion current density J. For example, average human thresholds have been obtained as E_p = 40 kV/m for J_p = 0 nA/m^2 and E_p = 25 kV/m for J_p = 100 nA/m^2. However, since it would not be economically feasible to design corona-free transmission lines, design criteria should take into account the inevitable presence of both electric fields and ion currents for practical HVDC transmission lines.

It is therefore recommended that HVDC transmission lines be designed to limit fair weather ground-level values to E_g = 25 kV/m and J_g = 100 nA/m^2. In the absence of information or data on J_m, a tentative guideline to limit the electric field to E_g = 25 kV/m under the line may be used. Table 4.28 shows the minimum clearance to ground as function of the voltage and conductor configuration, considering a maximum of 25 kV/m under the line.

Table 4.28: Minimum clearances to ground

Voltage kV	Conductor per pole	I strings MCM/MCM*	I strings Clearance (m)	V string MCM*	V string Clearance (m)
±300	1	1,590/2,515	> 6	2,034/2,515	6.5
	2	605/2,515	7	795/2,515	6.5
	3	336.4/2,515	7	336.4/2,515	6.5
±500	2	2,312/2,515	10.7	None	
	3	1,113/2,515	11.5	1,351.5/2,515	11
	4	605/2,515	11.8	795/2,515	11
	5	477/2,515	11.8	< 477/2,515	11
±600	3	1,780/2,515	13.2	2,167/2,515	13.5
	4	954/2,515	13.8	1,272/2,515	13.5
	5	605/2,515	14.3	795/2,515	13.5
±800	4	2,167/2,515	17.5	2,515	17.5
	5	1,272/2,515	18.0	1,590/2,515	17.5
	6	954/2,515	18.7	1,113/2,515	17.5

*1 MCM=0.5067 mm^2

4.9.2 Further Considerations

Although recognizing that the method proposed in [31] may be questionable, an investigation was made applying the equations from there. The results for the Pacific Intertie (BPA) line [24] are shown on tables 4.29 to 4.32.

Table 4.29: Electrical Field Lateral Profile (kV/m), 50% value - Pacific Intertie

Weather condition	E+ (50%)			E- (50%)		
	worst (*)	7.9m (*)	22.9m	Worst	7.9m	22.9m
Summer fair	25.4	27.9	11.5	17.2	18.4	7.3
Summer high hum., fog	32.0	36.1	15.0	27.6	31.0	12.8
Spring	21.6	24.2	9.8	16.1	17.9	7.1
W/O space charge		9.6	3.4		9.6	3.4
Pacific Intertie meas.		10.0	5.0		16.0	10.0

* See note A

Table 4.30: Electrical Field Lateral Profile (kV/m), 95% value. Pacific Intertie

Weather condition	E+ (95%)			E- (95%)		
	worst(*)	7.9m(*)	22.9m	worst	7.9m	22.9m
Summer fair	36.4	40.8	17.1	27.3	30.2	12.4
Summer high hum, fog	38.9	43.8	18.4	35.4	39.9	16.7
Spring	33.9	38.2	16.0	30.3	34.1	14.2
W/O space charge		9.6	3.4		9.6	3.4
Pacific Intertie meas.		20.0	15.0		33.0	22.0

* See note A

Values calculated with BPA software: E_+ = 28.7 and 14.5 kV/m and E_- = 30.9 and 15.4 kV/m, for 7.9 m and 22.9 m respectively

Table 4.31: Ion Current Lateral Profile (nA/m²), 50% value

Weather condition	J+ (50%)			J- (50%)		
	worst	7.9m	22.9m	worst	7.9m	22.9m
Summer fair	52.5	47.5	5.5	32.8	36.4	4.2
Summer high hum., fog	75.7	68.6	8.0	80.0	88.7	10.3
Spring	41.8	37.8	4.4	31.0	34.4	4.0
Pacific Intertie meas.		2.0	2.0		20.0	5.0

Table 4.32: Ion Current Lateral Profile (nA/m²), 95% value

Weather condition	J+ (95%)			J- (95%)		
	worst	7.9m	22.9m	worst	7.9m	22.9m
Summer fair	89.2	80.7	9.4	76.7	85.1	9.9
Summer high hum., fog	98.0	88.7	10.3	113.1	125.4	14.6
Spring	81.8	74.0	8.6	91.3	101.3	11.8
Pacific Intertie meas.		45.0	20.0		125.0	50.0

Calculation of Ion current with BPA software (not probabilistic) resulted in J_+= 66 and 10 nA/m^2 , and J_-=95.0 and 14.5 nA/m^2 at 7.9 and 22.9 m (sic).

Notes:

A) There are two different EPRI equations for calculation: one as function of distance (equation valid for distance from conductor equal 1 to 4 heights), and “worst place” condition. They show inconsistent results when applied out of the range of validity (see columns marked with * in the Tables above).

B) The calculation (not probabilistic) done with BPA software (E-) resulted in 30.9; 15.4 kV/m at 7.9; 22.9m respectively (sic). As per [24] these values should be L_{10} (10% probability of not being exceeded).

C) Values obtained from measurements should be compared with calculated average values, (meaning fall/spring).

It can be seen that:

- Values for positive field do not match measurements. Values for negative fields are not so close to measurements.
- Measured E+ 50% value is equal to value calculated without representing space charge.
- (E+ greater than E-) using EPRI equations, however the measurements show the opposite. Authors from [24] highlight this aspect.
- The calculation results are quite different from measurements mainly for positive ion current.

As the calculations results does not compare reasonably with the measured values, and in the absence of better practical procedure, the reference [31] will be used with appropriate judgment.

4.9.3 Design Criteria

In order to define the final design criteria (a preliminary one was indicated in the item 4.9.1 above) a survey on the various recommendations was carried out and is listed below.

A) Reference [5]:

In this reference, EPRI Green Book**,** they address the following situations:

- Person normally grounded with a current It = 4 μA current through its body
- Person highly insulated touching ground objects, It = 4 μA
- Person grounded touching large vehicle (grounded through 1 MΩ).

They concluded that there is no hazard of important shocks, even with the current level of 4 μA. There is a mention of "disturbing nuisance" when a person is in a field of 40 to 45 kV/m. One can conclude that those values should be taken as limit.

B) Reference [33]

Reference [33], from Blondin et alli shows results of human perception of electrical fields in the presence of ionic current. A set of values are shown on Table 4.33.

Table 4.33: Sensitivity of person close to DC lines

Electric Field (kV/m)	Ion flow (nA/m^2)	Perception (%) Index
25	0	10
35	0	33
22	100	33
25	90	33
45	0	50
30	60	33

Therefore, one can propose the following limiting conditions: field of 25kV/m; 100nA/m^2 or 35% for the perception index. Calculations for various line alternatives considered in this work (Table 4.36 latter – 50% fall/fair) show ionic current lower than 50nA/m², and the criteria may be stated related to the following field only: 25kV/m at ground level under the line.

However, the field varies with the season and within one season they have a random behavior, in order that additional conditions have to be stated: for instance, 25 kV/m should not be exceeded in summer fair-weather in 50% of the time. This would mean that in most of the time the field will be lower than 25 kV/m.

C) Reference [46]

On Reference [46], Wu et alli suggests as criteria: electrical field limited to 30 kV/m in the right of way and 25 kV/m close to buildings.

D) Reference [47]

ICNIRP addresses only AC field and indicates as reference value: current densities for head and trunk not exceeding 40 mA/m² up to 1Hz, and 10kV/m for electric field for 1 to 8 Hz system. No mention is done to frequencies below 1Hz or DC.

E) Reference [48]

Experimental European Standard "Exposition of humans in low frequency electromagnetic fields" recommends a limit of 42 kV/m (peak) for frequencies from 0 to 0.1 Hz, as related to workers and 14 kV/m for general public.

F) Reference [49]

Reference [49], Koshcheev, brings the recommendation (for workers) as stated in Table 4.34.

Table 4.34: Russian criteria for exposure time

Field kV/m	Ion flow nA/m^2	Exposure time (hours)
15	20	8
15 to 20	25	5
20 to 60	-	Equation below
$\leq$ 60	-	1

The exposition (He) of “workers” (hours) to electric fields is determined by:

$$He = 3600/(E + 0.25\ J)^2$$

Where E is the field (kV/m) with space charge and J is the ionic current 9 nA/m^2).

For “general public”, the values 15kV/m and J=20 nA/m^2 were indicated initially; later on, in a personal communication, the author indicated the values: 40 kV/m; 100 nA/m^2, as L5 worst fair-weather value. It is stated there that the criteria “is stringent” and it is recognized by the author that criteria in other countries are “not easily comparable to Russia”.

G) Reference [50]

CIGRE B4-45 carried out analysis from the following countries/entities:

- WHO EHC: “typical exposure to ±500 kV HVDC lines are under 30 kV/m”;
- Health Council of Netherlands: “Threshold for hair movement field is 20 kV/m; studies on animals with exposure up to 340 kV/m have not identified any effect on blood count, reproduction and prenatal mortality”;
- German Standard (DIN) states: “occupational exposures should not exceed a static electric field of 40 kV/m, and a higher limit of 60 kV/m is permitted for exposures up to 2 hours”.

It concludes with the recommendation of E< 25 kV/m and Ion< 100 nA/m^2, this meaning 33% perception index. No mention is made on which season and what probability should be considered.

H) Reference [51]

EPRI 2257 considers three design cases defined by the criteria indicated in Table 4.35.

Table 4.35: Electric Field and Ion current criteria

		Maximum in the ROW	Outside ROW
Case 1	No requirements		
Case 2 Basic Specification	nA/m^2	100	5
	kV/m	40	10
	ions/cm^3	100,000	20,000
Case 3 Severe Specification	nA/m^2	20	1
	kV/m	20	5
	ions/cm^3	20,000	5,000

Note: Maximum values applied to the worst weather conditions (summer with rain and fog for instance). It is recognized that the worst weather conditions are seldom reached.

From the above discussion, it is proposed to set the criteria as:

a) 40 kV/m and 100 nA/m², L95 values (95% of not be exceeded), in summer with high humidity and fog, in any spot in the right of way. The calculation for existing HVDC lines in operation, in the next clause, will show how this assumption reflects in the others recommendation.

b) On the edge of the right of way the perception levels shall be examined as well as the values (E=10kV/m and J=5nA/m^2 "classified as "Basic Specification") recommended by [51]. The "perception index " in this condition is null, even increasing E to 15kV/m, this last values can be reconsidered in case a large ROW results from the calculation.

c) Consideration shall be made to the exposure time indicated in [49] and [48]. It is proposed to check the design in order to have exposure of 1 h to allow for electricians working in the ROW.

4.9.4 Calculations for Existing Projects

Table 4.36 shows the electrical field and the ionic flow values calculated according [6]) for the following projects:

- Pacific Intertie line (Bundle of 2x4.62cm conductors, ±500 kV, Pole Spacing PS=12.8m, Height H=12.2m)
- Itaipu (Bundle of 4x3.417 cm, ±600 kV, PS=15.4m, H=13.0m)
- India (Bundle of 4x3.505 ±500 kV, PS=12.0m, H=12.5m)
- China (Bundle of 4x3.624cm, ±500 kV, PS= 14.0m, H=11.5m)
- China ±800 kV new design (Bundle of 4x4.24cm, PS=19.4m; H=19.5m)

Table 4.36: Calculated electrical field (E) (kV/m) and ions (J) (nA/m^2), at worst place

Line	**kV**	**PS (m)**	**H (m)**	**95% summer Fair-weather**		**95% summer foul-weather**			**50% summer foul-weather**		**50% fall fair-weather**		
				E	**J**	**E**	**J**	**Pi(*)**	**E**	**J**	**E**	**J**	**Pi (*)**
India	±500	12.0	12.5	33.0	73.0	35.7	81.9	45	28.5	58.2	20.0	31.4	15
Itaipu	±600	15.4	13.0	43.4	116.8	46.4	128.9	70	38.7	98.2	26.0	45.5	25
China	±500	14.0	11.5	38.3	106.4	41.5	120.1	70	32.9	83.0	23.5	42.6	22
BPA	±500	12.8	12.2	36.9	91.7	39.6	100.9	55	32.7	77.6	24.0	47.9	25
±800kV New line	±800	19.4	19.5	36.7	56.3	39.2	61.7	40	32.8	48.1	24.3	30.3	20
China modified			12.0			39.2	103.0	55			22.1	36.5	18
Itaipu modified			14.0			40.6	93.4	50			26.0	45.6	27

Notes:

A) Pi → perception index (probability of a person to percept the field).
B) At the edge of ROW (±800 kV new line): E= 10.6 kV/m and J=2nA/m², at 50 m far from the center.

- If the criteria a) of 4.9.3.8 (40 kV/m and 100 nA/m^2) are stated for the condition summer foul-weather, high humidity/fog (L95), then Itaipu and China lines do not meet them. However, with a reasonable increase in height (10%), the criteria are matched.

- The average perception index (see column 50% fall fair-weather) is about 20%, and therefore is acceptable.
- As related to ROW applying criteria b) (in the edge of ROW or E=10kV/m and J =5 nA/m^2 for summer foul) for the lines in the Table above:
  - India, ROW=60m lead to $E_{95\%}$=11.4 kV/m
  - Itaipu ROW=70m lead to $E_{95\%}$=12.8 kV/m, or ROW=80m $E_{95\%}$=9.8 kV/m
  - China ROW=60m lead to $E_{95\%}$=12.1 kV/m, or ROW=70m $E_{95\%}$=8.9 kV/m
  - BPA ROW=60m lead to $E_{95\%}$=12.5 kV/m, or ROW=70m $E_{95\%}$=9.4 kV/m
  - ±800 kV ROW=100m lead to $E_{95\%}$=11.4 kV/m
- The limits of ion density in Table 4.35 are also matched when the other criteria are matched.
- As related to exposure, the ±800kV line, summer fair weather allows for: $He=3600/(36.7+0.25*56.3)^2$ = 1.4 h (L_5) and $He=3600/(32.8+0.25*48.1)^2$ = 1.8 h for L_{50} summer foul. These allow for at least one hour continuously under the field condition what does not happen as an individual will be infrequently there.

4.10 Mechanical Design

The basis for the design of the towers, towers and guy wires foundation weights and volumes will be presented from here on, as well as the respective results.

It will be included: tower silhouette conception, tower top configuration, heights, assumptions related to weather conditions (temperature, wind, and ice) and loadings. As a matter of simplicity, the guyed tower with I insulator strings shown on the Figure 4.28 will be considered at the first basic design, in the calculations. Self-supporting towers will also be considered at an appropriate detail, as well as towers with V strings.

4.10.1 Base Case

The set of Basic Cases and the related dimensions are shown on Table 4.37 for guyed tower with I strings.

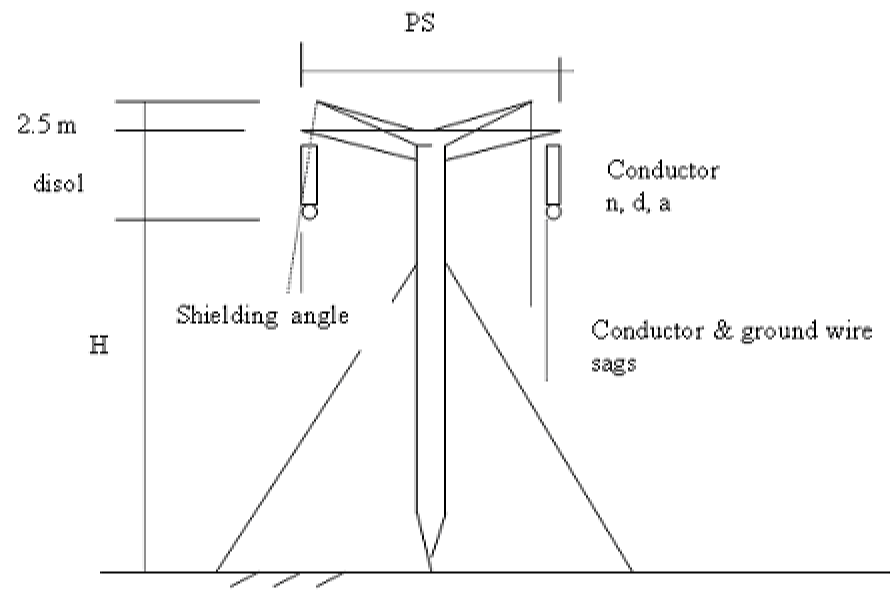


Figure 4.28: Tower Dimensions

Figure 4.28 and Table 4.37 show the minimum clearances, pole spacing, heights, insulator string dimensions, swing angles and shielding angles provided by the shield wires.

Table 4.37: General dimensions (guyed tower with I string) - Base Cases

Volt. (kV)	**Pole spacing PS** (m)	**Dist. between shield wires** (m)	**Cond. height** (m)	**Shield wires height** (m)	**Insul. string length dins** (m)	**Nº of Cond. (n)**	**Alum. (MCM)***	**Alum/steel (mm^2/ mm^2)**	**Cond. code**
±300	8.4	6.8	36.9	42.6	3.22	2	2,167	1,098/49	Kiwi
	8.5	6.9	35.9	41.6	3.22	4	1,780	902/75	Chukar
±500	13.4	11.1	39.5	47.2	5.2	2	1,272	645/45	Bittern
	13	**10.7**	**39.7**	**47.4**	**5.2**	**3**	**1,590**	**806/57**	**Lapwing**
	12.8	10.5	41.9	49.6	5.2	4	2,167	1,098/49	kiwi
±600	15.8	13.1	41.5	50.2	6.2	3	1,272	645/45	Bittern
	15.1	12.4	42.9	51.6	6.2	4	1,780	902/75	Chukar
	15	12.3	43.9	52.6	6.2	6	2,167	1,098/49	Kiwi
±800	20.8	17.4	46.2	56.9	8.17	6	954	483/34	Rail
	19.3	15.9	48.4	59.1	8.17	5	2,167	1,098/49	Kiwi

*1 MCM=0.5067 mm^2

Table 4.38 shows the minimum clearances and swing angles to be observed in the design.

Table 4.38: Minimum Clearances and Swing Angle

Voltage (kV)	**n cond.**	**MCM***	**Code**	**Operating Voltage Clearance (m)**	**Operating Voltage Swing Angle (º)**	**Switching surge Clearance to Tower (m)**	**Switching surge Clearance to Guy wires (m)**	**Switching surge Swing Angle (º)**
±300	2	2,167	Kiwi	0.7	46.9	1.3	1.23	7
	4	1,780	Chukar	0.7	47.5	1.3	1.23	7.1
±500	2	1,272	Bittern	1.2	52	3.06	2.87	8.1
	3	1,590	Lapwing	1.2	49.5	3.06	2.87	7.5
	4	2,167	kiwi	1.2	46.9	3.06	2.87	7
±600	3	1,272	Bittern	1.5	52	4.14	3.89	8.1
	4	1,780	Chukar	1.5	47.5	4.14	3.89	7.1
	6	2,167	Kiwi	1.5	46.9	4.14	3.89	7
±800	6	954	Rail	1.9	55	6.81	6.37	8.8
	5	2,167	Kiwi	1.9	46.9	6.81	6.37	7

Notes:

a. Tables 4.37 and 4.38 include the list of Base Cases, as related to the conductor configurations.
b. Two ground wires: Steel 3/8” EHS (Region I) and 9/16” EHS (Region II)
c. Conductor type: ACSR

d. Bundle spacing: a = 45 cm
e. Average span: 450 m
f. Conductor sag at 55ºC;
g. Shield wires sags are taken as around 90% of the conductor sags. In fact, the final values will be determined by sag and tension calculations;
h. Shield wire protection angle ~10°.

4.10.2 Meteorological Conditions and Basic Stresses

Two conditions will be considered:

- Region I without ice
- Region II with ice.
-

Reference [40} IEC/TR 60826 is used here as basis for the calculation unit forces acting in the conductors, shield wire and towers. This standard indicates also how to consider the combination of weather conditions and supply graphics indicating thge values of parameters to be used in the equations.

4.10.2.1 Region I

A) Temperatures

The temperature values taken into account for Region I are shown on Table 4.39.

Table 4.39: Region I Design Temperatures (°C)

Condition	Temperatures (°C)
EDS Every Day Stress	20
Minimum	0
Coincident with wind	10
Mean maximum	30

B) Wind

B1) Wind Data

The statistical wind parameter data adopted in this study are shown on Table 4.40.

Table 4.40: Wind data

Description	Data Values
Reference height (m)	10
Intensity - mean of the sample (m/s) (10 min average wind)	18.4
Standard deviation (m/s)	3.68 (20% of mean)
Sample period (years)	30
Ground roughness	B (open country, few obstacles)

Considering a Gumbel distribution (extreme values), the wind velocity to be considered, depending on the return period, is determined by:

$$V_t = \overline{V} + \frac{S}{C_1}(Y - C_2)$$

$$Y = -\ln(-\ln(1 - \frac{1}{T}))$$

Where:

V_t $\rightarrow$ Wind velocity (m/s) with return period T.
$\overline{V}$ $\rightarrow$ Wind velocity - mean (m/s).
S $\rightarrow$ Standard deviation (m/s).
C_1 = 1.11237 and C_2 = 0.53622 are coefficients, for a sample of 30 years [35].
T $\rightarrow$ return period (years).

On Table 4.41, the calculated values are shown.

Table 4.41: Wind velocities

Return period (yr)	Wind Velocities (m/s)
50	29.52
150	33.175

B2) Wind Loading

B2.1) High Wind Loading (T = 150 years)

- **Reference dynamic wind pressure.**

According to [35], CIGRÉ Brochure 178, the dynamic wind pressure is determined by:

$$q_0 = \frac{1}{2}\ \tau\ \ \mu\ \ V_R^2$$

Where:

q_0 $\rightarrow$ reference dynamic pressure (Pa)
μ $\rightarrow$ air mass (1.225 kg/m^3)
τ $\rightarrow$ air density correction factor (0.95)
V_R $\rightarrow$ high wind velocity (33.175 m/s)

Then: $q_0 = 640.4 \quad N/m^2$

- **Wind pressure on conductors**

The high wind pressure on the conductors are:

$$P_{cond} = q_0\ C_{xc}\ G_C\ G_L\ \sin^2\Omega$$

where:

$C_{XC} = 1.0$
$G_C = 2.0$ for conductors; $G_C = 2.14$ for shield wires
$G_L = 0.938$ is span factor = [1,05 – 0,15 (L/600)]; with span L = 450m
Ω: angle between wind and line directions.
$P_{cond} = 1201.4 \sin^2\Omega$
$P_{sh\ wire}$ $1285.5 \sin^2\Omega$

- **Wind pressure on insulator strings**

The wind pressure P_{isol} on the insulator strings is calculated by:

$$P_{isol} = q_0 \; C_{xl} \; G_l$$
$$C_{xl} = 1.20$$
$$G_l = 2.3$$

Then: $P_{isol} = 1769.1$ Pa

- **Wind pressure on the tower sections**

The pressure F_{struc} on tower sections (Pa) is evaluated by:

$$F_{struc} = q_0 \; G_T(1 + 0.2\sin^2(2\varnothing)(S_{T1}C_{XT1}\cos^2\varnothing + S_{T2}C_{XT2}\sin^2\varnothing)$$

Where:
G_T → gust factor, from Figure 5 of IEC/TR60826, [40]; it is a function of the height to ground of the gravidity center of the tower section in consideration.
S_{T1} → net area of the tower section, face 1.
C_{XT1} → drag coefficient, from Figure 7 of [40]
S_{T2}, C_{XT2} → same as above for face 2 of the tower section in consideration.
$\varnothing$ → angle between wind direction and face 1, according to Figure 6 of [40].
Note that $\varnothing + \Omega = 90^o$.

On Table 4.42 some particular cases of the formulae are shown.

Table 4.42: Pressure in the structures for different angles $\varnothing$; high wind

$\varnothing$ **(degree)**	F_{struc} **(Pa)**	**Wind direction**
0	$640.4\ G_T\ S_{T1}\ C_{XT1}$	Transverse
45	$384.2\ G_T(S_{T1}C_{XT1} + S_{T2}C_{XT2})$	45^o
90	$640.4\ G_T S_{T2} C_{XT2}$	Longitudinal

B2.2) Wind During Storm

The wind velocities during storms [35], in general present the following characteristics: high intensity, small variation with height and short front (≤ 100 m).

As there are no internationally accepted criteria to take this phenomenon into account, usually a safety factor of 1.2 is applied to the high wind velocity (Return period→150 year s).

As this type of wind has a narrow front, its effect is over a reduced length of the line, and so it is recommended to be apply a factor of 0.25 to the resulting pressure on the conductors:

- **Reference dynamic pressure**

Using the assumptions mentioned before, it results:

$$V_{storm} = 52.15 \quad m/s$$
$$q_0 = 1583.8 \quad Pa$$

- **Wind pressure on conductors**

$$\left.\begin{array}{l} P_{conduct} = 396.7 \quad Pa \\ P_{shwire} = 396.7 \quad Pa \end{array}\right. \text{(transverse wind)}$$

- **Wind pressure on insulation strings**

$$P_{isol} = 2047.6 \quad Pa$$

The values are shown on Table 4.43.

Table 4.43: Storm Wind

$\varnothing$ **(degree)**	F_{struc} **(Pa)**	**Wind direction**
0	$1583.8\, S_{T1}C_{XT1}$	Transverse
45	$950.3\,(S_{T1}C_{XT1} + S_{T2}C_{XT2})$	45^o
90	$1583.8\, S_{T2}C_{XT2}$	longitudinal

4.10.2.2 Region II

A) Temperature

Region II, different from Region I, is a place with ice. The temperature values are shown on Table 4.44.

Table 4.44: Region II Design Temperatures (°C).

Condition	Temperatures (°C)
EDS Every Day Stress (Installation condition)	0
Minimum	-18
Ice load condition	-5

B) Wind

B1) Wind Data

The wind statistical parameter data adopted in this study are shown on Table 4.45.

Table 4.45: Wind data.

Description	Data Values
Reference height (m)	10
Intensity - mean of the sample (m/s) (10 min average wind)	20
Standard deviation (m/s)	3.60 (18% of mean)
Sample period (years)	30
Ground roughness	C

- **High wind loading without ice (T = 150 years)**

Using data for 150 years return period, it results:

$$V_t = 20 * 1.625 = 32.50 \text{ m/s (Table A.9, pg 157 [40])}$$

$$V_R = 32.50 * 0.85 = 27.63 \text{ m/s (Table 4, pg 44 [40])}$$

- **Reference wind dynamic pressure**

According to [35], CIGRE Brochure 178, the dynamic wind pressure is:

$$q_0 = \frac{1}{2} \tau \quad \mu \quad V_R^2$$

where:

q_0 → reference dynamic pressure (Pa)
μ → air mass (1.225 kg/m^3)
τ → air density correction factor (1.0)
V_R → high wind velocity (2.63 m/s)

Then: $q_0 = 467.4$ Pa

C) Ice

C1) Ice data

The statistical ice parameter data adopted in this study are shown on Table 4.46.

Table 4.46: Ice data

Description	Data Values
Intensity - mean of the sample - g_m (N/m)	16.0
Standard deviation (% of mean)	70
Sample period (years)	20

C2) Ice Loading Without Wind

The reference design load g_R using reliability level 2 is:

$$g_R = K_d\, K_h\, g_{Rs}$$

K_{dcond} = 1.12 (Figure 10, pg 65 [40])
$K_{dshield}$ = 0.80 (Figure 10, pg 65 [40])
K_h = 1.0 (Figure 11, pg 67 [40])
g_{Rcond} = 75.38 N/m
$g_{Rshield}$ = 53.84 N/m

- **Load on support I- Uniform ice formation**

g_{Icond} = 75.38 N/m
$g_{Ishield}$ = 53.84 N/m

- **Load on support II – Non-uniform ice formation: longitudinal and transverse bending condition.**

g_{IIcond} = 0.7*75.38= 52.77 N/m
ά.g_{IIcond} = 0.4*52.77= 21.11 N/m
$g_{IIshield}$ =0.7*58.22= 40.75 N/m
ά.$g_{IIshield}$ = 0.4*40.75= 16.30 N/m

- **Load on support III – Non-uniform ice formation: torsion condition.**

$g_{IIIcond}$ = 0.7*75.38= 52.77 N/m
ά.$g_{IIIcond}$ =0.4*52.77= 21.11 N/m
$g_{IIIshield}$ =0.7*53.84= 37.69 N/m
ά.$g_{IIIshield}$ = 0.4*37.69= 15.07 N/m

D) Combination Ice/ Wind

According to [40] the return period of combined events of ice and wind are shown in Table 4.47.

Table 4.47: Ice data- return period

Reliability level	**Return period T (years)**	**Return period of the variable having a low probability of occurrence (index L)**	**Return period of remaining variables (index H)**
1	50	50	Average of yearly maximum values
2	150	150	Average of yearly maximum values
3	500	500	Average of yearly maximum values

For any selected reliability level, three loading conditions are defined as shown in Table 4.48.

