353

GUIDELINES FOR INCREASED UTILIZATION

OF

EXISTING OVERHEAD TRANSMISSION LINES

Working Group
B2.13

August 2008

cigré

Working Group B2.13

Guidelines for increased utilization of existing Overhead Transmission Lines

ISBN: 978- 2- 85873- 040-7

Members of Working Group B2.13

Keith Lindsey, **WG Convenor** (U.S.A)

Gary Brennan, **TF Convenor** (Australia)

Rob Meijers, **Secretary** (Netherlands)

Regular members:

Regis Clerc (France); Rafael Garcia Fernandez (Spain); Detlef Hussels (Germany); Zibby Kieloch (Canada); Henning Øbro (Denmark); Yrjö Ojala (Finland); Steinar Refsnæs (Norway); Jiri Steinbauer (Czech Republic); Fernando Witbooi (South Africa)

Corresponding members:

Rikus Bekker (Australia); Magdi Ishac (Canada); Peter Tarczy (Hungary); Irena Kuczkowska (Poland); Glen van der Wijk, former WG Convenor (Netherlands); Eric Marshall (South Africa); Gilbert R Marshall (United Kingdom); George Niles (U.S.A.); Finn Rimmer (Canada); Jan Rogier (Belgium); Marius van Rensburg (South Africa); Ed Shantz (Canada); Anand Goel (Canada); Peter Fiers (Austria); Andy Stewart (U.S.A); Rob Stephen (South Africa)

Guidelines for increased utilization of existing overhead transmission lines

Abstract
Summary – TB No xxx – WG B2.13
Guidelines for Increased Utilization of Existing Overhead Transmission Lines.
Over the past twenty years, there have been major developments in transmission line asset renewal driven by increasing network constraints and demands for high availability and capacity. The aim of the Brochure is to provide executives and asset managers guidelines for the economic and technical considerations for transmission line asset renewal and any combination of uprating, upgrading, refurbishment and asset expansion.

Keith Lindsey, WG Convenor, USA; Gary Brennan, TF Convenor, Australia; Rob Meijers, Secretary, Netherlands

Regular members
Regis Clerc, France; Rafael Garcia Fernandez, Spain; Detlef Hussels, Germany; Zibby Kieloch, Canada; Henning Øbro, Denmark; Yrjö Ojala, Finland; Steinar Refsnæs, Norway; Jiri Steinbauer, Czech Republic; Fernando Witbooi, South Africa

Corresponding members
Rikus Bekker, Australia; Magdi Ishac, Canada; Peter Tarczy, Hungary; Irena Kuczkowska, Poland; Glen van der Wijk, former WG Convenor, Netherlands; Eric Marshall, South Africa; Gilbert R Marshall, United Kingdom; George Niles, USA; Finn Rimmer, Canada; Jan Rogier, Belgium; Marius van Rensburg, South Africa; Ed Shantz, Canada; Anand Goel, Canada; Peter Fiers, Austria; Andy Stewart, USA; Rob Stephen, South Africa

Introduction

In the foreseeable future most countries with major electrical infrastructure may be confronted with three coinciding critical issues. Firstly, much of this infrastructure was constructed in the fifties and the sixties, which result in the age of the assets being about 50 years. Secondly, the design life of much of the infrastructure is in many cases about 50 years and has matured beyond the engineering serviceability and or economic life and requires some form of life extension. Thirdly, the need to increase capacity of the existing infrastructure places extraordinary demands on utilities to establish strategies to uprate the infrastructure as approvals for the construction of new lines are difficult to obtain.

In addition, increasing or emerging opportunities for complementary use of existing assets such as installation of antennas and optical fibres allow *asset expansion* options to be explored.

The Technical Brochure [1] discusses the economic and technical considerations for asset renewal: any combination of uprating, upgrading, refurbishment and asset expansion that will assist in addressing the previously mentioned issues. In summary, the Technical Brochure contents and structure is illustrated in Figure 1.

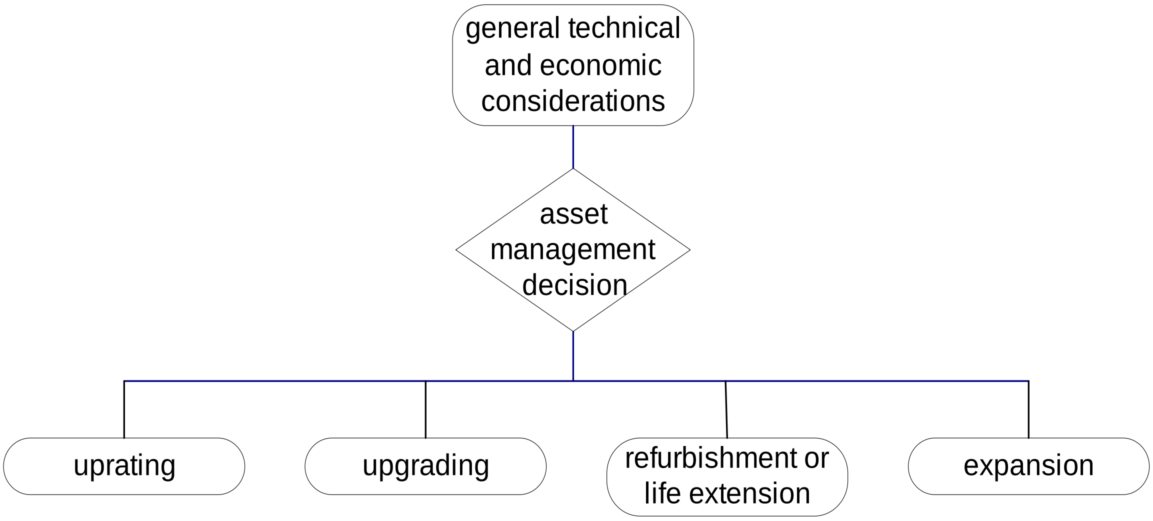


Figure 1: Technical Contents and Brochure Structure

Uprating is defined as increasing the electrical characteristics of a line due to, for example, a requirement for: higher electrical capacity or larger electrical clearances.

Upgrading is defined as increasing the original mechanical strength and or electrical for increased applied loads such as wind, ice and any load case combination or increasing electrical performance such as pollution or lightning performance.

Refurbishment is defined as being the extensive renovation or repair of an item to restore the intended design working life. Life extension is an option of refurbishment which does not result in the complete restoration of the original design working life.

Asset Expansion is defined as increasing the functionality of transmission lines.

Table 1 provides a summary of the various asset management options, risk management considerations, drivers, actions and propositions. The Technical Brochure details the effects on the overhead line of all the mentioned propositions.

terminology	definition	failure probability, P	failure consequence, C	failure risk, (R = PxC)	driver	action	proposition
uprating	increasing capacity	=	↑	↑	thermal rating by	installing	higher capacity conductors additional conductors active line rating systems
						increasing	conductor tension conductor attachment height
						adopting	probabilistic ratings
						redesign	high surge impedance performance
					voltage rating by	increasing	insulation electrical strength conductor attachment height
upgrading	improving reliability	↓	=	↓	structural performance by	increasing	structure strength foundation strength
		↓	=	↓	electrical performance by	improving	insulation pollution performance lightning performance by improving insulation lightning performance by improving earthing lightning performance by installing earthwires
						reducing	structure potential rise electrical induction
						installing	lightning arrestors
refurbishment	restoring to design working life	↓	=	↓	arrest degradation by	restoring	structure strength foundation strength conductor strength and capacity insulation pollution performance fitting strength lightning performance
life extension	repairing without restoring to original design life	↓	=	↓	arrest degradation by	repairing	structures foundations conductors insulators fittings earthing earthwires
asset expansion		↓	=	↓	improve availability by	increasing	maintainability by adopting live line techniques
		=	↑	↑	providing third party access by	installing	telecommunication equipment fibre optics (OPGW / ADSS)

Table 1: Transmission Line Asset Management Options

General Economic and Technical Considerations

To increase the utilization of existing overhead transmission lines, a number of economic and technical factors need to be considered. Some of these factors are influenced by the basic need to increase system capacity. The decision to increase the utilization of an existing line will be influenced by the asset life expectancy, the load growth forecast, the planning horizon, the value of capital, cost benefit analysis, economic optimization and consideration of other project constraints. The fundamental objective of a transmission asset owner is to continuously assess the capacity of the electrical network to determine the most economic and technical viable options for network operation and development. This should be done in order to meet the increasing demands for electricity and reliability of the electricity supply to customers.

Usually *technical end of life* occurs when the line fails to perform within the normal operating requirements and is no longer fit for the original purpose.

One should however also consider the *economic end of life*. Let us then consider the cumulative net present value (NPV) of the cost of the transmission line asset including depreciation, maintenance, losses and risk costs per years of service as illustrated in Figure 2. The cumulative NPV of costs are the initial capital expenditure (o to a) followed by the NPV of recurrent costs (a to b), followed by a period of increased recurrent cost as a result of the early stages of asset deterioration and increased maintenance activities (b to c) and then followed by an accelerated and an increasing recurrent maintenance costs (after c).

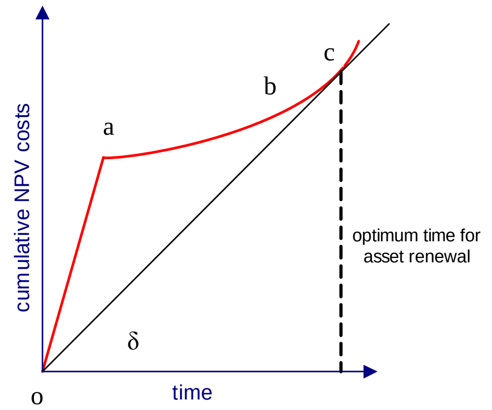


Figure 2: Economic Model of a Transmission line

The Technical Brochures defines the optimum time for asset renewal or *economic end of life* when the long run marginal costs are a minimum that is, where δ is a minimum as highlighted in Figure 2. In most cases utilities do not have historical financial asset data. Hence a more realistic financial model will have shifted axis as illustrated in Figure 3.

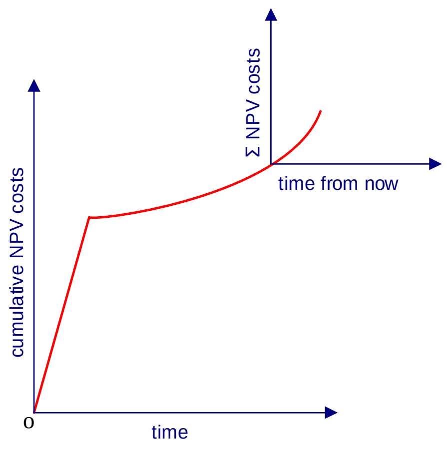


Figure 3: Updated Economic Model of a Transmission Line

Now let us consider an asset renewal project with a designated financial and or technical planning horizon. As before, there will be some capital costs followed by recurrent costs. This is illustrated in Figure 4 where the previous "do nothing" cost curve and the "asset renewal project" costs curve are shown as x and y respectively. The average long run marginal costs of the asset renewal project where δ is a minimum is also illustrated. Also illustrated is the optimum time to undertake the project when the maximum savings of the renewal project are realised. Past the optimum time results in decreasing potential savings and prior to the optimum time, results in the maximum savings not being achieved.

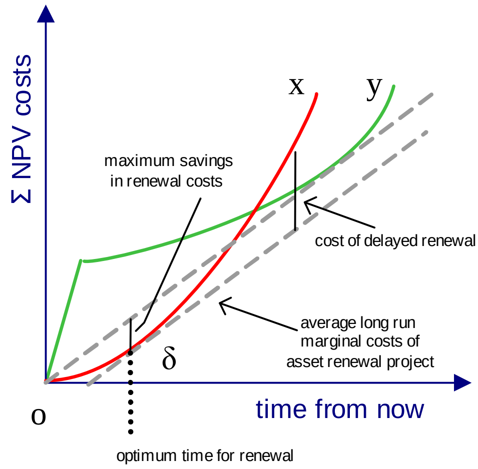


Figure 4: Economic Model of Asset Renewal Project

Prudent financial return for capital investments for a long planning horizon asset renewal projects is achieved by recognising the time dependent value of capital, the entitlement to interest earnings, the NPV of capital and the optimum time to undertake the project. The Technical Brochure details four financial case studies of prudent economic decisions.

Transmission Line Uprating Options and Case Studies

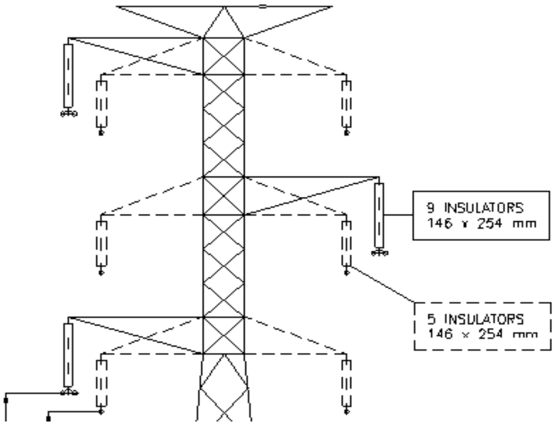
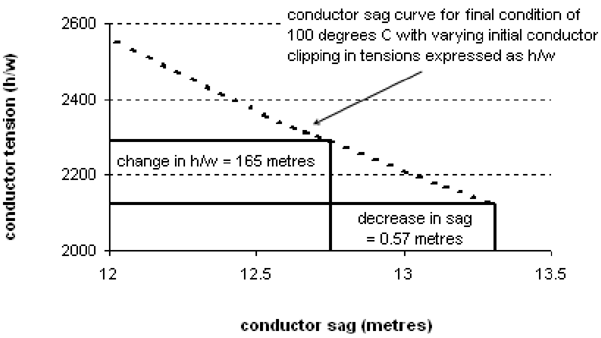
Transmission lines are theoretically modelled using engineering principles as either long or short. A long transmission line in general is a major interconnector between load centres or load centres and generation centres. On the other hand a short transmission line in general is an interconnector around or within load centres

The operation of long transmission lines is strongly influenced by the voltage regulation and the need to ensure that the receiving end voltage is within defined tolerances. The decision to uprate a long transmission line is therefore linked to improving the voltage regulation.

Short transmission lines are influenced by the thermal capacity of the conductors and the need to ensure that the electrical safety clearances are not breached. Therefore the decision to uprate a short transmission line is linked to improving the thermal capacity.

The Technical Brochure discusses uprating long and short transmission line elements. Uprating transmission lines are directly influenced by the considerable variation of transmission line designs and construction methods employed throughout the world. Nevertheless, uprating of transmission lines generally fall into either increasing voltage capacity or increasing thermal capacity. In some circumstances, the opportunity is taken to simultaneously increase the voltage and the thermal capacity (rating) of a transmission line.

Transmission line uprating case studies:

	**Line Thermal Uprating (Czech Republic)** bundle conductors are attached at a higher level thanks to a T insulator string arrangement. On the left: previous situation and on the right: new arrangement.
	**Line Voltage Uprating (Brazil)** double-circuit 69 kV line becomes a single-circuit 138 kV line. the same conductors of the double-circuit were arranged in twin bundles, and new crossarms were designed for increased vertical load, attaching the new insulator strings and clearances. The number of insulator units were increased from 5 to 9 - 100% increase in line capacity was obtained. - Power increase from 100 to 200 MVA - Cost: 20% of a new line.
	**Line Thermal Rating (Australia)** increasing the 207 mm^2 ACSR conductor thermal capacity by 15% by increasing the operating temperature from 85 °C to 100 °C permitted an increase in the current carrying capacity from 565 to 655 A (15%). The conductor tension parameter was required to increase from 2124 meters to 2289 meters or an increase of about 8% to compensate for the increased conductor sag of about 0.57 meters in a 400 meter span. The increase in conductor tension and decrease in conductor sag is illustrated.

Transmission Line Upgrading Options and Case Studies

The main reason for upgrading is increasing the structural and or the electrical availability of the line. Upgrading is generally concerning with the whole transmission line or some part of it and is also often associated with uprating.

Upgrading of transmission line structures and foundations depends on technical and practical limitations such as availability of equipment and materials as used in the original structure and feasibility of implementing the upgrading itself.

The electrical parameters that provide opportunities to upgrade a transmission line are improvements in lightning performance or outage rate; improvements in insulator pollution performance; improvements in corona, radio & television interference and audio noise; reductions in earth potential rise; reductions in electric and magnetic field (EMF) levels and reductions in induction in adjacent long parallel metallic infrastructure such as pipelines and or metallic telecommunications.

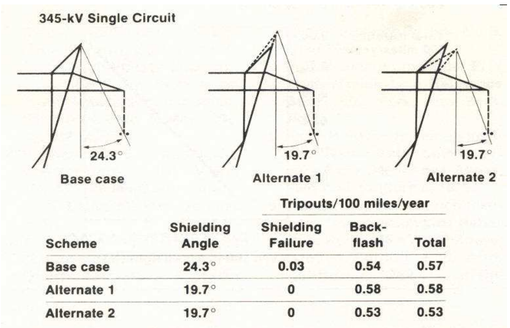
Transmission line upgrading case studies:

Upgrading of 400 kV Towers (Spain)

Upgrade of existing towers to withstand 140 km/h rather than originally used 120 km/h wind speed.

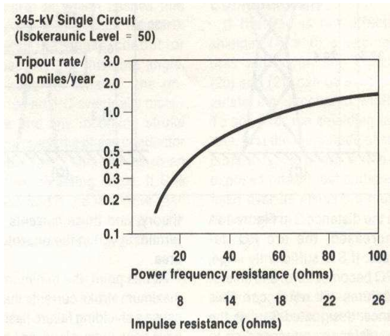
Replacement and/or reinforcement of main legs and angle bars to upgrade the tower under schedule outage limitations time (one month per year)

Upgrading on a 345 kV Line (USA)



Scheme	Shielding Angle	Tripouts/100 miles/year Shielding Failure	Back-flash	Total
Base case	24.3°	0.03	0.54	0.57
Alternate 1	19.7°	0	0.58	0.58
Alternate 2	19.7°	0	0.53	0.53

to improve shielding failure rates by varying shielding angles



to reduce the outage rate by decreasing structure earth resistance

6. Transmission Line Refurbishment Options and Case Studies

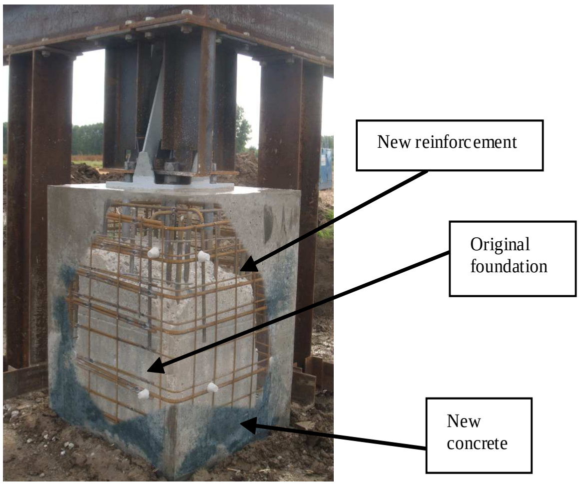
The line refurbishment options include interventions to the key components of the line, namely, structures, foundations, insulator strings, conductors and earthing. Transmission line components can be subjected to severe environmental conditions such as pollution, wind and corrosion that affect their performance. Other causes including improper manufacturing or assembly and vandalism may also contribute to the gradual deterioration of the condition of the components.

The process starts with determining the extent of the refurbishment. A number of engineering studies may be required to verify and analyse the extent of the refurbishment required.

Firstly, an understanding of the problem and its causes. This includes assessing the condition of the components, its causes and developing a number of options for refurbishment. This is followed by an economical considerations and justification. An engineering assessment of the various technical options is required in order to select the most suitable option to implement.

When it comes to implementation further assessment may be required to verify the actual condition of each component. For example, it is necessary to determine the state of corrosion of the zinc-coated galvanizing and the remaining thickness of metal to ensure that the structural integrity of lattice steel towers is maintained.

Transmission line refurbishment case studies:

	**Case Study 6-4 (USA) – Reinforcement of 230 kV Wood Pole K-Frame** Case of poles severely damaged by woodpeckers and decay, in danger of failing. The line is critical to system reliability. It is not practical to schedule an extended outage in the near future to enable the necessary repairs to be performed using de-energized work practices. Access to the damaged structures is not easy. Pole replacement was deemed to be cost prohibitive. Restoring strength to the damaged pole was carried out by using composite reinforcement technology: a patented composite repair consisting of a fiberglass wrap coupled with a phenolic resin system installed over a four day period with the line energized at a substantial cost savings relative to pole replacement.
	**Refurbishment of Concrete Foundations (ASR) of 150 kV Overhead Line (The Netherlands)** In the overhead line there were many foundations with deformation. In 1995 the foundation of one tower had already been refurbished. After a new line inspection in 2005 the conclusion was that further investigation was necessary It was found that in the concrete there were traces of alkali-silica reactivity (ASR). Because of the limited outage time it was decided to re-use a special temporary constructions to take over the foundation loads during refurbishment.

Transmission Line Asset Expansion

The location of structures of transmission lines may provide opportunities to install different third party assets in order to generate additional income for the transmission asset owner. In certain cases the utilization of transmission structures is the only way to install telecommunication equipments (antennas) or fibre optic links (FO) due to the absence of permission of other land-owners or is perhaps the best way to reduce the expenses of installation or overcome environmental restrictions.

Several strategic topics should be addressed prior to considering the installation of third party assets, such as the structure and foundation capacities, possible compromising of the electrical performances of the transmission line and possible restricted work practices.

Case Studies:

	**installation of ADL in South Africa:** 10,000 kilometers of optic fibre telecommunication network were installed on existing power lines over 14 months. Three basic technologies were employed: OPGW (Optic Fibre Ground Wire), ADL (All Dielectric Lashed cable) and ADSS (All Dielectric Self-Supporting cable). Both hand and motor lash techniques for ADL were used on 275 and 400 kV transmission lines. Due to clearance requirements between the earthwire and phase conductor the work could be done live with motor lash technique on 400 kV lines and with hand lash technique on 275 kV lines.

Conclusion:

Over the past twenty years, there have been major developments in transmission line asset renewal driven by increasing network constraints and demands for high availability and capacity.

This article and the associated Technical Brochure have been prepared to provide a greater understanding of the management, economical and technical requirements to respond to these increasing constraints and demands.

The Technical Brochure gives a management perspective of detailed technical studies undertaken by the Study Committee B2 Overhead Lines. In this regard, the Technical Brochure provides over sixty references from the various B2 working groups and some fifty case studies from all over the world covering various asset renewal options for uprating, upgrading, refurbishment and asset expansion.

References:

[1] CIGRE Technical Brochure No. xxx (2007), "Guidelines for increased utilization of existing overhead transmission lines," SC B2 WG B2.13

Guidelines for increased utilization of existing overhead transmission lines

Guidelines for increased utilization of existing overhead transmission lines

Examples / Case Studies

3. General economic and technical considerations

4. Transmission line uprating and case studies

5. Transmission line upgrading options and case studies

Definitions

increased utilization	For the purposes of this paper the term increased utilization will be used for one or any combination of uprating, upgrading, life extension, refurbishment and asset expansion of a transmission line
asset expansion	Increasing the functionality of transmission line components
asset renewal	Increasing the reliability and/or availability of a transmission line by any combination of uprating, upgrading, life extension, and refurbishment.
life extension	Extensive renovation or repair of an item without restoring their original design working life [47] Life extension results in a decrease of the probability of failure and no change to the consequence of failure
refurbishment	Extensive renovation or repair of an item to restore their intended design working life [47] Refurbishment results in a decrease of the probability of failure and no change to the consequence of failure
upgrading	Increasing the original mechanical strength of an item due to, for example, a requirement for: higher meteorological actions. Upgrading will decrease the probability of failure [47] For the purpose of this Technical Brochure the term upgrading will also mean increasing the original electrical performance of a transmission line Upgrading does not change the consequences of failure
uprating	Increasing the electrical characteristics of a line due to, for example, a requirement for: higher electrical capacity, or larger electrical clearances. Uprating will increase the electrical capacity of the line thereby potentially increasing the consequences of a failure.

1. Introduction

An analysis of the technical and economic characteristics of power transmission, such as AC and DC overhead lines, superconductive lines, cable lines and gas insulated lines will lead to the conclusion that in the foreseeable future the principle role in electrical transmission will be played by overhead AC transmission lines.

Furthermore, in the foreseeable future most developed countries with major electrical infrastructure will be confronted with three coinciding critical issues. Firstly, much of the electrical infrastructure was constructed in the fifties and the sixties, which result in the age of the assets being about 50 years. Secondly, the design life of much of the electrical infrastructure is in many cases about 50 years and has matured beyond the engineering serviceability and or economic life and requires some form of life extension. Thirdly, the need to increase capacity of the existing electrical infrastructure places extraordinary demands on utilities to establish strategies to uprate existing electrical infrastructure because getting approvals for the construction of new lines is difficult.

Transmission lines fall into part of the critical elements of electrical infrastructure that require uprating, upgrading, life extension and or refurbishment (i.e. increased utilisation). An additional influencing consideration is that transmission line uprating, upgrading, life extension and or refurbishment will lead to extended outages that are, in general, difficult to secure in competitive and deregulated electricity markets, or very high cost alternative works.

The long term integrity, performance and value of transmission lines are dependent on the asset operating within performance standards. A key business objective for asset owners and operators is the timely renewal of assets when these commence to operate outside these standards due to age, condition, suitability, capability, reliability, safety, performance, legislative requirements, social & community amenity and economic efficiency. The renewal process of assets is particularly relevant to transmission lines consisting of various elements and components which have various life expectancy.

This guideline will discuss the uprating upgrading and refurbishment of existing transmission lines. Section 3 of the guideline will discuss the economic analysis of transmission line and the associated decisions. Section 4 is given over to discussing various technical options and associated decisions for uprating transmission lines. Section 5 will discuss technical options for upgrading and Section 6 will discuss refurbishment and associated decisions. Section 7 will discuss various options for asset expansion. A range of international case studies will be presented to provide examples of innovative solutions used throughout the world.

In summary, the Technical Brochure structure is illustrated in Figure 1.1.

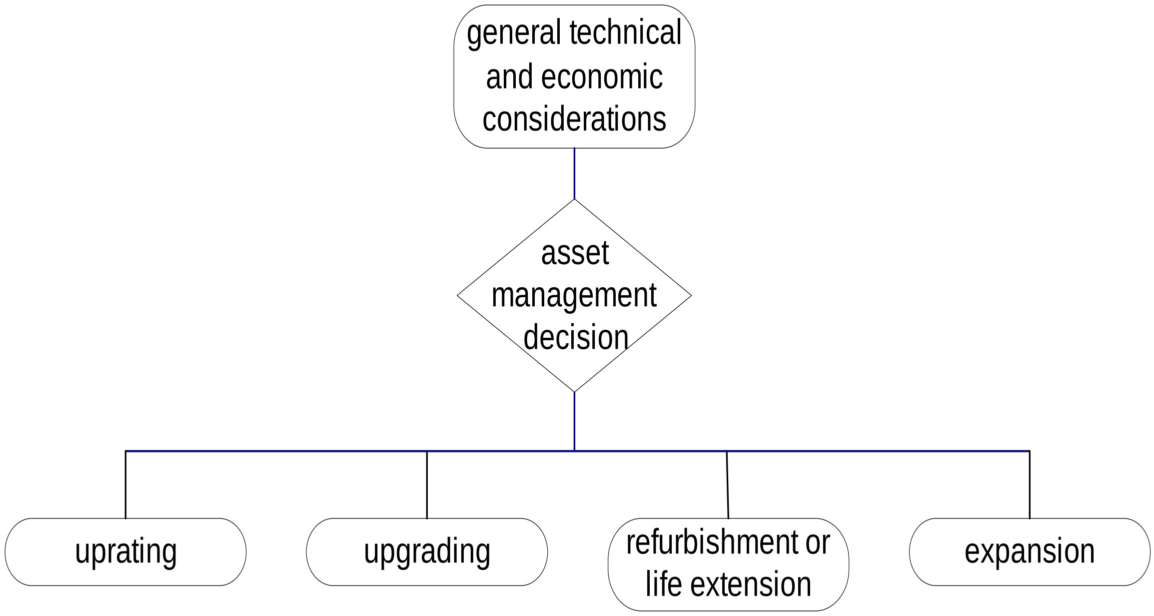


Figure 1.1: Technical Brochure Content

2. Purpose

The purpose of the Technical Brochure is to provide the overhead transmission line asset manager a general overview of economic and technical considerations in order to facilitate proper decisions on uprating, upgrading and refurbishment of overhead transmission lines.

Table 1 provides a summary of the various asset renewal options, risk management considerations, drivers, propositions and the effects on the transmission line.

3. General Economic and Technical Considerations

To increase the utilization of existing overhead transmission lines, a number of economic and technical factors need to be considered. Some of these factors are influenced by the basic need to increase system capacity. The decision to increase the utilization of an existing line will be influenced by the asset life, the load growth forecast, the planning horizon, the value of capital, cost benefit analysis, economic optimization and consideration of other constraints.

terminology	definition	failure probability, P	failure consequence, C	failure risk, (R = PxC)	driver	action	proposition	effects on line: components or elements							effects on line: electrical paramater						
								structure	foundations	conductors	insulators	fittings	earthing	earthwire	earth potential rise	lightning peformance	induction	EMF	radio interference	audio interference	pollution performance
uprating	increasing capacity	=	↑	↑	thermal rating by	installing	higher capacity conductors	o	o	x	o	o	-	-	-	-	o	o	o	o	-
							additional conductors	x	x	x	x	x	-	-	o	-	o	x	x	x	-
							active line rating systems	-	-	-	-	o	-	-	-	-	-	-	-	-	-
						increasing	conductor tension	x	x	x	x	x	-	-	-	-	-	-	-	-	-
							conductor attachment height	x	x	-	o	o	-	-	-	-	-	o	o	o	-
						adopting	probabilistic ratings	-	-	-	-	-	-	-	-	-	-	-	-	-	-
						redesign	high surge impedance performance	o	o	o	o	x	-	-	-	-	-	x	x	x	-
					voltage rating by	increasing	insulation electrical strength	o	o	o	x	x	-	-	-	x	-	x	x	x	o
							conductor attachment height	x	x	o	o	o	-	-	-	o	-	x	x	x	o
upgrading	improving reliability	↓	=	↓	structural performance by	increasing	structure strength	x	o	-	-	-	-	-	-	-	-	-	-	-	-
							foundation strength	-	x	-	-	-	-	-	-	-	-	-	-	-	-
		↓	=	↓	electrical performance by	improving	insulation pollution performance	-	-	-	x	-	-	-	-	o	-	-	-	-	x
							lightning performance by improving insulation	-	-	-	x	-	-	-	-	x	-	-	-	-	o
							lightning performance by improving earthing	-	-	-	-	-	x	-	x	x	-	-	-	-	-
							lightning performance by installing earthwires	o	o	-	-	-	-	x	x	x	x	-	-	-	-
						reducing	structure potential rise	-	-	-	-	-	o	o	x	o	o	-	-	-	-
							electrical induction	-	-	-	-	-	-	x	x	-	x	-	-	-	-
						installing	lightning arrestors	o	-	-	o	o	o	-	x	x	x	-	-	-	-
refurbishment	restoring to design working life	↓	=	↓	arrest degradation by	restoring	structure strength	x	-	-	-	-	-	-	-	-	-	-	-	-	-
							foundation strength	-	x	-	-	-	-	-	-	-	-	-	-	-	-
							conductor strength and capacity	-	-	x	-	-	-	-	-	-	-	-	-	-	-
							insulation pollution performance	-	-	-	x	-	-	-	-	-	-	-	x	x	x
							fitting strength	-	-	-	-	x	-	-	-	-	-	-	-	-	-
							lightning performance	-	-	-	o	-	o	o	o	x	-	-	-	-	-
life extension	repairing without restoring to original design life	↓	=	↓	arrest degradation by	repairing	structures	x	-	-	-	-	-	-	-	-	-	-	-	-	-
							foundations	-	x	-	-	-	-	-	-	-	-	-	-	-	-
							conductors	-	-	x	-	-	-	-	-	-	-	-	-	-	-
							insulators	-	-	-	x	-	-	-	-	-	-	-	-	-	-
							fittings	-	-	-	-	x	-	-	-	-	-	-	-	-	-
							earthing	-	-	-	-	-	x	-	-	-	-	-	-	-	-
							earthwires	-	-	-	-	-	-	x	-	-	-	-	-	-	-
asset expansion		↓	=	↓	improve availability by	increasing	maintainability by adopting live line techniques	o	o	-	o	o	-	o	-	-	-	-	-	-	-
		=	↑	↑	providing third party access by	installing	telecommunication equipment	x	x	-	-	-	o	-	-	-	-	o	-	-	-
							fibre optics (OPGW / ADSS)	o	o	-	-	-	-	o	o	o	o	-	-	-	-

Table 3.1: Transmission Line Increased Utilization Options

3.1 Increasing System Capacity

The growth in demand for energy, the new developing energy markets and in particular the fact that electricity is an intrinsic characteristic of modern society, is placing a greater demand on existing overhead transmission lines. This growth of demand may be driven by normal demographic growth demands and or growth demands triggered by changes of technology and standards of living such as the affordability of domestic air conditioning.

The fundamental objective of a transmission asset owner is to continuously assess the capacity of the electrical network to determine the most economic and technical viable options to meet the increasing demands for electricity to ensure that the reliability of the electricity supply to customers is not compromised and the increasing demand for electricity associated with existing and future residential, commercial and industrial development is met.

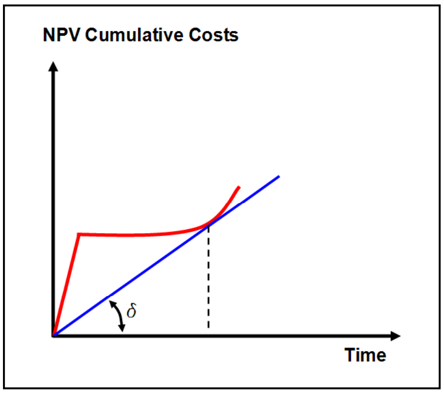
Decisions to increase the utilization of a transmission asset in a timely manner are influenced by technical and economic factors, including the age of the asset.

3.2 Optimum Time for Renewal [47], [48]

The *economic end of life* of a long lived asset has been defined where the cumulative cost of the asset (including depreciation, maintenance, losses and risk costs) per years of service is a minimum.

This can best be illustrated in by Figure 3-1, in which after the initial asset purchase, annual maintenance and risk costs are a minimum for many years. During this period of time the long-run average cost of the asset is decreasing. At some point in time the maintenance costs start to increase along with the risk cost of failure until the long-run average cost per years of service start to increase. With some assets, at this point in time, when the long-run average cost is at it's minimum value (when the Tangent of the angle δ is a minimum), the asset would be replaced with a new asset as shown in Figure 3-2.

An everyday example of this principle is the purchase of an automobile. After the initial purchase, very little maintenance is required. After ten of fifteen years, more maintenance is required and there is a risk that the automobile will not perform it's function and get the owner to his destination as scheduled. At this point in time a new automobile would be purchased. Over the time span of purchasing several automobiles in this manner, the owner would receive the most benefit (i.e. travelled the most miles) for the least long run average cost per mile.



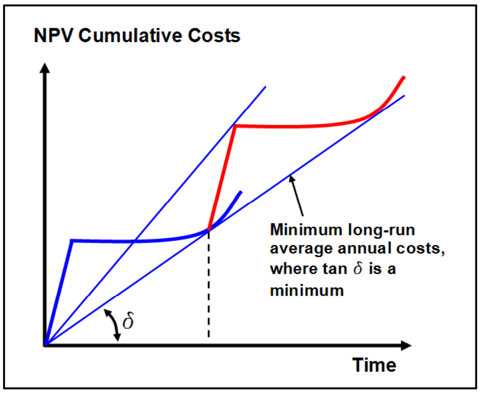


Figure 3-1 **Figure 3-2**

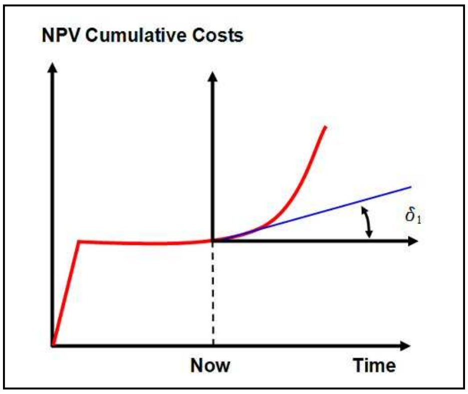
Example of Economic End of Life.

Unfortunately, a transmission line asset can not be replaced as easily as an automobile, and the economic model does not totally apply to current concerns of transmission line asset owners. The most important exception to this model is that historical initial and maintenance costs are of little concern to the asset owner. A more important concern is future maintenance and risk costs from the current point in time (i.e. "now" in Figure 3-3).

Therefore, for the purposes of this paper, this definition will be modified to not include historical costs, because most of these costs are unknown and may not be relevant in considering future investment. Therefore for purposes other than normal accounting procedures, the technical end of life and the optimum time for renewal of a transmission asset will be defined in this document as follows:

i. *Technical end of life* where the line fails to perform within the normal operating requirements without abnormal maintenance or when the line is no longer fit for the original purpose; or

ii. *Optimum time for renewal* where the cumulative net present value of future annual costs of the transmission line (including maintenance, losses and risk costs) per years of service (δ_1 of Figure 3-3) is equal to the minimum long run average costs of a renewal project (δ_2 of Figure 3-4).