Table 4.48: Ice/wind combination

Loading conditions	Ice weight	Wind velocity	Effective drag coefficient	Density
Condition 1	g_L	V_{iH}	C_{iH}	δ_1
Condition 2	g_H	V_{iL}	C_{iH}	δ_1
Condition 3*	g_H	V_{iH}	C_{iL}	δ_2

* In practice, it was found that condition 3 is not critical for design purposes

D1) Low Probability Ice with High Probability Wind (Condition 1)

- **Low probability ice**

Reliability level→ 2
g_{Lcond} = 75.38 N/m
$g_{Lshield}$ = 53.84 N/m

- **High probability wind**

V_{iH} = 20 m/s
$V_R = K_R \cdot V_{iH}$ = 20 * 0.85 = 17.0 m/s
$A_{C1} = q_0 .C_{iH} \cdot G_C \cdot G_L. \sin^2 \Omega \cdot D_L .L$
C_{iH} = 1.0 (Table 8 pg 77 [40])
$q_{0H} = 1/2 \cdot \mu \cdot VR^2$ = 177.0 Pa
δ_1 = 600 kg/m^3 (Table 8, pg 77 [40])

$$D_L = \sqrt{d^2 + \frac{4.g_L}{9.82.\pi.\delta_1}}$$

d = 0.03921 m (conductor diameter)
D_{Lcond} = 0.1336 m
d = 0.01432 m (shield wire diameter)
$D_{Lshield}$ = 0.1088 m

D2) High Probability Ice with Low Probability Wind (Condition 2)

- **High probability ice**

$g_H = K_d \cdot K_h .16.0$
K_{dcond} = 1.12 (Figure 10, pg 65 [40])
$K_{dshield}$ = 0.80 (Figure 10, pg 65 [40])
K_h = 1.0 (Figure 11, pg 67 [40])
g_{Lcond} = 17,92 N/m
$g_{Lshield}$ = 12,80 N/m

- **Low probability wind**

Reliability level→ 2
V_{iL} = 27.63 m/s
$V_R = K_R \cdot V_{iL}$ = 27,63 * 0,85 = 23,49 m/s
$A_{C2} = q_0 .C_{iH} \cdot G_C \cdot G_L \cdot \sin^2 \Omega \cdot D_{H1} .L$
C_{iH} = 1.0 (Table 8, pg 67 [40])
$q_{0H} = 1/2 \cdot \mu \cdot V_{R2}$ = 338.0 Pa
δ_1 = 600 kg/m^3 (Table 8 pg 67 [40])

$$D_{H1} = \sqrt{d^2 + \frac{4.g_H}{9.82.\pi.\delta_1}}$$

d = 0.03921 m (conductor diameter)
D_{Lcond} = 0.062 m
d = 0.01432 m (shield wire diameter)
$D_{Lshield}$ = 0.053 m

4.10.3 Sag and Tension Calculations

4.10.3.1 General Conditions

To carry out this evaluation, the following parameters are assigned for initial state:
EDS → Every Day Stress:

- 20% of UTS/RTS Ultimate/Rated Tensile Strength for the conductor, or
- 11% of RTS for the shield wires (EHS Extra High Strength Steel).
- Temperature → 20ºC
- Creep → corresponding to 10 years
- High wind simultaneous with temperature of 15ºC. In this case, the tension shall be lower than 50% of the cables RTS.
- At the minimum temperature (equal to 0ºC), with no wind, the tension shall be lower than 33 % of the cables RTS.

4.10.3.2 Conductor Configuration Alternatives and Wind Pressures

The conductor configurations, sags, conductor heights and wind pressure are shown on Table 4.49.

Table 4.49: Conductor configuration, wind pressure, sag, and height

Voltage (kV)	Conductor Height (m)	Number of Cond.	Cond. Cross section (MCM)	Cond. Code	Cond. Sag EDS (m)	Average Cond. Height (m)	Average S.Wire Height (m)	Cond. Wind Pressure (Pa)	Shield Wire Wind Pressure (Pa)	Insulator String Wind Pressure (Pa)
±300	35.1	2	2,167	Kiwi	19.22	22.3	31.9	1264	1339	1775
	32.9	4	1,780	Chukar	16.93	21.6	29.7	1258		
±500	38.0	2	1,272	Bittern	17.47	26.4	36.8	1293	1434	1844
	38.2	3	1,590	Lapwing	17.68	26.4	37.0	1281		
	40.2	4	2,167	kiwi	19.22	27.4	38.9	1293		
±600	40.0	3	1,272	Bittern	17.47	28.4	39.8	1299		
	39.9	4	1,780	Chukar	16.93	28.6	39.7	1305		
	42.1	6	2,167	Kiwi	19.22	29.3	41.9	1311		
±800	44.8	4	954	Rail	17.24	33.3	46.5	1341	1434	1884
	46.6	5	2,167	Kiwi	19.22	33.8	48.3	1347		1884**

*1 MCM=0.5067 mm^2

4.10.3.3 Tensions

The conductor and shield wires tensions are calculated for all the conductor configuration alternatives and are used in the tower loading conditions.

An average span of 450 m is considered, and the conditions checked are:

- high transverse wind
- high wind 45°
- temperature 10ºC, no wind
- temperature 0ºC, no wind
- temperature 65ºC, no wind
- storm wind, transverse
- storm wind, 45°
- EDS, 20ºC, no wind

The horizontal tensions are shown on Table 4.50 for the conductors and Table 4.51 for the shield wires.

Table 4.50: Conductor tensions (kgf)

Voltage (kV)	Conduct. Code	High wind. Transv.	High wind 45º Wind	10ºC no Wind	0ºC no Wind	65ºC no Wind	Storm Wind Transv.	Storm Wind 45º	EDS 20ºC no Wind
±300	Kiwi	6,775	5,890	4,618	5,036	4,166	5,166	4,763	4,526
	Chukar	8,642	6,044	4,738	5,255	4,190	5,310	4,890	4,624
±500	Bittern	6,754	4,453	3,173	3,533	2,804	3,614	3,271	3,096
	Lapwing	7,693	5,218	3,920	4,354	3,473	4,477	4,069	3,827
	Kiwi	8,610	5,942	4,618	5,036	4,166	5,166	4,763	4,526
±600	Bittern	6,775	4,463	3,173	3,533	2,127	3,724	3,322	3,096
	Chukar	8,850	6,129	4,738	5,255	4,190	5,310	4,890	4,624
	Kiwi	8,687	5,973	4,618	5,036	4,166	5,166	4,763	4,526
±800	Kiwi	8,851	6,038	4,618	5,036	4,166	5,166	4,763	4,526
	Rail	5,828	3,706	2,413	2,694	2,127	2,953	2,563	2,353

Table 4.51: Shield wire (3/8” EHS steel) tensions (kgf)

<table>
<tr><th>Voltage (kV)</th><th>High Wind, Transv.</th><th>High Wind 45º Wind</th><th>10ºC no Wind</th><th>0ºC no Wind</th><th>65ºC no Wind</th><th>Storm Wind Transv.</th><th>Storm Wind 45º</th><th>EDS 20ºC no Wind</th></tr>
<tr><td>±300</td><td>2,075</td><td>1,324</td><td>785</td><td>801</td><td>740</td><td>1,007</td><td>837</td><td>769</td></tr>
<tr><td>±500</td><td rowspan="3">2,178</td><td rowspan="3">1,376</td><td rowspan="3">785</td><td rowspan="3">801</td><td rowspan="3">740</td><td rowspan="3">1,007</td><td rowspan="3">837</td><td rowspan="3">769</td></tr>
<tr><td>±600</td></tr>
<tr><td>±800</td></tr>
</table>

4.10.3.4 Tower Families

The tower and foundation weights were calculated only for suspension tangent and small angle towers. For suspension towers, line angles vary in general from d = 0° to d = 2°.

4.10.4 Loading Conditions

The first calculation was carried out for a guyed tower, ±500 kV, with 3 Lapwing conductors per pole, I string. The loading conditions considered are shown on Table 4.52, where:

d → line angle in degree;
HS → horizontal span;
VS → vertical span;
SW → storm wind;
HW → high wind

Table 4.52: Loading conditions

Code	Description
V_0	HW at 90º; d = 0; highest VS
V_{OR}	HW at 90º; d = 0; lowest VS
V_1	HW at 90º; d = 2; highest VS
V_{1R}	HW at 90º; d = 2; lowest VS
V_4	HW at 45º; d = 2; highest VS
V_{4R}	HW at 45º; d = 2; lowest VS
W_1	SW at 90º; d = 2; highest VS
W_{1R}	SW at 90º; d = 2; lowest VS
W_3	SW at 45º; d = 2; highest VS
W_{3R}	SW at 45º; d = 2; lowest VS
W_4	SW at 0º; d = 2; highest VS
W_{4R}	SW at 0º; d = 2; lowest VS
R_1	No wind; shield wire 1 failure; d = 2; highest VS
R_{1R}	No wind; shield wire 1 failure; d = 2; lowest VS
R_2	Same as R_1 but for shield wire 2 failure
R_{2R}	Same as R_{1R} but for shield wire 2 failure
R_4	No wind; pole 1 conductor 1 failure; d = 2; highest VS
R_{4R}	No wind; pole 1 conductor 1 failure; d = 2; lowest VS
R_5	Same as R_4 but for pole 2 conductor failure
R_{5R}	Same as R_{4R} but for pole 2 conductor failure
D_1	No wind, longitudinal unbalance; d = 2; highest VS
D_{1R}	No wind, longitudinal unbalance; d = 2; lowest VS
M_1	Shield wire 1 on shivers and maintenance; d = 2
M_2	As M1; shield wire 2
M_4	As M2; pole 1 conductors
M_5	As M4; pole 2 conductors
MVR	Conductors on shivers; wind = 0,6 HW
MS_1	Shield wire 1 erection; no dynamic forces; d = 2
MS_2	As MS1; shield wire 2
MS_4	Same as MS2; pole 1 conductors
MS_5	Same as MS4; pole 2 conductor

MS_7	As MS_5 but pole 1 is the last pole to be erected
MC_1	Shield wire 1 erection; with dynamic forces; d = 2
MC_2	Same as MC1; shield wire 2
MC_4	Same as MC2; pole 1 conductors
MC_5	Same as MC4; pole 2 conductors
MC_7	Same as MC_5 but pole 1 is the last to be erected

Note: Appropriate safety margins are applied to the loads and to the tower angles (bars) for design purposes. The values are different depending on the loading condition, as a general practice. According to IEC 60826, no safety factors are applied to transverse loads, which are ultimate and defined by the return period and wind statistics.

For the remaining configuration other than (3 Lapwing, ±500 kV guyed, I string), only the following conditions were checked:

$$V_0;\ V_4;\ W_4;\ R_4;\ D_1;\ MS_5$$

This is due to the fact that they were found to be the governing design conditions.

4.10.5 Results of the Tower Weights

The tower weights (including the guy wires) and foundation (of concrete type) weights/volumes were calculated on the basis established before. The tower weights were subjected to a regression analysis trying to define an equation as follows:

$$\text{Tower weight} = a + b\,V + S\,(c\,N + d) \qquad \text{ton}$$

Where:

a, b, c, d are parameters to be obtained by curve fitting of the tower weight data

V is the pole to ground voltage (kV)

$S = N\,S_1$ is the total conductor aluminum cross section (MCM); S_1 being one conductor aluminum (only) cross section, so not including steel area; Note S(MCM)= (1/0.5067)* S(mm^2 Aluminum)

N is the number of conductor per pole.

Note that the equation above depends on the total conductor cross-section used (N S1) and on the conductor cross-section itself S_1.

After obtaining the first set of the equation parameters, it was observed that some original weights were far to fit the curve and a new parameter calculation was done disregarding the respective points. The parameters obtained are:

$$a = 2{,}232;\ b = 7.48;\ c = 0.091;\ d = -0.08$$

Table 4.53 shows the “calculated weights” (based on a complete tower stress analysis) and the “estimated weights” (based on equation above) and the errors involved.

Table 4.53: Regression analysis, tower weight calculation

kV	N	Total section (MCM)	Calculated weight (ton)	Estimated weight (ton)	Error (%)
±300	2	4,334	4,218	4,904	-14.0
	4	7,120	6,676	6,477	3.1
±500	2	2,544	5,960	6,223	-4.2
	3	4,770	7,248	6,878	5.4
	4	8,668	8,727	8,408	3.8
±600	3	3,816	6,232*	7,445	-16.3
	4	7,120	9,303	8,721	6.7
	6	13,002	18,354 *	12,743	44.0
±800	6	5,724	11,027	10,868	1.5
	5	10,835	11,570	12,248	-5.5

Note: points marked with * are disregarded in the final calculation of equation parameters

The adjusted tower weights and the corresponding original weight and characteristics shown on Table 4.53 were used for the cost estimation of the bipole alternatives.

4.10.6 Sensitivity Analysis

In order to allow for extrapolation/interpolation of the results, the sensitivity of the weights to the factors listed below were evaluated.

- Base Case: increase 2m in the pole spacing;
- Base Case: increase 3m in the tower height;
- Tower with V string: ±500 kV, 3xLapwing;
- Self supporting tower: ±500 kV, 3xLapwing, I strings;
- Only one shield wire: ±500 kV, 3xLapwing, I strings;
- Region with ice: ±500 kV, 3xLapwing (or equivalent) , I strings;
- Monopolar line: ±500 kV, 3xLapwing, I strings;
- Metallic return using the shield wire: ±500 kV, 3xLapwing, I strings;
- Base case: period of return of wind 500 yr.;
- Base case: Chainette (cross-rope) tower.

The following weights were obtained – See Table 4.54.

Table 4.54: Weights obtained in Sensitivity Analysis

Case	Description	Tower Weight (kg)
1	Base Case: increase 2m in the pole spacing	7,498
2	Base Case: increase 3m in the tower height	7,579
3	Tower with V string, ±500 kV, 3xLapwing	9,700
4	Self supporting tower, ±500 kV, 3xLapwing, I string	15,600
5	Only one shield wire	7,749
6	Region with ice, ±500 kV, 3xFalcon, guyed tower, I string	12,983
7	Monopolar line, Base Case	6,380
8	Metallic return by the shield wire	10,384
9	Base Case: period of return of wind 500 years	10,454
10	Base Case: Chainette (cross-rope) tower	7,878
	BASE CASE (±500 kV,3xLapwing, guyed, I string, non ice, bipolar, no metallic return, 2 shield wires)	7,248

- Case 1: no tower redesign was done and base case tower design was maintained; the weight was estimated based on the increased cross arm size;

- Case 2: as above, weight estimated based on the increased tower body size;

- Case 3: the tower was redesigned. The weight of the tower with V strings is higher than the base case, because the cross arms resulted bigger. The V tower pole spacing is 9.3 m long but the cross arms are 8.9 m long each one, for inserting the V strings, whereas the cross arm is 6.55m long for inserting I string insulator strings;

- Case 4: The tower was redesigned, but not optimized and the estimated weight was 14,500 kg;

- Case 5: The tower was redesigned in order to have one shield wire 5m high, above the cross arm. The tower height increase effect was bigger than the effect of elimination of two shield wire cross arms;

- Case 6: The tower was redesigned considering icing conditions. Instead of 1,590 MCM Lapwing, the conductor 1,590MCM Falcon (larger steel cross section) was required. Larger shield wires were also required;

- Case 7: The monopolar line may be designed as one pole in the side of the tower and one shield wire, as in the previous case. This results in an unbalanced situation affecting the weight. One may consider that a monopolar line may have two poles of the same polarity with half of the conductor cross section in each one, becoming a kind of bipolar silhouette. This condition is taken here as the lower limit of the monopolar tower weight. The weight was then estimated by the regression equation described above (6,500 kg) and checked with the calculation;

- Case 8: the tower was redesigned considering two conductors ACSR 795 MCM Tern shield wires suspended in I insulator strings with 1m length.
- Case 9: the tower was redesigned by changing the wind loading according to correspondent wind obtained from the wind distribution of Region I (37.1m/s instead of 33.1m/s, base wind);
- Case 10: the tower was redesigned with the new silhouette.

4.11 Line Economics

The estimated transmission line costs as well as the economic analysis considering staging, losses, operation and maintenance costs and financial parameters are presented hereinafter.

The calculations are based on references [1], [2], [3], [41], [42].

4.11.1 Line Costs Involved

The following typical costs listed below will be considered:

a. Line material and labor
    - i) Engineering
        - design
        - topography
        - survey
        - environmental studies
    - ii) Materials
        - towers
        - foundations
        - conductors
        - shield wires
        - guy wires
        - grounding (counterpoises)
        - insulators
        - conductor hardware
        - shield wire hardware
        - guy wire hardware
        - spacer dampers
        - accessories
    - iii) Man labor
        - ROW and access
        - tower erection
        - tower foundation erection
        - tower foundation excavation
        - guy wire foundation erection
        - guy wire foundation excavation
        - conductor installation
        - shield wire installation
        - guy wire installation
        - grounding installation

iv) Administration & Supervision
material transportation to site
inspection at manufacturer’s site
construction administration

v) Contingencies

vi) Taxes were considered separately from items above

b. Operation costs
Joule and corona losses
Operation and maintenance

c. Electrode and electrode lines (see clause 6 latter)

4.11.2 Transmission Line Costs

As mentioned in the previous clause, some configurations of bipolar lines (base cases) shown on Table 4.55 were selected in order to determine line design and costs.

Table 4.55: Configurations for cost evaluation

Voltage (kV)	n conductors	MCM*	Code
±300	2	2,167	Kiwi
	4	1,780	Chukar
±500	2	1,272	Bittern
	3	1,590	Lapwing
	4	2,167	Kiwi
±600	3	1,272	Bittern
	4	1,780	Chukar
	6	2,167	Kiwi
±800	6	954	Rail
	5	2,167	Kiwi

*1 MCM=0.5067 mm^2

The cost budgets, broken down in the components indicated above, were done and are shown on Table 4.56. The values obtained from the curve fitting equation were used for the tower weights.

Table 4.56: Bipolar line costs parcels in percent (100% is the reference in Line 6 of the Table)

ITEM	DESCRIPTION	±300kV 2 Kiwi	±300kV 4 Chukar	±500kV 2 Bittern	±500kV 3 Lapwing	±500kV 4 Kiwi	± 600kV 3 Bittern	±600kV 4 Chukar	±600kV 6 Kiwi	±800kV 6 Rail	±800kV 5 Kiwi
	MCM total	4334	7120	2544	4770	8668	3816	7120	13002	5724	10835
1	Engineering %										
	Engineering (design, topography, survey, environmental studies)	4.79	3.44	4.57	3.95	2.94	3.86	3.04	2.06	2.88	2.19
2	Materials %										
	Tower, foundation, guy and hardware	17.53	16.40	19.84	19.28	17.66	20.22	19.01	19.09	21.45	20.16
	Conductor	30.93	39.96	18.5	29.80	37.98	23.21	35.27	39.84	26.07	35.33
	Shield wire, insulator, grounding, cond & shield wire hardware ,spacers, accessories	4.53	4.08	4.70	4.63	5.17	4.45	4.61	5.10	5.61	5.15
	Sub total materials	52.99	60.44	42.89	53.71	60.81	47.88	58.89	64.03	53.13	60.63
3	Man labor %										
	ROW and access	15.05	9.89	26.63	15.91	10.45	22.45	11.89	7.73	16.78	11.60
	Tower, foundation and guy erection	6.58	6.19	7.67	7.35	6.81	7.85	7.34	7.34	8.46	7.61
	Conductor installation	7.62	7.74	5.73	6.62	6.98	5.77	6.83	7.32	7.01	6.49
	Shield wires and grounding installation	3.29	2.36	3.14	2.72	2.02	2.65	2.08	1.41	1.98	1.50
	Sub total man labor	32.54	26.18	43.17	32.60	26.26	38.72	28.15	23.80	34.23	27.20
4	Administration & Supervision %										
	Material transportation to site	1.18	1.31	1.06	1.24	1.35	1.15	1.33	1.42	1.28	1.35
	Inspection at manufacturer site	3.71	4.23	3.00	3.76	4.26	3.35	4.12	4.48	3.72	4.24
	Construction administration	1.87	1.48	2.39	1.83	1.46	2.13	1.56	1.29	1.86	1.47
	Sub total adm & superv.	6.76	7.02	6.45	6.83	7.07	6.63	7.01	7.19	6.85	7.06
5	Contingencies %										
		2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
6	TOTAL U$/km (100%)	**155,719**	**217,101**	**163,273**	**188,790**	**253,618**	**193,636**	**245,952**	**362,673**	**259,063**	**340,877**

Table 4.57 shows the cumulative figures also in percent of the Table 4.56 Item 6 value.

Table 4.56 A Same as previous table however cost values are in US$

ITEM	DESCRIPTION	±300kV 2 Kiwi	±300kV 4 Chukar	±500kV 2 Bittern	±500kV 3 Lapwing	±500kV 4 Kiwi	± 600kV 3 Bittern	±600kV 4 Chukar	±600kV 6 Kiwi	±800kV 6 Rail	±800kV 5 Kiwi
	MCM total	4334	7120	2544	4770	8668	3816	7120	13002	5724	10835
1	Engineering										
	Engineering 9design,topography,survey,environmentalstudies)	7465	7465	7465	7465	7465	7465	7465	7465	7465	7465
2	Materials										
	Tower, foudation, guy and hardware	27295	35603	32401	36399	44778	39148	46756	69243	55575	68711
	conductor	48167	86756	29967	56262	96333	44951	86756	144500	67532	120416
	shield wire, insulator, grunding,cond & shield wire hardware,spacers, acessories	7054	8866	7667	8734	13114	8622	11330	18482	14530	17548
	sub total materials	82516	131225	70035	101395	154226	92721	144843	232225	137637	206676
3	Man labor										
	ROW and access	23436	21471	43478	30040	26497	43478	29249	28026	43478	39526
	Tower, foudation and guy erection	10252	13435	12527	13871	17279	15198	18060	26617	21904	25949
	Conductor installation	11864	16804	9358	12501	17708	11174	16804	26561	18158	22134
	Shield wires and groundinginstallation	5126	5126	5126	5126	5126	5126	5126	5126	5126	5126
	sub total man labor	50678	56836	70489	61538	66609	74976	69240	86330	88666	92735
4	Administration & Fiscalization										
	material transportation to site	1841	2850	1727	2346	3432	2222	3267	5144	3308	4595
	inspection at manufacturer site	5776	9186	4902	7098	10796	6490	10139	16256	9635	14467
	construction administration	2907	3215	3898	3450	3704	4122	3835	4690	4807	5010
	sub total adm&fiscaliz	10525	15251	10527	12894	17932	12835	17241	26090	17749	24073
5	Contingencies										
		4536	6323	4756	5499	7387	5640	7164	10563	7546	9928
6	TOTAL U$/km	155719	217101	163273	188791	253618	193637	245952	362673	259063	340877

Table 4.57 shows the cumulative figures also in percent of the Table 4.56 Item 6 value.

Table 4.57: Cumulative costs by group of items

DESCRIPTION	± 300kV 2 Kiwi	±300kV 4 Chukar	±500kV 2 Bittern	±500kV 3 Lapwing	±500kV 4 Kiwi	± 600kV 3 Bittern	±600kV 4 Chukar	± 600kV 6 Kiwi	±800kV 6 Rail	±800kV 5 Kiwi
Group of items										
materials	52.99	60.44	42.89	53.71	60.81	47.88	58.89	64.03	53.13	60.63
man labor	47.01	39.56	57.11	46.29	39.19	52.12	41.11	35.97	46.87	39.37
Total	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
man labor taxes included	4.01	3.33	4.93	3.94	3.30	4.47	3.47	3.00	4.00	3.31
material taxes included	15.14	17.27	12.26	15.34	17.37	13.68	16.83	18.29	15.18	17.32
Total taxes included	19.15	20.60	17.18	19.29	20.67	18.15	20.30	21.30	19.17	20.64

Recognizing that the cost budgets may have certain inaccuracies, the available data were worked out in order to have consistent values close to the calculated costs. Similarly to the methodology presented in [1], a bipolar line cost equation of the type below is determined.

$$\text{Cline} = a + b\,V + S\,(c\,N + d) \qquad \text{U\$/km}$$

Where:

a, b, c, d are parameters to be obtained by curve fitting of the tower weight data
V is the pole to ground voltage (kV);
$S = N\,S_1 \rightarrow$ total conductor aluminum cross section (MCM); S_1 being one conductor aluminum (only) cross section, so not including steel area; Note S(MCM)= (1/0.5067)* S(mm^2 Aluminum)
N is the number of conductor per pole.

Note: the equation above depends on the total conductor cross-section used ($N * S_1$) and on the conductor cross-section itself S_1.

To obtain the regression curves, the line costs shown on Table 4.56 were used. Important to note that the parameters of the regression resulted in:

a = 69,950
b = 115.37
c = 1.177
d = 10.25

The bipolar line cost values for 2, 3, 4 and 5 and conductors per pole, respectively, for voltages of ±300, ±500, ±600 and ±800 kV, are shown on Figure 4.29.

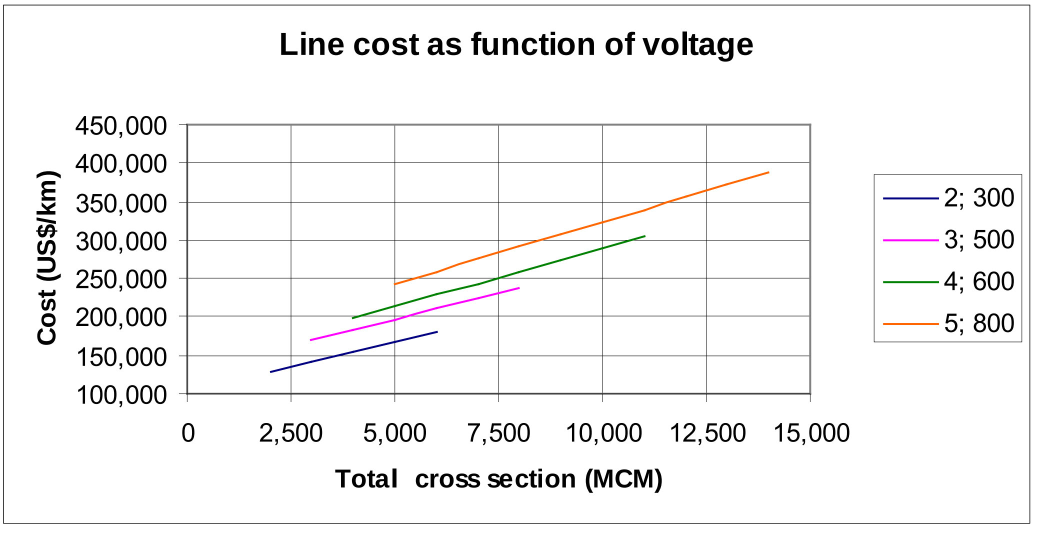


Figure 4. 29: Adjusted line costs (2; 300: means 2 conductor and ±300kV)

Figures 4.30, 4.31, 4.32, and 4.33 show the bipolar line costs as a function of the voltage.