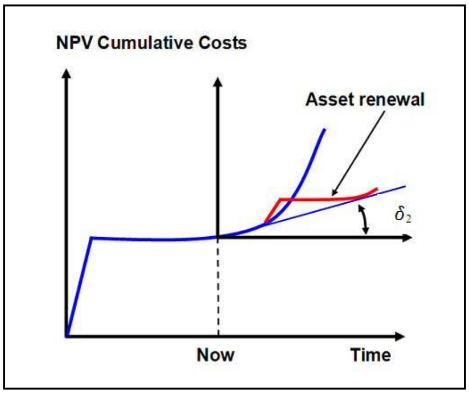


Figure 3-3 **Figure 3-4**

The need of the transmission line asset owner is to find the optimum time of renewal to uprate, upgrade or refurbish the asset in order to produce the minimum long-run average cost for the asset within a specified planning horizon (i.e. to produce the minimum Tan δ_2 of Figure 3-4).

The optimum time for renewal and the technical end of life are intrinsically linked as the optimum time for renewal is affected by a large number of technical factors, including

i. Original design of the asset;

ii. Original construction materials and workmanship;

iii. Operating environment that considers corrosion, ultra violet radiation, extreme ambient temperature, lightning, wind and ice exposure;

iv. Level of accumulated damage through overloading and faults;

v. Maintenance standard and quality of material and workmanship;

vi. Technological advances such as revised safety standards, design codes and legislation changes; and

vii. Operational or environmental constraints on increased utilization for continued use.

The renewal option for a transmission line asset may include corrective, responsive and or preventive measures from any one or a combination of the following actions:

i. Repair at each failure;

ii. Operate until first failure and then initiate responsive action;

iii. Uprate to increase the electrical characteristics;

iv. Upgrade to increase the mechanical strength;

v. Refurbish to extensively renovate or repair to restore the intended design working life;

vi. Life extension to extensively renovate or repair without restoring the intended design life; or

vii. Dismantle high risk obsolete assets with or without replacement.

All future management decisions will be based on a comparison of various options with the “do nothing” option. Therefore, assume an example where the age of the asset in Figure 3-4 is forty (40) years, so that “now” is year 40. Also assume we look ahead at the next twenty years (our planning horizon), reflecting future costs into today’s values utilizing the Net Present Value (NPV) of future costs. If we look at the cumulative NPV of all future costs associated with a renewal project, shown in Figure 3-5, we can see that there is a minimum long-run average cost associated with this asset renewal project expressed in cumulative NPV cost per years of service the slope of which is tan δ (in the case of Figure 3-5, tan δ would be approximately 35 units of cost per 18 years of service).

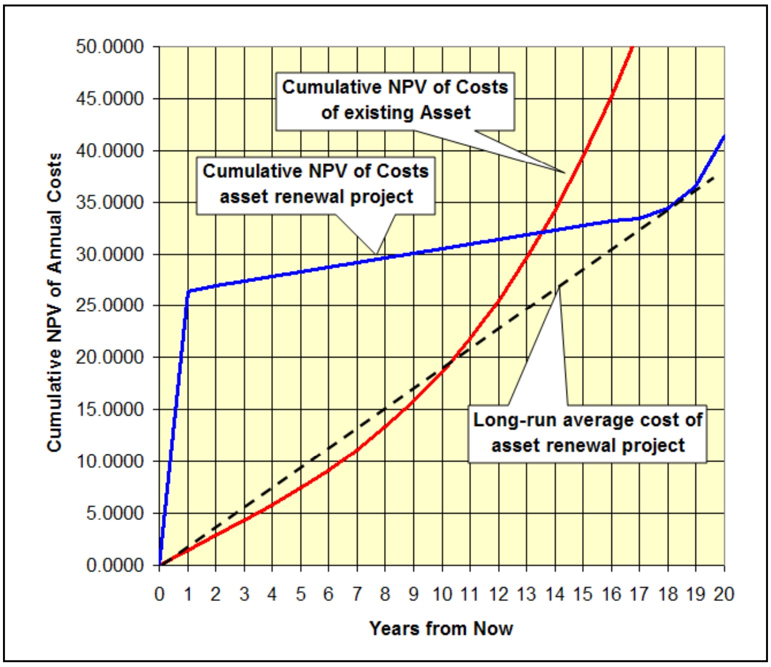


Figure 3-5: Example of a Proposed Renewal Project

The point we are seeking is the optimum time to make the asset renewal investment. This point is shown in Figure 3-6 as a time approximately seven (7) years in the future. It is the point in time at which the long-run average cost of the renewal project is equal to the marginal cost (cost per year) of the existing asset "do nothing" option. The cost of early renewal and of late renewal is also shown in Figure 3-6.

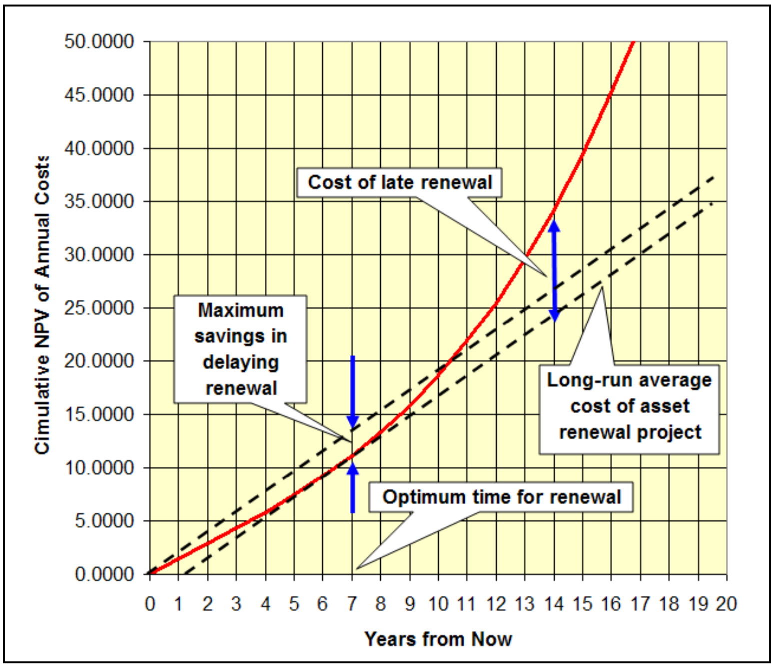


Figure 3-6: The Optimum Time to Make the Renewal Investment Shown in Figure 3-5 is at Year 7. The Cost of Early and Late Renewal is also Shown

If the slope of the long-run average cost of the asset renewal project is less that the marginal cost of the existing asset, then the existing asset is past due for renewal.

3.3 Planning Horizon and Net Present Value

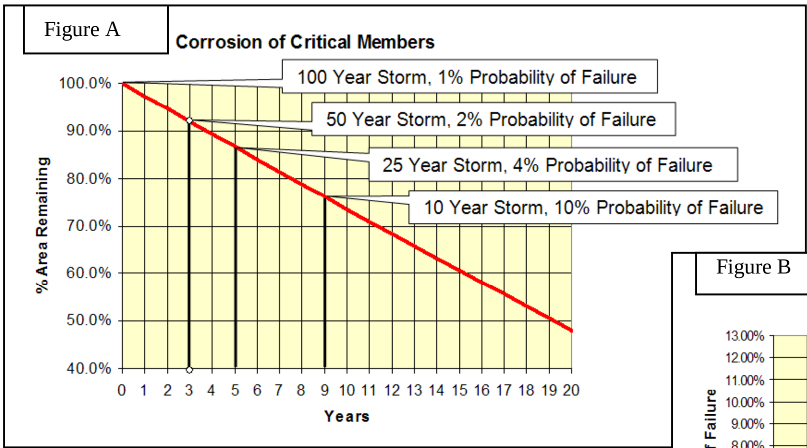
The planning horizon selected for evaluation should cover all significant cost and benefit items throughout the life cycle of the transmission line for the renewal options considered. For transmission lines consisting of major components with differing life expectancies, the planning horizon should be chosen to synchronise replacement of different components to optimise the replacement costs. For example, insulators may have a life expectancy of 17 years and fittings may have a life expectancy of 32 years. For economic reasons, the common multiple periods for the insulators would be 15, 30, 45 and 60 years and for fittings 30 and 60 years.

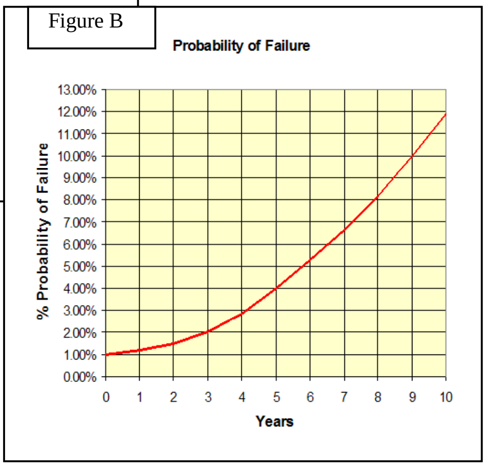
Financial return for capital investments for a long planning horizon is achieved by recognising the time dependent value of capital, the entitlement to interest earnings and the net present value of capital. Consideration of the level of data accuracy, load seasonal demand variation, organisational budget control and long term budget variability suggests that annual aggregation of costs is a practical approximation. This approximation also applies when considering the effect of inflationary trends and NPV determination. A sensitivity analysis of the variation of the data assists in determining this approximation.

Example 3-1 – Refurbishment of Towers [Part 1]

Given:

i. A double circuit 230kV transmission line feeds a load center.
ii. Length of this line is 100km.
iii. The line is in an Industrial-Marine environment (IEC Level IV).
iv. The towers are galvanized lattice steel.
v. The original design of the towers is capable of withstanding a 100 year storm.
vi. The galvanizing is gone on critical structural members; they will corrode at a rate of up to 200µm per year, shown on Figure A, for the next 20 years
vii. The withstand strength of the corroded structure is also shown on Figure A, and the probability of failure is shown in Figure B, for the next 10 years.
viii. Consequences of a tower failure is estimated at 10,000,000, therefore the annual risk cost is 100,000 with 1% probability of failure, and higher with a higher probability of failure.
ix. The cost to paint the towers is 10,000/km including the costs of outages
x. The cost to paint the towers and replace corroded steel in year 5 is 20,000/km





For the purposes of this example, the effects of Net Present Value will be neglected since the time frame is short and the effects of inflation will approximately offset the cost of capital.

Find: Compare three options against the option of doing nothing:

A. Paint the towers now.
B. Paint the towers in 5 years.
C. Replace the corroded steel and paint the towers in 5 years.

The calculations of the cumulative cost of each option is shown in Table A.

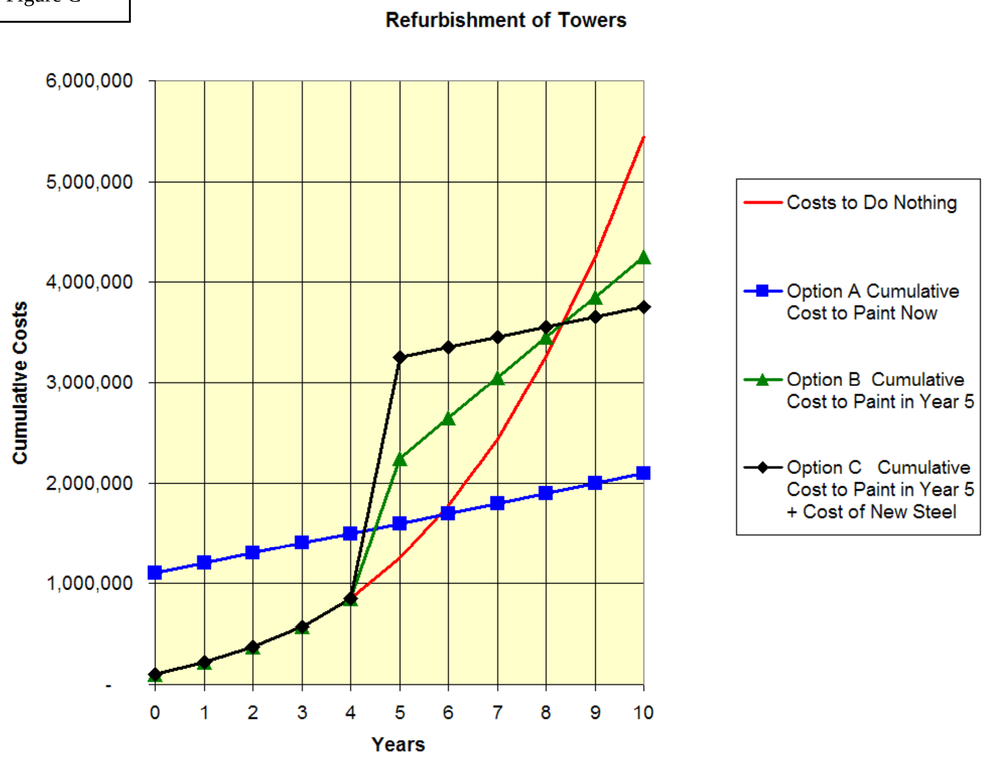
Year	Probability of Failure	Consequence	Risk Costs	**Costs to Do Nothing i.e. Cumulative Costs**	Cost to Paint Now with 1% Risk	**Option A Cumulative Cost to Paint Now**	Cost to Paint in Year 5 with 4% Risk	**Option B Cumulative Cost to Paint in Year 5**	Cost to Paint in Year 5 + Cost for New Steel	**Option C Cumulative Cost to Paint in Year 5 + Cost of New Steel**
0	1.00%	10,000,000	100,000	100,000	1,100,000	1,100,000	100,000	100,000	100,000	100,000
1	1.17%	10,000,000	117,000	217,000	100,000	1,200,000	117,000	217,000	117,000	217,000
2	1.50%	10,000,000	150,000	367,000	100,000	1,300,000	150,000	367,000	150,000	367,000
3	2.00%	10,000,000	200,000	567,000	100,000	1,400,000	200,000	567,000	200,000	567,000
4	2.84%	10,000,000	284,000	851,000	100,000	1,500,000	284,000	851,000	284,000	851,000
5	4.00%	10,000,000	400,000	1,251,000	100,000	1,600,000	1,400,000	2,251,000	2,400,000	3,251,000
6	5.27%	10,000,000	527,000	1,778,000	100,000	1,700,000	400,000	2,651,000	100,000	3,351,000
7	6.65%	10,000,000	665,000	2,443,000	100,000	1,800,000	400,000	3,051,000	100,000	3,451,000
8	8.15%	10,000,000	815,000	3,258,000	100,000	1,900,000	400,000	3,451,000	100,000	3,551,000
9	10.00%	10,000,000	1,000,000	4,258,000	100,000	2,000,000	400,000	3,851,000	100,000	3,651,000
10	11.90%	10,000,000	1,190,000	5,448,000	100,000	2,100,000	400,000	4,251,000	100,000	3,751,000

Table A

Example 3-1 – Refurbishment of Towers [Part 2]

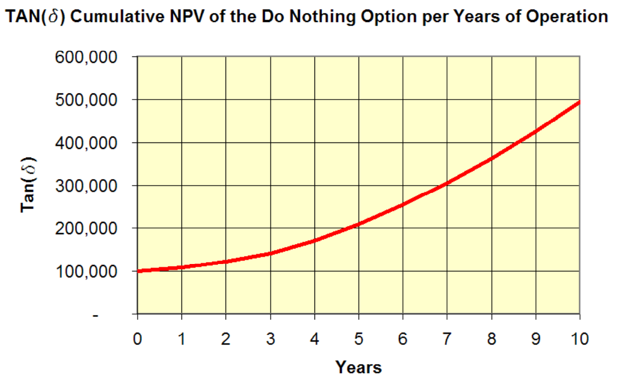
Figure C shows the comparison of these various options.

Figure C



From the data presented in Figure C, the risk and cost of various decisions can be clearly seen. The breakeven for option A is approximately 6 years. Options B and C delays the expenditure for 5 years and has a faster breakeven due to the higher probability of failure. Option B continues to have a 4% probability of failure while option C restores the towers to their original strength (i.e. a 1% probability of failure).

Figure D



The Tan(δ) of the Do Nothing Option is plotted in Figure D, it shows that the minimum point of Tan(δ) curve is now to maintain a 1% probability of failure, and that further delay is uneconomical. Also, from Figure C, it can be seen that the long run average cost of Option A approximately matches the slope of the "Do Nothing" curve now; therefore, the optimum time for renewal of Option A is now. The cost of delaying Option A for 5 years can be seen from Figure C as the difference between the initial, or current, slope of the "Do Nothing" curve and the "Do Nothing" curve (i.e. 651,000) and the additional cost to replace the steel members (i.e. 1,000,000).

Example 3-2 – Upgrading of Insulators

Given:

i. The same double circuit 230kV transmission line used in Example 1 is used here.
ii. Normal maintenance cost on this line is 1000/km/yr.
iii. Due to the high contamination, insulator washing cost on the line is 2000/km/yr.
iv. Even with washing the insulators, the line experiences an average of 2 flashover trips per year.
v. The character of the load has changed and is now very sensitive to line voltage fluctuations caused by tripping (i.e. new customers include chemical processing plants and computer chip manufacturing plants).
vi. When the line trips, the customers processes are interrupted, and they are beginning to collect damages from the asset owner. The cost of litigation and settling each tripping incident is increasing. It now averages 100,000/tripping incident, but is expected to increase by 20,000/year for each tripping incident due to increasing customer plant capacities.

For the purposes of this example, the effects of Net Present Value will be neglected since the time frame is short and the effects of inflation will approximately offset the cost of capital.

One option is considered and compared against the option of doing nothing:

A. Replace the existing insulators with new composite insulators. It is estimated that this will decrease the probability of flashovers to approximately 0.2 trips/year. The cost to change out the insulators is 30,000/km; however, the need for insulator washing would be eliminated producing a savings of 2000/km/yr. In addition there is some concern that since the composite technology is new, there may be an increased probability of insulator mechanical failure. It is estimated that due to the quantity of composite insulators installed the probability of a mechanical insulator failure in the first year is between 0% to 100%. Thereafter the probability of a mechanical insulator failure is between 0% and 50%. Each failure would case the line to trip.

Find: The range of time to payback the installation of composite insulators considering no mechanical failures or the maximum estimated number of mechanical failures

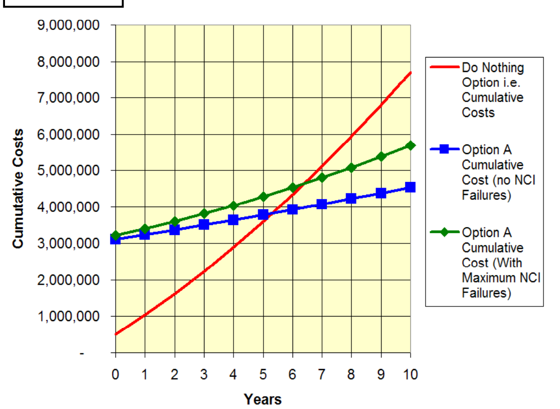
Examples of the calculations of the cumulative cost of each option is shown in the Table below.

Year	Maintenance Costs	Cost for 2 Trips/ year	Total Line Cost	Do Nothing Option i.e. Cumulative Costs	Option A Cost to Install NCIs and Maintain the Line	Option A Cost for 0.2 Trips/year	Option A Cumulative Cost (no Mechanocal NCI Failures)	Option A Probability of NCI Mechanical Failure	Option A Cost of Line trip due to NCI Failure	Option A Cumulative Cost (With Maximum NCI Mechanical Failures)
0	300,000	200,000	500,000	500,000	3,100,000	20,000	3,120,000	100%	100,000	3,220,000
1	300,000	240,000	540,000	1,040,000	100,000	24,000	3,244,000	50%	60,000	3,404,000
2	300,000	280,000	580,000	1,620,000	100,000	28,000	3,372,000	50%	70,000	3,602,000
-	-	-	-	-	-	-	-	-	-	-
9	300,000	560,000	860,000	6,800,000	100,000	56,000	4,380,000	50%	140,000	5,380,000
10	300,000	600,000	900,000	7,700,000	100,000	60,000	4,540,000	50%	150,000	5,690,000

The data from the table is plotted in Figure E. This shows that the time to pay back the investment in upgrading the existing insulators to an insulator with less flashover events is between 6 and 7 ½ years, depending on the performance of the insulators.

If the Tan(δ) curve is plotted it will also show that the minimum point on the curve has passed and that further delay is not economical.

Figure E



Example 3-3 – Uprating of Line Capacity

Given:

i. The same double circuit 230kV transmission line used in Examples 1 and 2, is used here.
ii. The highest average peak load served by the line is 1000MW. It occurs 50 days each year and lasts for 4 hours. The Load is increasing at 25MW/year.
iii. The maximum thermal rating of this double circuit line is 1125MW.
iv. When the load exceeds the thermal rating of the line, local generation is used to make up the difference. The differential cost for this local generation is 300/MW-hr

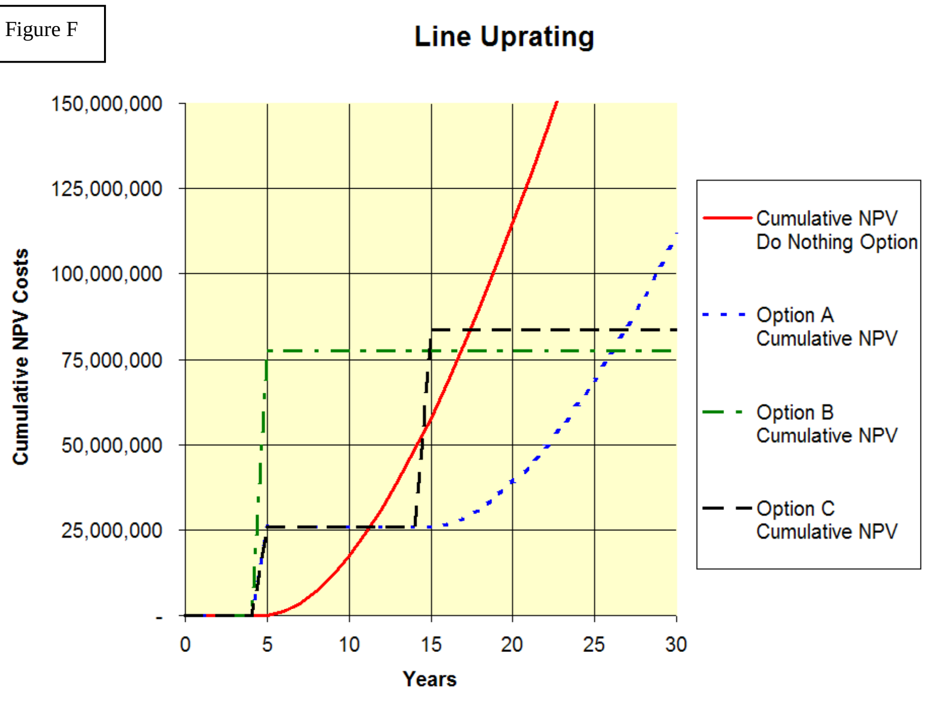
For the purposes of this example, the effects of Net Present Value will be included since the time frame is long. It is assumed that inflation is 4% and the cost of capital is 7%; therefore, a discount rate of 3% will be used to calculate the NPV.

Find: Consider three options and compare them against the option of doing nothing:

A. In 5 years, selective raise the conductor height at 50 towers. This will allow operating the ACSR conductor at a higher temperature and increase the thermal rating of the line by 250MW, thus providing 10 years of additional operation before the thermal rating is again exceeded. Current cost of option A is 30,000,000.
B. In 5 years replace the ACSR conductor with ACSS conductor. This will increase the thermal capacity of the line to 2000MW before other constraints are encountered. This solution would prevent the line from reaching it's thermal limit for 35 years. Current cost of option B is 90,000,000.
C. In 5 years, selective raise the conductor height at 50 towers (initial Option A). In 15 years replace the ACSR conductor with ACSS conductor (delayed Option B).

The comparison of the three options along with the "Do nothing" option are shown in Figure F.

Figure F



Option A has a payback by year 11 while Option B has a payback in Year 17. However, due to the effect of the cost of capitol over time, Option C may be the most attractive.

If the Tan(δ) curve is plotted it will show the minimum Tan(δ) occurs from now until year 5, after that the Tan(δ) curve increases showing that further delay in taking action is uneconomical.

3.4 Cost-Benefit

Cost-benefit assessment based on net present value is widely accepted because influential factors will allow examination of a range of trade-off possibilities. The future cost of construction (new line, upgrading, etc), component replacement, operation, energy losses, risk costs and the maintenance of the transmission line are estimated and calculated for each year within the planning horizon and converted to the net present value by applying a discount rate. The improvement of network availability should also be captured in the cost-benefit assessment by including an equivalent monetary value to represent its community benefit.

The optimization focus is to minimise "costs minus benefits". A project option can deliver savings when the net present value of all cost-benefit summed over the assessment horizon is lower than that of the base case. The input data, intermediate processes and results of such assessment form an essential part of the analysis for justifying network renewal projects.

The economic and financial analysis of the renewal should take into account the following factors within the assessment horizon for the base case asset configuration and any renewal options under consideration;

i. Weighted average cost of capital;

ii. Optimum time for renewal of transmission asset;

iii. Operating expenditure, including inspection and maintenance;

iv. Statistical and probabilistic analysis of risk cost including failure rates and consequences that include supply interruption costs; and

v. Energy losses.

3.5 Optimization

The cost-benefit analysis for the project options should provide project economic viability and associated ranking. The net present cost of the do nothing option would provide the base case for comparison and any option with net present cost lower than the base case would be considered economical and viable.

Under most circumstances, renewal expenditure may be scheduled with considerable degree of flexibility and offer considerable opportunities for optimisation. In this regard, a proposed renewal option may be uneconomical in the current year if the capital expenditure cannot be adequately compensated for by the reduction of other costs. With the exception of capital expenditure component, all other cost items for a renewal option are likely to increase with the degree of "wear-out" accumulated on the existing transmission line targeted for renewal. Hence, an uneconomical option in the current year may become economical in subsequent years as all other costs gradually increase over time. However, the planning horizon should always take into account the time required for permitting, planning and executing any major renewal project.

Example 3-4 – Optimized Tower Painting

Given:

i. The double circuit 230kV transmission line in Examples 1 is used here.

ii. For this example neglect the risk cost associated with a tower failure, only consider the cost to paint and replace corroded members.

iii. Assume the towers still have approximately 10 years of galvanizing left before bare steel is exposed to the environment.

iv. When the galvanizing is gone, the cost of painting increases. The Figure G shows today's costs of Painting per km as a function of the deterioration expected over the next 20 years.

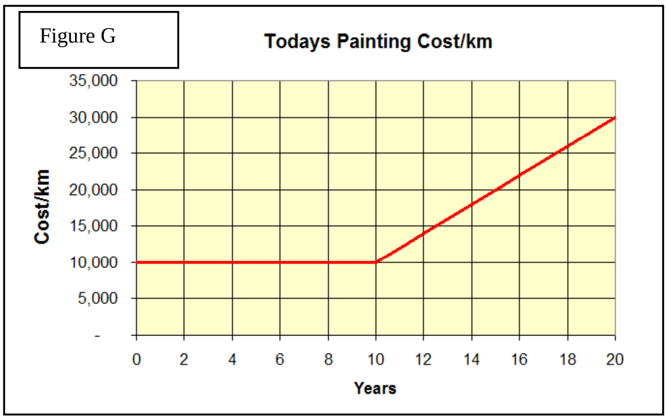


Figure G

Find: the Optimum time to paint.

For the purposes of this example, the effects of discount rate and Net Present Value will be included. The discount rate will be varied from 0% to 6% to see how it effects the optimum time to paint.

A portion of the calculations for the minimum Tan(δ) are shown in the Table at the right.

Year	TAN(δ)	TAN(δ)	TAN(δ)	TAN(δ)
	Discount Rate=0%	Discount Rate=2%	Discount Rate=4%	Discount Rate=6%
0	10,000	10,000	10,000	10,000
1	10,000	9,902	9,808	9,717
3	10,000	9,710	9,438	9,183
5	10,000	9,522	9,086	8,687
7	10,000	9,340	8,753	8,228
9	10,000	9,162	8,435	7,802
10	10,000	9,075	8,283	7,600
11	10,167	9,123	8,242	7,494
12	10,462	9,270	8,281	7,452
13	10,857	9,492	8,376	7,456
15	11,875	10,087	8,672	7,543

Figure H shows the plot of Tan(δ). As can be seen from the Table and Figure H, the optimum time to paint will vary between 10 and 12 years, depending on the discount rate.

It is interesting to note that if this analysis is done again in year 8, the optimum time to paint for all these discount rates will be year 10. A higher discount rate is required to delay the painting.

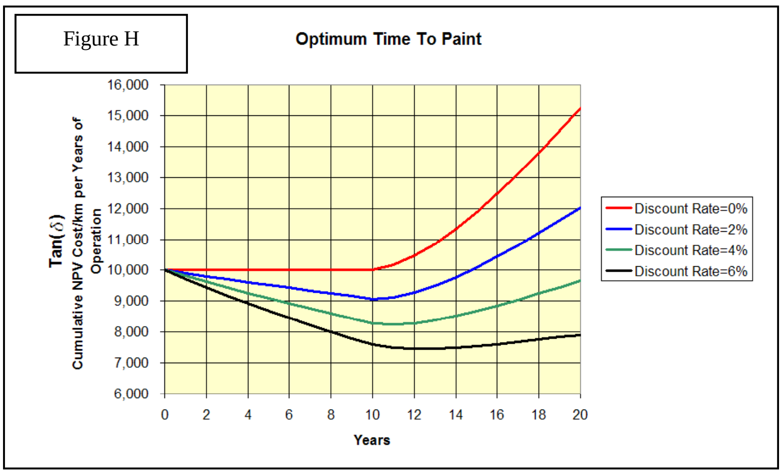


Figure H

The timing of a renewal project should be optimised by selecting the year of implementation to minimise the net present value of cost-benefit. For a given project option there could be three types of possible results

i. The net present cost is minimal for renewal in the current year indicating that renewal is overdue;

ii. The net present cost is minimal for renewal at a future year within the planning horizon indicating the optimal time for renewal; or

iii. The net present cost is decreasing with delaying renewal throughout the planning horizon and indicating that renewal should be deferred beyond the planning horizon.

iv.

If there is more than one viable renewal option, the option with the lowest net present cost at its optimal time should be selected as the preferred option.

3.6 Constraints

Ideally the preferred option of all economically viable renewal projects should be implemented at the optimal time and thus the scheduled network asset renewal capital expenditure will deliver the most favourable cost benefit outcome to the asset owner. However, there are many practical constraints, which may prevent the timely execution of the optimum options. Typical constraints are

v. Financial constraints due to limited expenditure budget or restrictions on raising revenue;

vi. Labour resource constraints from either or both internal employees and external contractors;

vii. Supply security constraints prohibiting coincidental outages of parts of the network;

viii. Technical constraints due to testing and approving an emerging technology;

ix. Timing constraints due to obtaining approval from government authorities and or public consultation processes; and or

x. Sequential dependence among network projects.

Some of the above resources constraints can be pooled. When a pooled resource becomes binding, the conflict has to be resolved by re-scheduling projects from the pool. Taking the original optimal timing as the ideal case, each rescheduling action whether to advance or defer can be assessed for its costs by calculating the corresponding increase in net present cost. Due to the difference in the sensitivity of net present cost to the timing for each project, the project with the smallest increase in costs should be selected for rescheduling.

In addition to the above, there are a number of factors affecting the project renewal which should be considered when evaluating options. They include:

Environmental Protection Measures and Permits

Any construction activities, including work on existing transmission lines, affect environment. Strict environmental regulations in many countries require that transmission line companies must secure necessary work permits prior to carrying out field work, especially in environmentally sensitive areas. In some cases regulatory process might be quite lengthy and it may include review of an appropriate Environmental Protection Plan documents prepared by a power utility. Regulatory bodies may also impose very strict restrictions on types of construction activities and schedules. These may include: acceptable noise levels, use of specific materials and design configurations, protection of endangered wildlife and plant species, protection of religious/sacred sites and many others. This process can result in extensions to a project schedule.

Transmission Line Outage Availability

In current electricity markets, many utilities are operating their power lines close to their capacity. Under such conditions it is becoming increasingly difficult to de-energize transmission lines. Those utilities which use live-line work procedures may perform work on energized lines by deploying qualified personnel. Strict safety measures and proper work techniques must be used to complete live-line work. This often results in a lower productivity, higher number of staff involved and higher labour wages. However, these higher premiums are often offset by revenues realized from continued power sales.

As an alternative, a temporary line by-pass can be used to isolate a transmission line section or an individual structure from the energized circuit. Such installation allows line crews to get access to the isolated and de-energized line section for a limited period of time. Since such installations are of temporary nature, lower safety factors are often used in design.

Working on Structures Under Loads

Safety of field staff is of great concern while working on transmission lines under load. It is essential to carry out a comprehensive structural analysis of the transmission line system considered for upgrading prior to any field work. Existing conductor tensions, component dead weight and resulting loads transferred onto structural supports must be carefully examined and taken into account when developing work procedures and selecting required equipment.

Use of Heavy Equipment

Transmission line components are often under heavy loads and may require use of heavy construction equipment. Proper safety procedures must be adhered to and only qualified personnel must be allowed to work with heavy machinery.

3.7 Terminal Equipment Considerations

All transmission line source and end point connections involve terminal equipment. The primary terminal equipment generally consists of insulators, overhead connections to disconnectors, disconnectors, current and voltage transformers, circuit breakers and in some cases power line communication coupling equipment.

Consideration for the uprating of transmission lines must include a review of the rating of the terminal equipment to ensure compatibility with the line rating.

3.8 Electric and Magnetic Fields

The voltage of a transmission line produces an electric field and the current flowing in a transmission line produces a magnetic field.

Considerations of uprating a transmission line by increasing the thermal capacity or increasing the voltage rating or changing the geometry of the conductor configuration may result in changes to the electric and magnetic fields.

The transmission line uprating design should consider the potential changes to the electric and magnetic fields limited by statutory and safety regulations.

4. Transmission Line Uprating Options and Case Studies *[49]*

Transmission lines are theoretically modelled using engineering principles as either long or short. A long transmission line in general is a major interconnector between load centres or load centres and generation centres and voltage regulation is one of the principle operating criteria which results in determining the level of power transfer capacity. On the other hand a short transmission line in general is an interconnector around or within load centres and power transfer capacity is determined by thermal capacity and is the principle operating criteria.

The operation of long transmission lines is strongly influenced by the voltage regulation and the need to ensure that the receiving end voltage is within defined tolerances. The decision to uprate a long transmission line is therefore linked to improving the voltage regulation.

Short transmission lines are influenced by the thermal capacity of the conductors and the need to ensure that the electrical safety clearances are not breached. Therefore the decision to uprate a short transmission line is linked to improving the thermal capacity.

This Technical Brochure limits the discussion of increasing system needs to considerations of uprating either long or short transmission line elements and it is acknowledged that a number of other methods may be used to increase transmission system capacity such as FACTS (Flexible AC Transmission Systems).

The variety and number of methods and techniques adopted and implemented throughout the world to uprate transmission lines is directly influenced by the considerable variation of transmission line designs and construction methods employed throughout the world. Nevertheless, uprating of transmission lines generally fall into either increasing voltage capacity or increasing thermal capacity. In some circumstances, the opportunity is taken to simultaneously increase the voltage and the thermal capacity (rating) of a transmission line. Table 4-1 provides a list of the most common voltage and thermal capacity uprating mechanisms, the associated techniques, methods and process.

uprating mechanism	method	technique	solution
increased thermal rating	increase conductor rating	conductor replacement	• increased conductivity area • high temperature conductors • composite conductor systems
		modify rating criteria	• meteorological study
	increase conductor temperature & maintain ground clearance	conductor tension	• increase tension • negative sag devices
		increased conductor attachment height	• structure body extension • insulator crossarms • interspaced structures
	increased thermal rating by active line rating systems	line thermal, sag, tension and/or climatic conditions measurement	• line sag or tension monitors • conductor distributed temperature sensing • weather stations
	Probabilistic rating	actual load profile	• temporary increase in rating
		modify rating criteria	• probability based meteorological study
	high surge impedance	conductor bundling & geometry	• physical reconfiguration
increased voltage rating	increased electrical clearances	insulators	• insulator crossarms
		increased conductor attachment height	• structure body extension • insulator crossarms • interspaced structures

Table 4-1: Transmission Line Uprating Mechanisms

The remainder of this section will be given over to describe the various transmission line uprating mechanisms and providing some case studies.

4.1 Increasing Thermal Rating [1]

The practicality of increasing the thermal rating of transmission lines is a function of a number of variables:

i. Terrain – Lines in hilly and mountainous terrain, where structure location is dictated by terrain rather than load, may have many structures that are not loaded to design limits;

ii. Meteorological conditions and corridor characteristics;

iii. Condition of the conductor, insulation and structures;

iv. Cost of losses, which is a function of the planned length of time to operate at high electrical loads;

v. Regulations and standards regarding line to ground clearances;

vi. Regulations relating to tower loadings;

vii. Line length;

viii. Original design capacity of structures

Increasing the thermal rating of transmission lines may be accomplished by one or a combination of the following:

i. Increasing the conductor area by
    a. Adding conductors to existing conductors or conductor bundles
    b. Replacing existing conductors with new conductors of different size or construction;
ii. Increasing the conductor rating by changing the thermal rating criteria based on a statistically-based meteorological study and an evaluation of the characteristics of the line corridor;
iii. Installation of special conductors intended for high temperature and/or low sag operation;
iv. Increasing the conductor operating temperature limit, which will require one or more of the following to maintain adequate ground clearance:
    a. Increasing conductor tension (with associated tower reinforcement);
    b. Modifying towers and / or insulation to increase ground clearance;
    c. Insertion of new towers in critical spans;
    d. Installing negative sag devices;
    e. Excavation at key locations to increase ground clearance;
v. Modifying the line to achieve a higher surge impedance load;
vi. Installation of active line rating systems (this may not be considered a method to increase line ratings; it does not change the maximum capacity, but it does allow better utilization of the existing capacity);
vii. It may also be possible to increase the rating at very nominal cost by a very precise survey of the conductor clearances against standards.
    a. The survey results may show that in hilly terrain there may be a very small number of structures to raise or ground profile to modify to achieve a significant increase in rating;
    b. Suspension insulator offsets may be used to remove sag from critical spans, although at the expense of a sag increase in adjacent spans.

These methods will be discussed in the following sections.