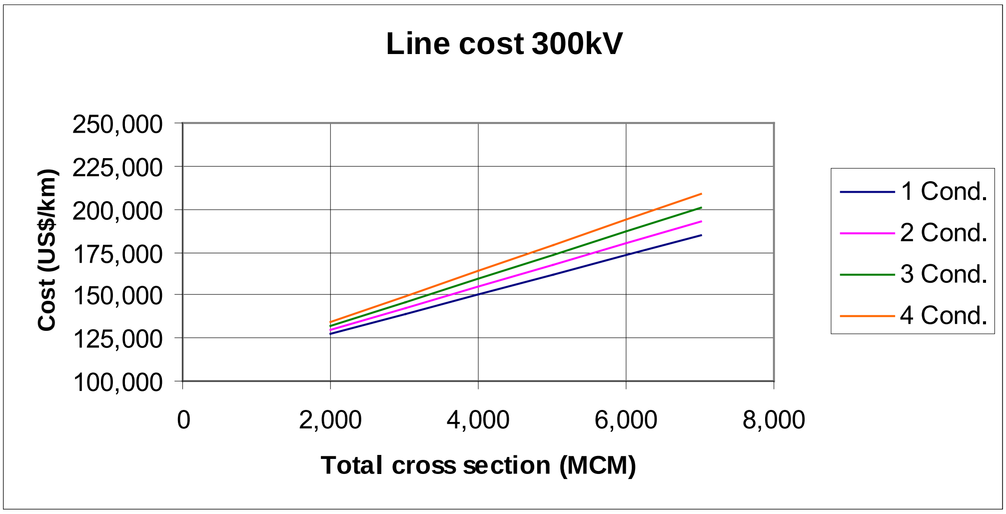


Figure 4.30: Line Costs ± 300 kV

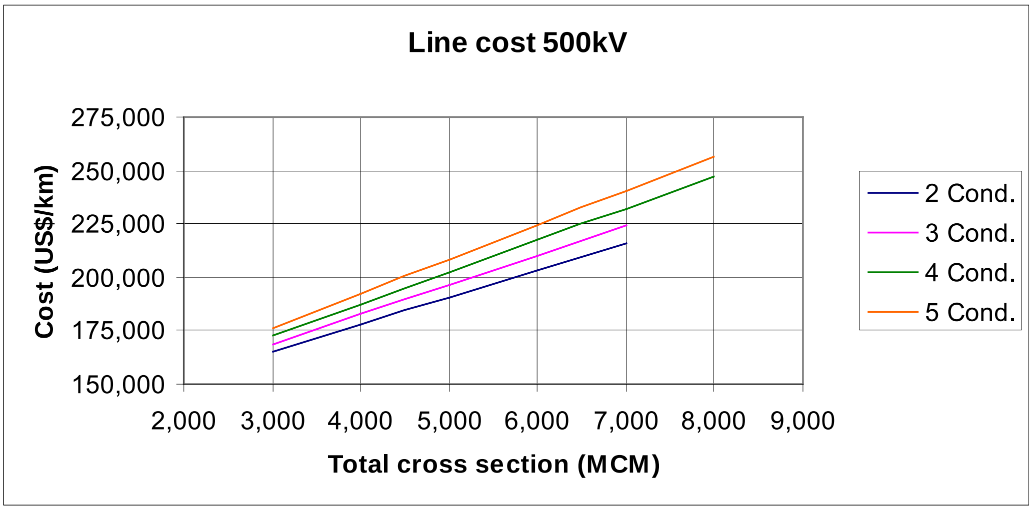


Figure 4.31: Line Costs ± 500 kV

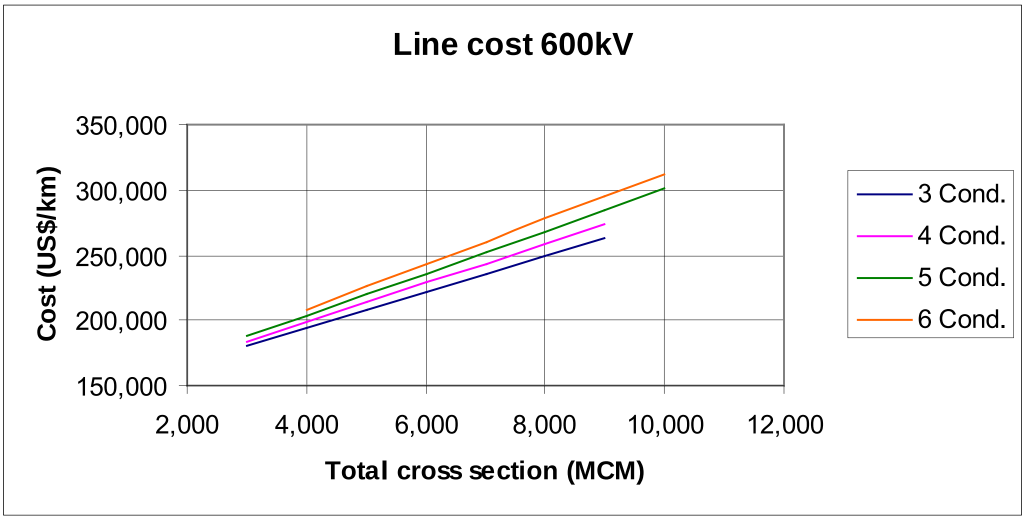


Figure 4.32: Line Costs ± 600 kV

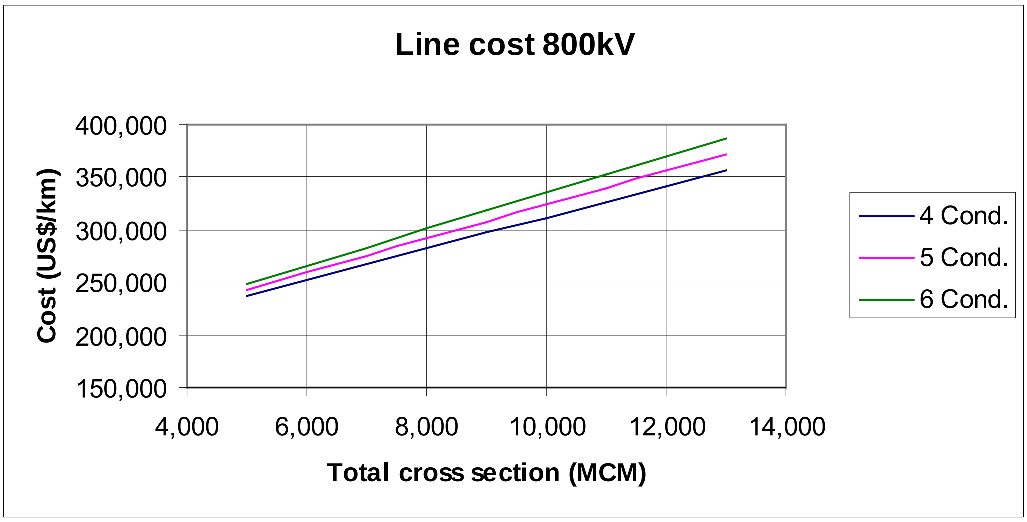


Figure 4.33: Line Costs ± 800 kV

The bipolar transmission line costs per km (Base Cases) are shown on Table 4.58 for climatic conditions of Region I described before, for the elected alternatives (Base Cases).

Table 4.58: Estimated bipolar transmission line costs, Region I

kV	Conductor (MCM)*	U$/km
±300	2 x 2,167 Kiwi	159,181
	4 x 1,780 Chukar	211,061
±500	2 x 1,272 Bittern	159,691
	3 x 1,590 Lapwing	193,365
	4 x 2,167 Kiwi	257,291
±600	3 x 1,272 Bittern	191,753
	4 x 1,780 Chukar	245,671
	6 x 2,167 Kiwi	364,272
±800	5 x 954 Rail	261,337
	5 x 2,167 Kiwi	337,072

*1 MCM=0.5067 mm^2

It should be noted that the prices above reflect Brazilian market and Brazilian taxes. The taxes in Brazil are 40% for materials and 10% for man labor and were shown on Table 4.57. For every country, the final prices will depend on the specific taxes.

Note: For future adjustments of the prices on the Tables, the following raw material prices (without taxes) on May 2006 are presented.

- Cost of steel 1.7 U$/kg FOB
- Cost of aluminum cable 3.5 U$/kg FOB
- Cost of concrete 0.35 U$/m3 FOB
- Exchange rate at the time: U$1.00 = R$2.20 (Brazilian currency)
  U$1.00 = ..0.695 €

Table 4.54 has shown the sensitivity of tower weights to some conditions different from the Base Case. Therefore, the values of the line costs were calculated and are reported on Table 4.59.

Table 4.59: Line cost sensitivity

Case	**Description**	**Line cost U$/km**	**% of Base Case**
1	For the Base Case increase 2m in the pole spacing	193,200	101.0
2	For the Base Case increase 3m in the tower height	193,900	101.3
3	Tower with V string, $\pm$500 kV, 3xLapwing	217,100	113.5
4	Self supporting tower, $\pm$500 kV, 3xLapwing	236,800	123.8
5	Only one shield wire, Base Case	192,200	100.5
6	Region with ice, $\pm$ 500 kV, 3xFalcon	244,600	127.8
7	Monopolar line, Base Case	155,500	81.3
8	Metallic return by the shield wire	217,050	113.4
9	For the Base Case period return wind 500 years	215,660	112.7
10	For the Base Case cross-rope tower	194,600	101.7
	BASE CASE	**191,328**	**100**

4.11.3 Losses

As related to the transmission lines, the losses are due to Joule and Corona effects.
The Joule losses (Lj) are calculated by:

$$\mathrm{Lj} = \frac{1}{2}\,\mathrm{r}\left(\frac{\mathrm{P}}{\mathrm{V}}\right)^2 \qquad \mathrm{MW/km}$$

where:
P → rated bipole power MW
V → the voltage to ground kV
r → bundle resistance ohms/km
r = ro L / S
ro → conductor resistivity 58 ohms MCM/ km (or 58/0.5067 mm^2/km)

L → the line length in km
S → the aluminum cross section in MCM

The economical basis for determining the cost of losses is that a thermal power plant is built at the load center to supply the losses.

The cost of Joule losses (CLj) in one year will be:

$$\mathrm{CLj} = (\mathrm{Cp} + 8760\ \mathrm{Ce}\ \ \mathrm{lf})\,\mathrm{Lj} = \mathrm{Cl} * \mathrm{Lj}$$

where:

Cp → yearly cost of the power plant
Ce → fuel cost
lf → loss factor

4.11.4 Operating and Maintenance Costs

Yearly operating and maintenance costs can be considered as a percent of the total line cost, generally about 2% per year.

4.11.5 Interest During Construction

It is considered here that two to four years are required for the construction time of the transmission line, depending on the length and number of construction crew. If interest rate is assumed as 10 % per year and the costs are allocated in the middle of the years, with equal parcels, then at the end of the construction period, the budgetary cost shall be adjusted by a factor of: 1.10 (2 years), 1.16 (3 years) and 1.22 (4 years).

4.11.6 Most Economical Conductor

The yearly bipolar line cost is expressed by:

$$Cline = (k+0.02) * 1.1\ (A1 + B1\ S) = A + B\ S$$

where:
S → aluminum cross section per pole,
k → factor to convert Present Worth into yearly cost, $k = j/[1-(1+j)^{-n}]$, j being the interest rate and n the period of amortization;
0.02 → factor to consider operation and maintenance cost, and 1.1 is the factor related to the interest during construction assuming 2 years as construction period.

Considering that Closses = C/S is the yearly cost of the Joule losses and neglecting initially the corona losses, then the total yearly cost is:

$$Cty = Cline + Closses$$
$$Cty = A + B\ S + C/S$$

The minimum value of the function occurs for $d(Cty)/dS = 0$, or:

$$Sec = \sqrt{\frac{C}{B}}$$ which is the “most economical conductor cross section”.

Note: The Sec value does not depend on the line length, because it is a common multiplier in the Cty equation.

The related minimum yearly cost is:

$$Ctymin = A + 2\sqrt{B\ C} \qquad \text{U\$/km per year}$$

The line part of the yearly cost is:

$$\text{Cline min} = A + \sqrt{B\,C} \qquad \text{U\$/km per year}$$

Dividing the above value by k the line investment is obtained. This procedure can be used for preliminary calculation. However, for final calculation the costs shall be allocated along the years and the Present Worth calculated.

Tables 4.60 to 4.64 summarize the optimized values of the most economical configurations for power ratings 700; 1,500; 3,000; 4,500, and 6,000 MW. It should be noted that the most economical configuration is determined by the equations above (disregarding corona losses). However, if the conductor size is above 2,500 MCM, then the conductor size is set as 2,500 MCM; if it is too low (high surface gradient), then a minimum size is chosen to get a surface gradient lower than 28 kV/cm for reasonable corona performance.

Table 4.60 Most economical bipolar line for 700 MW

kV	**±300**	**±500**	**±600**
cond/pole	2	2	3
MCM (1)	2,280	1,800 *	1,500 *
tot U$/yr/km	31,714	31,441	34,428

A) Most favorable solution – losses cost base case

kV	**±300**	**±500**	**±600**
cond/pole	2	2	3
MCM (1)	2,102	1,800 *	1,500 *
tot U$/yr/km	30,329	30,324	33,449

B) Losses cost reduced by 15%
* See note after Table 4.64.

Table 4.61 Most economical bipolar line for 1,500 MW

kV	**±300**	**±500**	**±600**	**±800**
cond/pole	3	3	3	4
MCM (1)	2,515	1,870	1,560	1600*
tot U$/yr	51,970	41,803	41,575	43,935

A) Most favorable solution – losses cost base case

kV	**±300**	**±500**	**±600**
cond/pole	3	2	3
MCM (1)	2,515	2,515	1,435
tot U$/yr/km	48,513	39,326	39,613

B) Losses cost reduced by 15%

Table 4.62 Most economical bipolar line for 3,000 MW

kV	±500	±600	±800
cond/pole	4	4	4
MCM (1)	2,515	2,245	1,680
tot U$/yr/km	64,221	59,262	54,789

A) Most favorable solution – losses cost base case

kV	±500	±600	±800
cond/pole	4	3	4
MCM (1)	2,480	2,515	1,680
tot U$/yr/km	60,378	55,453	54,789

B) Losses cost reduced by 15%

Table 4.63 Most economical bipolar line for 4,500 MW

kV	±500	±600	±800
cond/pole	5	5	4
MCM (1)	2,515	2,515	2,515
tot U$/yr/km	90,253	79,368	67,962

A) Most favorable solution – losses cost base case

kV	±600	±800
cond/pole	4	4
MCM (1)	2,515	2,325
tot U$/yr/km	74,113	64,267

B) Losses cost reduced by 15%

Table 4.64 Most economical bipolar line for 6,000 MW

kV	±600	±800
cond/pole	6	5
MCM (1)	2,515	2,515
tot U$/yr/km	101,473	83,290

A) Most favorable solution – losses cost base case

kV	±600	±800
cond/pole	6	4
MCM (1)	2,515	2,515
tot U$/yr/km	94,321	78,154

B) Losses cost reduced by 15%

Notes on Tables above:

* minimum size for corona performance
2,515 MCM is the maximum size assumed
1 MCM=0.5067 mm^2

It should be noted that when considering the corona losses, the optimal conductor configuration for every alternative will have a bit larger conductor than the one shown. Table 4.65 illustrates this effect for ± 800 kV.

Table 4.65 Impact of corona losses in the most economical conductor choice (±800 kV line) cost per km

MW	**3,000**	**3,000**	**3,000**	**3,000**	**3,000**
kV	**±800**	**±800**	**±800**	**±800**	**±800**
cond/pole	4	4	4	4	4
MCM	**1,680***	**1,800****	1,900	2,000	2,200
tot U$/yr	54,789	54,700	54,730	54,839	55,251
line U$/yr	36,442	37,438	38,268	39,097	40,756
Joule U$/yr	13,970	13,039	12,352	11,735	10,668
Corona loss U$/yr	4,377	4,224	4,110	4,007	3,826

* optimal solution calculated disregarding corona losses (see “tot U$/yr” value in Table 4.62)
** optimal solution considering corona losses

It is important to say that the converter station costs increase with voltage, whereas the line losses reduce. There is a minimum total system cost, for the Optimal Voltage, will be determined provided that the line and the losses have the minimum costs.

5 Converter Station Cost Equation

This clause aims at defining cost for the converter stations and establishing what are the corresponding main circuit equipment and criteria for costing.

5.1 Cost Data

Having such costs available, it is expected to deduce a cost equation to be used in the economic calculations. The resulting equation shall also take into consideration the costs shown on [41] CIGRE Brochure 186, and also other published values [45] duly adjusted. Table 5.1 shows some published costs available and Table 5.2 the cost for several alternatives supplied by the manufacturer's members in the group.

Table 5.1: Converter Station Costs (Rectifier plus Inverter)

Voltage	Bipolar Rating MW	Cost U$/kW	Total cost Million U$	Source
±500	1,000	170	170	[41] CIGRE Brochure 186
±500	2,000	145	290	[41] CIGRE Brochure 186
±600	3,000	150	450	[41] CIGRE Brochure 186
±500	3,000	140	420	[45] IEEE Power and Energy
±500	4,000	170	680	[45] IEEE Power and Energy]
±600	3,000	150-153	450-460	[45] IEEE Power and Energy
±800	3,000	170	510	[45] IEEE Power and Energy

Table 5.2: Costs of Converter Stations (Rectifier plus Inverter) obtained by JWG-B2.B4.C1.17 from manufacturers: FOB prices without taxes and duties (on March 2007).

	Bipolar Rating MW	kV	12 pulse Converter/pole	Suggested Costs M U$	Costs M €
1	750	±300	Voltage Source Converter *	165	115
2	750	±300	1 (6 pulse)*	155	108
3	750	±300	1 (12 pulse)	165	115
4	750	±500	1 (12 pulse)	185	129
5	1,500	±300	1 (12 pulse)	265	184
6	1,500	±500	1 (12 pulse)	305	212
7	3,000	±500	1 (12 pulse)	425	295
8	3,000	±600	1 (12 pulse)	460	320
9	3,000	±800	1 (12 pulse)	505	351
10	6,000	±600	2 parallel 1 (12 pulse)	875	608
11	6,000	±800	2 series 1 (12 pulse)	965	671
12	6,000	±800	2 parallel 1 (12 pulse)	965	671

Notes:

* All others 12 pulse

1U$ = 0.695€

It should be noted that for ±800 kV and 6,000 MW the costs for series or parallel arrangements are the same, in general, the parallel arrangement has a higher cost (10 to 15%).

There are some parcels that are not included in the costs listed above, like for instance permits. Also there are many conditions, which are not known, and which may be significant for the cost, the most important ones being related to the time frame of the defined project, the site location and conditions, the environmental conditions and requirements, the AC grid parameters and the grid interconnection requirements. No short time overload capability is specifically considered here although it may be recognized that some intrinsic value may exist.

The cost will vary with the price of steel, aluminum, the labor cost, and currency exchange rates. The cost above were collected in March 2007, at that time the cost for magnetic oriented grain steel was 6,483 U$/ton and for the aluminum =>2,809 U$/ton.

Therefore Table 5.2 and consequently Table 5.3 are for study purposes only, and may not represent the actual rates. The results of costs, Tables 5.1 and 5.2, are inserted into a diagram (see Figure 5.1).

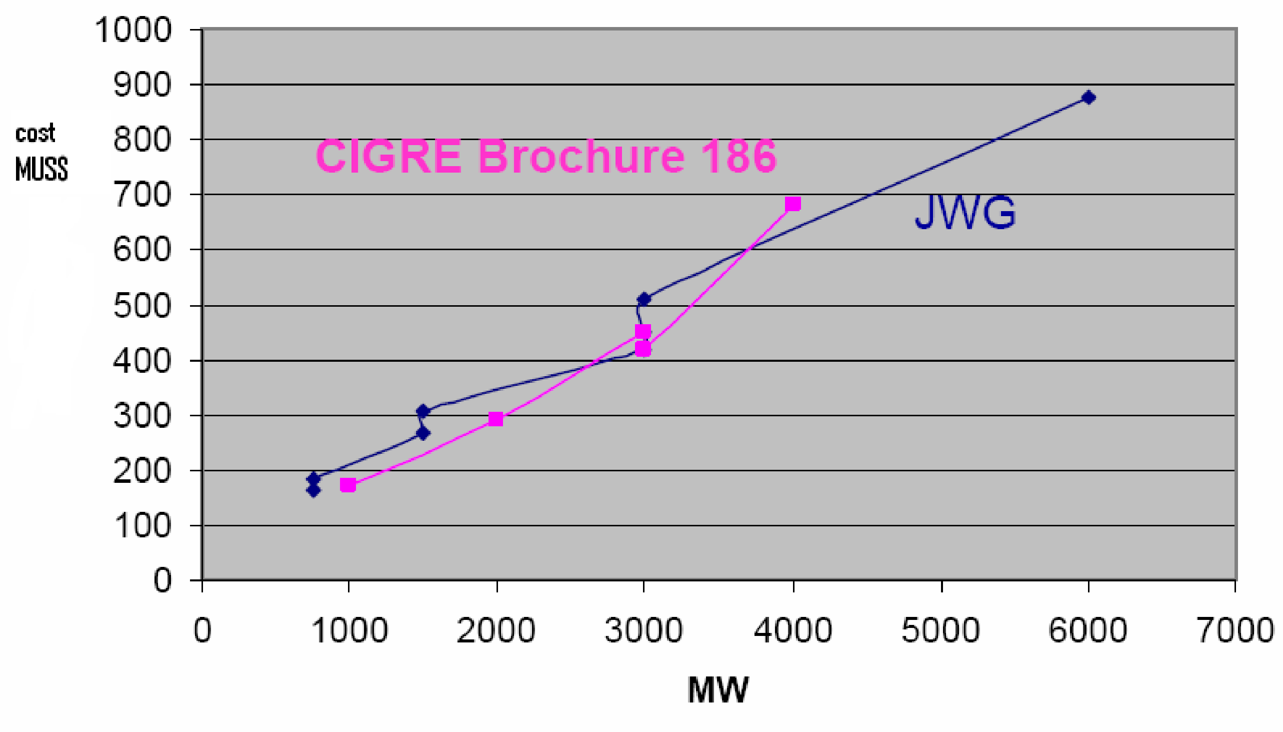


Figure 5.1: Converter Station Cost

5.2 Cost Equation

Some cost equations for both stations (rectifier/inverter), for line commutated converter and without losses cost were tested, and the one below was selected:

$$\text{Log Ct} = \text{Log A} + B*\log V + C*\log P \quad \text{or}$$

$$Ct = A\,(V^B)\,(P^C)$$

Ct → Millions U$
P → bipole power in MW

V → pole voltage kV

Table 5.3 shows the parameters of the equations and the accuracy obtained.

Table 5.3: Converter Station costs: Results and accuracy

Case	**kV**	**MW**	**Obtained Cost**	**without 6,000 MW cost**	**Dif (%)**	**with 6,000 MW cost**	**DIF (%)**
1	±300	750	165	170	2,8	135	-18,0
2	±500	750	185	199	7,8	153	-17,2
3	±300	1,500	265	250	-5,8	238	-10,3
4	±500	1,500	305	293	-3,8	269	-11,7
5	±500	3,000	420	432	2,7	473	12,7
6	±600	3,000	450	457	1,6	495	10,0
7	±800	3,000	510	501	-1,8	531	4,1
8	±600	6,000	875	673	-23,1	870	-0,6
9	±800	6,000	965	737	-23,7	933	-3,3

Curve fitting parameters

without 6,000 MW		with 6,000 MW	
A=	0,698	A=	0,154
B=	0,317	B=	0,244
C=	0,557	C=	0,814

The first series of parameters (A, B and C) is recommended for powers up to 4,000 MW, whereas the second one is recommended for powers in the 6,000 MW range. Figure 5.2 shows the comparison of the accuracy of the equations.

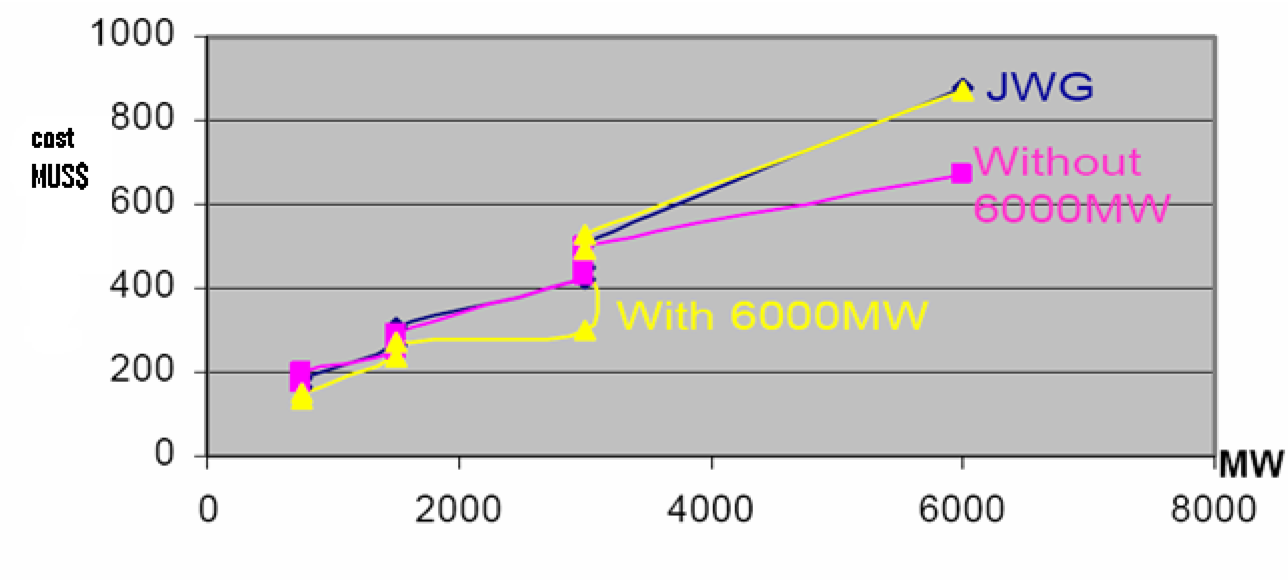


Figure 5.2: Converter Station costs: Results and accuracy

5.3 Cost Support Information and Breakdown

The HVDC systems are all different and in detail designed to customer technical preconditions and necessary investigations for future developing of grid system. Each HVDC system is therefore unique [44], as per CIGRE´ Brochure186. The cost division gives a rough overview.

Table 5.4: Cost Division

Standard thyristor bipole with two terminals	**Standard Bipole [%]**
Valve Group	22
Converter Transformer	22
DC Switchyard and filter	6
AC Switchyard and filter	9
Control, protection, communication	8
Civil, mechanics, works	13,5
Auxiliary Power	2,5
Project engineering, administration	17
Total	100

Regional market prices of raw material, energy cost, new developments and available infrastructures are some samples for which the above splitting can push the figures out of average.

Table 5.5 shows the station components of cost.

Table 5.5: Converter Station Cost Components (both terminals)

	1	2	3	4	5	6
Bipole Power in	750 MW	750 MW	750 MW	750 MW	1,500 MW	1,500 MW
Bipole Voltage	± 300, VSC	± 300, 1x12	± 300, 2x12	± 500	± 300	± 500
Primary Equipment						
Converter Transformers	2 (1)	8	14 (2)	14 (2)	14 (2)	14 (2)
Thyristor Valves and Wall bushings					thyr. type 4”	thyr. type 4”
AC Filter/ Cap. Banks (500kV AC buses)	2	14*66Mvar	14*66Mvar	14*66Mvar	18*100Mvar	18*100Mvar
Breaker Bays, 1 1/2 (500kV AC Busses)	2	5	5	5	12	12
DC Filters		4	8	8	8	8
DC Yard			(4)	4)	4)	4)
Smoothing Reactors	phase reactors	6 (5)	6 (5)	6 (5)	6 (5)	6 (5)
Civil Works EPC Subcontract	2 valve halls	2 valve halls	4 valve halls	4 valve halls	4 valve halls	4 valve halls
Secondary Equipment						
HVDC C&P	(6)	(6)	(6)	(6)	(6)	(6)
AC C&P	(7)	(7)	(7)	(7)	(7)	(7)
Aux. Equipment	(8)	(8)	(8)	(8)	(8)	(8)
Other Services						
Project Management and Engineering	24 Month Proj.	24 Month Proj.	30 Month Proj.	30 Month Proj.	36 Month Proj.	36 Month Proj.
Transportation	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia
Installation	(9)	(9)	(9)	(9)	(9)	(9)
Commissioning	6 months	6 months	7 months	7 months	8 months	8 months

Notes: (1) Three phase transformers
(2) One phase three winding transformer with spare in each terminal
(3) One phase two winding transformer with spare
(4) Includes metallic return
(5) With spare reactor in each terminal
(6) Includes: DC filter protection; telecomm; RCI; SFR; and TFR
(t) Includes: bus/bay/filter/capacitor protections; breaker control
(8) Includes converter valve cooling
(9) Without line; electrodes and mitigation measures

Table 5.5 Continuation

	7	8	9	10	11	12
Bipole Power in	3,000 MW	3,000 MW	3,000 MW	6,000 MW	6,000 MW	6,000 MW
Bipole Voltage	± 500	± 600	± 800	± 600 parallel	± 800, series	± 800 parallel
Primary Equipment						
Converter Transformers	28 (3)	28 (3)	28 (3)	52 (3)	56 (3)	52 (3)
Thyristor Valves and Wall bushings	thyr. type 5”	thyr. type 5”	thyr. type 5”	thyr. type 5”	thyr. type 6”	thyr. type 5”
AC Filter/ Cap. Banks (500kV AC buses)	26*125 MVAr	26*125 MVAr	26*125 MVAr	26*300 MVAr	26*300 MVAr	26*300 MVAr
Breaker Bays, 1 1/2 (500kV AC Busses)	16	16	16	18	18	18
DC Filters	8	8	8	8	8	8
DC Yard	(4)	(4)	(4)	(4)	(4)	(4)
Smoothing Reactors	10 (5)	10 (5)	10 (5)	18 (5)	18 (5)	18 (5)
Civil Works EPC Subcontract	(9)	(9)	(9)	(9)	(9)	(9)
Secondary Equipment						
HVDC C&P	(6)	(6)	(6)	(6)	(6)	(6)
AC C&P	(7)	(7)	(7)	(7)	(7)	(7)
Aux. Equipment	(8)	(8)	(8)	(8)	(8)	(8)
Other Services						
Project Management and Engineering	36 Month Proj.	36 Month Proj.	36 Month Proj.	42 Month Proj.	42 Month Proj.	42 Month Proj.
Transportation	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia	Europe to Asia
Installation	(9)	(9)	(9)	(9)	(9)	(9)
Commissioning	(7)	9 months	9 months	12 months	12 months	12 months
	(8)					

Notes: (1) Three phase transformers
(2) One phase three winding transformer with spare in each terminal
(3) One phase two winding transformer with spare
(4) Includes metallic return
(5) With spare reactor in each terminal
(6) Includes: DC filter protection; telecomm; RCI; SFR; and TFR
(7) Includes: bus/bay/filter/capacitor protections; breaker control
(8) Includes converter valve cooling
(9) Without line; electrodes and mitigation measures

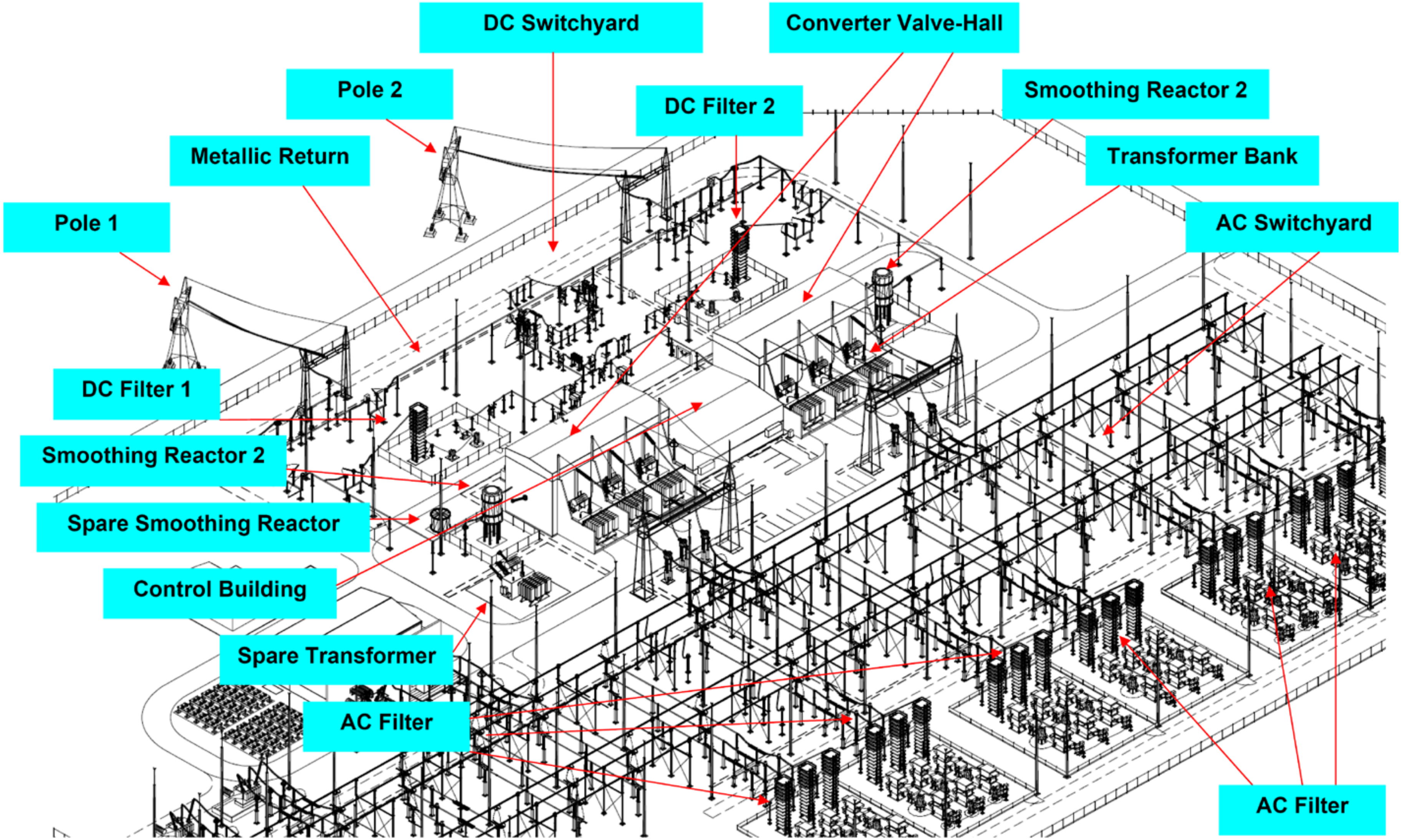


Figure 5.3: General Layout, HVDC Station

For a classic HVDC-terminal the following facilities are necessary, as per Figure 5.3:

- Line connection with DC switchyard
- DC-filter systems and smoothing reactors
- Converter hall with thyristor valve and control building
- Transformer bank and AC-switchyard
- AC filter systems and auxiliary transformer/auxiliary-yard

This example of switchyard is a design for an AC two bus bar system.