4.1.1 Increasing Conductor Rating

<u>4.1.1.1 Increasing Conductor Area</u> [2], [3]

It is quite obvious to increase conductor area in order to increase the power carrying capacity of an overhead transmission line. However, there are certain factors that should be considered during this activity as follows:

i. In general, the higher the area of the conductor is, the higher its weight will be. This may be mitigated to some degree by changing material or conductor type. Increased conductor weight will generally result in increased tensions, which will most likely require reinforcement of termination and angle structures.

Higher conductor area may increase the ice and wind load on the conductor as well, increasing the vertical load on all structures. (Note: there are conductors with trapezoid wires where the area of the conductor increases without the increase of its diameter. It helps to increase the capacity of the line by some percent, with lower impact on mechanical loading than an equivalent increase using standard round stranding); and

ii. The higher the diameter of the conductor is the higher wind and ice load will occur. It means that increasing conductor area (more precisely: increasing conductor diameter) will increase the horizontal loads on the structures.

There are two basic solutions for increasing conductor area of a transmission line: it can be done either with or without substantial reinforcement of the structures and foundations.

Beyond the network requirements arising from expected electric loads in the future, there are some mechanical factors to be considered before the decision about reinforcement. Some of them are as follows:

i. It is important to make a clear distinction between the design status and the actual status of the structures. It is easy to evaluate the mechanical capacity of the structures in design status, however, the actual status of the structures need thorough investigation and evaluation;

ii. The mechanical capacity of the overhead line may be understated by a substantial percentage. Additional loading may be applied without the need for substantial reinforcement to the structures;

iii. Some structures may need only partial reinforcement on the body or on the crossarms therefore they can be strengthened relatively easily and economically;

iv. No extra load is advisable without substantial reinforcement on overhead lines where frequent mechanical failures have occurred in the past;

v. Lines where structure location is governed by terrain rather than structure load limits, i.e. through very rough terrain, may have less than full utilization of mechanical design load capacity for a significant portion of structures. These structures can have loads increased with little or without reinforcement; and

vi. New conductors may operate on the same temperature or on higher temperatures than the old conductors therefore sagging is a key issue for the decision.

It is quite common to replace ACSR (Aluminium Conductor Steel Reinforced) conductors with AAAC (All Aluminium Alloy Conductor) conductors with the same or slightly higher diameter as the ACSR conductors. If the diameter of AAAC conductor is the same as the diameter of the ACSR conductor then its weight is smaller, and the current carrying capacity of the line will increase with some 20…40% [1] depending on the clearances and on the tension applied. Even higher capacity can be reached if the diameter of the conductor is a little bit higher. Changing ACSR to similar diameter AAAC does not need substantial reinforcements to the structures and foundations. Using AAAC with the same diameter as the ACSR but with trapezoidal sections will further increase the area and thermal capacity, with little or no loading impact (wind and ice loading should not change). Also replacement of standard ACSR with ACSR of the same diameter but using trapezoidal strands, will cause some increase in tensions and vertical load, but should not change the wind and ice loading.

Conductors on overhead transmission lines can be replaced with conductors of substantially higher diameter or conductors can be added to existing bundles or single conductors can be bundled. In addition to increasing the thermal capacity very substantially, the addition of a bundled conductor configuration significantly changes the Surge Impedance Loading (SIL) of the line, which has system implications. The transfer capacity may be doubled if a new bundle is created in each phase doubling the number of the conductor. However, these methods generally require substantial reinforcement to the structures and foundations. Also line to structure clearances will require evaluation and perhaps some structure reconfiguration.

In order to minimize the effects of higher loads to the structures, special wires can be used. As mentioned previously, formed wires will have higher aluminium content in the same cross-section, i.e., less extra load will be observed (less wind load, less ice load, etc.).

4.1.1.2 High Temperature Conductors

There is a range of new conductors that have been recently developed for high temperature operation. Some of them are as follows:

i. Aluminium-zirconium alloy conductors: TAL, ZTAL, XTAL;

ii. Aluminium-zirconium alloy conductors steel reinforced: TACSR;

iii. Aluminium-zirconium alloy conductors invar steel reinforced (low thermal coefficient conductors): TACIR, ZTACIR, XTACIR;

iv. Gap-type aluminium conductors steel reinforced: GTACSR, GZTACSR.

The details of these conductors and their behaviour can be read in Technical Brochure 244 “Conductors for the Uprating of Overhead Lines” written by WG B2.12 [1]. There are some common features of these conductors as follows:

i. These new conductors have the same goal: to increase the ampacity of the conductor without substantial increase of the sags;

ii. Low thermal coefficient materials are used for the core if any;

iii. Depending on the type of the conductor the maximum operating temperature can be up to 230 °C;

iv. Losses will be high during the peak hours. If the length of peak hours is rather high then the costs of losses may be substantial; and

v. Ampacity of the overhead line may increase by additional 50…100 % without substantial reinforcement to the structures. For some of these conductor types the tensions are higher requiring reinforcement of at least terminal and angle structures.

Also other conductors like ACSS (Aluminium Conductor Steel Supported) and ACCC could be used as high temperature conductors.

Case Study 4-1 (USA) – Increasing the Capacity of a 345kV Line from 1251MVA to 1972MVA while Energized [62]

The increase in capacity was accomplished by replacing the existing ACSR conductor with ACSS/TW (trapezoidal wire) and matching the design working tensions so that it would not be necessary to change out structures or anchors.

Do to system constraints the line could not be taken out of service for the extended period of time required for normal uprating. Therefore, the 52km line, consisting of 234 H-Frame structures with the three phases in a horizontal configuration, was reconductored while energized. Work plans were developed to enable the sequential transfer of electric load between the three existing phases and a temporary transfer bus. Supplementary pole structures were constructed to support the energized temporary line. Rollers were installed on the de-energized existing phases to be reconductored. In this configuration, the induced voltages on the “de-energized” conductor ranged up to 30kV, therefore, the equal potential stringing method was used to eliminate potential hazards to the line crews and public. Other procedures that were developed were:

i. Tying off the existing and new conductor at night by insulating and isolating the conductor from the equipment.
ii. Transferring of large loads from existing conductor to the temporary line, and from the temporary line to the new conductor, using a mobile 345kV breaker.

Installing rollers on the de-energized phase while the temporary line at the left is energized.

Mobile 345kV Breaker.

4.1.1.3 Meteorological Studies

The traditional means for establishing thermal conductor ratings has been to perform the calculations based a commonly used set of weather parameters deemed to be conservative for most situations (e.g. 0.6 mps wind speed, 40º C ambient temperature and full sun). Too often, less conservative values have later been selected based on quasi-scientific evidence as an easy way to increase these ratings. This is dangerous and can lead to an unacceptable level of thermal breaches. However, a thorough scientific study of the meteorological variables can produce a less restrictive set of values to use that would still provide the level of conservatism warranted. This approach is viable only if there is sufficient meteorological data to do so and a statistical study is conducted by a qualified wind engineer who also considers the local effects of terrain and sheltering at the line sites.

4.1.2 Increasing Conductor Temperature and Maintaining Ground Clearance [1], [4], [5]

Knowledge of the material behaviour and limits of conductors when subjected to various heating conditions is essential when designing and operating overhead lines. Two areas are particular interest when consideration is being given to increasing the rating of transmission line by increasing the operating temperatures of conductors. These areas are loss of tensile strength by annealing and longer term permanent conductor elongation through metallurgical creep

The additional effects of increasing conductor temperature on the galvanized steel core, current carrying connectors, conductor hardware and the protective properties of grease are summarized in Appendix 1.

Conductor Annealing [6]

The design maximum operating temperature of a conductor is partly a function of the acceptable level of permanent loss of tensile strength or annealing of the conductor. Annealing is caused by the heating of a material generally followed by a cooling period. During the annealing process, the material experiences a change in its microstructure and for metals, this not only results in a loss in tensile strength but also an increase in conductivity. In general, changes in conductivity will be insignificant compared with the changes of tensile strength.

Isothermal annealing curves illustrate the permanent loss of tensile strength when a conductor operates at elevated temperatures. It is appropriate to establish the maximum design temperature at which a conductor can operate while maintaining acceptable levels of degradation of tensile properties.

More recent research indicates that the annealing characteristics of a conductor depend not only on temperature and time of exposure but also on the diameter of the wires in the conductor. Smallest wire size suffering the greatest loss in strength and the largest size the least. The magnitude of this wire size dependence is considered, at this stage, to be of a lower order than the effect of temperature. Copper has similar annealing properties, which are not as well documented as those for aluminium, but it has less loss of strength for the same temperature.

The recommended maximum temperature limit for normal operation of AAC, AAAC and ACSR is approximately100 °C. This permits an approximate loss of strength of 3% of the original tensile strength after 1000 hours operation at this temperature.

For ratings for emergency conditions (eg. when one circuit has to carry more than normal current for a short time), both the maximum temperature and the duration of the emergency load should be taken into account in determining the annealing of the aluminium wires. The annealing effect is cumulative. For example, if a conductor is heated to 150 °C under emergency conditions for 24 hours a year for 30 years it is much the same as heating the conductor continuously at that temperature for 720 hours. For this example the loss of ultimate strength in AAC would be approximately 15%. For 30/7 ACSR the ultimate tensile strength would be reduced approximately 7%. The effect is less significant for ACSR where an increase in temperature results in a load transfer from the aluminium to the steel wires. The steel provides most of the strength of the conductor and is essentially unaffected by the temperature until 200 ^{o}C. Above this temperature for normal steel there is a gradual fall off in strength until at a temperature of 400 ^{o}C where the strength of the wire is only half of that of the room temperature strength.

If ratings for emergency conditions are to be applied then the combined effects of elevated temperature and increased tensile loading on the steel core due to compression loading in the aluminium wires on the sag of the line should be taken into account. Practically, the tension in a line reduces with increasing temperature so the effect is less severe [1].

Conductor Permanent Elongation

Conductor permanent elongation is non-recoverable for inelastic material deformation that is a logarithmic function of conductor stress, conductor temperature and exposure duration. Permanent elongation begins at the instant of applied axial tensile load and continues at a decreasing rate providing tension and temperature remain constant. Permanent elongation consists of, in the short term, primarily wire radial and tangential movement during the early loading period (settlement & short-time, high-tension creep elongation) and in the longer term, primary metallurgical logarithmic creep (long-time, moderate-tension creep elongation).

Conductors operating at elevated temperatures will experience elevated conductor creep. In changing from low temperature conductor creep to high temperature conductor creep, it is necessary to convert the equivalent low temperature elongation equivalent time to an equivalent high temperature elongation equivalent time and project the longer term reduction in conductor tension and increase in conductor sag.

Increasing the conductor operating temperature of a transmission line within the previously mentioned material limits of the conductor and maintaining ground clearance will increase the thermal rating of the transmission line. A typical relationship of the thermal rating of non homogenous and homogenous conductors is illustrated in Figure 4-1. This relationship is essentially based on the fact that increasing the current will increase the thermal elongation which results in a reduction of conductor tension and a corresponding increase in conductor sag.

For example, increasing the operating temperature from 85 °C to 100 °C of a 207 mm^2 non homogenous conductor results in an increase of the conductor thermal capacity from 565 A to 655 A or about 15% which will result in a conductor sag increase of about 0.57 meters in 400 meter span or about 5%. Similarly, for the same 400 meter span, for a 506 mm^2 homogenous conductor increasing the operating temperature from 85 °C to 100 °C results in an increase of the conductor thermal capacity from 880 A to 1030 A or about 17% which will result in a conductor sag increase of about 0.62 meters or about 4%.

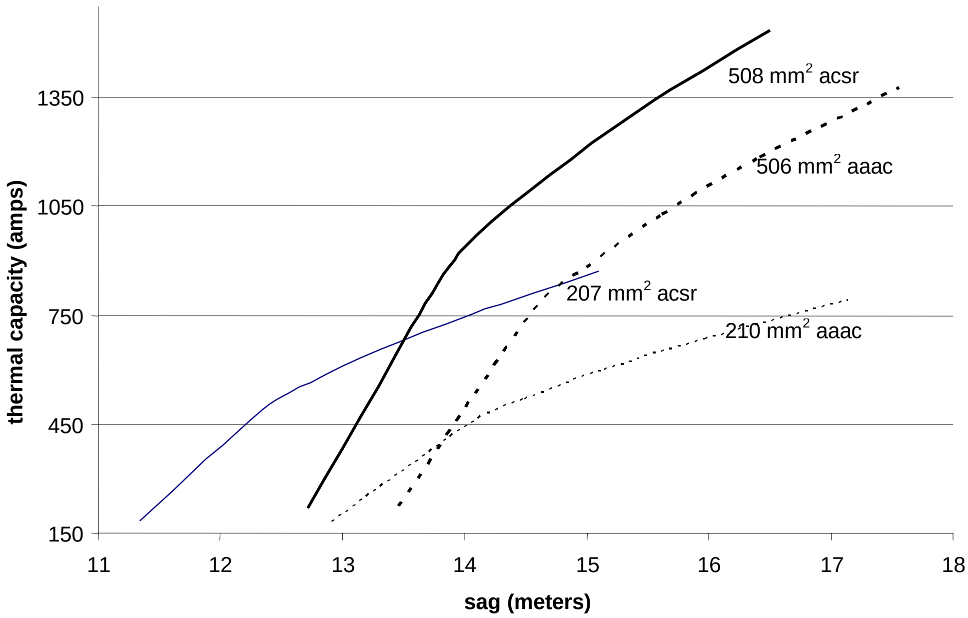


Figure 4-1: Typical Relationship of Conductor Thermal Capacity to Conductor Sag for a Given Span

To ensure statutory ground clearance is maintained, mechanisms are required to compensate for this increased sag. Increasing the conductor operating temperature of transmission lines and maintaining ground clearance may be achieved by either increasing conductor tension, application of negative sag devices and or increasing the conductor attachment height. Increasing conductor attachment height is carried out by structure body extensions and or insulator crossarms.

4.1.2.1 Increasing Conductor Tension [7]

Increasing conductor tension is one of the most common forms of increasing the rating of a transmission line. One of the most significant considerations in increasing conductor tension is the increased likelihood of aeolian vibration and associated increase in probability of longer term conductor permanent damage and even failure by fatigue. Notwithstanding this when consideration is given to increasing conductor tension it would be normal that the line would have been in service for a considerable period of time which would suggest that the aeolian vibration performance of the line is well known and the consequences of increasing conductor tension would be well understood.

Other design verification considerations would include

i. Increased conductor tension loads on angle and tension structures and even suspension structures under broken conductor loading conditions or other imbalanced longitudinal loading condition;

ii. Increased foundation loads for angle structures;

iii. Increased conductor tension loads on tension insulators and associated fittings;

iv. For spans with differing conductor attachment relative levels, the changes in the weight span and resultant changes in suspension structure clearances for suspension insulators or changes in load factors for V string insulators; and

v. Increased conductor loads on all conductor joints under tension.

The technical limits of increasing conductor tension is normally determined by

i. The capacity of tension and termination structures and any associated cost benefit of increasing this capacity; and or

ii. Aeolian vibration and or the fatigue limits of the conductors. The fatigue limits of conductors and the safe design tension has been the subject of widespread international research. An example of the publication of this research is the CIGRE SC B2.11.04 [7] recommendation for conductor safe design tensions at average temperatures of the coldest month as a function of terrain category for homogeneous and non homogeneous conductors and is given in Figure 4-2. Any proposed increase in conductor tension should be considered within the conductor safe design tension criteria

<u>CIGRE TF22.11.04</u>
<u>Safe Design Homgeneous and Non Homgeneous Conductor Tension</u>
Terrain Category 2
(open, flat, no obstructions, no snow cover, eg farmland without any obstructions, summer time)

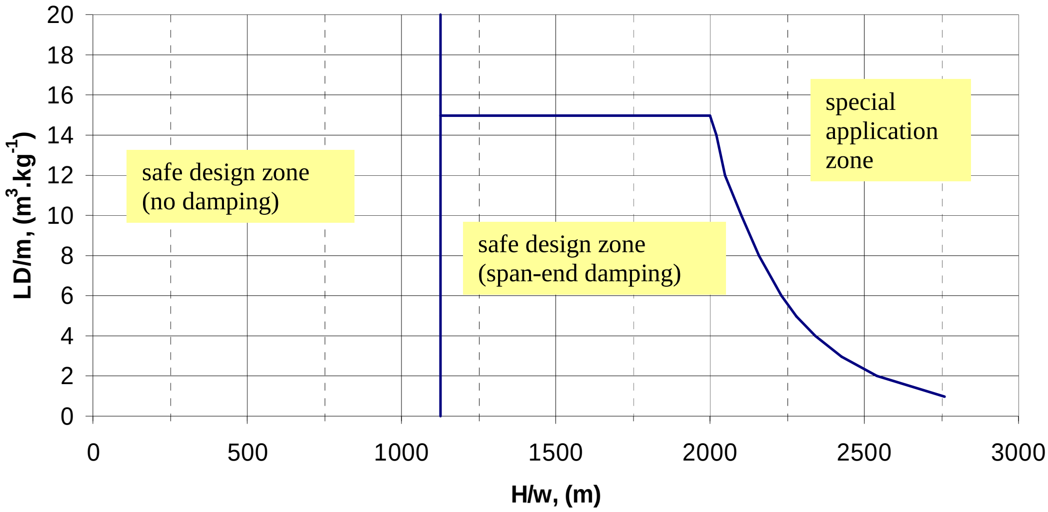


Figure 4-2: CIGRE SCB2.11.04 Conductor Safe Design Tensions Recommendation

Where: L = actual span length, D = conductor diameter, m = mass of the conductor per unit length H = horizontal tension in the conductor and w = weight of the conductor per unit length

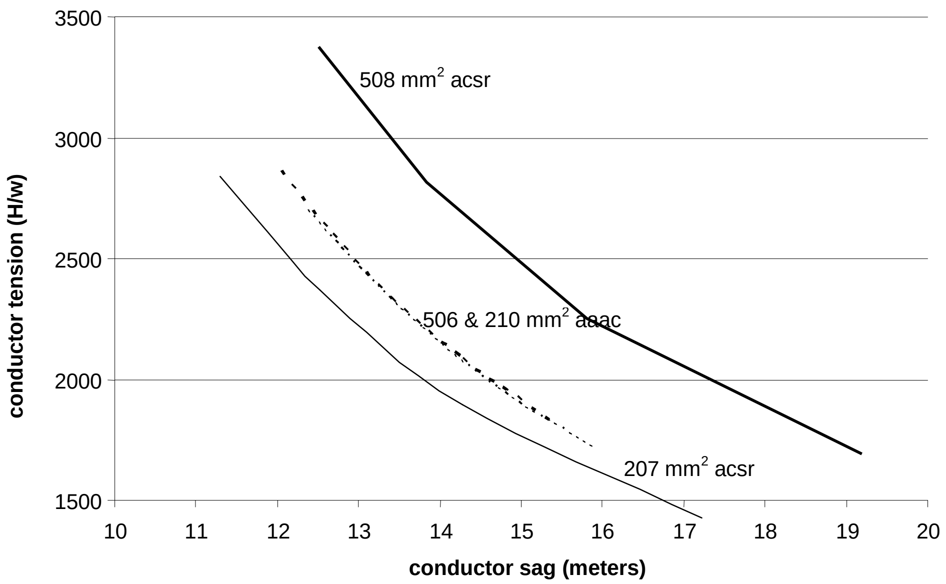
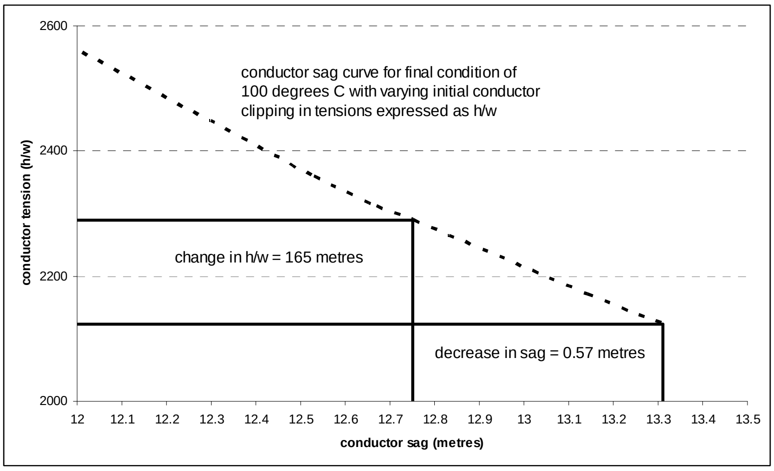


Figure 4-3: Typical Relationship of Conductor Tension Parameter (H/w) and Sag

A typical relationship of conductor tension parameter (H/w) and conductor sag for non homogenous and homogenous conductors is illustrated in Figure 4-3. The figure illustrates that decreasing the conductor sag will require a corresponding increase in the conductor tension.

Case Study 4-2 (Australia) – Increasing the 207 mm^2 ACSR Conductor Thermal Capacity by 15%

Based on the previous example of increasing the operating temperature from 85 °C to 100 °C to increase the current carrying capacity from 565 to 655 A or about 15% the conductor tension parameter will be required to increase from 2124 meters to 2289 meters or an increase of about 8% to compensate for the increased conductor sag of about 0.57 meters in a 400 meter span. The increase in conductor tension and decrease in conductor sag is illustrated in the following figure



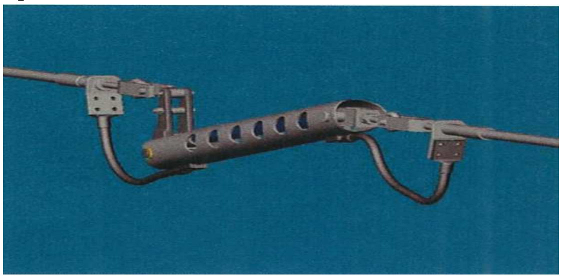
4.1.2.2 Negative Sag Devices

Negative sag device is relatively new transmission line hardware and is based on a reaction to increasing conductor temperature by decreasing the effective length of conductor in the span thus mitigating thermal expansion experienced by the conductor during high temperature operations.

The negative sag device is activated by the same temperature changes that cause the conductor to sag. As temperature rises, conductor lengthens and the conductor sag increases. Under same circumstances, the negative sag device changes the device's geometry to decrease span length. As the conductor temperature returns to normal and sag is no longer excessive then the negative sag device returns to the original shape.
At the time of writing these devices are the subject of current product commercialization.

Case Study 4-3 (USA) - Full Scale Tests Negative Sag Device

Tests were carried out on a control and a test span of 152 m for a 403-A1/S1A-54/7 (Condor) operating at 22,2 kN (50001bs) at 32 °C with an ambient temperature of about 32 °C. Both conductors were heated by a current of 1200A and the sag differential between the two spans at the maximum conductor temperature of 100 °C was over 1 200 mm.



4.1.2.3 Increasing Conductor Attachment Height

Increasing conductor attachment height to compensate for increased conductor thermal ratings is a natural consideration to compensate for increased conductor sag. Increasing conductor attachment height may be carried out by either the insertion of structure body extensions into existing structures and/or application of insulator crossarms to existing steel crossarms.

4.1.2.3.1 Structure Extensions [8], [9]

General experience indicates that given the magnitude of the required structural works it is not economical to increase the heights of all structures in a transmission line. Nevertheless it has been found that in many cases an increase in maximum operating temperature may be achieved by selectively increasing the height of approximately 10% of the structures. Selective inclusion of structure extensions is normally limited to the suspension structures given the inherent structural and practical difficulty of including a body extension into a tension or terminal structure.

Design verification of increasing conductor attachment heights by the inclusion of a body extension would include

i. Structural capacity of the existing structure to determine the availability of any marginal capacity;

ii. Design of the structure extension which may in general be limited to the structure where the structure geometry would permit the inclusion of a structure extension; and

iii. An assessment of the foundation capacity and any increased overturning moments.

The technical limits [3] of the inclusion of a body extension would normally determined by the structure and foundations ultimate load factor for the defined loading conditions.

Case Study 4-4 – Increasing the Capacity of a Double Circuit 132 kV Lattice Steel Tower Transmission Line from 212 MVA to 262 MVA

The solution involved two elements

i. Replacement of the existing 322-A1/S1A-30/7 (Scoter)with a maximum operating temperature of 75 ^{o}C with 61/3.25 mm AAAC 6201 with a maximum operating temperature of 85 ^{o}C; and
ii. Insertion of a 4 meter structure extension by the progressive removal of the crossarms, the rebuilding of the lattice steel tower structure section and the progressive replacement of the crossarms.

The work was carried out with one 132 kV circuit in service at all times.

Increasing Tower Height

Increments in the tower height have generally been achieved by inserting a new steel panel into the lower portion of the tower (Figure 4-4). Usually a 2-3 meter new extension is enough to achieve the new desired clearance.

Figure 4-4: Increasing Tower Height

The new panel is designed in such a way (the same connection type) that it can be perfectly connected in the upper and lower parts of the structure.

As the original base width of the tower is concurrently not changed this naturally causes increases on the lower body stresses. That can demand:

i. A completely new reinforced lower part (not very common); or

ii. Reinforcements on the existing lower body.

The reinforcements on the existing lower body can consist basically of duplication of the main members (Figure 4-5) or complete substitution for bigger ones.
Replacement of cross bracing members may also be required.

Figure 4-5: Duplication of Leg Members

Foundation Questions [11], [12]

As mentioned before, the current practice is not to change the tower base width, the aim being to keep the existing foundations. This naturally causes increments on the foundation loading since they are now subjected to greater loads, due to higher conductor attachment points. That means bigger overturning moments. These moments will in the end increase the uplift and compressive loads.

Bigger uplift reactions can be counteracted by adding additional concrete within the soil frustum or in critical cases by the installation of injected micro-piles plus a new concrete block connected to the existing foundation.

Compressive resistance is normally not a problem and if it is the proposed solution can be achieved with the same injected micro-piles technology.

Erection Techniques [13]

The current erection technique for raising tower heights was first used in the 1930's. Afterwards more than 100 projects using this methodology have been reported. It consists basically of two solutions:

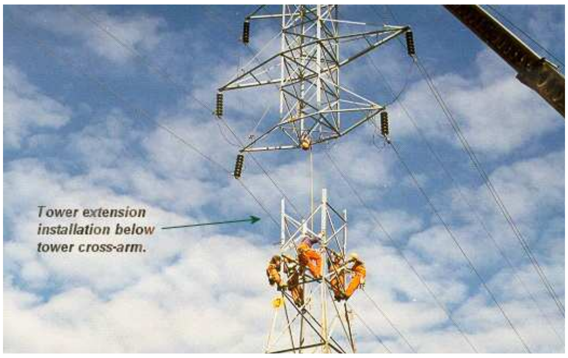
i. Using external support structure;

ii. Using an internal central mast.

Some advantages have been reported for using the second system: standardization in the process, easy transportation, reduction in installation time and lower cost.

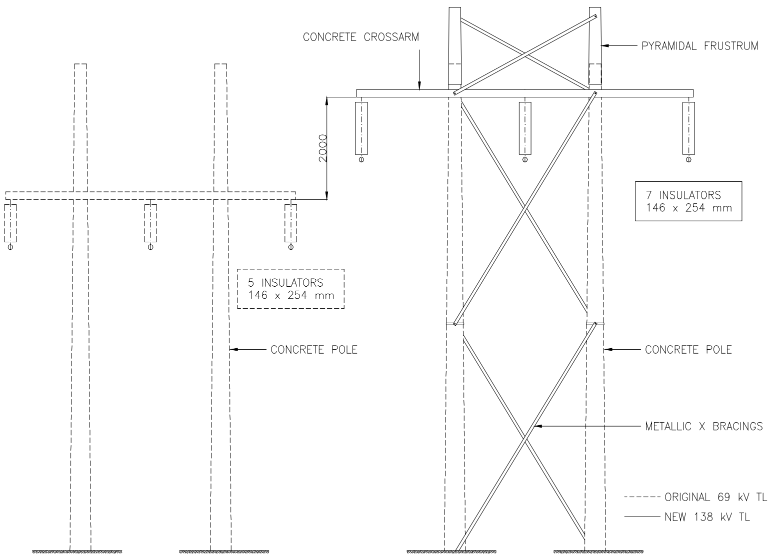
Depending on the conditions, raising of the tower height is an erection process that can be done with the lines in service without any outage. This can be attained with sophisticated erection equipment (raising device) and a team with deep knowledge and experience.

Case Study 4-5 (Canada) – Installation of Tower Extensions
Tower extensions were used to increase conductor ground clearance of the existing 115 kV double circuit lattice steel transmission line. The original line rating of 50^{o}C was increased to 100^{o}C with the use of tower extensions and re-tensioning of the conductor. The work was done with both circuits energized.



Case Study 4-6 (Brazil) – Uprating of a 138 kV Line with Concrete Pole Structures

In this case, the conductors were raised by installing a new concrete crossarm two metres above the old one on the same poles. An extension consisting of pyramidal frustum was installed at the pole tops to support and raise the position of the shield wires. Two metallic "X-bracings" were introduced to provide stability to the new higher structure.



Case Study 4-7 (Spain) – Uprating by Increasing the Conductor Temperature

Voltage: 220 kV single circuit
Length of line: 48 km
Conductor: Single 403-A1/S1A-54/7 (Condor)
Capacity increase: from 342 MVA to 421 MVA
Conductor Temperature: from 50º to 75º
The solution involved next steps:

i. Topography study in order to verify the ground clearances and the clearances with others electric lines, roads, railways, etc.
ii. To analyse the increase of sag from 50 ºC to 85 ºC
iii. To define the spans where the clearances are below of minimum clearances
iv. Insertion of structure extensions in towers where it is needed (to maintain minimum clearances). The usual extensions height 5 meters.
v. Refurbishment of foundation if it is needed

Structure extensions: 14
Foundation refurbishment: 0

Case Study 4-8 (USA) – Increasing the Ampacity Rating of a 345 kV Line by Raising Structures

A utility identifies the need to increase the capacity of a key transmission path. A preliminary assessment of limiting factors shows that the ampacity of a 345 kV line built in the mid–1960s is thermally limited by ground clearance due to conductor sag occurring at higher operating temperatures. A detailed line rating study is initiated to identify cost-effective means to uprate the capacity of the line. Hardcopies of original plan and profile drawings are scanned and imported into state-of-the-art transmission line modeling and design software to perform an initial assessment of limiting factors, next LIDAR is used to enable refinement of the line model, and the model is then used to identify the number of spans with inadequate ground clearances, the degree to which ground clearances are exceeded within these spans, and possible means to increase the clearances. Analyses revealed that only a relatively small number of spans within the 156 mile long line exceeded the governing safety code imposed ground clearance limits at the target operating temperatures. Several options were identified for increasing the clearances. These options included replacing existing structures or poles with new taller structures or poles in critical locations, inserting additional structures in critical spans, resagging short sections of the line, or using an innovative technology that enables the heights of existing wood pole structures to be increased in place. Raising the existing structures was determined to be the most cost-effective option for this situation. Implementation of this option resulted in approximately 50% savings relative to the next most favourable option, and enabled a 25% increase in line capacity to be realized within a very tight schedule (18 months from design to completion). In addition, the line remained energized throughout the entire structure raising operation.

Installation of System to Raise Structure

Raised Structure

Case Study 4-9 (Spain) – Uprating by Increasing the Conductor Temperature

Voltage: 400 kV single circuit
Length of line: 62.5 km
Conductor: Twin 484-A1/S1A-54/7 (Cardinal)
Capacity increase: from 1398 MVA to 1829 MVA
Conductor Temperature: from 50 ºC to 85 ºC
The solution involved the next steps:

i. Topography study in order to verify the ground clearances and the clearances with others electric lines, roads, railways, etc.
ii. To analyse the increase of sag from 50 ºC to 85 ºC
iii. To define the spans where the clearances are below of minimum clearances
iv. Insertion of structure extensions in towers where it is needed (to maintain minimum clearances). The usual body extension height 5 meters
v. Refurbishment of foundation if it is needed

Structure extensions: 14 (see Photographs below)
Foundation refurbishment: 1

4.1.2.3.2 Insulator Crossarms or Insulator Modifications [14], [15], [16]

Similar to increasing conductor tension, the replacement of existing insulators with some form of insulating crossarm or modifying the existing insulator arrangement are also some of the most common ways of increasing the rating of a transmission line. The conductor attachment relative level is thus raised permitting the conductor sag to increase. This is particularly so since the advent of composite insulators and the possibility to apply composite or hybrid insulator sets to fulfil the geometrical, electrical and mechanical requirements of a new insulator system with in most cases enhanced performance.

One of the most important considerations in replacing existing crossarms or insulators is a fundamental understanding of the pollution levels and the performance of the existing insulation design of the transmission line. Notwithstanding this, when consideration is given to modifying the existing transmission line insulation it would be normal that the line would have been in service for a considerable period of time which would suggest that the insulation performance of the line is well known and the consequences of changing the insulation design would be well understood. Other design verification considerations would include.

i. Mechanical loads of the insulator arrangement;

ii. Changes in the coupling point of the applied insulator loads on the structure;

iii. Changes in the electrical clearance envelope caused by changes in the insulator swing;

iv. Changes in the conductor attachment fittings and associated loads; and

v. Any changes in structure longitudinal load and restrained insulator movement.

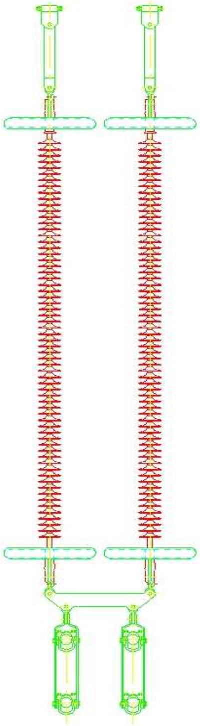
The technical limits of insulator crossarms or insulator modifications are normally determined by

i. Required electrical clearance window;

ii. Required coupling and creepage length of the insulators; and

iii. Flexibility of changing the insulator loading structure coupling points.

Case Study 4-10 (Germany) – Uprating a 420 kV Line from 60°C to 80°C Maximum Conductor Temperature Using Short Composite Insulator Strings



For the purpose of increasing the thermal rating, the conductor system was uprated from 60°C to 80°C maximum conductor temperature. Due to the higher sags at 80°C, measures had to be taken to increase the clearances to ground. The action could have been either a tower height increase which was determined to be uneconomical or the design of shorter insulation. Before uprating to 80°C, a double I-string with 3 porcelain longrod units LG75/22/1270 in series was used. The total set length from tower crossarm to conductor was reduced by 1000 mm by using only one unit composite longrod short string units in the set instead of the three old units (see picture).

420 kV set with short nominal length. Insulator strings have a nominal length of 3000 mm (2650 mm arcing distance) which is sufficient to reach BSL=1050 kV and BIL=1425 kV in accordance with IEC 60071-1.

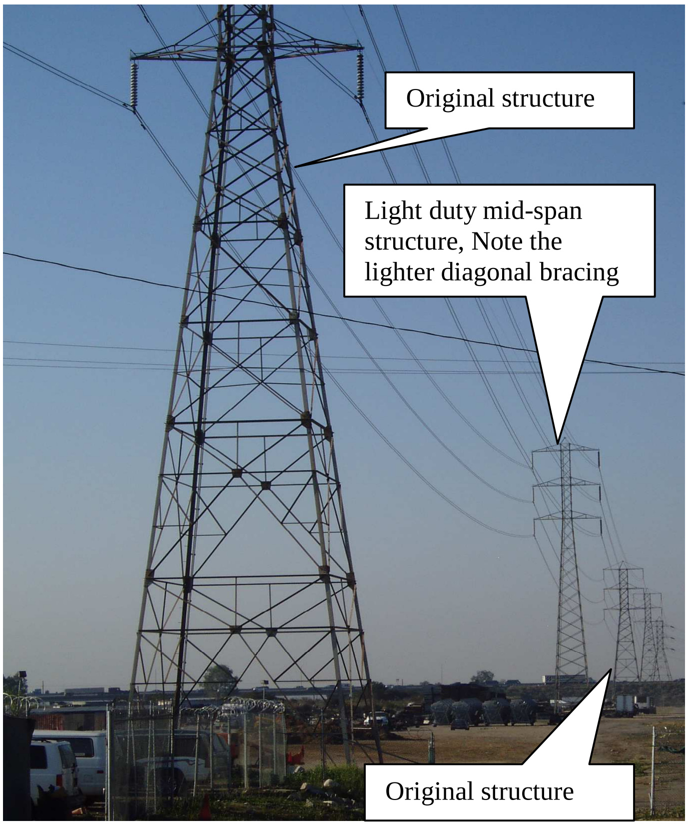
4.1.2.4 Use of Interspaced Structures

The use of interspaced structures is another way to increase line clearance. The installation point(s) would normally be where the greatest amount of sag occurs or at the point on the ground profile where a clearance problem exists at increased conductor operating temperature.

It is desirable to install the structures at the mid-point of the span in order to minimize the amount of in-line tension that would be affecting the structures tangential strength requirements. Essentially the structure should be capable of supporting the span weight of the conductors as well as any environmental impacts the line would be expected to experience such as wind and ice build-up on conductors.