Figures 5.4 to 5.8 show examples of the basics single line diagrams for a HVDC terminal.

The AC switchyard is designed for 500kV. The converter operates with the DC line voltage of ±500kV.

The AC yard could be designed in various bus bar system types. The example in Figure 5.4 presents a one and a half circuit breaker arrangement.

The 500 kV AC filters are divided in some filter banks which have three ore four sub banks. The sub banks could be tuned as:

- single tuned,
- double tuned and
- triple tuned.

As required for reactive compensation only capacitors or inductances could be used too. One terminal could have 13 to 17 sub banks for a variable designed reactive power.

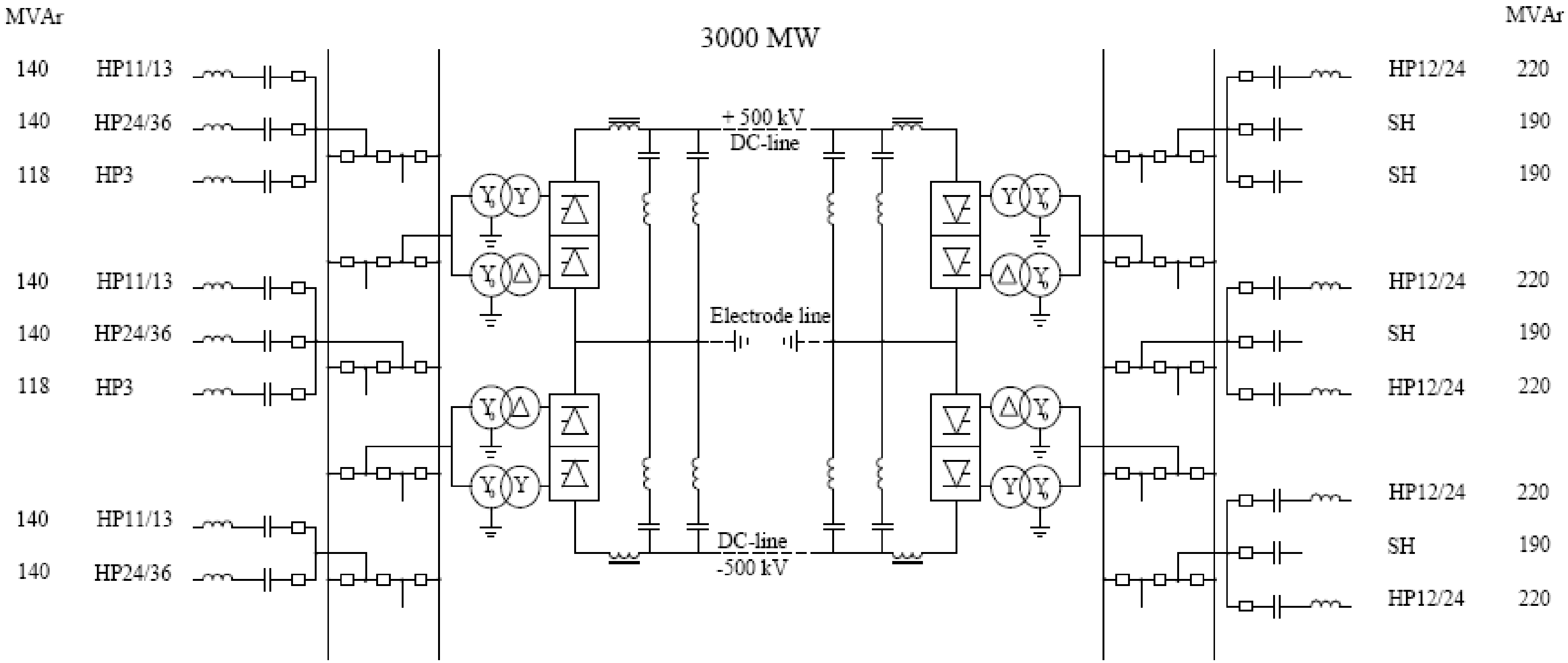


Figure 5.4: General single line diagram

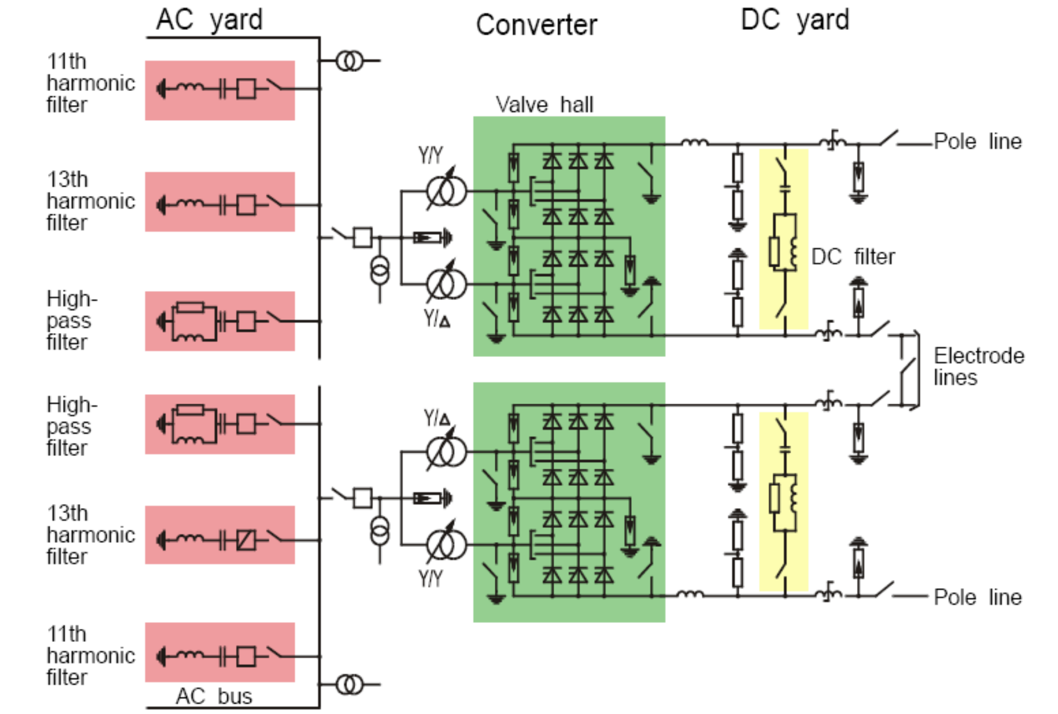


Figure: 5.5: General one line diagram with equipment details

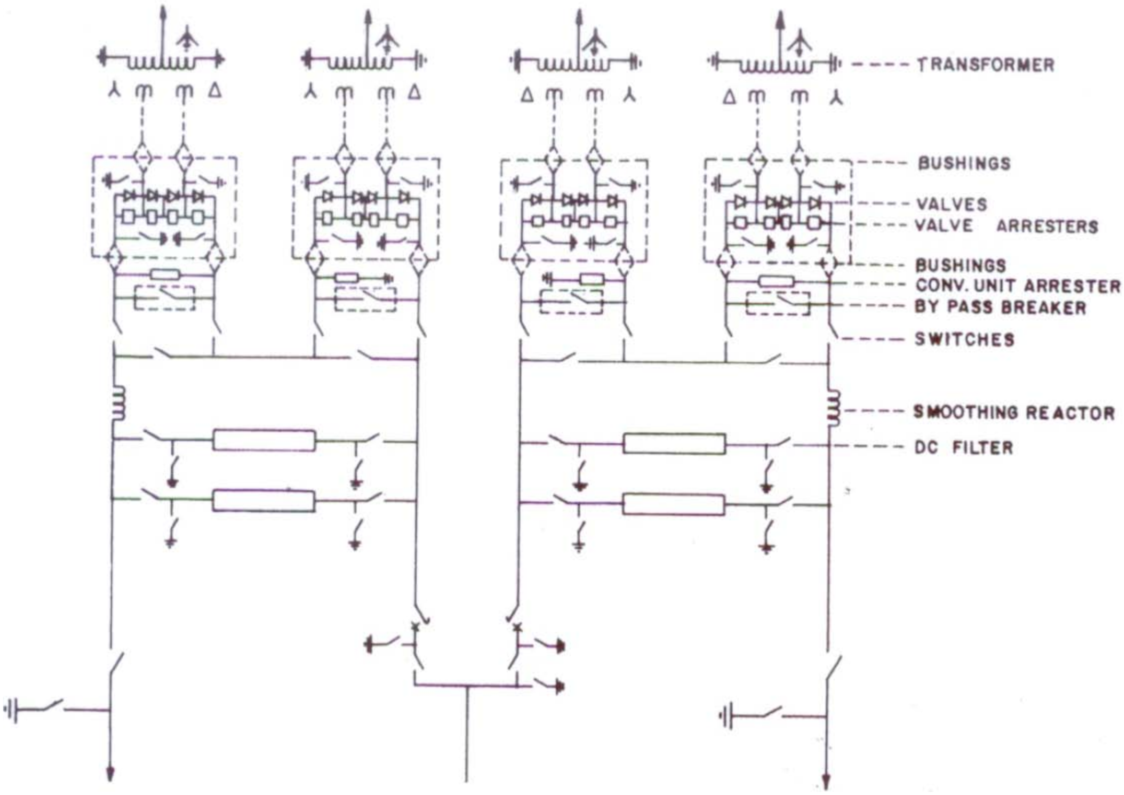


Figure: 5.6: Converter station DC yard, Itaipu, 2 converters per pole

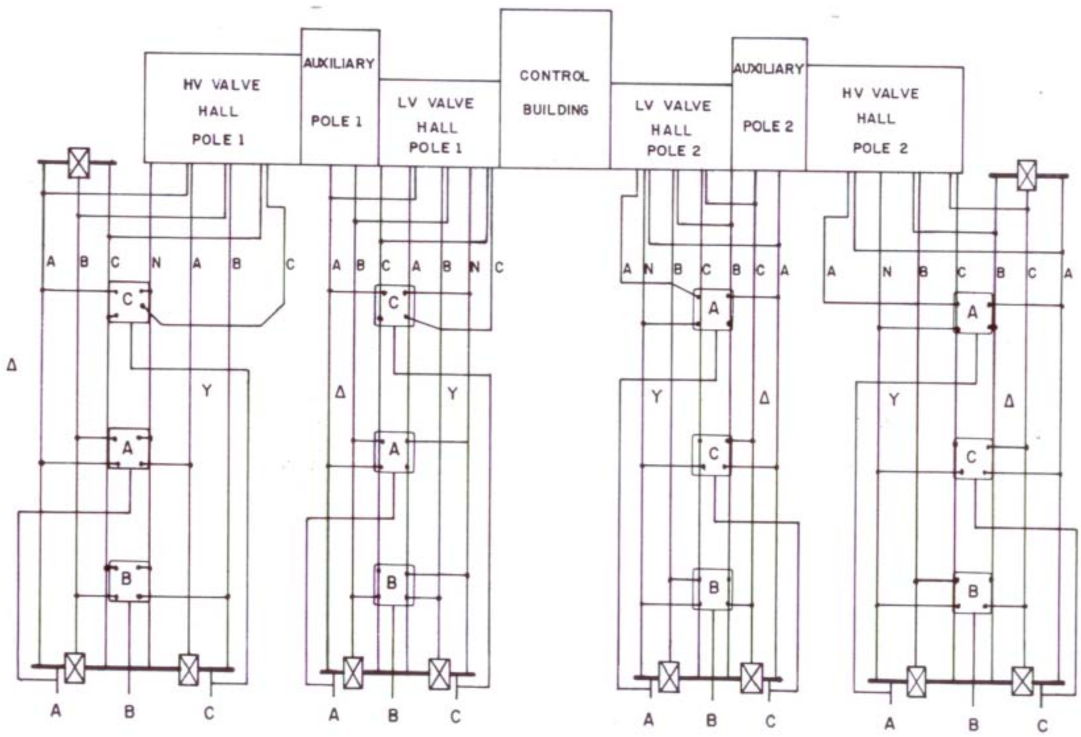


Figure 5.7: Itaipu Station (plant)

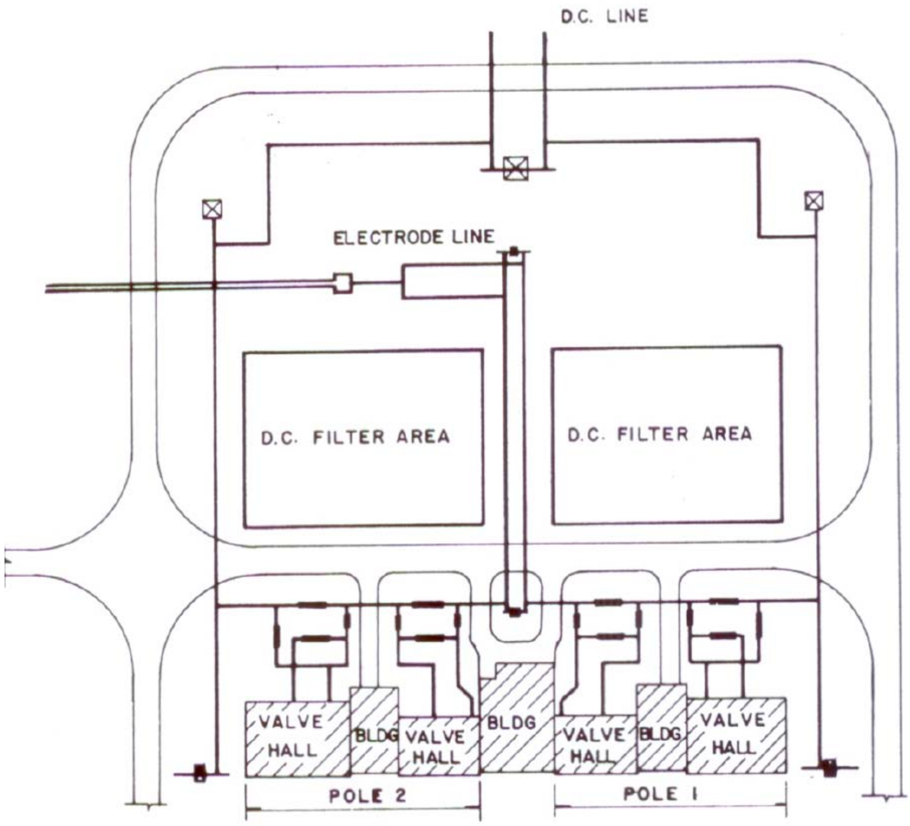


Figure 5.8: Itaipu DC Yard

5.4 Converter Station Considerations

5.4.1 Introduction HVDC/FACTS

FACTS is the acronym for Flexible AC Transmission Systems and refers to a group of plants used to overcome certain limitations in the static and dynamic transmission capacity of electrical networks. The IEEE defines FACTS as “alternating current transmission systems incorporating power-electronics-based and other static controllers to enhance controllability and power transfer capability”. HVDC transmission systems can also be considered as FACTS systems. These can be implemented as: back to back, DC-cable, overhead line or a combination of cable and overhead line.

The other means of enhancing AC transmission systems is to employ installations which supply the network as quickly as possible with inductive or capacitive reactive power that is adapted to its particular requirements, while also improving transmission quality and the efficiency of the power transmission system.

5.4.2 Transport Limitation

Transportation studies have to clarify infrastructures and further details concerning requested weights and dimensions. International and local standards have to be considered.

Clarification of available routes, waterways, airports and railways tracks with trailers barges and sea vessels with their capability and other limits are necessary. A study for transport and logistic is essential to find an economic construction design and shipping plan for the heaviest components. The result could be new or broaden infrastructure or else a new design for the equipment.

The limitation by HVDC equipment will be mostly stressed regarding converter transformer and smoothing reactors.

With this first view, apart of technical requirements of a HVDC system, the transformer type could be limited by its shipping weight.

Transformers will be transported without oil to limit the weight. The transformers are filled with nitrogen or other compressed gas. The acceleration forces seen by transformers due to loading, unloading, rough road or railcar humping are limited and have to be respected.

For example some type of transformer and its shipping weight is given for different standard HVDC systems:

Three-phase two winding transformer with	500 MVA	and	360 t
Single-phase three winding transformer with	297 MVA	and	371 t
Single-phase two winding transformer with	300 MVA	and	375 t
Single-phase two winding Transformer with	125 MVA	and	130 t

UHVDC one phase two winding transformers 300 MVA (for a 6,000 MW terminal) have to be transported with at transport weight of 375 t.

The transport dimensions could be for this type approximately: 13 x 4.4 x 5 m.

Twelve single-phase two winding transformers would weight around 1.7 times as two three-phase-three-winding transformers. The cost situation however becomes near equal if spare converter transformers are supplied, as is almost the case.

Three-phase–three-winding-transformer could be used only for small converter systems because of transport limitation and design limits.

Standard systems working with overhead lines, in the range of 750 MW to 1,500 MW, use single phase three winding transformer. It is economical to have only one spare part for each of the two terminals, see Table 5.6.

Table 5.6: Cost (in % of one single phase two winding) for various types of Converter Transformer (same MVA base)

Type of Transformer	Cost for one unit (%)	Total Cost for one Bipolar HVDC system (%)	Cost for spare units (**%**)	Total Bipolar HVDC system Cost including spare (**%**)
Three Phase three winding	360	720 two units	360 one units	1,080
Three Phase two winding	220	880 four units	440 two units	1,320
Single Phase three winding	160	960 six units	160 one unit	1,120
Single Phase two winding	100	1,200 twelve units	200 two units	1,400

The difference in cost varies according to whether the system is a back to back link with the same or with different voltages on the two terminals, or if it is a long distance transmission with one or two twelve-pulse groups per pole. Without taking into consideration costs of other components, for example valve design, there seems to be no reason for application of a three phase configuration of the converter transformer. The cost in % mentioned in table 5.6 is assumed for a standard converter twelve pulse group.

Smoothing reactors are designed in oil immersed or air core dry type coils. Single air core units are preferred for UHVDC. A unit with 75 mH has a weight of approximately 45 t. The transport dimensions are approximately 5 x 5 x 5 m.

The air-core coils could be installed in series at the site.

5.4.3 Station Losses

5.4.3.1 General

System losses are a very important factor for the economic efficiency of an HVDC system. Therefore they are often specified as a guaranteed value. They should be verified in a suitable manner by the manufacturer. Losses above the specified guaranteed value are subject to monetary penalties.

System losses include:

- Total losses in the two HVDC stations
- Loss in the HVDC line
- Losses in the two earth electrodes and associated electrode lines occurring in monopolar operation

In this item only the converter station losses are regarded here.

Direct measurement of system losses is not possible due to inadequate precision of available measuring instruments and methods. For this reason, it is customary and is accepted as verification to determine total losses through addition of individual losses of system components which are easier to determine. Even the individual losses of the most important components of an HVDC system can only be determined with some degree of uncertainty by using a combination of field test measurements, mathematical adjustments for actual conditions and circumstances, and consideration of individual measurements in running HVDC systems.

The recommended procedure for loss calculation is described [52], in detail in the IEC Standard 61803 "Determination of power losses in high-voltage direct current (HVDC) converter stations", for line commuted converter technology.

5.4.3.2 Converter Valves

In converter operation, losses occur mainly in the thyristors, as follows: Losses due to their differential resistance are proportional to the square of the current; losses due to their threshold voltage are proportional to current, switching-through losses occur at gating and finally losses due to the carrier storage effect during extinction. Additional losses occur in the RC snubber circuits and in saturable valve reactors.

The determination of all these different losses is a very complex task. In practice, conversion methods have proven to be useful which are based on heat loss measurements performed in a module test circuit (i.e. in actual converter operation). Original elements are used but are limited to one module. Thus, six to ten thyristors in series are used per valve branch. Additional loss sources are current heat losses in valve buses. According to IEC 919, the power of the valve cooling system is to be included in valve losses to the extent it is needed for the load case under consideration.

5.4.3.3 Converter Transformers

No-load losses are verified in customary test field measurements. Increase of losses as a result of DC pre magnetization, particularly at minimum power, can only be determined mathematically. For load losses, the additional losses caused by harmonic currents must be taken into consideration by means of selection of a higher fundamental current for test field measurements. The earlier IEC 146 recommended that the valve current shall be assumed to be rectangular (neglecting commutation overlap) leading to an increased fundamental r.m.s. value. This method has proven to be inadequate for HVDC transformers. Until a new IEC publication is available, the transformer manufacturer must perform the calculation of an adequate test current incorporating the considerations of CIGRE-WG 14-12. The cooling system power needed for the contemplated load case must also be included in the transformer losses.

5.4.3.4 Smoothing Reactor

Here also the additional losses caused by dc-side harmonic currents can only be taken into account by mathematically increasing the test DC current by an appropriate amount. With forced cooled reactors, the inclusion of cooling system power is necessary.

5.4.3.5 AC filter Circuits and Capacitor Banks

In loss determination, it is assumed that 100% of the characteristic and non characteristic harmonic currents generated at a particular load by the converters are flowing into the AC filter circuits and capacitor banks which are connected in the particular case, and that no additional harmonic currents flow in from the AC network.

5.4.3.6 DC Filter Circuits

In addition to capacitor coils, the interior and/or exterior discharge resistors should be considered for direct voltage-caused losses. With respect to losses caused by DC-side harmonic currents in capacitors, reactors and resistors, in contrast to the AC filter circuits, only the harmonic currents which actually flow into the filter circuits have to be considered. This includes, however, currents flowing from the other station. Thus non-harmonic frequencies may also be included.

5.4.3.7 Other Components of HVDC Stations

Auxiliary power demand (reduced by the cooling system power included in the equipment losses) covers station service facilities and may include air conditioning systems of control room and valve halls, control equipment cubicles, auxiliary power transformers.

Details on procedure and methodology on calculation of losses of the equipment above are given in the IEC 61803 Standard, “Determination of power losses in high-voltage direct current (HVDC) converter stations”.

5.4.3.8 Environmental Conditions

All relevant environmental conditions of the stations for which the system losses are to be determined must be clearly defined. Extreme values should not be used. Instead, averages over a period of many years or prevailing conditions should be used.

In general it is assumed that the environmental conditions prevail long enough for all components to reach their end temperature.

5.4.3.9 Load Cases

In determining system losses for the specified load cases, the following assumptions should be made in addition to the above listed ambient conditions.

For quantities regulated through transformer tap changers (control angle, DC voltage, if applicable) the mean values between the limits which trigger switching should be used.

AC filter circuits and reactive power units should be considered activated to the extent they are needed in the particular load to establish the specified reactive power balance and to meet the distortion limits.

If electronic reactive power regulation is used at minimum load, the enlarged control angles, the transformer tap setting and the resulting modified DC-side parameters must be taken into consideration when calculating line losses.

For no-load stand-by condition (the system is prepared to start power transmission), unless otherwise specified, the following assumptions apply: Converter transformers energized, valves under voltage but blocked, AC filter circuits and reactive power units disconnected, all auxiliary systems active, ventilators and pumps running at the lowest level, hall ventilation and air conditioning system activated.

In monopolar systems and bipolar systems for which loss determination is required for monopolar operation with ground return, losses of earth electrodes must be determined using the transition resistances applicable in continuous operation, or at the end of half the time specified for emergency operation. For electrode lines, end temperatures corresponding to the current and ambient conditions are assumed.

5.4.3.10 Practical Loss value

The Table 5.7 gives the significant loss sources. As typical and as example, losses of one HVDC converter station a 2,000 MW system is used.

Table 5.7: Typical Losses of one LCC system

Components	No Load (Standby)	Rated Load
Filters:		
AC-Filters	4 %	4 %
DC-Filters	0 %	0.1 %
Converter Transformer, 1phase, 3 winding	53 %	47 %
Thyristor Valves	10 %	36 %
Smoothing Reactor	0 %	4 %
Auxiliary Power Consumption		
Cooling System, Converter Valves	4 %	3 %
Cooling System, Converter Transformer	4 %	1 %
Air-Conditioning System	15 %	4 %
Others	10 %	1 %
Referred to rated power of one 2000 MW Bipole-Station	2,2 MW	14 MW

The total losses for two terminals as a result of No-Load and Rated-Load are 1,62 %.

5.4.4 Standard Thyristor Bipoles

5.4.4.1 Layout and Single Line Diagram

The layout of a bipole is arranged in three areas:

- AC switchyard with harmonic filters and reactive power compensation
- DC Buildings with valve halls and control building
- DC switchyard with smoothing reactor and harmonic filters

For details, see Figure 5.3 to 5.8, and Figure 5.9 single line with an inserted "Metallic Return" into a DC yard. The necessary area for the AC yard depends of bus-bar type and amount of AC filter systems with reactive power compensation.

For a 2,500MW HVDC system the 400 kV AC yard needs 120,000 m² to 150,000 m², by a one and a half circuit breaker arrangement scheme. This required space could be reduced by other AC bus bare systems.

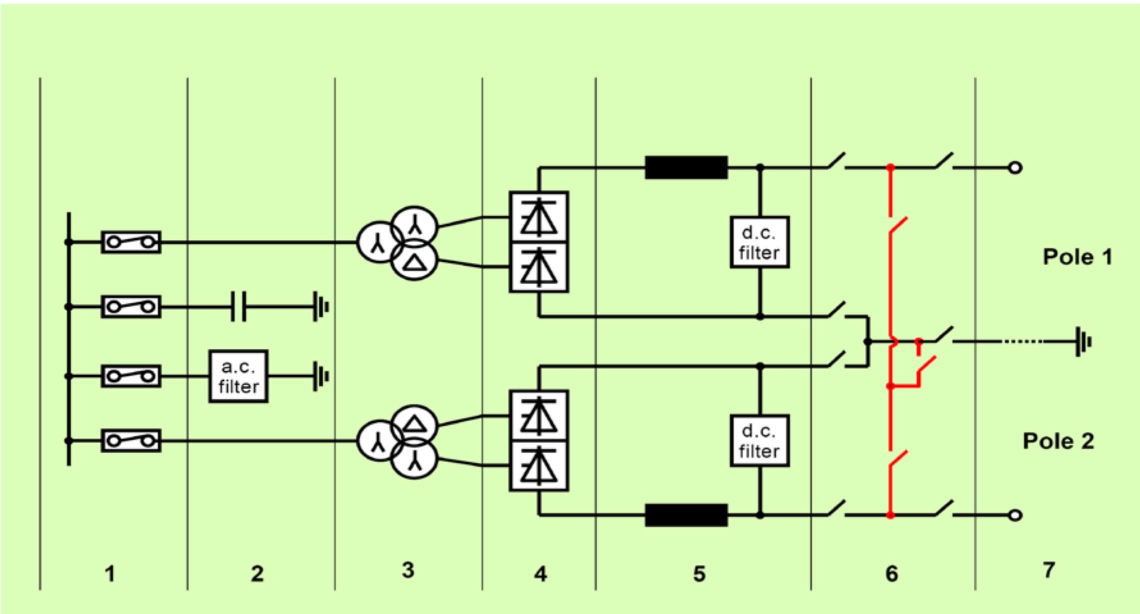
A standard ±500 kV DC yard with two 12 pulse groups needs a construction of two valve halls and one control building. For the DC yard 30,000 m² is the required area.