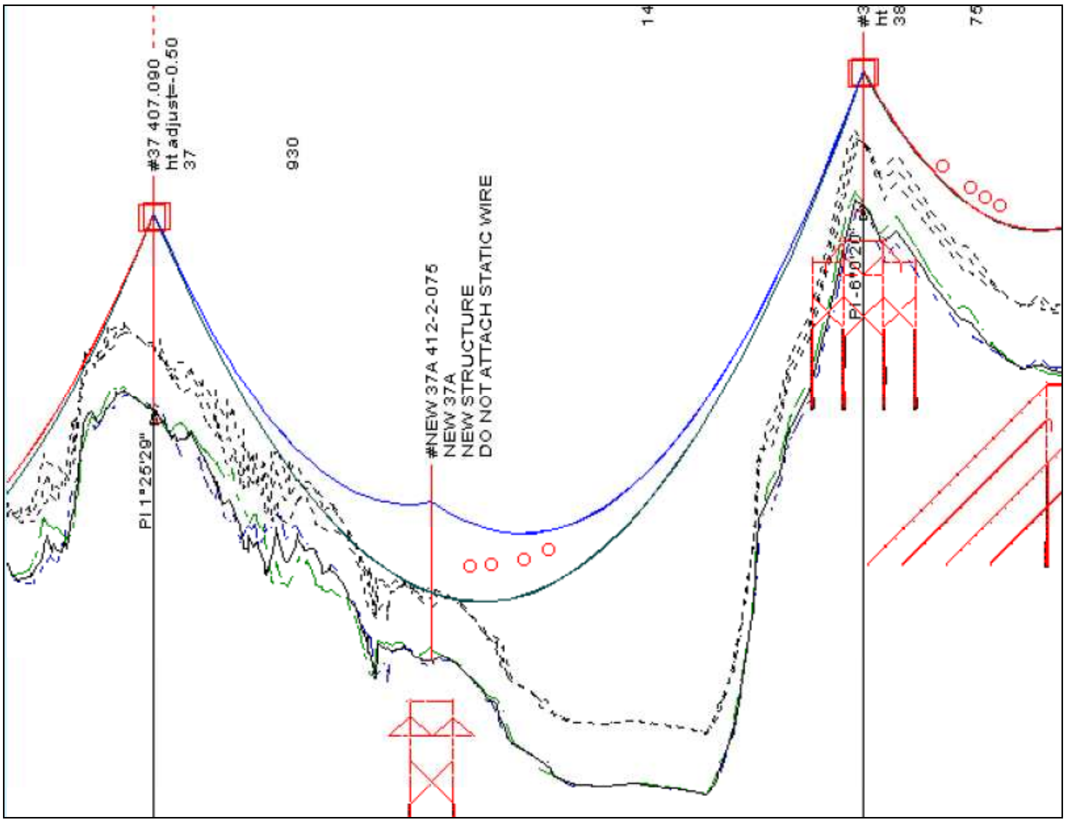
Factors impinging on the design and ease of use for this solution may include items such as ownership of the right of way or easement restrictions as well as aesthetic considerations in built up areas.

Case Study 4-11 (USA) : Mid-span Structures for Uprating



The double circuit 230kV line above was uprated from single 305 mm^2 ACSR conductor to vertical twin 523 mm^2 ACSR conductor. Due to the heavier conductor weight and increased sag, light duty mid-span lattice structures were installed as shown above.

Case Study 4-12 (USA): Mid-span Structures for Uprating



A utility in the United States wanted to maximize existing conductor capacity on a wood pole line by either: installing taller poles; installing additional mid-span structures (shown above); re-sag conductor or raise the phases on some of the existing structures. They achieved a 30% to 50% increase in capacity.

4.1.2.5 Separated Mechanical Conductor System (SMCS)

SMCS, similar to aerial cable or messenger wire systems, is a very recent application on overhead lines. The basic concept is to divide the current carrying function and the mechanical function by using minimum one mechanical conductor and minimum one current carrying conductor in a bundle. As the mechanical conductor (made of steel for instance) is separated from the current carrying conductor, its temperature will not practically change if the electric load becomes higher, therefore the sag will not increase. On the other hand, as the current carrying conductor usually made of aluminium has no mechanical function, its temperature may increase up to about 250 °C causing the loss of strength of the conductor without any drawback to the operation of the line.

SMCS can be applied to existing overhead lines simply by adding a new mechanical conductor to the existing conductor(s) in a bundle using the old conductor(s) (mainly) as current carrying conductor(s).

Note, that SMCS is under investigation and there is no operational experience with SMCS.

4.1.3 Increasing Thermal Rating by Active Real Time Line Rating Systems

[17], [18], [20], [21], [22], [23], [24], [25], [26], [27], [59]

Most utilities in the world base their transmission line "book" ratings on deterministic assumptions of a low wind speed and direction, high ambient temperature and full solar radiation. The most significant of these variables is the assumed effective wind speed. Such assumptions are commonly chosen in a way that there is a small but finite risk of the conductor exceeding its design temperature, but in reality such chances are low, because lines are seldom operated at their rated currents. This is illustrated in Figure 4-6.

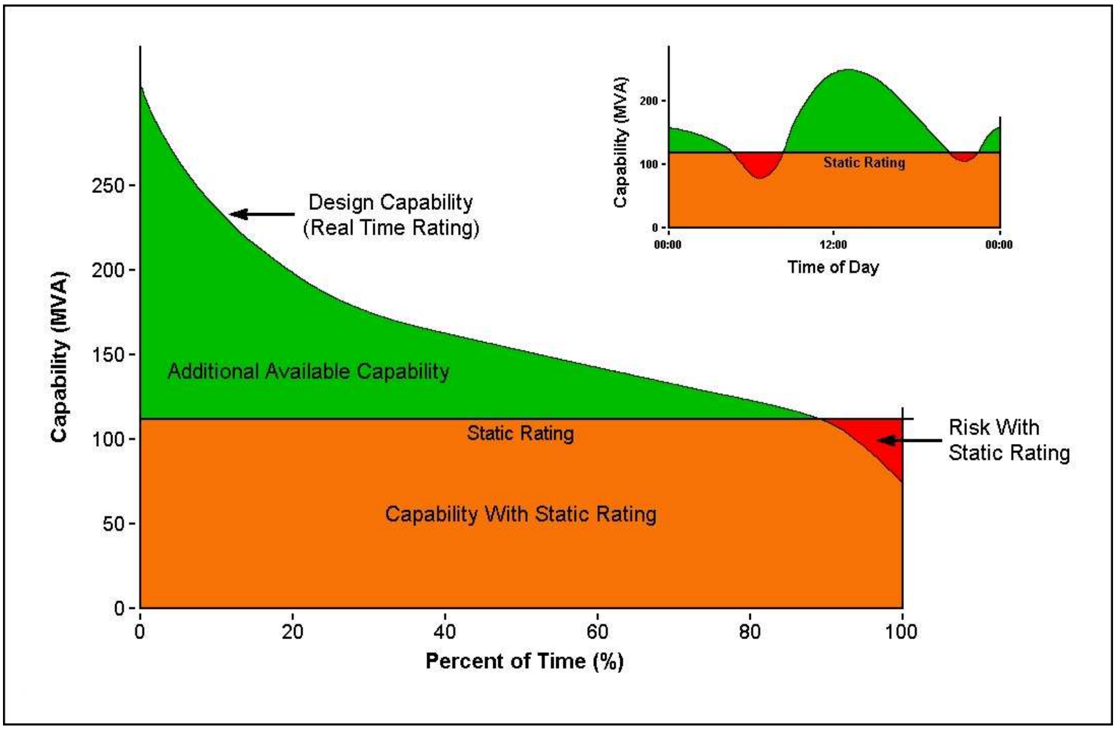


Figure 4-6: Relationship of Transmission Line Load Factor and Static & Real Time Ratings

The uprating objective, using real time monitoring, is to utilize the conditions when rating conditions are favourable compared to the assumptions as illustrated in the green area in Figure 4-6 and simultaneously avoiding the rare conditions when the actual rating conditions are unfavourable as illustrated in the red area in the same Figure. Because the thermal state of the conductors changes rather slowly, with a time constant of about 10 to 20 minutes, the system operators have sufficient time to react to forecasted unfavourable conditions.

The capacity increase and benefits of uprating achieved by real time monitoring depends on the rating assumptions, the nature of operating steady state or contingency limitations, the general system economics, type of generation and the range of remedial action options available for operators. They also depend on the economic and regulatory criteria used in each country or locality.

Based on current experience, the rating gains vary typically between 10% and 30% and higher gains may be achieved in special cases. For example, application at wind farms has shown realized gains of 30-50%. In addition real time monitoring can help to avoid uneconomic system dispatch when electricity costs are extreme.

Furthermore, a CIGRE survey [19] indicated that under most circumstances transmission line thermal limits are caused by clearance limits and not material annealing limits. This has supported the consideration of adopting real time ratings of transmission lines to enable lines to operate closer to the clearance limits more often by utilizing the frequent occasions when the prevailing climatic conditions would permit higher ratings than those that would have been assumed by conservative deterministic static ratings.

In summary, the objective of real time monitoring of transmission lines is based on

i. The thermal rating of an overhead transmission line is the maximum current that the circuit can carry without exceeding its temperature limit;

ii. The current required to enable the conductor to reach a given temperature can be far higher when the cooling is greatest than when the cooling is low which implies higher ratings at times of high wind speeds, low ambient temperatures or combinations of these parameters and vice versa; and hence

iii. Real time monitoring is the monitoring of parameters such that the conductor position above the ground may be determined in real time at a current instant and the permissible thermal limits are then calculated to optimize the power flow of the transmission line.

Report B2-201, 2004 [20] discusses the different available methods of real time line rating systems. It divides these methods by their closeness to the primary objective of maintaining safe clearances and discusses the relative merits of different methods by dividing them into direct and indirect. Specific benefits and drawbacks of the different methods are described in this report.

Three common methods are employed to provide real time ratings and are the determination of,

i. Line clearances based on either real time conductor tension or sag measurements (direct method);

ii. Conductor distributed temperature measurements using phase conductor embedded sensors (direct method) and direct measurement of conductor temperature[22]; and

iii. Prevailing climatic conditions by the installation of weather stations and the application of deterministic methods in rating (indirect method).

Two specific methods dominate the practical utility applications, tension and sag monitoring methods and weather methods used in different ways in several countries.

4.1.3.1 Line Tension and Sag Monitors [28], [29]

The tension or sag monitors are mounted on selected tension structures along the transmission line. At each location, the conductor's mechanical tension or sag is measured by a tension sensor or sag sensor, respectively. A conductor tension monitor is illustrated in Figure 4-7. A conductor sag sensor is illustrated in Figure 4-8.

Figure 4-7: Conductor Tension Monitor

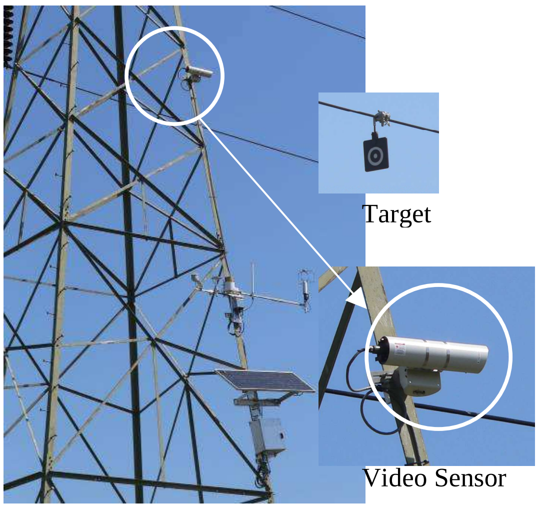


Figure 4-8: Conductor Sag Monitor

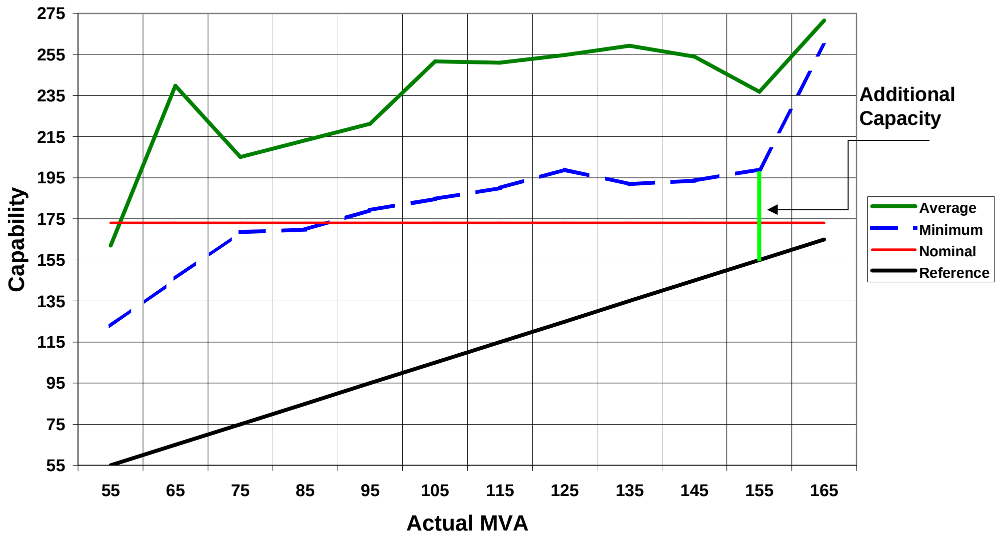
When using a tension monitor, conductor tension is measured by an electronic load cell and communicated to the utilities' control room where an algorithm determines the real time conductor temperatures, real time line ratings and provides alarms of possible clearance violations. A sag monitor performs the same function by using a video sensor and target hung on the conductor to directly measure the actual sag and clearance in the monitored span.

In general, the monitored line tension or sag follows the average temperature of the line section between the adjacent tension structures and gives a representation of the rating conditions of a long section of the line. Typically, two monitoring locations, each monitoring two adjacent line sections, are required at line lengths of up to 25-35 km [28]. The rating of the transmission line is then determined based on the lowest rating or highest temperature of the monitored sections. For longer lines, additional monitoring locations are required.

Case Study 4-13 (USA) – Proposal to Maximise the Output of Several Winds Farms by the Application of Conductor Real Time Tension Monitors

As is often the case, the wind farms were built in remote locations ideal for wind power, but with less than ideal transmission access. In this case additional transmission capacity was required during the period of wind farm generation.

The graph below demonstrates the synergy between real time monitoring and wind generation. The wind farm output was previously constrained to a static rating of 173 MVA. The reference line shows the actual power flow or generation output recorded over a sample period. The top curve is the average real time line rating and the middle curve shows the lowest observed rating. It is noted that the line capacity and generation output increase simultaneously. When the generation output was 155 MVA, the average real time capability of the line was typically 235 MVA and the lowest capability recorded was 197 MVA.



The result of the application of conductor real time temperature monitors to the transmission line is an increased dynamic rating of 42 MVA or 24% without generation limitations.

4.1.3.2 Conductor Distributed Temperature Sensing [13], [30]

The method is based on the replacement of an existing phase conductor with another conductor containing an optical fibre. The conductor system is called an optical phase conductor or OPPC and is similar in design to an optical ground wire or OPGW.

Temperature measurement of the phase conductor is achieved by the coupling of a monochromatic light into a fibre and observing the scattering and the back scattering effects. The scattering effects are a result of interaction of the photons and grid oscillations. If a photon contacts an oscillating grid the photon energy changes and the backscattered signals are visible as equidistant side bands. These side band lines change intensity as a function of temperature. Hence, a temperature change is related to a change of intensity of the side bands and therefore may be used as a reference value for the temperature measurements.

The OPPC system requires an electrical phase insulation decoupling device and a microprocessor to analyse the measurements and determine the conductor temperature. Sensor lengths can be up to 4 km and with differential comparisons to a reference span, temperature changes can be detected to within one meter.

4.1.3.3 Weather Stations and Application to Deterministic Rating Methods [31], [50]

Weather monitors can be used to calculate conductor temperature and ratings using various methods such as the CIGRE and IEEE methods. The weather stations monitor at least wind speed, ambient temperature and solar radiation. Although wind direction can also be monitored most rating calculations default to using a wind direction at a small angle to the conductor because of the high variability of wind direction. (Case Study 4-14)

Because wind conditions are highly dependent on the terrain and sheltering of the line, weather monitors must be mounted in the actual transmission corridor to be monitored. Use of weather data at airports or other remote locations away from the transmission line may have little or no correlation with the weather conditions at transmission line corridors. When such is demonstrated to be true, the data from the remote weather station has minimal value in establishing conductor ratings.

Weather stations report data from a single point of the line and line ratings calculated from weather data will in general be influenced by the number of weather stations installed to monitor the transmission line. Weather based ratings can be least accurate when the wind speed is low which is the most critical rating condition.

The cost of weather monitoring stations is relatively low but they can be maintenance intensive.

4.1.4 Probabilistic Rating of Lines [6], [32], [33], [35], [36], [37], [38]

The ampacity of a conductor is defined as "*is that current which will meet the design, security and safety criteria of a particular line on which the conductor is used*" [6]. It is thus not only a function of the conductor integrity but also a function of safety to the public. As such the thermal rating of a line is depending on the following factors [38]:

i. Ambient conditions

ii. Conductor types

iii. Bundle configuration

iv. Templating temperature

v. Line Direction

vi. Exposure of the line to the public

vii. Traffic Patterns

viii. Surges on the line
   a. type
   b. magnitude
   c. frequency of occurrence

ix. Likelihood of above factors occurring simultaneously

x. Probability of flashover if above do occur simultaneously

Probabilistic rating of lines allows one to use the actual weather data prevalent in an area to determine the risk associated with a particular current and design or templating temperature. Extreme caution needs to be exercised when considering a shift to probabilistic ratings. If probabilistic ratings are to be used, they should be based on a thorough scientific study of both the meteorological conditions of the area and the sheltering characteristics of the line corridors, and it is important that the study be conducted by qualified wind engineers. Such a study will allow determination of the level of risk associated with a given deterministic rating method and provide guidance for establishing an appropriate risk level for future operations. The resulting probabilistic ratings are often less conservative than the deterministic method resulting in higher current ratings.

There are two major probabilistic methods of determining the thermal rating of conductors: the absolute method and the exceedence method [38].

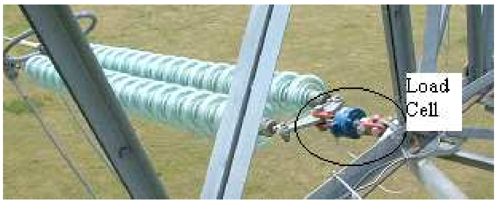
The absolute method determines the current for a specific level of risk or probability of an unsafe condition arising. The primary benefit to using this method of probabilistic rating is that it permits a utility to most fully manage the risk inherent in its line operations. When desired, this method permits conductor ratings to be varied across geography, terrain, season and/or diurnal period while maintaining a constant level of operational risk. This risk can be expressed in terms of $1x10^{-6}$, for example, allowing the comparison of line safety to that of a nuclear power plant or other structures.

The exceedence method determines the amount of time the conductor will exceed the templating or design temperature. The method is normally used assuming a flat load profile, that is assuming that the line will carry full load at all times. This method is used in the United Kingdom [38].

Case Study 4-14 (South Africa): Real Time Monitoring System -RETMOS

The aim of this project was to reduce the operational risk of a 400 kV overhead transmission line by measuring the heat balance of a phase conductor, mechanical tension/sag and the phase conductor electrical load.

The RETMOS consists of:



Discussion of the results:

i. For a wind speed of 6.4m/s (23 km/h) at an angle of 36 degrees to the line , an ambient temperature of 6.86 °C and with an electrical load of 2850 A on 2 bundle Dinosaur (54/19 3.95/3.27) phase conductor – the RETMOS measured a phase conductor temperature of 45 °C.
ii. When the wind speed dropped to 3 m/s (10.8 km/h) for a period greater than30 min, the temperature of the phase conductor rose to 63 °C..
iii. When the wind speed dropped to 2 m/s (7.2 km/h) for a period greater than 30 min, the temperature of the phase conductor rose to 79 °C..
iv. When the wind blew along the line and the sun was at full brightness – the phase conductor temperature rose to 135 °C.