For additional two-valve halls, it is just required to extend to an ±800 kV DC system further 10,000 m² are required.

A standard 12 pulse group is installed in one valve hall. Two 12 pulse groups are necessary for one terminal up to 3,000 MW. For further details (see Figure 5.9).

For maintenance purpose and economy in the building construction each bipole terminal has four valve halls.

This is a commonly used single line configuration for a bipolar transmission system. The solution provides a high degree of flexibility with respect to operation with reduced capacity during contingencies or maintenance. A metallic return is integrated in the DC yard integrated (Fig. 5.9). This enables operation with the neutral via one overhead line if one thyristor pole is under maintenance.



1 AC Switchyard
2 AC Filters, Capacitor Banks
3 Converter Transformers
4 Converters
5 Smoothing Reactors and DC Filters
6 Metallic Return
7 DC Line

Figure 5.9: Single line, HVDC terminal with Metallic Return

5.4.4.2 Power Range

The HVDC systems are performed in a large range from 40 MW for back to back link “Broken Hill”, in Australia, up to 7,200 MW for long inter connections, at present under construction in China.

A) Thyristors

Thyristors are used as switches and thus the valves become controllable. The thyristors are made of highly pure mono crystalline silicon. The high speed of innovation in power electronics technology is directly reflected in the development of the thyristor. For long distance high power there is thyristor available with high blocking voltage of 8 kV and three different types of current. The high performance thyristors installed in HVDC plants today are characterized by silicon wafer diameters of up to 5’’ (125 mm), blocking voltages up to 8 kV and current carrying capacities up to 4 kA DC (Figure 5.10). The new 6’’ (150 mm) with a current capability of 4.8 kA and 8kV is under development. Thus no parallel thyristors need to be installed in today’s HVDC systems to handle the DC current. The required DC system voltages are achieved by series connection of a sufficient number of thyristors.

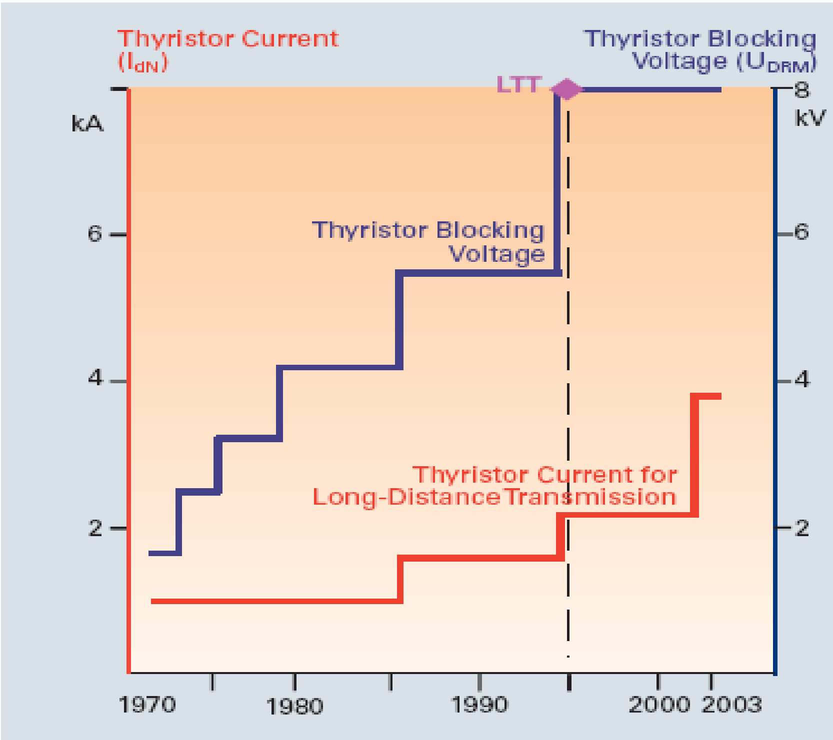


Figure 5.10: Thyristor development

As example a 500kV, 12 pulse converter has a total of 936 thyristors. There are 312 thyristors connected in series in a quadruple valve. For one valve 78 thyristors are installed. This figure could be different in case of certain required network situation and further technical necessity and request. The amount of spare thyristor should be determined with the station availability and reliability study. Statistical data such as minimum time between failures, minimum downtime and the concept of maintenance have to be regarded. The result, in general, leads to one or two spare thyristors per valve. The following list of standard HVDC systems points out the use of different standard thyristors.

line current	Line Voltage	Rated Power	Diameter of wafer
2 kA	±500 kV	2,000 MW	4'' / 10.0 cm
3 kA	±500 kV	3,000 MW	5'' / 12.5 cm
3,125 kA	±800 kV	5,000 MW	5'' / 12.5 cm
3,75 kA	±800 kV	6,000 MW	6'' / 15.0 cm
4,5 kA	±800 kV	7,200 MW	6'' / 15.0 cm

With these different types of thyristors, all requested valve configurations in current and voltage could be arranged. The typical arrangement of a 12 pulse group is shown in Figure 5.11. Three quadruple valves are fixed under the roof. One quadruple valve has four branches in series. Assigned to each branch is a Metal Oxide Surge Arrester.

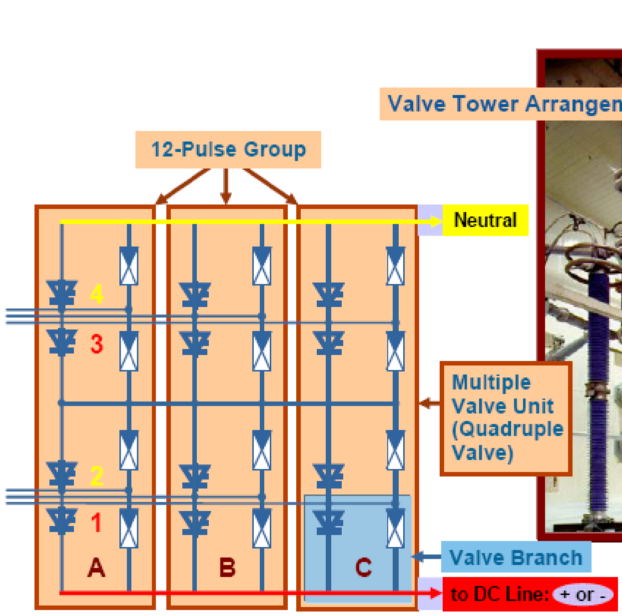


Figure 5.11: Example of a ± 500 kV 12-Pulses Valve Tower Configuration

The thyristor converter valves with metal oxide arresters are designed to withstand the steady state, transient and dynamic operation behavior with the connected AC network and DC line including switching and lightning stresses. The thyristor valve are tested for the adequate dimensioning according IEC 60700-1, “Thyristor Valves for HVDC Power Transmission, Electrical Testing” [52].

B) Bipole Advantages

The advantages of a bipolar solution over a solution with two monopoles are: reduced cost due to one common or no return path; and lower losses.

The main disadvantage is that unavailability of the return path with adjacent components will affect both poles. The availability of power transfer could be influenced.

C) Limitations

The limitation of power for a standard bipole system will be the accepted load rejection behavior of the AC network system, manly in voltage rise and frequency drop.

In a ± 800 kV solution one can find 12 pulse groups designed up 1,800 MW with single phase transformers for ± 400 kV, and ±800 kV levels. This design status is not a technical limit for future projects.

5.4.5 Cost Basis

The effective costs for two standard converter terminals will be described in this clause.

The main parameters are the terminal voltage and transmission power for long distance HVDC systems. As main construction a bipolar system is considered.

As basic for cost estimation it is used:

- Main technical data,
- quantity of equipment;
- buildings;
- construction;
- engineering.

The spares (transformers, reactors, etc.) are included in the cost of converter station.

The framework for primary equipment is fixed in Table 5.5 and the price list for HVDC Terminals in Table 5.2.

5.4.5.1 Primary Equipment

The primary equipment listed in Table 5.5. should be understood with additional aspects for all evaluated converter stations.

Civil works are evaluated without site preparation; heating, ventilation and air conditioning are included.

5.4.5.2 Secondary Equipment

The secondary equipment part, HVDC control and protection, has included, therefore:

- DC Filter Protection,
- Telecommunication,
- Remote Control Interface (RCI),
- Sequence Event Recorder (SER),
- Transient Fault Recorder (TFR).
- Services.

Excluded are other services and installation for DC lines, electrodes and mitigation measures.

5.4.6 Individual Design or Equipment

The prices refer to a design with one 12 pulse converter per pole except when indicated. Metallic return capability is included in all alternatives. The technical impact of metallic return can be seen in the single line diagram in Figure 5.9. Additional equipment, such as line insulators in the DC yard are necessary. The neutral system insulation is designed for 60 kV to 138 kV. The extra cost of the DC yard for metallic return system is not a considerable amount in the total project cost.

A) For 750 MW-Converter

Some of the listed converter terminals are equipped or designed with different features to the standard specification. In this issue the cost of three possibilities are informed: conventional (one 12 pulse converter per pole); centre-point grounded (one 6 pulse converter per pole); and one converter per pole but using Voltage Source Converter (VSC).

The 750 MW single 12 pulse groups with grounded centre point can be used and present an economy as related to the quantity of transformers. It allows the use of larger size transformers that result also in price reduction. One can see this alternative as a bipole composed of two 6 pulse converter one with wye connection of the transformer secondary and another with delta connection maintaining the benefits as related to harmonic performance.

The VSC alternative is appropiate for back-to-back, and DC system with cables. The first VSC alternative with overhead transmission line (Caprivi Link) will come to operation soon [37]. Figure 5.12 illustrates this alternative.

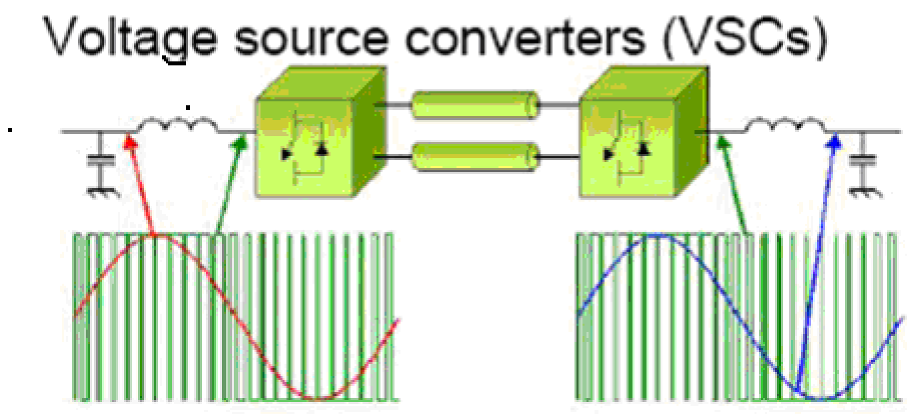


Figure 5.12 VSC converters and cables

The VSC alternative presents the following advantages:

- it does not need an active network in the inverter side (thus can supply passive loads);
- it does not require VAR compensation;
- it does not need filters (except a small amount for high frequency due to voltage switching).

On the other side, in general this alternative is more expensive and produces higher losses

B) For 1,500 MW-Converter

The converter transformer for the 1,500 MW terminals is designed as one phase three winding units. The transformer bank uses 3 units for each of the two DC poles. Each terminal is equipped with one additional spare device. The metallic return transfer equipment is included and completes the DC yard.

C) For 3,000 MW-Converter

Single phase, 2 winding transformers are used. Consequently, the transformer bank is equipped with 6 units in each 12 pulse converter. Two additional spare units are used for each terminal. This converter transformer is designed for 125 MVA (approximate shipping weight 130 t) and could be transported under special heavy vehicles. The design also includes:

- 4 valve halls,
- 2 control buildings,
- 4 relay houses,
- spare parts.

Repeater station for telecommunication systems is not included.

The metallic return transfer equipment is included.

D) For 6,000 MW-Converter

The 12 pulse converter groups could be designed and connected in series or in parallel. The designs here include two 12 pulse group per pole, in parallel or in series, for ±800 kV. For a parallel connection 48 transformers are necessary with 4 additional spare units, each of 300 MVA. Series connected converter groups need 48 transformers and 8 additional spare transformers, one for each DC voltage level of 200 kV and for each terminal.

The civil construction is more extensive for such systems. For maintenance purposes 8 valve halls are necessary. This allows operating during maintenance with 50% of a pole system. Dry type multiple air core smoothing reactors are used in series connection. According to individual specification and design, several units may be necessary. For ± 600 kV and 6,000MW, parallel arrangement is used in order to apply 5” thyristors.

5.4.7 Power Tap (T off)

Many times a concern is raised as related to the fact that the HVDC line is crossing a region without adequate supply and a solution to tap power from the HVDC line is required. The tap can be of a large size (example 30 % of the power at the rectifier) in this case a multi terminal system is the solution. However when this tap is very small another solution needs to be found. The VSC converter can be the solution to this requirement, although of course the cost will be expensive. The situation is not different with an AC system, where one can install a transformer to tap certain small power but the solution will also be expensive. When this requirement exists, it is better to find other type of solution like: bringing power through the shield wire (like a V-V transformer connection in distribution systems); or use of photo voltaic or wind or small hydro system dedicated to the place.

Figure 5.13 depicts the tapping using VSC devices.

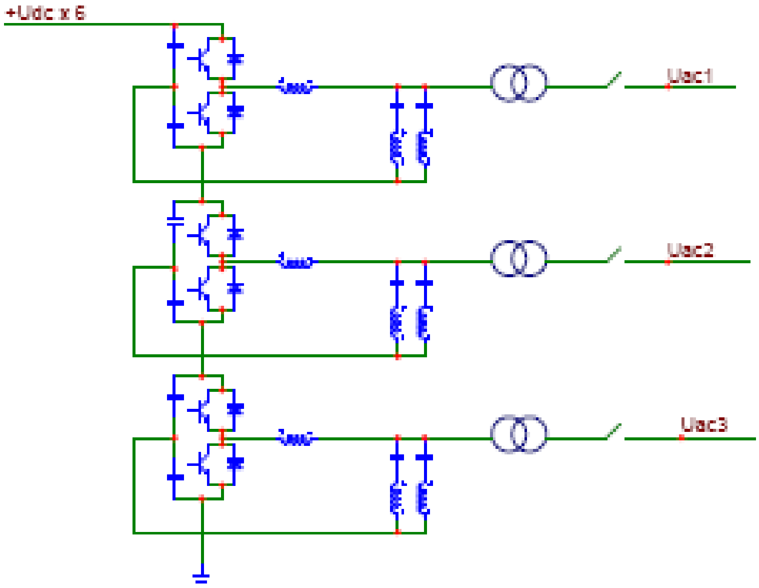


Figure 5.13 Tapping using VSC

The architecture above uses one DC voltage level. By using multi-level solution a better waveform is obtained and high frequency filters become unnecessary (Figure 5.14).

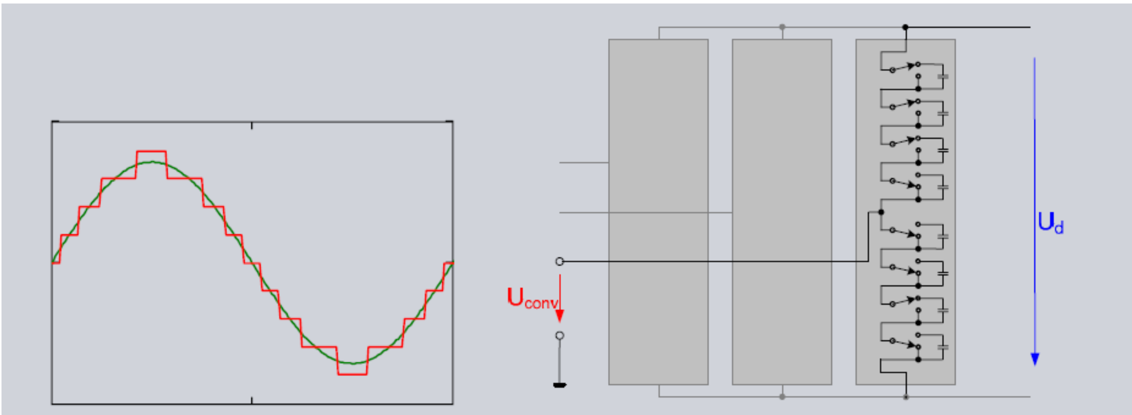


Figure 5.14 VSC with multi level converter

There is no such of these T off application in operation yet.

However, many VSC solutions are in operation and under construction.

The commissioning for the novel application of Figure 5.14 is planned for San Francisco at 2010 [53]. This “Trans Bay Project” is designed for 400MW, ±170 MVAr and ±200kV.

6 Electrodes, Electrode Lines and Metallic Return

6.1 Introduction

In the HVDC systems, current flows from the positive pole of the rectifier through the line, inverter and returns to the negative pole of the rectifier. When one pole or a pole converter is unavailable, there is a need for a current path in order to transmit part of the power by the DC system. This can be done using ground path or metallic return, the former being the most common option.

6.2 Ground Return

Figure 6.1 shows the scheme that includes the electrode line and the electrode.

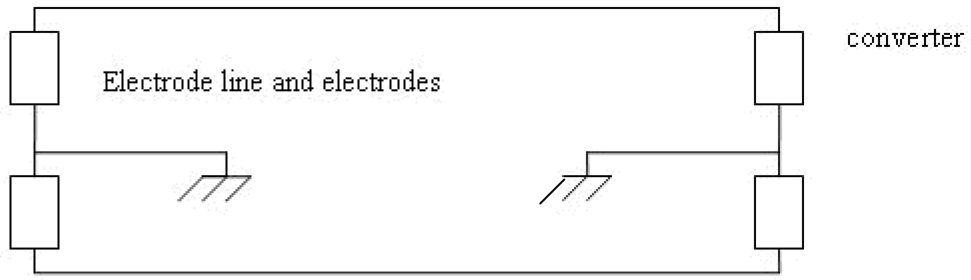


Figure 6.: Ground return

The electrodes (one in the rectifier and another in the inverter terminal) in general are located up to 30 to 50 km from the converter station to avoid interference problems of the current flowing to the ground and provided that adequate surface and deep soil resistivity are found. This current establishes a voltage drop in the electrode line and electrode, and the neutral point of the converter station shall have adequate insulation for that.

6.3 Metallic Return

Figure 6.2 shows a particular case, when a pole converter is unavailable due to maintenance or repair of the converter. In this case, the current returns by the pole where the converter is out. The grounding condition may not be special due to the fact that the current flows to the ground for short time during equipment switching. In this case, there is a need for a breaker to move the current from ground (smaller resistance) to the pole (higher resistance). The neutral point of the converter station shall be insulated to withstand the voltage drop in the pole where the current is returning.

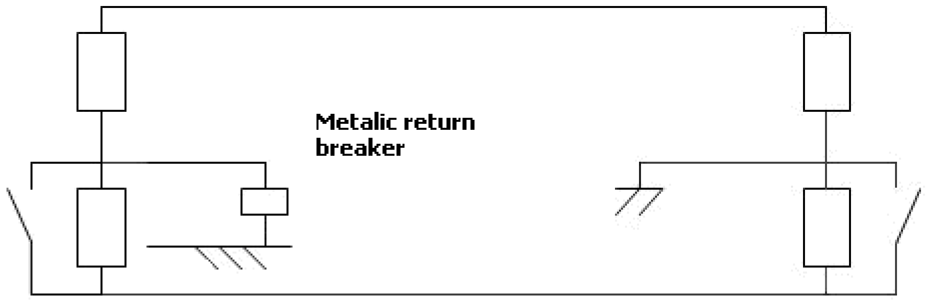


Figure 6.2: Metallic return through one pole

Therefore, if one considers as criteria, that a pole may be out by failure in the line, then the shield wire may be used for return (however insulation has to be provided). DC filter outage may not require use of metallic return because the system may be designed for degraded operation. Outage of smoothing reactor is not a special case due to the fact that one may have spares or may use a design with more than one piece and degraded operation. Figure 6.3 shows a case where the return path is the shield wires.

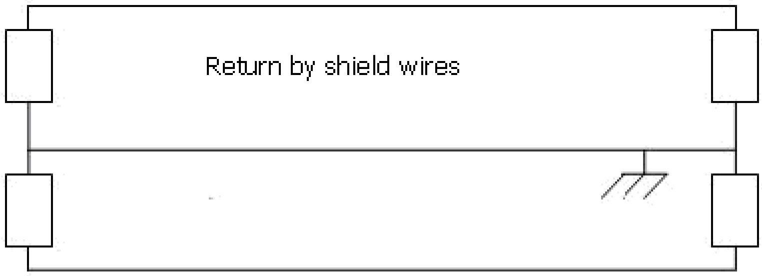


Figure 6.3: Return by shield wires

It should be noted that the neutral point shall be insulated for the voltage drop due to the return current.

6.4 Electrode Line Cost

In general, the following design criteria are used for the electrode line:

- The line shall have more than one conductor as its failure causes a bipole outage.
- Choice of the number and type of insulators in a string: this depends on the voltage drop on the electrode line due to the DC current flowing during monopolar operation; the electrode line length and the conductor selected dictate the choice. The pollution level in the electrode area has also an influence.
- A gap shall be provided to make easier the arc extinction after a fault to ground in the electrode line.
- The relative position of the electrode line as related to the bipole is an important aspect, as related to the electrode line insulation design.
- The electrode line tower grounding is an important aspect in order to limit the flashovers to ground (structure).
- An adequate clearance to ground has to be provided to comply with the current passing through and an eventual loss of one of the conductors

Table 6.1 shows the costs of electrode line cost for several conductor configurations. The electrode line concept includes: concrete pole; concrete foundation; 250m span; cross arm; suspension string with two insulators and gap for arc extinction.

Table 6.1 - Electrode line costs parcels in percent (100% is the reference value – Item 6)

Item	Description	2xJoree	2xLapwing	4xLapwing	4xRail
	MCM total *	5,030	3,180	6,360	3,816
1	**Engineering %**				
	Engineering (design & topography.)	2.19	2.84	1.74	2.38
2	**Materials %**				
	Poles and foundation	12.22	14.61	12.59	14.91
	Conductor	42.09	35.57	43.60	35.74
	Insulator, hardware & accessories, grounding	2.53	3.28	2.32	3.17
	Sub total materials	56.84	53.46	58.52	53.83
3	**Man labor %**				
	ROW and access roads	3.01	3.90	2.39	3.26
	Pole erection	7.16	7.36	7.00	8.46
	Conductor installation	16.05	16.79	15.44	16.34
	Poles foundation excavation	0.33	0.42	0.29	0.37
	Sub total man labor	26.55	28.46	25.11	28.43
4	**Administration and Fiscalization %**				
	Material transportation to site	6.09	7.01	6.28	7.14
	Inspection at manufacturer's site	3.98	3.74	4.10	3.77
	Construction administration	1.44	1.57	1.34	1.54
	Sub total administration and supervision	11.51	12.32	11.72	12.45
5	**Contingencies %**				
		2.91	2.91	2.91	2.91
6	TOTAL U$/km (100%)	**68,310**	**52,723**	**86,029**	**62,979**

* 1MCM=0.5067 mm^2

Figure 6.4 depicts the costs shown in Table 6.1.

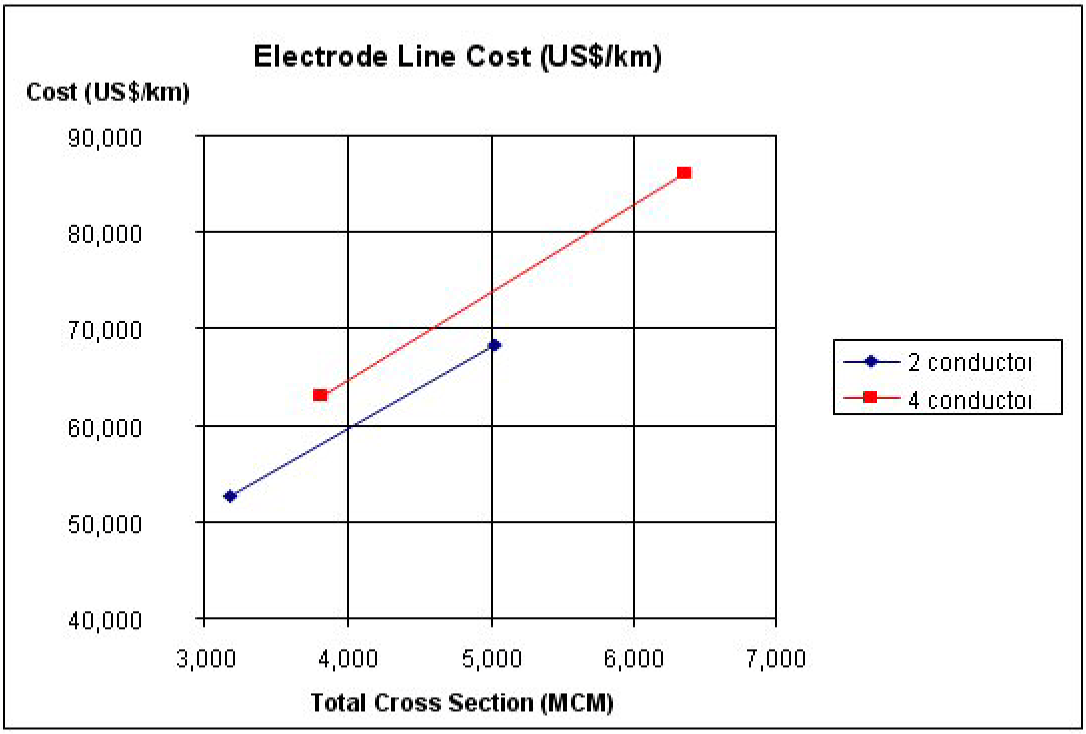


Figure 6.4 electrode line cost.

Table 6.2 shows group items cost and taxes in %.

Table 6.2 : Electrode line - Group items figures and taxes

Description	ACSR 2xJoree	ACSR 2xLapwing	ACSR 4xLapwing	ACSR 4xRail
Group item				
Materials	56.8	53.5	58.5	53.8
Engineering, man labor and contingencies	43.2	46.5	41.5	46.2
Total	**100**	**100.**	**100**	**100**
Man labor and cont. taxes (10%)	3.9	4.2	3.8	4.2
Material taxes (40%)	16.2	15.3	16.7	15.4
Total taxes in the cost	**20.1**	**19.5**	**20.5**	**19.6**

6.5 Electrode Line and Metallic Return Design

Table 6.3 shows the electrode line and metallic return design result.

Table 6.3: Electrode and metallic return lines design

Power (MW)	700	700	1,500	1,500	3,000	3,000	3,000	6,000	6,000
Pole Voltage (kV)	±300	±500	±500	±600	±500	±600	±800	±600	±800
Pole Current (kA)	1.17	0.70	1.50	1.25	3.00	2.50	1.88	5.00	3.75
Pole cond number	2	2	3	3	4	4	4	6	5
MCM one conductor	2,400	1,950	2,017	1,681	2,515	2,420	1,815	2,515	2,515
MCM total	4,800	3,900	6,051	5,043	10,060	9,680	7,260	15,090	12,575
Current/ Conductor (kA)	0.58	0.35	0.50	0.42	0.75	0.63	0.47	0.83	0.75
Conductor Temperature (°C)	45	40	45	45	55	45	45	55	55
Sag (m)	19	19	19	19	19	19	19	19	19
Proposed electrode line design									
Electrode Line cond. number	2	2	2	2	2	2	2	3	3
Electrode Line MCM	1,200	1,033.5	1,513	1,261	2,515	2,420	1,815	2,515	2,096
MCM total	2,400	1,950	3,025.5	2,521.5	5,030	4,840	3,630	7,545	6,287.5
Current/ Conductor (A)	1.17	0.70	0.75	0.63	1.50	1.25	0.94	1.67	1.25
Temperature (°C)	65	55	55	55	70	65	60	75	65
Sag (m)	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Electrode Line Voltage drop and losses									
kV/km	0.028	0.021	0.029	0.029	0.035	0.030	0.030	0.038	0.035
Losses MW/km	0.033	0.015	0.043	0.036	0.104	0.075	0.056	0.192	0.130
kV for 50 km electrode line	1.41	1.04	1.44	1.44	1.73	1.50	1.50	1.92	1.73
losses two 50 km elect lines (MW)	3.29	1.46	4.31	3.59	10.38	7.49	5.62	19.22	12.97
Metallic return through pole									
kV/km	0.014	0.010	0.014	0.014	0.017	0.015	0.015	0.019	0.017
Return conductor losses (%) for 3,000 km	-	3.1	4.3	3.6	5.2	3.7	2.8	4.8	3.2
kV for 1,000 km (metallic return)	14.1	10.4	14.4	14.4	17.3	15.0	15.0	19.2	17.3
kV for 1,500 km(metallic return)	21.1	15.6	21.6	21.6	25.9	22.5	22.5	28.8	25.9
kV for 3,000 km(metallic return)	42.3	31.2	43.1	43.1	51.9	44.9	44.9	57.7	51.9
Metallic return by shield wire									
kV/km	0.028	0.021	0.029	0.029	0.035	0.030	0.030	0.038	0.035
Return conductor losses (%) for 3,000 km	NA	NA	8.6	7.2	10.4	7.5	5.6	9.6	6.5
kV for 1,000 km (metallic return)	28.2	20.8	28.8	28.8	34.6	30.0	30.0	38.4	34.6
kV for 1,500 km (metallic return)	42.3	31.2	43.1	43.1	51.9	44.9	44.9	57.7	51.9
kV for 3,000 km (metallic return)	84.6	62.5	86.3	86.3	103.8	89.9	89.9	115.3	103.8

In Table 6.3 the range of powers and voltages established in this report are used as base for design. For the electrode line and shield wire return design, the conductor cross section is adopted as one half of the pole conductor cross section, which are an economical configuration for these conditions.

Note: Another way to determine the return conductor cross section would be trying to apply the "most economical section" calculation (see also clause 4.11.6 for better understanding of the equations). In this case, the electrode line cost, Cel, can be expressed by the equation:

$$Cel = A1 + B1\ S \qquad \text{being S the aluminum cross section}$$

From Figure 6.4, B1 = 9.06 (return with 2 conductors) and the yearly cost is:

$$B = 0.106*9.06= 0.96$$

The Joule losses cost is Closs = C/S = 58*I*I*(c1 +c2 h)/S . Using c1=55 U$/kW; c2=0.04 U$/kWh and assuming that in 2% of the time the system operates monopolar and 98% operates bipolar with 2% unbalance, then h=178.6 equivalent hours at full current. Taking as example P=1,500 MW and V=500kV then Closs= 8 109 969/S and the most economical cross section Sec =SQRT(C/B)= 2X 1,452 MCM. Other values are:

- P= 3,000 MW; V=±500 kV Sec=2X 2,771 MCM
- P=6,000 MW; V=±800 kV Sec=3x 2,310 MCM

In all these cases, the return conductor cross section varies from 0.48 to 0.55 of the pole cross section.

From Table 4.3, the following conclusions can be taken for the cases listed:

- Electrode line voltage drop is smaller than 2 kV, and the losses smaller than 20 MW for 50 km electrode line;

- Electrode line conductor temperature is below 75 °C and the difference in sag from pole and electrode line conductors are smaller than 1.5 m.

- Metallic return through pole conductor results in voltage drops below 30 kV and 60 kV for lines of 1,500 and 3,000 km (this becomes an insulation requirement for converter station neutral point). The losses are below 5% of the rated power even for a 3,000 km line.

- Metallic return through conductor in the shield wire place results in voltage drops below 60kV and 116 kV for lines of 1,500 and 3,000 km, respectively. This becomes an insulation requirement for converter station neutral point. The losses are below 10.5% of rated power even for 3,000 km.

- Shield wire conductor temperature is below 75 °C and the difference in sag from pole and shield wire conductors is smaller than 1.5 m. As shield wires are 2.5 m above conductor cross arm at the tower, then the minimum clearance for insulation is kept.

- In the economic calculations, the additional cost in the station for installing metallic return should be considered.

6.6 Electrode Design and Costs

From a system point of view the most important criteria are the rated current and the time of operation at this current, as well as the reliability and lifetime energy consumption design and soil resistivity. As an example, Itaipu electrodes are designed for:

- Full current 2.5% of the time;
- 2.5% of unbalance current permanently.

There are various interference effects to be considered when locating and designing a land electrode. The most significant thereof are:

- Potential gradient and step voltage at electrode site;
- Current density to avoid electro-osmosis in the anode operation;
- Touch voltages to fences, metallic structures and buried pipes nearby;
- Corrosion of buried pipes or foundations;
- Stray current in power lines, especially via transformer neutrals;
- Stray current in telephone circuits.

The main mitigation method for the possible interference issues, except step voltage, is to maintain a distance from the electrode, which is very important when selecting electrode location. Step voltage is a function of current density at the electrode. The most effective mitigation option is to choose a site where the soil resistivity is low, thus limiting the area over which the current density at the surface has a significant value.

The design criteria fall into two categories, those for design lifetime and definition of electrical parameters and those related to safety and interference issues. Design lifetime is typically 50 years, with the need to define currents in operation and times for which they are expected. This should take into account the operating modes and reliability criteria, as well as normal unbalance current which is very small, only of the order of 1% of rated current in modern converter station design.

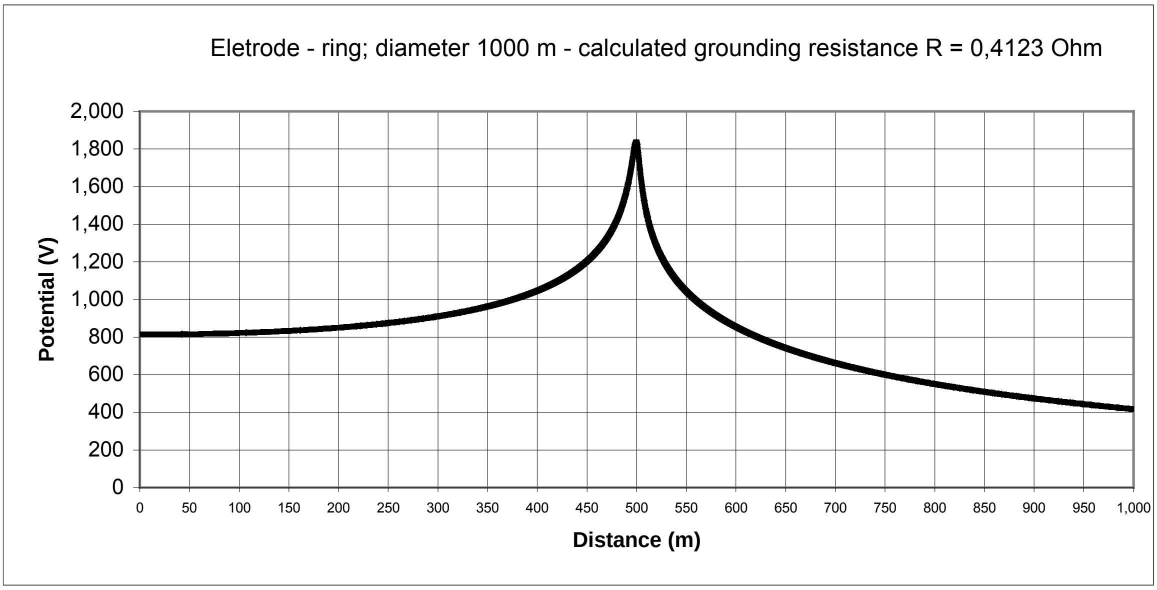
Typical values of criteria associated with interference issues are given below, however, it must be reminded that not only the conditions of the site and surrounding area must be taken into consideration, but also the local regulations regarding safety and interference.

- Potential gradient on surface: 2–20 V/m, mitigated by electrode depth;.
- Step voltage at electrode site: 2–8 V/m mitigated by the depth or fencing higher areas;
- Current density at soil/electrode interface: 1 A/m2 (typical);
- Touch voltages: 2–5 V typically, mitigated by distance or section insulation (of say fences, pipes).
- Corrosion of buried pipes or foundations: Requires local survey, 1–5 km distances typical, may consider also the cathodic protection or increase in existing protection;
- Stray current in power lines, especially via transformer neutrals: it requires local survey and study of mitigation methods;
- Stray current in telephone circuits: it requires local survey and study of mitigation methods.

The electrode material may be silicon-iron, steel and copper in a coke bed. The type may be vertical rods, ring, ellipse, square or star. A very common design is a ring type with 400 to 1,000 m of diameter. For the purpose of this work, a ring type electrode, with 400 and 1,000m diameter, using coke and silicon-iron, will be assumed.

Figure 6.5 shows the voltages in an electrode area with the following characteristics

- soil resistivity 500 ohm x meter;
- ring type with 1,000 m diameter;
- 4 cm diameter steel wire buried in a coke bed with a square cross section and 60 cm side;
- depth of burial: 3m
- ground current: 5 kA



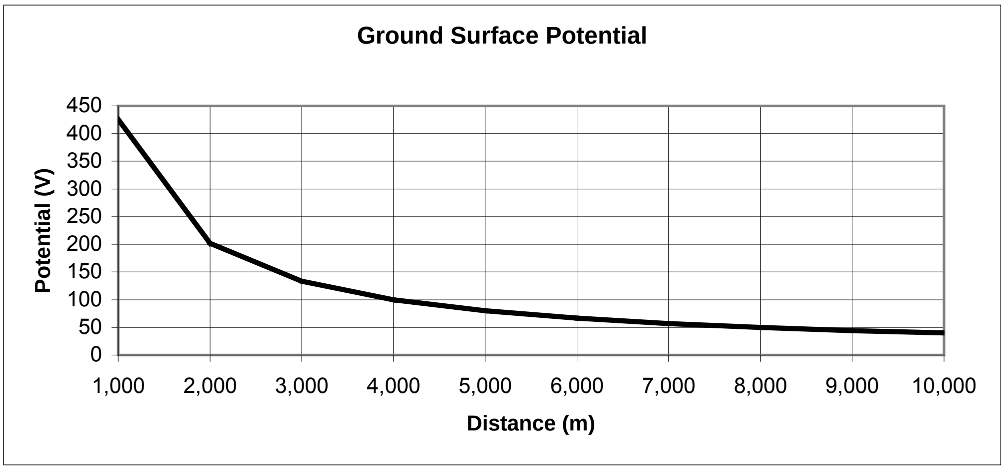


Figure 6.5: Ground surface potential as a function of distance from electrode center

The step potential is shown on Figure 6.6.

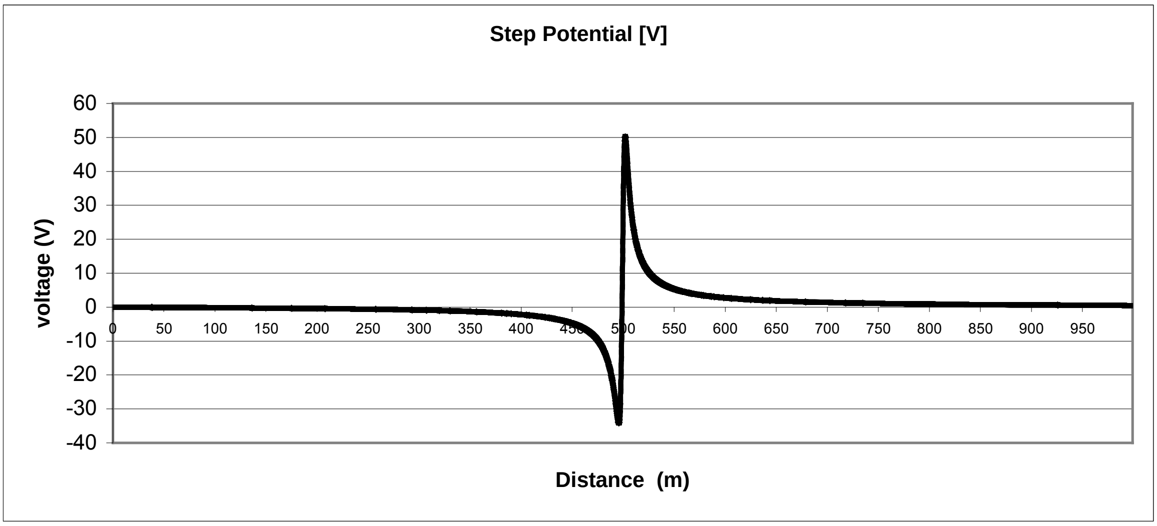


Figure 6.6: Step Potential (distance from electrode center)

The soil surface potential is 1,800 V just over the buried conductor. Step potential is below 10 V at 50 m apart from 500 m radius circle. The ground surface potential at 1, 5 and 10 km are 420; 80 and 40 V, respectively, for this electrode design, and for comparison purposes were 900, 500 and 150 V for Itaipu project at the inverter end.

The electrode cost estimate is shown on Table 6.4.

Table 6.4: One electrode cost

Item	**%**
Materials	
buried wire	8.0
coke	13.8
connections house	1.6
sub total materials	23.5
Man labor	73.6
Engineering - contingencies- land	2.9
Materials taxes	9.4
Man labor taxes	7.4
Total cost (100%) U$	483,000 U$

7 System Economics

7.1 Introduction

The economics of an HVDC system is analyzed here. For that the following costs are determined:

- transmission lines;
- Joule losses;
- corona losses;
- converter station losses;
- operating costs and interest during construction for line and converter stations;
- converter stations;
- others (electrodes, electrode lines, etc.).

The cost formulae, presented in other sections, are repeated here in order to clarify them and provide a better understanding.

In the calculation, initially it is considered that all parts of the system come to operation at the same time, electrode and electrode line is disregarded as it is a first view of the economics and its cost in general are low as compared to the other costs.

After that, the influence of staging is analyzed.

7.2 Components of the System Costs

7.2.1 Transmission Lines

In item 4.11.2, a bipolar line cost equation of the type below was determined.

$$\text{Cline} = a + b\,V + S\,(c\,N + d) \qquad \text{U\$/km}$$

Where:
a, b, c, d are parameters obtained by curve fitting of the data;
$V \rightarrow$ pole to ground voltage (kV)
$S = N\,S_1 \rightarrow$ total conductor aluminum cross section (MCM); S_1 being one conductor aluminum (only) cross section, so not including steel area; Note S(MCM)= (1/0.5067)* S(mm^2 Aluminum)
$N \rightarrow$ number of conductor per pole.

The parameters were determined in item 4.11.2 and resulted in:

a = 69,950 U$/km
b = 115.37 U$/kV
c = 1.177
d = 10.25

7.2.2 Joule Losses

As related to the transmission lines, the losses are due to Joule and Corona effects.
The Joule losses (Lj) are calculated by:

$$Lj = \frac{1}{2}\, r \left(\frac{P}{V}\right)^2 \qquad \text{MW / km}$$

where:
P → rated bipole power MW
V → the voltage to ground kV
r → bundle resistance ohms/km
r = ro L / S
ro → conductor resistivity 58 ohms MCM/ km (or 1./0.5067 mm^2/km)
L → the line length in km
S → the aluminum cross section in MCM

The economical basis for determining the cost of losses is that a thermal power plant is built at the load center to supply the losses.

The cost of Joule losses (CLj) in one year will be:

$$CLj = (Cp + 8760\ Ce\ lf)\, Lj = Cl * Lj$$

where:
Cp → yearly cost of the power plant
Ce → fuel cost
lf → loss factor

It is assumed in this text:

- The power plant has an investment cost of 500 U$/kW, and its yearly cost is Cp=0,11*500= 55 U$/kW.
  This is because of the assumptions:25 years life; 10% per year of interest rate (commonly used figure); leading to n=0.11={0.1/[1-(1+0.1)$^{-25}$]};
- The fuel cost is Ce = 0,04 U$/kWh
- The losses factor is lf=0.50
- It result in Cl = 230 U$/kW

For the corona losses evaluation (Lc) the equation of clause below is used. For the value of Cl, the same reasoning above is used, except that lf = 1.0, and then Cl = 350 U$/kW.

However, a sensitivity analysis shall be carried out, considering the above values Cl defined as Losses Cost Base Case, and another value 15% lower.

7.2.3 Corona Losses

For bipolar DC transmission lines, some empirical formulas have been developed and the equations below were recommended on clause 4.8.1.2 reproduced below (bipole values).

$$P_{fair} = P_0 + 50\log\left(\frac{g}{g_0}\right) + 30\log\left(\frac{d}{d_0}\right) + 20\log\left(\frac{n}{n_0}\right) - 10\log\left(\frac{H\ S}{H_0 S_0}\right)$$

$$P_{foul} = P_0 + 40\log\left(\frac{g}{g_0}\right) + 20\log\left(\frac{d}{d_0}\right) + 15\log\left(\frac{n}{n_0}\right) - 10\log\left(\frac{H\ S}{H_0 S_0}\right)$$

P is the bipole corona loss, in dB above 1W/m; d is conductor diameter, in cm, and the line parameters g, n, H and S have the same significance indicated above. The reference values assumed are g_0 = 25 kV/cm, d_0 = 3.05 cm, n_0 = 3, H_0 = 15 m and S_0 = 15 m. The corresponding reference values of P_0 were obtained by regression analysis to minimize the arithmetic average of the differences between the calculated and the measured losses. The values obtained are P_0 = 2.9 dB for fair-weather and P_0 = 11 dB for foul-weather.

$$P(\ W / m\ ) = 10^{\ P/10} \qquad \text{bipole losses in watt per meter}$$

For the economic evaluation, it will be considered 80% of time as fair-weather and 20% as foul-weather. Therefore:

$$Pcl = (P_{fair} * 0.8 + P_{foul} * 0.2)$$

In order to evaluate the costs, the figure above has to be multiplied by the energy cost (like in the previous clause, except that here lf = 1.0).

7.2.4 Line Operating Cost and Interest During Construction

To include the operating and maintenance components in the line costs, the following factors apply in general:

- interest during construction: factor 1.1 to the total line cost(interest rate 10% and 2years construction time);
- operating cost: 2% of the total line cost, per year.

However, in the more detailed calculations, other factors may be used.

7.2.5 Most Economical Conductor

The line yearly cost is expressed by:

$$Cliney = 1.1 * (\ 0.02 + k) * \ (A1 + B1\ \ S) = A + B\ S$$

Where:
S → total pole aluminum cross section;
k → factor to convert Present Worth into yearly cost (k = 0.106, if interest rate is 10% per year and life is 30 years);
The numbers 0.02 and 1.1 are factors for considering operation and maintenance costs, and interest during construction, respectively A1 and B1 are obtained by the line equation above.

Being Closses = C/S (see clause 7.2.2) the yearly cost of the Joule losses (corona losses are disregarded by the moment and included in clause 7.4). Then, the total line and Joule losses yearly cost is:

$$Ctliney = Cliney + Closses$$

Neglecting staging and corona losses, at a first approach, the total line and losses yearly cost is so:

$$Ctliney = A + B\ S + C/S$$

The minimum value of this function occurs for:

$$\text{Sec} = \sqrt{\frac{C}{B}}$$ which is the “ most economical conductor cross section”

The related total line and losses minimum yearly cost, now named Cty_{min}, is:

$$\text{Ctymin} = A + 2\sqrt{B\ C} \rightarrow \text{ U\$/km per year}$$

The yearly line part of the system yearly cost, now named Clinemin, is:

$$\text{Clinemin} = A + 2\sqrt{B\ C} \rightarrow \text{ U\$/km per year}$$

Dividing by (1.1 *(0.02+ k)), the line investment may be obtained.

Note: the corona losses slightly affect the determination of the most economical conductor cross section; however, the calculation can be done with this simplification and, if necessary, a correction can be applied.

In the procedure here, when considering one set of P,V alternative, the value of Sec is calculated, and three possibilities can happen:

a) Sec = N*S1ec is too small leading to high surface gradient gmax; in this case, the value Sec is substituted by the cross section that leads to gmax = 28 kV/cm (assumed condition);
b) Sec is of reasonable size, gmax <28 kV/cm; in this case, the Sec value is kept;
c) Sec is too large; in this case Sec is replaced by N*2,515 MCM (ACSR conductor Joree - the largest in the manufacturer normal list);
d) With this procedure one configuration is kept for every N, to compete in cost with other alternatives.

7.2.6 Converter Station Cost

The following converter station cost equation is used:
$Ccs = A^* V^B * P^C$
P $\rightarrow$ bipole power (MW)
V $\rightarrow$ bipole voltage (kV)
Ccs is taken in US$;

The following parameters are obtained:

- For power ratings up to 4,000MW, one converter per pole:
  A = 100*0.698*1.5 (1.5 is a factor to include taxes in Brazil, for every country a specific value should be used); B = 0.317; C = 0.557;

- For power rating above 4,000 MW (2 converters per pole):
  A = 106*0.154*1.5 (1.5 is a factor to include taxes in Brazil); B = 0.244; C = 0.814

Note: In general, calculations do not include the converter station losses, and additional cost for metallic return.

Yearly operation and maintenance costs will be assumed as 2% of the total station cost.

The station yearly cost is similarly considered as the yearly line cost, or:

$$Cstaty = 1.1 * (0.02+ k) * Ccs$$

7.3 Simplified Calculation

This calculation follows the steps below:

- set the main parameters: P, V, N, km, interest rate, period for amortization, and loss factor and losses unit cost.

- calculation of the most economical section Sec (consider the three mentioned conditions to be kept or to be replaced by Sec min/max);

- calculation of the yearly cost of line, Joule losses (for Sec or Sec min/ max);

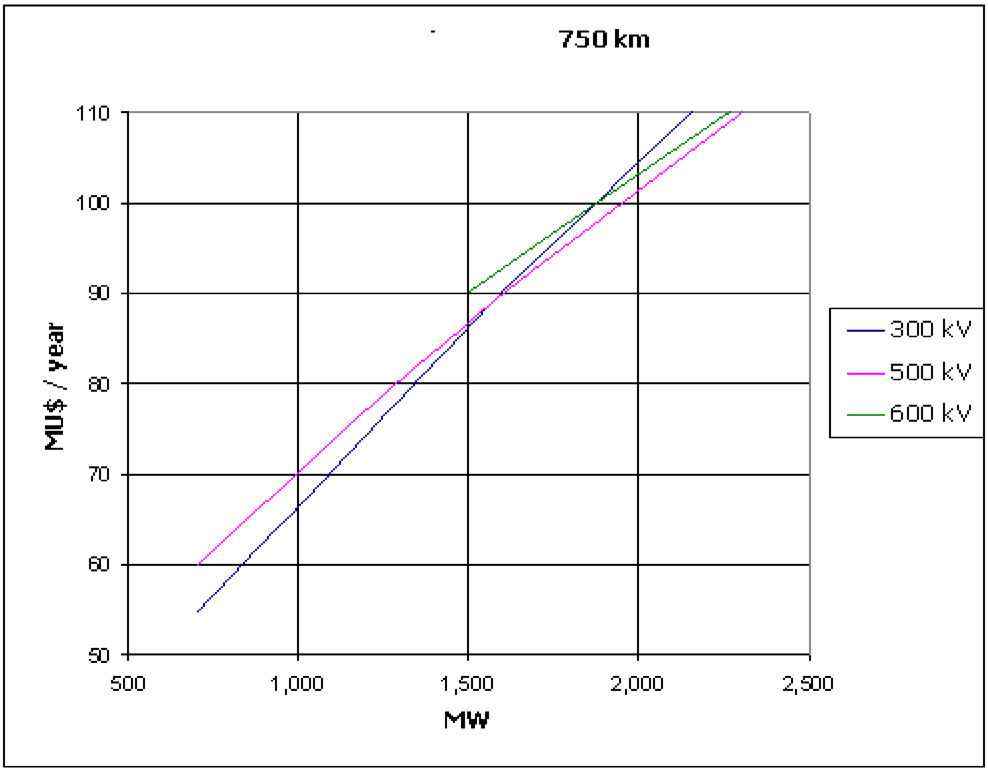
- calculation of total yearly cost including line cost, line Joule losses, line operation and maintenance, line interest cost during construction, converter station cost, converter station operation and maintenance, and converter station interest during construction. Line Corona losses are not included for simplification and its impact in the result is low. Station losses are not included because they are considered as a fixed 2 % of the rated power independent of the voltage;

7.3.1 Base Case Results

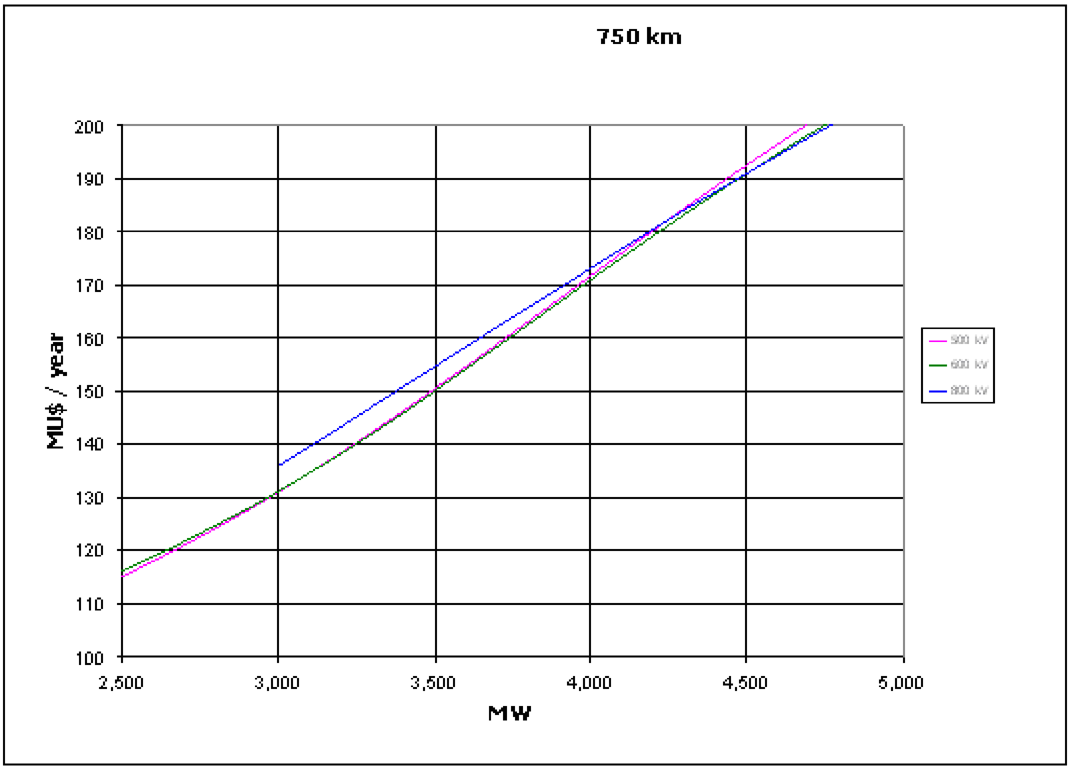
Figures 7.1 to 7.3 show the total yearly cost calculation results which include: total yearly cost of the line, line Joule losses, and total yearly station costs for 750, 1,500 and 3,000 km long lines.

As an example to understand the graphics in these figures, the value ~1,600 MW is the power when the most economical voltage change from ±300 kV to ±500 kV in the next figure.

Note: MUS$ is Million US$



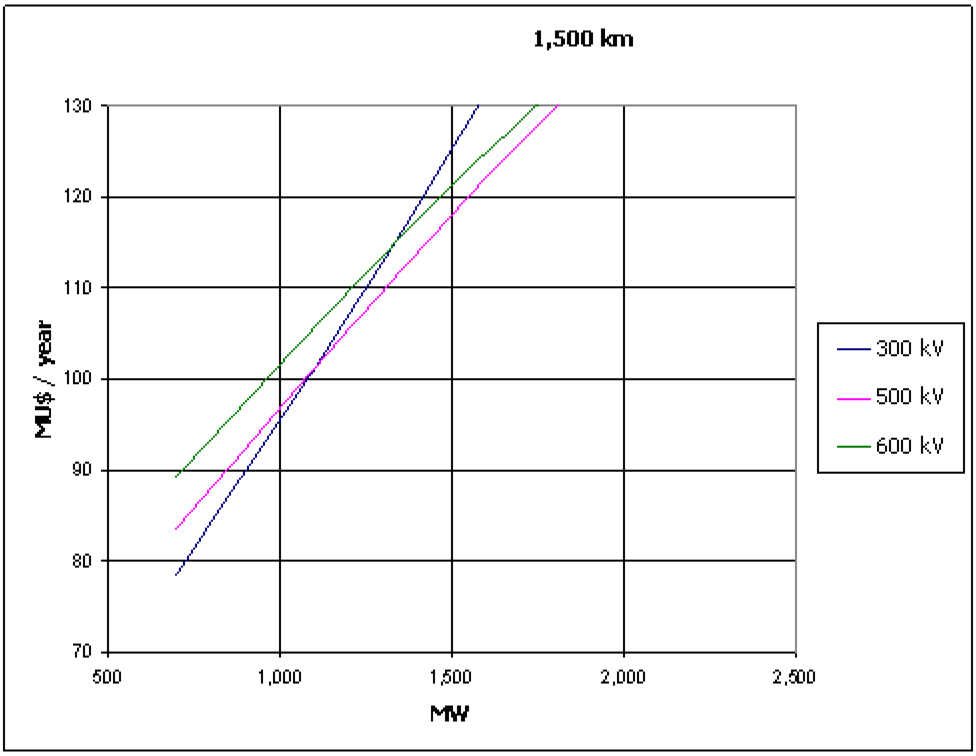
a) power < 2,500 MW



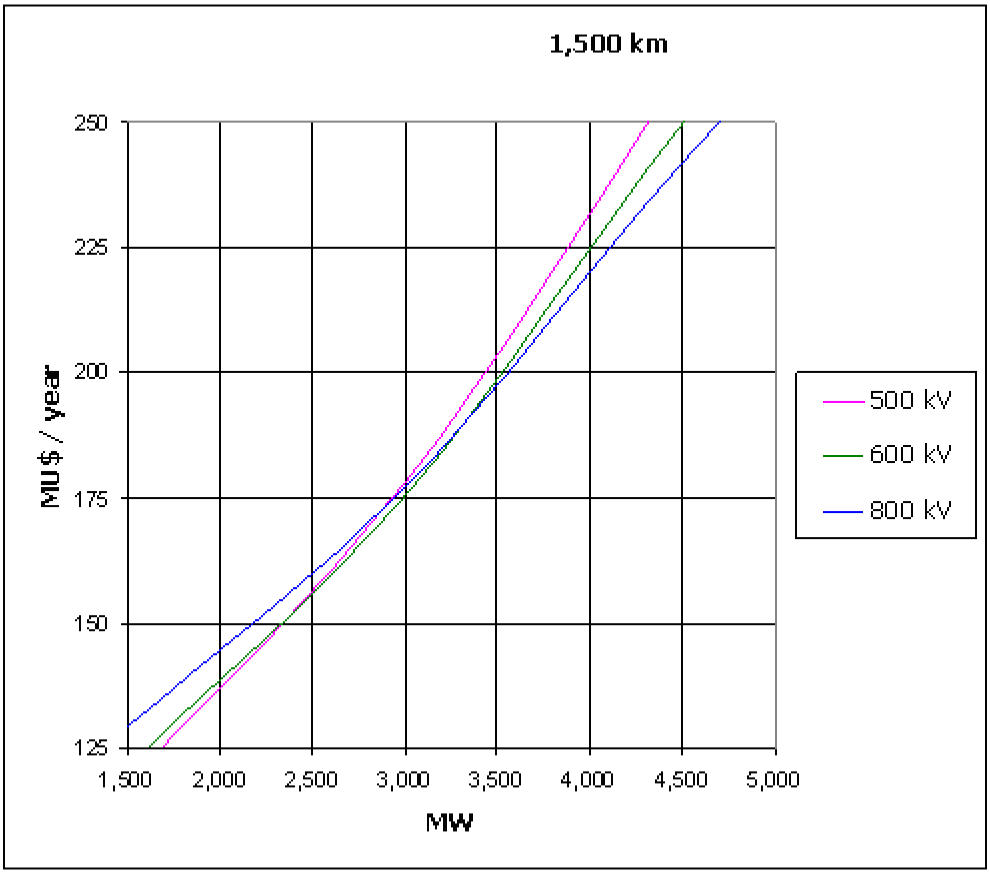
b) power from 2,500 to 6,000 MW

Figure 7.1: Yearly total cost as a function of power and voltage for 750 km line

Note that in the vertical axis of the figures is the yearly total cost in Million U$.

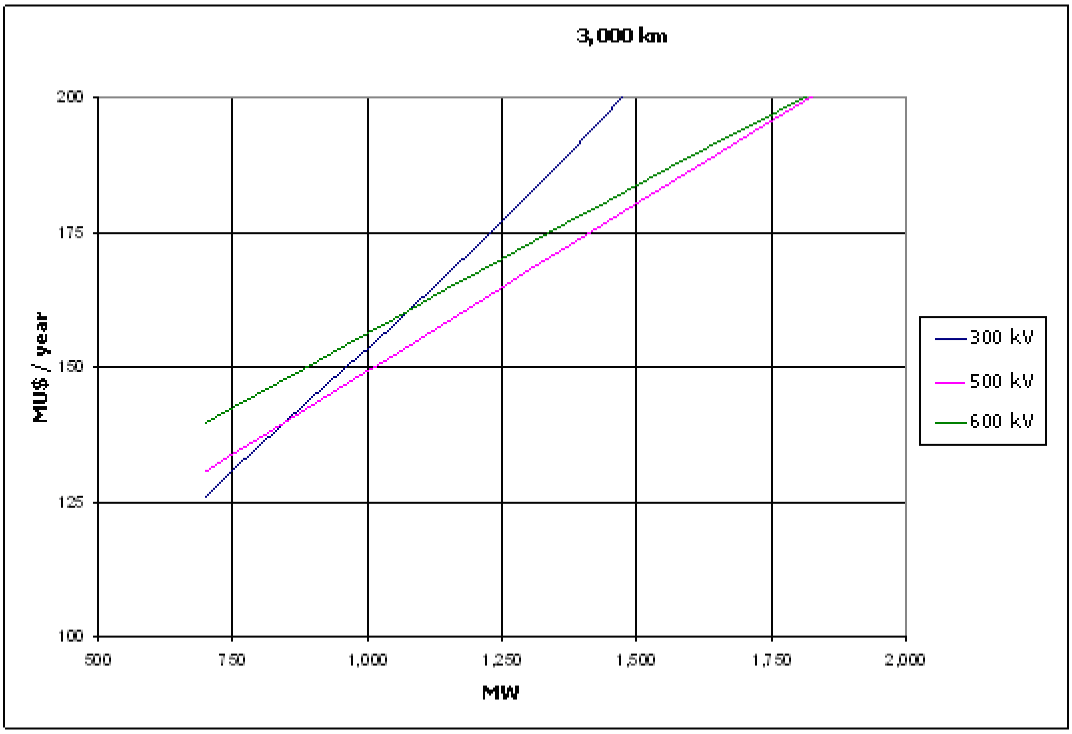


a) power < 2,500 MW

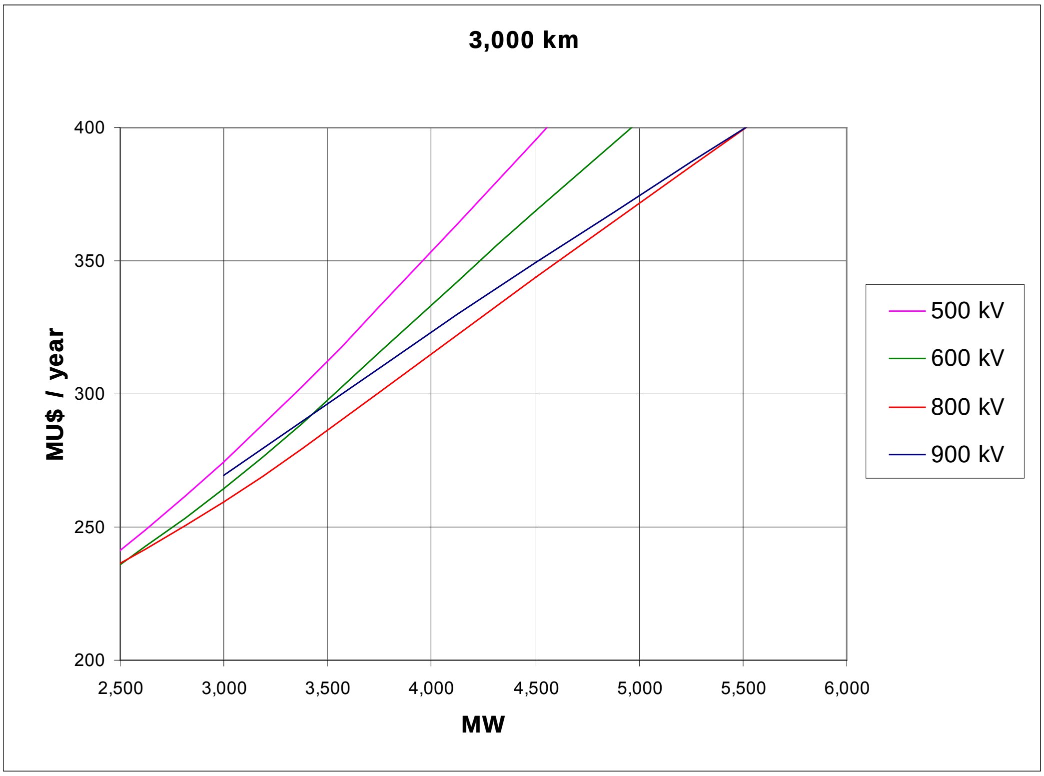


b) power from 1,500 to 6,000 MW

Figure 7.2: Yearly total cost as function of power and voltage for 1,500 km line



a) power < 2,500 MW



b) power from 1,500 to 6,000 MW

Figure 7.3: Yearly total cost as function of power and voltage for 3,000 km line

It should be noted that ±900 kV was inserted here in the calculations. Although the cost values for this voltage considers an extrapolation of the existing technology, and may not be correct, the calculation indicates that for power above 6,000 MW a new voltage higher than ±800 kV, may be needed. It is then recommended the examination of the viability of a new higher voltage.

The relations between the power and the optimal voltages are shown on Table 7.1

Table 7.1: Optimal voltage as a function of power and line length

Voltage (kV)	For 750 km	For 1,500 km	For 3,000 km
±300	<1,550 MW	<1,100 MW	<850 MW
±500	1,550 – 3,050 MW	1,100 – 2,200 MW	850 – 1,800 MW
±600	3,050 – 4,500 MW	2,200 – 3,400 MW	1,800 – 2,500 MW
±800	>4,500	>3,400 MW	>2,500 MW

Figure 7.4 depicts the information of Table 7.1

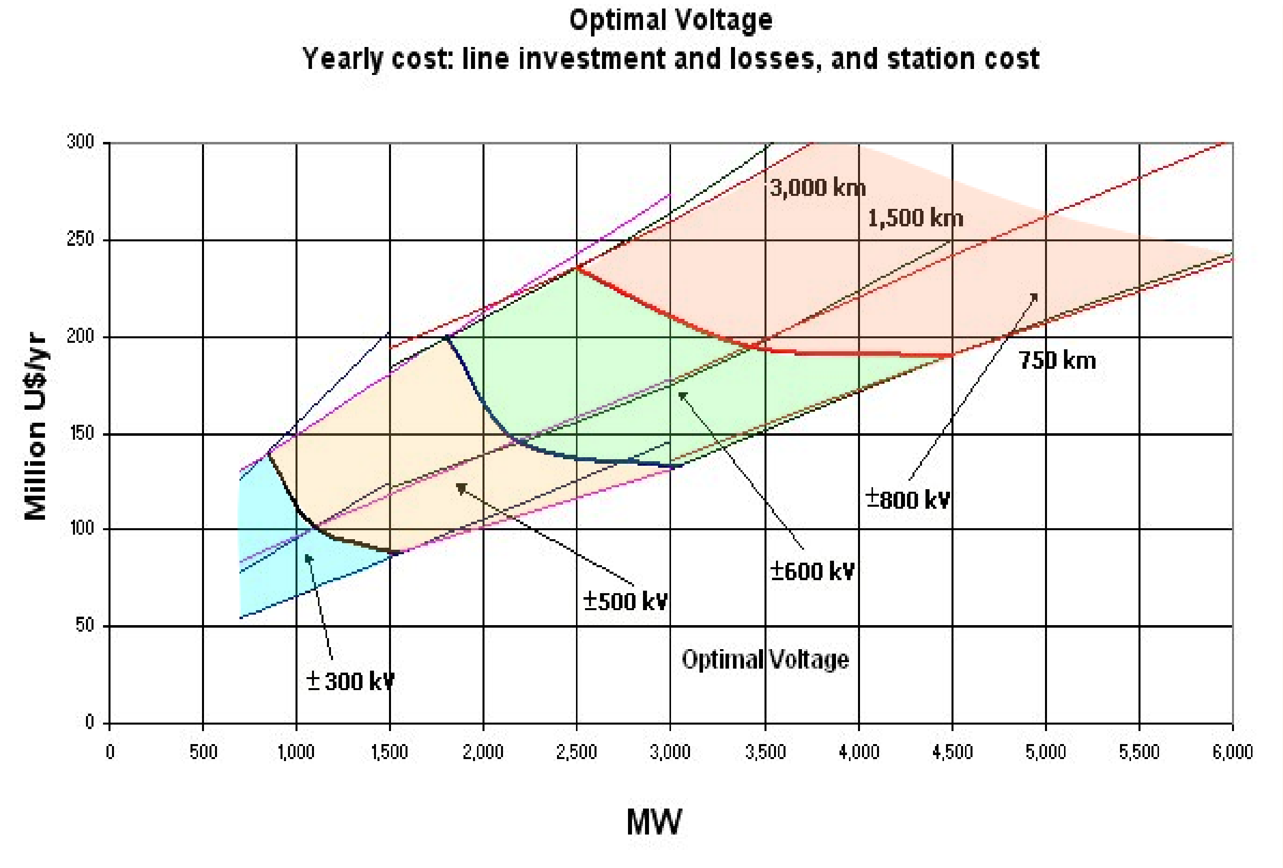


Figure 7.4: Optimal voltages as a function of power and length

Legend: Red → ±800 kV; green → ±600 kV; pink → ±500 kV; blue → ±300 kV

7.3.2 Sensitivity to Cost of Losses

Figure 7.5 shows the comparison for line length of 3,000 km, with the losses cost reduced to 85%.

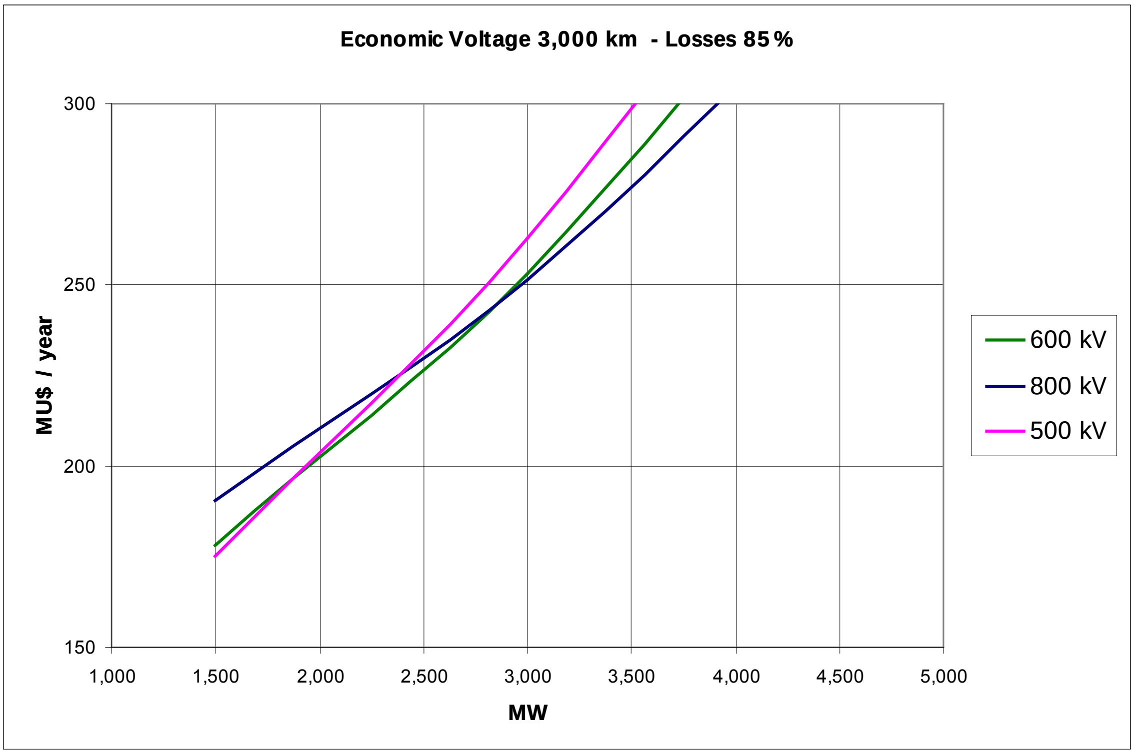


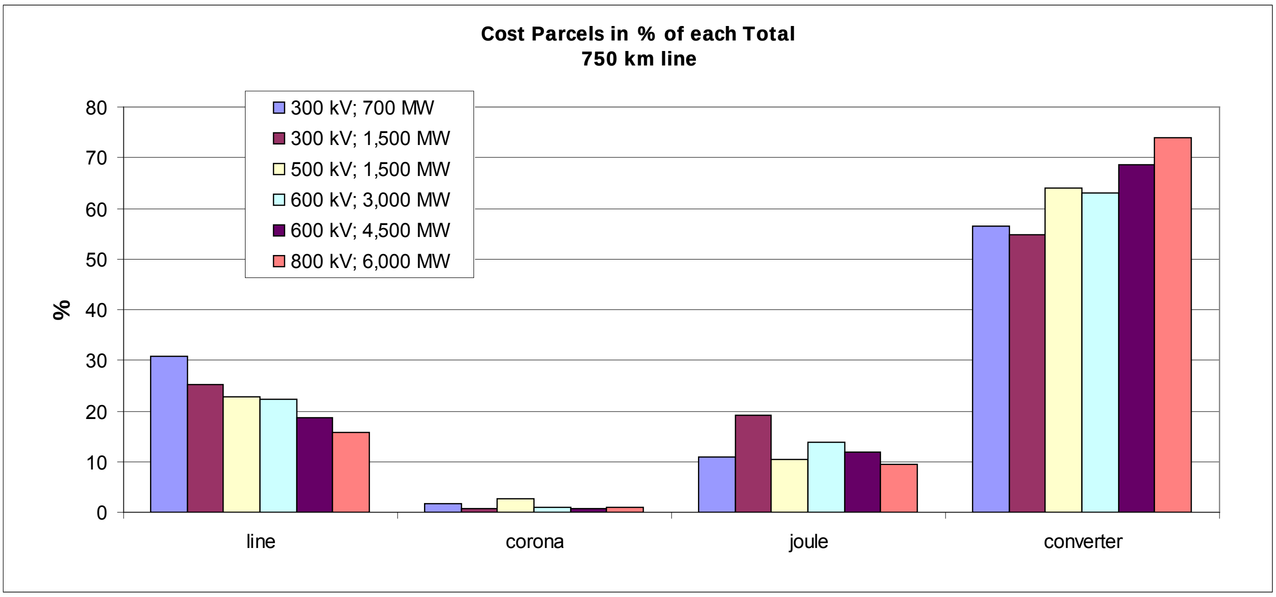
Figure 7.5: Sensitivity to the cost of Joule losses (3,000 km line)

The range of optimal voltage does not change significantly.

7.3.3 Evaluation of the Impacts

The basic aim of the Cigré JWG-B2/B4/C1.17 (Impacts of HVDC Lines on the Economics of HVDC Systems), as per the name itself, was to introduce an evaluation of how the cost of HVDC Lines affect the economics of main existing or possible HVDC Systems. Now it is possible to make this appraisal for the main set of HVDC Alternatives taken into account. (See Table 4.1).

Herein after the compositions of the costs (line, losses and converter), they are presented for line lengths of 750, 1,500 and 3,000 km , and power of 700; 1,500; 3,000; 4,500 and 6,000 MW, showing what are the impacts of the transmission lines cost in the total cost.

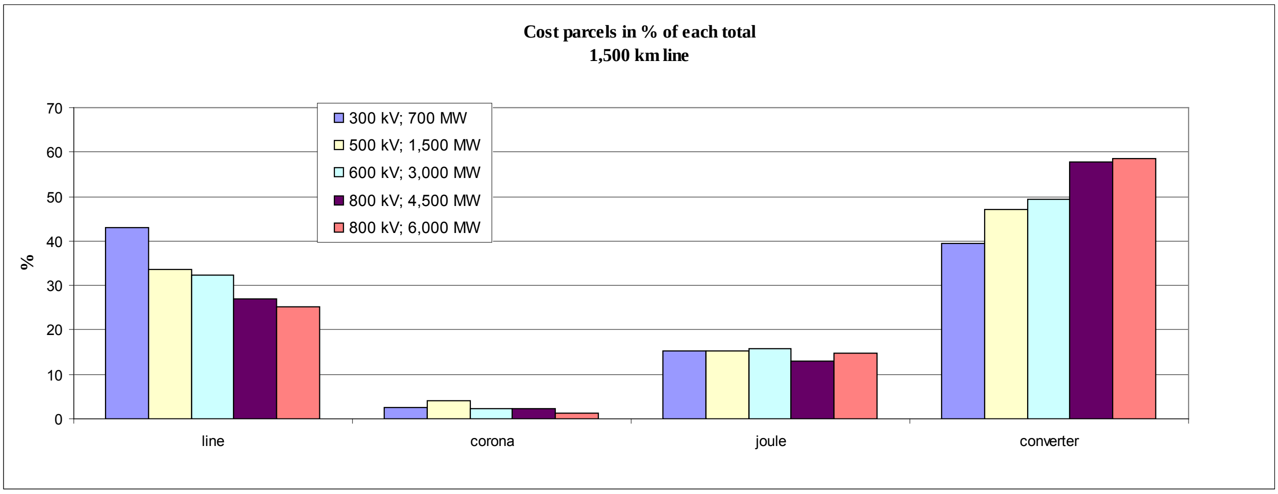


MW	700		1,500		1,500		3,000		4,500		6,000	
kV	±300		±300		±500		±500		±600		±800	
N X MCM*	2 X 2,280		3 X 2,515		2 X 2,515		4 X 2,242		5 X 2,515		5 X 2,515	
	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%
Line	16.9	30.8	21.7	25.1	19.9	22.9	28.9	22.3	35.6	18.7	38.0	15.9
Corona	1.0	1.7	0.7	0.8	2.4	2.7	1.3	1.0	1.5	0.8	2.1	0.9
Joule	6.0	10.9	16.6	19.2	9.0	10.3	17.9	13.8	22.4	11.8	22.4	9.4
Converter	30.9	56.5	47.3	54.8	55.6	64.1	81.8	62.9	130.6	68.7	177.0	73.9
U$/ year/ MW	54.7	100.0	86.3	100.0	86.8	100.0	130.0	100.0	190.1	100.0	239.5	100.0

*1 MCM=0.5067 mm^2

Figure 7.6: Cost Parcels, 750 km line

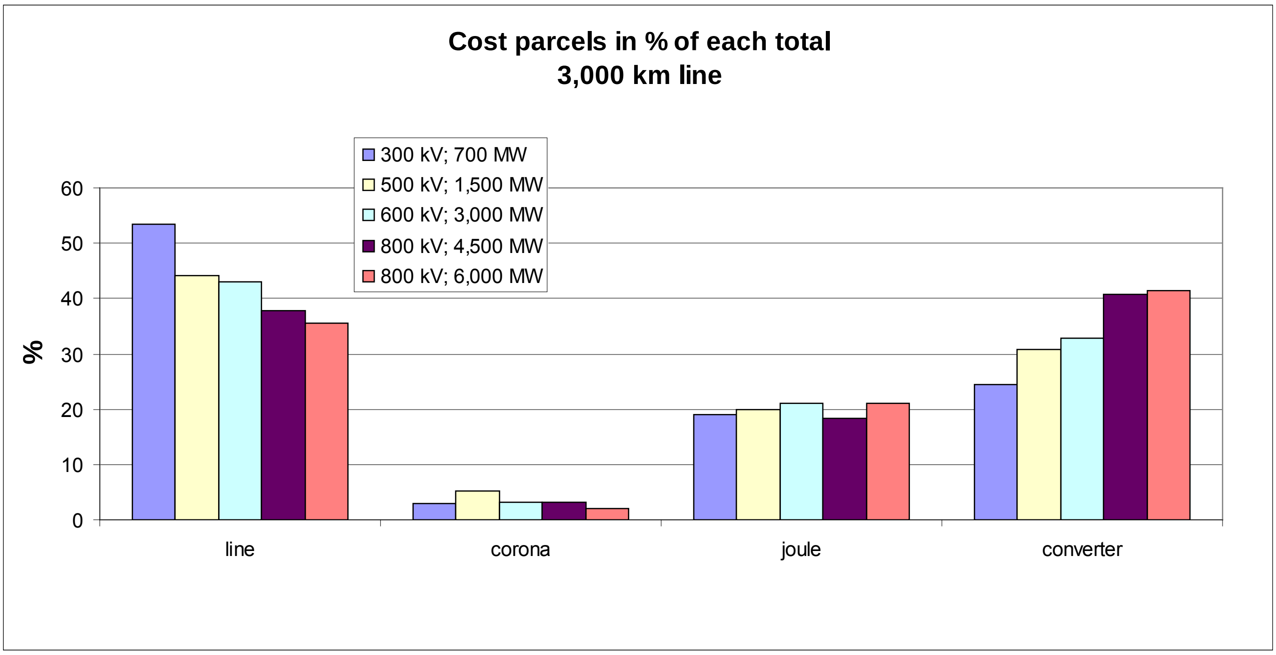
The values in the figures refers to the best most economic solution as related to V, N, S. For 1,500 MW both ±300 kV and ±500 kV led to quite close results, reason why both were included.



MW	700		1,500		3,000		4,500		6,000	
kV	±300		±500		±600		±800		±800	
N x MCM	2 X 2,280		2 X 2,515		4 X 2,242		4 X 2,515		5 X 2,515	
	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%
line	33,7	42,9	39,7	33,7	56,9	32,4	65,1	26,9	76,0	25,2
corona	1,9	2,4	4,7	4,0	4,1	2,3	5,4	2,2	4,2	1,4
joule	12,0	15,2	17,9	15,2	27,9	15,9	31,5	13,0	44,8	14,8
converter	30,9	39,4	55,6	47,1	86,7	49,4	140,1	57,9	177,0	58,6
U$/ year/ MW	78,5	100,0	118,0	100,0	175,6	100,0	242,0	100,0	302,0	100,0

*1 MCM=0.5067 mm^2

Figure 7.7: Cost Parcels, 1,500 km line



MW	700		1,500		3,000		4,500		6,000	
kV	±300		±500		±600		±800		±800	
N x MCM	2 X 2,280		2 X 2,515		4 X 2,242		4 X 2,515		5 X 2,515	
	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%	MU$/yr	%
line	67,4	53,5	79,5	44,1	113,7	43,0	130.1	37.8	151,9	35,6
corona	3,8	3,0	9,5	5,2	8,2	3,1	10.8	3.1	8,4	2,0
joule	23,9	19,0	35,8	19,9	55,8	21,1	63.0	18.3	89,6	21,0
converter	30,9	24,5	55,6	30,8	86,7	32,8	140.1	40.7	177,0	41,5
U$/year/ MW	126,1	100,0	180,4	100,0	264,5	100,0	344.0	100.0	426,9	100,0

*1 MCM=0.5067 mm^2

Figure 7.8: Cost Parcels, 3,000 km line

7.3.4 Simplified Evaluation of the Impacts

For a simplified evaluation, all the costs involved in a HVDC System were concentrated either on the lines (bipole cost and losses, here named as B) or on the Converter Stations (here named as CS). So, using the costs and optimized options developed in the group, an evaluation was carried out for every of the bipole alternatives taken into account, and varying the Powers and Lines Lengths. Tables 7.2 to 7.5 present a summary of this evaluation.

Table 7.2: Impact of B and CS costs in ± 300 kV HVDC Systems.

Power (MW)	**Line length (km)**	**B - Line and losses cost (%)**	**CS cost (%)**	**B - Line and losses PW (MU$)**	**CS cost PW MU$**
700	750	43.5	56.5	224.2	291.7
	1,500	60.6	39.4	448.5	291.7
	3,000	75.5	24.5	896.9	291.7
1,500	750	45.2	54.8	367.4	446.0

*PW Present Worth. To get yearly cost multiply it by k= 0.106

Table 7.3: Impact of B and CS costs in ± 500 kV HVDC Systems

Power (MW)	Line length (km)	B - Line and losses cost (%)	CS cost (%)	B - Line and losses PW (MU$)	CS cost PW MU$
	750	45.2	34.8	367.4	446.0
1,500	1,500	52.9	47.1	588.1	524.3
	3,000	69.2	30.8	1,176.2	524.3
3,000	750	37.1	62.9	454.1	771.4

Table 7.4: Impact of B and CS costs in ± 600 kV HVDC Systems

Power (MW)	Line length (km)	B - Line and losses cost (%)	CS cost (%)	B - Line and losses PW (MU$)	CS cost PW MU$
3,000	1,500	50.6	49.4	838.0	817.3
	3,000	67.2	32.8	1,676.0	817.3

Table 7.5: Impact of B and CS costs in ± 800 kV HVDC Systems

Power (MW)	Line length (km)	B - Line and losses cost (%)	CS cost (%)	B - Line and losses PW (MU$)	CS cost PW MU$
6,000	750	26.1	73.9	588.9	1,668.9
	1,500	41.4	58.6	1,177.7	1,668.8
	3,000	58.5	41.5	2,355.5	1,668.8

In figure 7.9 the parcels of cost are shown as function of the station power and line length. These parcels are in % of the total cost (investment plus losses). To get the losses parcels subtract from 100% the line plus station investment cost.

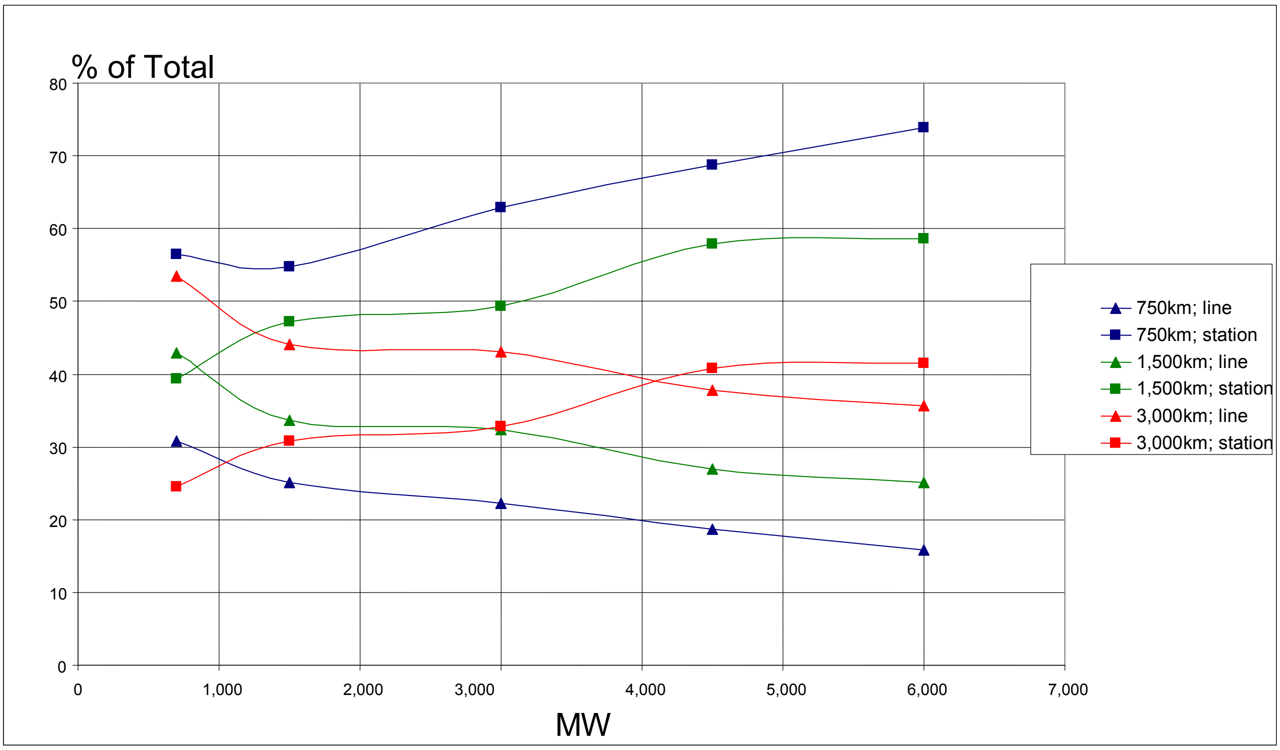


Figure 7.9: Cost parcels (line and converter station investment) as function of power and line length

7.3.5 Further Considerations

As related to the Simplified Calculation procedure above, the following comments apply:

- In this procedure, the growth of the transmitted power in the beginning of the system operation was not considered. However, this aspect may be taken into account, by using the more detailed procedure shown on next clause 7.4. As the power grows from zero to the rated value, initially the losses in this period will be smaller than the losses calculated with the final transmitted power. It results in a smaller average loss cost in the total period under study. Consequently the conductor cross section with minimum cost will be smaller. The difference is sensible when this period of growth is greater than five years.

- In the most economical cross section calculation (see 4.11.6), corona is not included. Once considered, the economic cross section will be bigger. One may carry out some iteractions to find the new economic cross section; however this was not done here as the influence is small in the final result and also considering that the transmitted power is neglected in this procedure.

- Electrode line and electrode costs are not included in this simplified procedure; they can be included in the procedure described in clause 7.4. The no-inclusion may affect the result when considering low HVDC voltage and short line length. For reference, a 750 km, ±300 kV, 700 MW system would have an economic conductor cross section of 2x ACSR 2,300 MCM, the line cost being 121.5 MU$; the 2x40 km electrode line and two electrode cost will be about 5.2 MU$.

- Converter station losses also were not included. Normally, such losses are expressed in % of the converter station rated power, so being the same value for all alternatives with the same rated power. However, in the procedure in clause 7.4 it may be included, and it is necessary when comparing alternatives with different losses (example: system with voltage or current source converter).

7.4 Calculations Considering Cost Components Allocated in Different Years (General Approach)

There are cases where the cost of certain items are spread around a defined period. This is the case of staging transmitted power varying along the period as well as in the case of several DC lines scheduled to be constructed in different years, refurbishments due to update of technology, equipment with life ending during the operating period, among others.

To take this into consideration a methodology will be used here, consisting of:

- Setting a spreadsheet where the different costs are located;
- Cost of lines and stations are located in the beginning of the year of starting operation;
- Losses and maintenance costs are located at the end of the due year;
- The sum of all costs in every year is calculated (yearly parcels Yi;
- The PWYi present worth values of Yi are obtained and summed:

  $PWYi = Yi/(1+j)^{i}$

  j is the interest rate per year (10% in this study)

An alternative would be the substitution of full investments (line and stations) by a series of yearly parcels, keeping the remaining steps above; however, a period of evaluation shall be chosen.

In the following Study Cases, the first alternative will be used.

7.4.1 Study Case 1: Basic Case

P = 3,000 MW for years 1 to 30; V= ± 600 and ±800 kV; and Length = 2,500 km

Regarding the unit cost of losses, operation and maintenance cost, interest during line construction, yearly interest rate the values listed in clause 4.11 are used. For this case, instead of the methodology described in this clause 7.4, the simple calculation of the yearly costs (line, stations, losses, etc.) will be applied.

Table 7.6 shows the parcels of yearly costs and total yearly costs. It should be noted that for ±600 kV alternative N= 4 led to the smallest cost as well as for ± 800 kV.

Table 7.6: Comparison between ± 600 kV and ± 800 kV

MW	**3,000**	**3,000**
kV	±600 kV	±800 kV
N	4	4
MCM*	2,242	1,681
line MU$/yr	94.77	91.14
joule loss MU$/yr	46.51	34.89
Corona loss MU$/yr	6.87	10.93
station MU$/yr	86.70	94.98
tot yr (Million U$)	234.86	231.94
Ratio	101.25	100

*1 MCM=0.5067 mm^2

The ± 800 kV alternative has the lowest cost (ratio= 101.25 %).

Note that the ± 600 kV line cost is greater than ± 800 kV line (due to the economic conductor section Sec).

7.4.2 Study Case 2: As Basic Case; P taking 4 years to reach 3,000MW

In this case the transmitted power in the various years are shown on Table 7.7:

Table 7.7: Power X year

Year	**MW**
1	750
2	1,500
3	2,250
4 to 30	3,000

Tables 7.8 and 7.9 show the yearly installments for ± 600 and ± 800 kV alternatives.

Table 7.8: Alternative ± 600 kV (values in US$)

Begin of year	End of year	Line	Station	Corona	Joule	Maint. line	Maint. station	Station losses	Sum. in the year	PW
1	0	751677637	687665390						1439343027	1439343027
2	1			6866408	2907345	15033553	13753308	0	38560613	35055103
3	2			6866408	11629381	15033553	13753308	0	47282649	39076570
4	3			6866408	26166107	15033553	13753308	0	61819375	46445812
5	4			6866408	46517523	15033553	13753308	0	82170792	56123756
6	5			6866408	46517523	15033553	13753308	0	82170792	51021597
7	6			6866408	46517523	15033553	13753308	0	82170792	46383270
8	7			6866408	46517523	15033553	13753308	0	82170792	42166609
9	8			6866408	46517523	15033553	13753308	0	82170792	38333281
10	9			6866408	46517523	15033553	13753308	0	82170792	34848437
11	10			6866408	46517523	15033553	13753308	0	82170792	31680397
12	11			6866408	46517523	15033553	13753308	0	82170792	28800361
13	12			6866408	46517523	15033553	13753308	0	82170792	26182147
14	13			6866408	46517523	15033553	13753308	0	82170792	23801951
15	14			6866408	46517523	15033553	13753308	0	82170792	21638138
16	15			6866408	46517523	15033553	13753308	0	82170792	19671034
17	16			6866408	46517523	15033553	13753308	0	82170792	17882758
18	17			6866408	46517523	15033553	13753308	0	82170792	16257053
19	18			6866408	46517523	15033553	13753308	0	82170792	14779139
20	19			6866408	46517523	15033553	13753308	0	82170792	13435581
21	20			6866408	46517523	15033553	13753308	0	82170792	12214165
22	21			6866408	46517523	15033553	13753308	0	82170792	11103786
23	22			6866408	46517523	15033553	13753308	0	82170792	10094351
24	23			6866408	46517523	15033553	13753308	0	82170792	9176683
25	24			6866408	46517523	15033553	13753308	0	82170792	8342439
26	25			6866408	46517523	15033553	13753308	0	82170792	7584035
27	26			6866408	46517523	15033553	13753308	0	82170792	6894577
28	27			6866408	46517523	15033553	13753308	0	82170792	6267798
29	28			6866408	46517523	15033553	13753308	0	82170792	5697998
30	29			6866408	46517523	15033553	13753308	0	82170792	5179998
31	30			6866408	46517523	15033553	13753308	0	82170792	4709089
									PW total (million)	2130

Table 7.9: Alternative ± 800 kV (values in US$)

Begin. of year	End of year	Line	Station	Corona	Joule	Maint. line	Maint. station	Station losses	Sum. in the year	PW
1	0	722892478	753325635						1476218113	1476218113
2	1			10935753	2180509	14457850	15066513	0	42640624	38764204
3	2			10935753	8722036	14457850	15066513	0	49182151	40646406
4	3			10935753	19624580	14457850	15066513	0	60084695	45142521
5	4			10935753	34888142	14457850	15066513	0	75348258	51463874
6	5			10935753	34888142	14457850	15066513	0	75348258	46785340
7	6			10935753	34888142	14457850	15066513	0	75348258	42532127
8	7			10935753	34888142	14457850	15066513	0	75348258	38665570
9	8			10935753	34888142	14457850	15066513	0	75348258	35150518
10	9			10935753	34888142	14457850	15066513	0	75348258	31955017
11	10			10935753	34888142	14457850	15066513	0	75348258	29050015
12	11			10935753	34888142	14457850	15066513	0	75348258	26409105
13	12			10935753	34888142	14457850	15066513	0	75348258	24008277
14	13			10935753	34888142	14457850	15066513	0	75348258	21825706
15	14			10935753	34888142	14457850	15066513	0	75348258	19841551
16	15			10935753	34888142	14457850	15066513	0	75348258	18037774
17	16			10935753	34888142	14457850	15066513	0	75348258	16397976
18	17			10935753	34888142	14457850	15066513	0	75348258	14907251
19	18			10935753	34888142	14457850	15066513	0	75348258	13552046
20	19			10935753	34888142	14457850	15066513	0	75348258	12320042
21	20			10935753	34888142	14457850	15066513	0	75348258	11200038
22	21			10935753	34888142	14457850	15066513	0	75348258	10181853
23	22			10935753	34888142	14457850	15066513	0	75348258	9256230
24	23			10935753	34888142	14457850	15066513	0	75348258	8414755
25	24			10935753	34888142	14457850	15066513	0	75348258	7649777
26	25			10935753	34888142	14457850	15066513	0	75348258	6954343
27	26			10935753	34888142	14457850	15066513	0	75348258	6322130
28	27			10935753	34888142	14457850	15066513	0	75348258	5747391
29	28			10935753	34888142	14457850	15066513	0	75348258	5224901
30	29			10935753	34888142	14457850	15066513	0	75348258	4749910
31	30			10935753	34888142	14457850	15066513	0	75348258	4318100
									PW total (million)	2124

Note that, in this case the alternatives have almost the same cost:100.3%.

7.4.3 Study Case 3: Power 6,000 MW; 2 x 600 kV or 1 x 800 kV

This case refers to : Basic Case; Power 6,000 MW (6 years); One System with 2 x 600 kV lines and another with one ±800 kV line.

The power growth is shown on Table 7.10.

Table 7.10: Power growth

Year	Ptot. MW
1	800
2	1,500
3	2,200
4	3,000
5	4,400
6	6,000

- Alternative 1 is composed of two ±600 kV lines and two 3,000 MW Converter Stations (one 12 pulse converter per pole).
  The conductor configuration is 4 x 2,242 MCM.

- Alternative 2 is composed of one ± 800 kV line and one 6,000MW Converter Station with two parallel 12-pulse converters per pole.
  The conductor configuration is 5 x 2,515 MCM.

It was included (for completeness of the Table) in the calculation the converter station losses (2% of station rating). The same losses unit cost and loss factor of the line were used. It has no influence, in this case, as the values are the same for both cases.

Tables 7.11 and 7.12 show the installments and present worth values.

Table 7.11: Alternative ±600kV

Begin. of year	End of year	Line	Station	Corona	Joule	Maint line	Maint station	Station losses	Sum. in the year	PW
1	0	751677637	690000000						1441677637	1441677637
2	1			6866408	3307913	15033553	13800000	982187	39990060	36354600
3	2			6866408	11629381	15033553	13800000	3453000	50782341	41968877
4	3			6866408	25016090	15033553	13800000	7427787	68143837	51197474
5	4	751677637	690000000	6866408	46517523	15033553	13800000	13812000	1537707121	1050274654
6	5			13732815	50032181	30067105	27600000	14855573	136287675	84623923
7	6			13732815	93035047	30067105	27600000	27624000	192058968	108412280
8	7			13732815	93035047	30067105	27600000	27624000	192058968	98556618
9	8			13732815	93035047	30067105	27600000	27624000	192058968	89596926
10	9			13732815	93035047	30067105	27600000	27624000	192058968	81451751
11	10			13732815	93035047	30067105	27600000	27624000	192058968	74047046
12	11			13732815	93035047	30067105	27600000	27624000	192058968	67315496
13	12			13732815	93035047	30067105	27600000	27624000	192058968	61195906
14	13			13732815	93035047	30067105	27600000	27624000	192058968	55632642
15	14			13732815	93035047	30067105	27600000	27624000	192058968	50575129
16	15			13732815	93035047	30067105	27600000	27624000	192058968	45977390
17	16			13732815	93035047	30067105	27600000	27624000	192058968	41797627
18	17			13732815	93035047	30067105	27600000	27624000	192058968	37997843
19	18			13732815	93035047	30067105	27600000	27624000	192058968	34543494
20	19			13732815	93035047	30067105	27600000	27624000	192058968	31403176
21	20			13732815	93035047	30067105	27600000	27624000	192058968	28548342
22	21			13732815	93035047	30067105	27600000	27624000	192058968	25953038
23	22			13732815	93035047	30067105	27600000	27624000	192058968	23593671
24	23			13732815	93035047	30067105	27600000	27624000	192058968	21448792
25	24			13732815	93035047	30067105	27600000	27624000	192058968	19498902
26	25			13732815	93035047	30067105	27600000	27624000	192058968	17726274
27	26			13732815	93035047	30067105	27600000	27624000	192058968	16114795
28	27			13732815	93035047	30067105	27600000	27624000	192058968	14649813
29	28			13732815	93035047	30067105	27600000	27624000	192058968	13318012
30	29			13732815	93035047	30067105	27600000	27624000	192058968	12107284
31	30			13732815	93035047	30067105	27600000	27624000	192058968	11006622
									PW total (million)	3789

Table 7.12: Alternative:±800kV

Begin. of year	End of year	Line	Station	Corona	Joule	Maint line	Maint stat	Station losses	Sum in the year	PW
1	0	1004144969	940875000						1945019969	1945019969
2	1			325000	5308787	20082899	18817500	982187	45516373	41378521
3	2			325000	18663705	20082899	18817500	3453000	61342105	50695954
4	3			325000	40147703	20082899	18817500	7427787	86800890	65214793
5	4		506625000	325000	74654821	20082899	18817500	13812000	634317220	433247197
6	5			6967114	40147704	20082899	28950000	14855573	111003291	68924310
7	6			6967114	74654821	20082899	28950000	27624000	158278834	89344276
8	7			6967114	74654821	20082899	28950000	27624000	158278834	81222069
9	8			6967114	74654821	20082899	28950000	27624000	158278834	73838244
10	9			6967114	74654821	20082899	28950000	27624000	158278834	67125677
11	10			6967114	74654821	20082899	28950000	27624000	158278834	61023342
12	11			6967114	74654821	20082899	28950000	27624000	158278834	55475766
13	12			6967114	74654821	20082899	28950000	27624000	158278834	50432514
14	13			6967114	74654821	20082899	28950000	27624000	158278834	45847740
15	14			6967114	74654821	20082899	28950000	27624000	158278834	41679764
16	15			6967114	74654821	20082899	28950000	27624000	158278834	37890695
17	16			6967114	74654821	20082899	28950000	27624000	158278834	34446086
18	17			6967114	74654821	20082899	28950000	27624000	158278834	31314624
19	18			6967114	74654821	20082899	28950000	27624000	158278834	28467840
20	19			6967114	74654821	20082899	28950000	27624000	158278834	25879854
21	20			6967114	74654821	20082899	28950000	27624000	158278834	23527140
22	21			6967114	74654821	20082899	28950000	27624000	158278834	21388309
23	22			6967114	74654821	20082899	28950000	27624000	158278834	19443918
24	23			6967114	74654821	20082899	28950000	27624000	158278834	17676289
25	24			6967114	74654821	20082899	28950000	27624000	158278834	16069353
26	25			6967114	74654821	20082899	28950000	27624000	158278834	14608503
27	26			6967114	74654821	20082899	28950000	27624000	158278834	13280457
28	27			6967114	74654821	20082899	28950000	27624000	158278834	12073143
29	28			6967114	74654821	20082899	28950000	27624000	158278834	10975585
30	29			6967114	74654821	20082899	28950000	27624000	158278834	9977804
31	30			6967114	74654821	20082899	28950000	27624000	158278834	9070731
									PW total (million)	3497

The alternative ± 800 kV system has the smallest cost ratio: 92.3 %.

However, a reliability cost shall be included in the comparison once 2 x ±600 kV and 1x ±800 kV lines may not have the same performance.

As a general view the line is designed for a wind with a certain return period (for instance 150 years) and a risk of bipole failure (say 10^{-4}). The wind intensity is normally selected by the worst location, meaning that despite of the line length the risk of failure is determined by the worst location, the remaining part do not contribute significantly to the risk. In this case, either the ± 600 kV or ± 800 kV lines will be subjected to the same risk.

The ± 600 kV lines solution in a certain period will have the failure of both lines (in different times) and 3,000MW will be lost during each repair time. It should be noted that if the two ±600 kV have feature for paralleling then nothing will be lost in that case. The ± 800 kV solution in the same period fails once, however loosing 6,000MW during the repair time. So in this condition both solutions have the same reliability. However, they may be different, for example if one designs the ±800 kV bipole for 500 years wind return period.

It should be noted that if the two 600 kV bipoles have feature for paralleling then nothing will be lost in that alternative.

As related to pole failure, it will be assumed here a failure rate of 0.1 failure per 100 km per year (note that in DC lines there is no high short circuit current and the pole may be restarted at 100 or 75 or 50% of the nominal voltage, so leading to a high chance of success). It will also be assumed that the repair time is 2 h and that the load factor is 0.7. It is also assumed that the ± 600 kV solution has a bipole paralleling capability, meaning that when one pole is out, its power is transferred to the second bipole. Then, when this event occurs with 2 x 600 kV bipoles, there will be no energy curtailment, but it is different for the case of 1 x 800 kV. The energy curtailment in the ± 800 kV system is so:

- Number of pole failures: 2.5 per year;
- Average power unavailable 0.7*3,000=2,100MWh/h (however the system may have this reserve);
- Energy not supplied: 2,100*2*2.5= 10,500 MWh per year;
- Considering US$ 100/MWh for the energy not supplied cost, it results in a Reliability cost =1.05 MU$ per year;
- Present Worth (30 years, interest rate= 0.1) is then MU$ 9.9.

The difference in the Present Worth (PW) of the two alternatives is (3,789- 3,497) = MU$ 292. The ± 800 kV solution is better even with an energy curtailment cost (US$ per MWh) 20 times higher (2,000 U$/MWh).
Besides of the economical evaluation above, the electrical performance of the system has to be analyzed. The steady state reserve of the system and the dynamic performance (power interruption during AC receiving system fault) may favor the solution with two bipoles.

7.4.4 Study Case 4: Power 6,000 MW; ±800 kV; series or parallel arrangement

In this case, it is considered that the transmitted power grows at 600 MW per year, thus taking ten years to reach 6,000MW. The DC line is considered the same (5xACSR 2,515 MCM) in this first evaluation, although in a optimization process they may result slightly different (size and cost lower in the parallel arrangement).

To arrive to the 6,000 MW Converter Station cost, the equation indicated in clause 7.2.6 before was applied by considering:

- series arrangement → 965 MUS$ (by the equation)
- parallel arrangement → 10% higher or 1,061.5 MU$
- it is assumed that 65% of the cost is expended in the first staging.

The staging considered are: first, 2x1,500 MW, and adding 2x,1,500 MW when necessary.

Tables 7.13 and 7.14 show the results.

Table 7.13: Parallel arrangement

Begin. of year	End of year	Line	Station	Corona	Joule	Maint line	Maint stat	Station losses	Sum in the year	PW
1	0	1004144969	689975000						1694119969	1694119969
2	1			6967114	746548	20082899	13799500	552480	42148542	38316856
3	2			6967114	2986193	20082899	13799500	2209920	46045626	38054237
4	3			6967114	6718934	20082899	13799500	4972320	52540767	39474656
5	4		371525000	6967114	11944771	20082899	13799500	8839680	433158965	295853401
6	5			6967114	18663705	20082899	21230000	13812000	80755719	50142948
7	6			6967114	26875736	20082899	21230000	9944640	85100389	48036951
8	7			6967114	36580862	20082899	21230000	13535760	98396636	50493032
9	8			6967114	47779085	20082899	21230000	17679360	113738459	53059830
10	9			6967114	60470405	20082899	21230000	22375440	131125858	55610164
11	10			6967114	74654821	20082899	21230000	27624000	150558834	58046948
12	11			6967114	74654821	20082899	21230000	27624000	150558834	52769953
13	12			6967114	74654821	20082899	21230000	27624000	150558834	47972685
14	13			6967114	74654821	20082899	21230000	27624000	150558834	43611531
15	14			6967114	74654821	20082899	21230000	27624000	150558834	39646847
16	15			6967114	74654821	20082899	21230000	27624000	150558834	36042588
17	16			6967114	74654821	20082899	21230000	27624000	150558834	32765989
18	17			6967114	74654821	20082899	21230000	27624000	150558834	29787263
19	18			6967114	74654821	20082899	21230000	27624000	150558834	27079330
20	19			6967114	74654821	20082899	21230000	27624000	150558834	24617573
21	20			6967114	74654821	20082899	21230000	27624000	150558834	22379611
22	21			6967114	74654821	20082899	21230000	27624000	150558834	20345101
23	22			6967114	74654821	20082899	21230000	27624000	150558834	18495547
24	23			6967114	74654821	20082899	21230000	27624000	150558834	16814133
25	24			6967114	74654821	20082899	21230000	27624000	150558834	15285576
26	25			6967114	74654821	20082899	21230000	27624000	150558834	13895978
27	26			6967114	74654821	20082899	21230000	27624000	150558834	12632707
28	27			6967114	74654821	20082899	21230000	27624000	150558834	11484279
29	28			6967114	74654821	20082899	21230000	27624000	150558834	10440254
30	29			6967114	74654821	20082899	21230000	27624000	150558834	9491140
31	30			6967114	74654821	20082899	21230000	27624000	150558834	8628309
									PW total (million U$)	2915

Table 7.14: Series arrangement.

Begin. of year	End of year	Line	Station	Corona	Joule	Maint line	Maint stat	Station losses	Sum in the yr	PW
1	0	1004144969	627250000						1631394969	1631394969
2	1			324996	2986193	20082899	12545000	552480	36491568	33174152
3	2			324996	11944771	20082899	12545000	2209920	47107586	38931889
4	3			324996	26875736	20082899	12545000	4972320	64800950	48685913
5	4		337750000	324996	47779085	20082899	12545000	8839680	427321660	291866444
6	5			6967114	74654821	20082899	19300000	13812000	134816834	83710647
7	6			6967114	26875736	20082899	19300000	9944640	83170389	46947516
8	7			6967114	36580862	20082899	19300000	13535760	96466636	49502637
9	8			6967114	47779085	20082899	19300000	17679360	111808459	52159471
10	9			6967114	60470405	20082899	19300000	22375440	129195858	54791656
11	10			6967114	74654821	20082899	19300000	27624000	148628834	57302850
12	11			6967114	74654821	20082899	19300000	27624000	148628834	52093500
13	12			6967114	74654821	20082899	19300000	27624000	148628834	47357727
14	13			6967114	74654821	20082899	19300000	27624000	148628834	43052479
15	14			6967114	74654821	20082899	19300000	27624000	148628834	39138617
16	15			6967114	74654821	20082899	19300000	27624000	148628834	35580561
17	16			6967114	74654821	20082899	19300000	27624000	148628834	32345965
18	17			6967114	74654821	20082899	19300000	27624000	148628834	29405423
19	18			6967114	74654821	20082899	19300000	27624000	148628834	26732202
20	19			6967114	74654821	20082899	19300000	27624000	148628834	24302002
21	20			6967114	74654821	20082899	19300000	27624000	148628834	22092729
22	21			6967114	74654821	20082899	19300000	27624000	148628834	20084299
23	22			6967114	74654821	20082899	19300000	27624000	148628834	18258454
24	23			6967114	74654821	20082899	19300000	27624000	148628834	16598594
25	24			6967114	74654821	20082899	19300000	27624000	148628834	15089631
26	25			6967114	74654821	20082899	19300000	27624000	148628834	13717847
27	26			6967114	74654821	20082899	19300000	27624000	148628834	12470770
28	27			6967114	74654821	20082899	19300000	27624000	148628834	11337063
29	28			6967114	74654821	20082899	19300000	27624000	148628834	10306421
30	29			6967114	74654821	20082899	19300000	27624000	148628834	9369474
31	30			6967114	74654821	20082899	19300000	27624000	148628834	8517703
									PW total (million U$)	2876

The alternative with series converter has lower total cost. Of course the result may be different depending on the series and parallel arrangement relative costs. It should also be mentioned that with series arrangement it would be possible to have an intermediate staging with 2 converters in one pole and one converter in the other, so improving the cost of this solution. The PW difference is 39 MUS$ or 4.1% of the station cost.

8 Conclusions and Summary

The methodology proposed in this Brochure for studying of HVDC alternatives, comprising the DC Line and the Converter Stations, tries to supply guidelines for selecting the both components and optimizing them, so as to make it easy to make an optimized choice of the required HVDC system. The Technical Brochure intends to furnish this tool for the interested engineers, either in a planning or in a design stage.

The choice of the DC system was therefore conducted with two optimization steps, the first one related to the DC line, in which the selection of the number and size of subconductors per pole was carried out, and the second one related to the converter station and the selection of the system voltage.

As for the DC lines, several line alternatives are considered, their costs plus losses (corona and joule) being minimized, thus leading to the selection of the “optimum choice” pole conductor configuration.

Regarding the converter stations and optimum voltage, the cost of the line plus losses added to the converter station costs plus own losses are minimized, and the system voltage is selected. This methodology can also be used when there is a gradual staging until coming to a final HVDC system, by comparing the yearly system cost, or otherwise setting the yearly parcels (line, losses and station) and then evaluating the Present Worth of the mentioned parcels.

The line cost is obtained by doing in sequence: the electrical design (switching and lightning overvoltages, insulation coordination, and corona effects studies); the mechanical design (sag-tension, tower loading stresses); tower and foundation calculation, and finally the estimated auxiliary line budgets. Using such budgets, regression equations are deduced, so that any option of line and converter losses costs can be estimated by their equation and economic assumptions.

A similar procedure is performed for the converter station costs, which can be estimated by using equations obtained from curve fitting over manufacturers’ cost information.

In this brochure all these steps are described and the results for voltages from ±300 to ±800 kV, powers from 700 to 6,000 MW and line lengths from 750 to 3,000 km, are shown.

Therefore, a methodology is herein described and proposed for selecting economic voltages through figures, as well as for evaluating the impacts of DC Lines by typical tables, and for choosing the most economical pole conductor configurations by technical economical approaches; it is then possible not only to choose the best HVDC option but to compare it with an equivalent AC option as well. Procedures for estimating electrode and electrode design are also included.

Considering the objectives of the group JWG-B2/B4/C1.17, impacts of the HVDC components into the economics of the whole HVDC Project were carried out based on the final costs of lines, converter stations and the respective losses. The evaluation of the impacts, carried out in clause 7, taking into account especially Tables 7.2 to 7.5, leads to the following basic conclusions:

- The attractiveness of the HVDC option is directly related to the line length, because of the influence of the lower DC line costs, and at a lesser degree also proportional to the power transmitted, because of the influence of the losses, usually lower at a DC line than at an equivalent AC line;

- For bipole lines 750 km long, the line share in the total costs lies much below 50% ; for such line length it is likely that an AC system may result more advantageous than the equivalent DC system, because of the high cost share of the Converter Stations;

- For the 1500 km line length range, it is highly probable that the breakeven point is exceeded, so that the HVDC option is more attractive than an AC equivalent option, as the DC line has a high share in the total costs, except perhaps for lowest power under consideration (700 MW);

- For 3000 km long lines, the HVDC option is always more attractive than a corresponding AC option, what can be deduced from the high share of the DC line costs into the total costs (between 58.5% and 69.2%); however, contrary to what would be expected, the relative costs of the lines decreased, when changing from 3,000 MW ± 600 kV into 6,000 MW ± 800 kV. This is due to the presently higher costs per kW played by the CS in the ± 800 kV level.

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