Conclusion

The increase in conductor ampacity by using a real time monitoring device is in the order of 10 % to 30 %. The value will vary according to the prevailing environmental condition.

At time of writing the practical implementation of this system on specific overhead transmission lines was in progress. The benefit of having real time information allows the National Control operators to determine maximum electrical loading for specific overhead transmission lines in specific areas.

For uprating of lines, it is possible to make use of these methods taking into account the local weather conditions as well as the actual load profile on the line to determine possible increases in the line rating. Note that due to the fact that weather stations are not likely to be stationed in the line servitude or right of way, that caution must be exercised relating to possible low wind conditions on the line route.

The use of this method of rating should NOT be used to revise the "book" value on a permanent basis. It is a method to use for a short term situation as described in the case study. It can also be used to determine the effectiveness of real time monitoring systems should they be used.

The following Figure 4-9 shows the difference in rating between a flat load profile (blue line) and the load profile of the line (yellow, black and pink lines). For a 10% exceedence (for example) 105-A1/S1A-6/1 (Hare) conductor can increase the rating from 290A to approximately 390A.

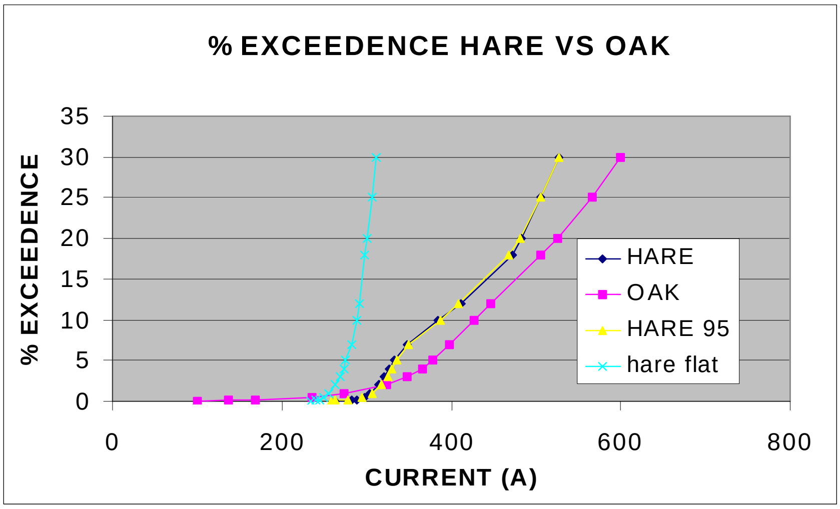


Figure 4-9: Variation of Ampacity with Load Profile

The method used in the rerating of lines is to determine the present exceedence limit used with the present "book" rating method (flat load profile). Then keeping this exceedence level constant, determine the new rating with the actual load profile. With regard to Figure 4-9, if the conductor "book" rating was 290A (blue line), the exceedence would be 10%. With the actual load profile, and the local weather conditions, the rating could be increased to 390A (yellow and black lines).

In addition to this rating, care should be taken to inspect the line to ensure that the actual line templating or design temperature is in line with the original specifications. The line must be checked for hot joints and broken conductor strands. With the new rating, checks need to be done to determine the possible maximum conductor temperature to ensure that there is no danger of annealing [6].

Case Study 4-15 (South Africa).
66kV line rerated from 292A to 390A in Winter months (May to November) to prevent load shedding in the area prior to network strengthening. Conductor 105-A1/S1A-6/1 (Hare) and 103-A2-7 (Oak). The hare conductor is the limiting conductor from an ampacity viewpoint. The results in using the exceedence method with the local weather conditions was that the line rating was increased from 292A to 390A for the period of 6 months. There was no safety issues reported. A jumper connector failed (non tension joint). No load was shed. The line was unloaded after 6 months.

Case Study 4-16 (USA)
A utility revised the thermal ratings of all its conductors based on a probabilistic analysis of historical meteorological conditions across its system and a thorough study of topography and the sheltering effects caused by surrounding buildings and vegetation. Using the absolute method of analysis, the utility established appropriate ratings for both peak and off-peak hours during three different seasonal periods (summer, winter and spring/autumn). These ratings were based on the effects of what was determined to be "normal" sheltering conditions for its lines. For lines with spans that are more sheltered than normal, their thermal ratings were adjusted downwards appropriately as determined by the findings of the meteorological study of local conditions. Conversely, for lines whose spans are more exposed to the wind, their thermal ratings were allowed to be upwardly adjusted in similar fashion. The net result was the increase in thermal ratings for peak-hour operations during the summer and spring/autumn seasons for all but the most heavily sheltered lines (ratings were increased by as much as 16% for the more lightly sheltered lines and 6% for lines with "normal" sheltering). Through the study, it was also determined that the thermal ratings for summer off-peak hours should remain basically unchanged but that spring/autumn off-peak as well as all operations during the winter season would need to be lowered to maintain the same level of risk for all line operations (winter ratings under normal sheltering conditions were lowered by 8 to 10%).

4.1.5 High Surge Impedance Loading Lines (HSILL) [39], [40]

HSILL is a technology that was initially developed in order to increase transmission capacity of overhead transmission line by maximising and equalising the electromagnetic field distribution on the conductors and eventually evolved into a transmission line optimisation concept.

HSILL technology strives at a total optimisation of all significant electrical and geometrical parameters of a transmission line. In comparison, conventional transmission lines are designed on a step by step procedure, changing one parameter at a time and keeping some other parameters fixed such as the conductor cross section, number of sub-conductors per phase, spacings between phase conductors and sub-conductors in the bundle and so on. Whereas the HSILL concept is a total optimisation process in order to reach more efficient and economical solutions.

HSILL concept represents a considerable change in the usual procedures such as the use of asymmetrical and or large bundle configurations.

HSILL technology has been initially developed for the transmission of electrical energy from large generating units over long distances, to maximise transmission capacity by operating the line at "the natural power" (surge impedance loading or SIL). In recent times the technology has evolved to being an electrical design optimisation technique, known as expanded bundle technology (EXB), suitable for

i. Design of new transmission lines of high transmission capacity;

ii. Uprating of existing transmission lines, in order to increase their transmission capacity; and

iii. Modification of transmission lines electromagnetic parameters aiming to optimise the power flow distribution in transmission systems.

In the design of new transmission lines the optimisation of electromagnetic parameters leads to higher SIL and consequently a higher transmission capacity compared to conventional transmission lines. This is obtained by means of an optimised electromagnetic field distribution. Essentially increasing conductor bundle diameter results in:

i. Increased shunt capacitance;

ii. Reduced series inductance;

iii. Reduced surge impedance to $Z_s = (L/C)^{1/2}$; and

iv. Increased surge impedance load resulting in increased power transfer.

In the uprating of existing lines, this technology explores different possibilities according to design characteristics of the original line. Either by the rearrangement of existing conductors or by addition of one or more conductors (not necessarily of the same type as the existing ones) the obtained result is an increased transmission capacity. In a couple of projects already in commercial operation, typical 230 kV lines have undergone upratings which increased their transmission capacity by 38% in one case and 60% in another case. In both cases the benefit to cost ratio was profitable as the transmission line modifications amounted to 18% in the first case and 25% in the second of the total cost of a new transmission line.

In the optimisation of transmission systems, a variation of the technique is used when desired values of transmission line electrical parameters (mainly the reactance) are selected instead of searching for the maximum possible transmission capacity of a single line. Obtaining the desired parameters results in a better power flow distribution among the lines in a given corridor or network. This possibility could be one of the most promising applications of the HSILL/EXB technology, since the ability to vary transmission line parameters may provide considerable gains with reduced investments.

Voltage (kV)	**SIL – Traditional (MW)**	**SIL – Expanded (MW)**
69	9 – 12	10 – 40
138	40 – 50	50 – 120
230	120 – 130	130 – 440
500	900 - 1020	950 – 2000

Table 4-2: Typical HSILL Transmission Line Capacities

HSILL and or EXB techniques are therefore well suited either to design new lines or to refurbish and or uprate existing transmission lines. In cases where transmission capacity limits are associated with voltage limits, SIL optimisation of line parameters may provide a solution by reducing series reactance and offering an economical and technical alternative to series compensation. In those cases where transmission capacity is limited by thermal ratings, the use of EXB techniques may allow for a better distribution of current flows on the transmission system, postponing or even eliminating the need for an exchange of conductors. Transmission gains must be calculated in each case, depending on system studies.

Another advantage of HSILL and or EXB technology is associated with systems having heavy thermal generation, where sub-synchronous resonance may become a problem if the needed series compensation levels are high. Here again, the adequate choice of transmission line parameters may eliminate the problem.

Finally, it has become quite noticeable in the last decade that a technique allowing for greater transmission capacity in the same right-of-way has an economic contribution which extends far beyond the simple transmission line construction costs, since the environmental issues are quite favourably met by HSIL and or EXB lines as they provide means for higher power density flowing on a given corridor.

In summary, HSILL technology enables the design of transmission line configurations that optimises electric and magnetic field distributions and consequently the electrical parameters and the power transmission capacity of the line, as well as the current sharing among different lines in the system.

Figure 4-10: 230 kV Experimental HSILL Transmission Line

Figure 4-11: 500 kV EXB Transmission Line 744 km Long

4.2 Increasing Voltage Rating [13]

Increasing the voltage of a transmission network is generally the most effective strategic way of providing a quantum step change in transmission capacity. In general for each nominal voltage level the natural capacity of the network is increased by about 4 to 5 times. An example which is not complicated by corona, radio interference and audible noise considerations is the simple case of increasing the voltage of an existing 33 kV subtransmission line to 132 kV with the existing conductor configuration by which the capacity of the line will quadruple with relatively small marginal cost of line reconfiguration works.

Another example of uprating a 110 kV line to 275 kV is shown in Figure 4-12.

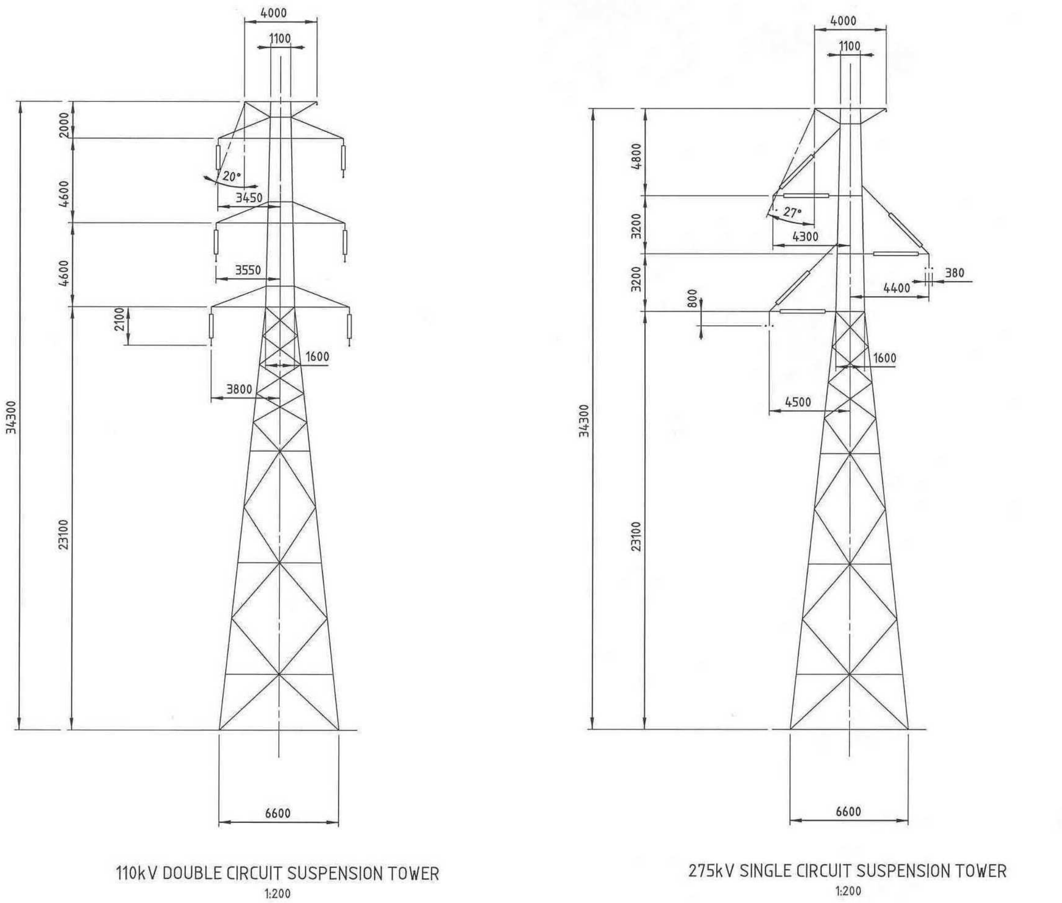


Figure 4-12: Transmission Line Structure Uprated from 110 kV to 275 kV

This section of the Technical Brochure will discuss the basic electrical design requirements and strategies that may be implemented for existing transmission lines to increase the voltage rating. Given the enormous world wide variety of transmission line designs the discussion will be limited to the basic principles.

An example of a typical transmission line voltage uprating study is shown in Table 4-3.

Conductor	Circuits	Voltage (kV)	Power Transfer (MVA)	Relative Uprating Cost/km
1 x 18.1 mm	2	110 (ac)	160	No cost existing line
1 x 18.8 mm	2	110 (ac)	200	100
2 x 18.1 mm	1	220 (ac)	320	235
2 x 18.8 mm	1	220 (ac)	400	285
1 x 29.3 mm	2	+/- 250 (dc)	900	350

Table 4-3: Typical Transmission Line Voltage Uprating Costs Uprating of a 110 kV Transmission Line to a Higher Voltage/Power with Different Alternatives, Including a DC Transmission Line

4.2.1 Requirements

The basic voltage design considerations are

i. Clearances to ground, to support structures, to over crossings of other power lines, roads and railway lines and clearances to adjacent structures and vegetation;

ii. Conductor motion and electrical phase to phase electrical clearance between conductors;

iii. Clearance between earth wires and conductors

iv. Insulation requirements for power frequency, switching and lightning surges;

v. Clearance for live line maintenance;

vi. Conductor surface voltage gradient, corona onset voltage and radio interference voltages which are influenced by conductor diameter and conductor bundle diameter; and

vii. Audible noise.

4.2.1.1 Clearances

One of the main criteria for a transmission line is to provide sufficient vertical clearance to the ground, over crossings, objects, supporting structures and vegetation; horizontal electrical clearance to adjacent structures, objects and vegetation; clearances between phase conductors and earth wires and conductors.

The above mentioned criteria must be in compliance with statutory regulations and or industry codes. Consideration of uprating a transmission line from the present voltage to a higher voltage will require the application of the higher voltage criteria to the uprated transmission line.

Internal clearance to supporting structures is a further primary insulation criteria consideration. Critical flashover values for air gaps are required to be assessed for power frequency voltage and switching and lightning overvoltages and applied to the insulator and conductor configuration for the uprated structure. Consideration of critical flashover voltages for insulator arrangements that are subject to horizontal swing movement are also required to be assessed to ensure satisfactory air clearance performance.

Earth wire to phase conductor clearance is an important point to analyse if the line to uprate is not originally provided with an earth wire. Structure extensions will probably be required to achieve adequate clearances and the body structure will need to be reinforced.

Phase to phase clearance and corresponding differential conductor motion is also a primary air clearance criterion for the uprated structure. Conductor motion may be induced by wind gusting, galloping, ice load shedding and fault currents.

In consideration of uprating an existing transmission line to a higher voltage rating, the design may result in the reduction of phase to phase clearances which will require special analysis of the phase to phase switching surge withstand. This analysis would include the examination of the maximum insulation stress and minimum insulation strength and for higher voltage lines also involve a probabilistic analysis of switching surge magnitudes and wave shapes with varying prevailing climatic variables such as air density, humidity, temperature and ice depositions.

In addition, internal clearance from conductor to structure is required to be provided for coinciding basic insulation level requirements and transmission line maintenance requirements.

Lack of adequate clearance could eliminate live-line maintenance operations or require more sophisticated and expensive maintenance procedures.

4.2.1.2 Insulation

For the insulation design of an uprated transmission line, an understanding of the critical flashover voltage transients and power frequency voltages and the corresponding insulation withstand is required.

Power frequency insulation design criteria is based either on the suggested geometric insulator creepage distance or on the insulator deposited density of salt index for given pollution level. In consideration of uprating an existing transmission line the historical pollution performance of the line in general, would be well known and the opportunities to develop a design to meet the required new design voltage should be well understood. In addition, many insulator manufacturers are well placed to provide custom insulator designs to meet particular power frequency design criteria.

Transient voltages may be either lightning or switching surges. Switching surges determine the insulation design for higher voltage lines or lines that have low earth resistance or where lines operate in regions of low keraunic levels. Lightning determines the insulation design for lower voltage lines or lines that have high earth resistance or where lines operate in regions of high keraunic levels.

The insulation design will be determined from the primary variables of air clearances, the insulator geometry such as V-string, I-string, tension, post and or horizontal-V and the structure geometry. Secondary variables are size of conductor or possible bundle conductor configuration, phase to phase clearances, number of insulators and the application of corona shields. Influencing climatic factors include air density, humidity, precipitation, temperature and pollution and ice depositions.

The outcome of the insulation design for a transmission line subject to voltage uprating is increased insulator surface creepage length and increased critical flashover transient voltage distances to meet the new voltage rating of the transmission line.

4.1.2.3 Audible Noise, Interference Voltage and Corona [41]

Conductor surface voltage gradient is an important point to be considered when uprating the line voltage. For voltage gradients above a critical level the conductor will commence the corona phenomenon resulting in the production of noise and power frequency energy loss. The effect of corona is visible light, audio noise and radio & television frequency interference.

The magnitude of conductor surface voltage gradient is dependent on operating voltage, conductor diameter, phase conductor spacing and in the case of bundled conductors the bundle diameter, bundle configuration and the number of sub-conductors in the bundle.

PARAMETER		Electric Fields	Magnetic Fields	Radio Interference	Audible Noice
Phase to phase distance	↑	↑	↑	↘	↓
Conductor height above ground	↑	↓	↓	↘	↘
Number of sub-conductors (for a given total cross-section)	↑	↑	=	↓	↓
Sub-conductor spacing	↑	↗	=	↗	↗
Total conductor cross-section	↑	↗	=	↘	↘

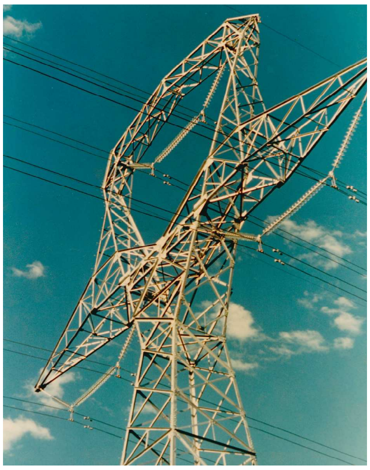
↑	Strong increase	↓	Strong decrease	=	No significant effect
↗	Slight increase	↘	Slight decrease		

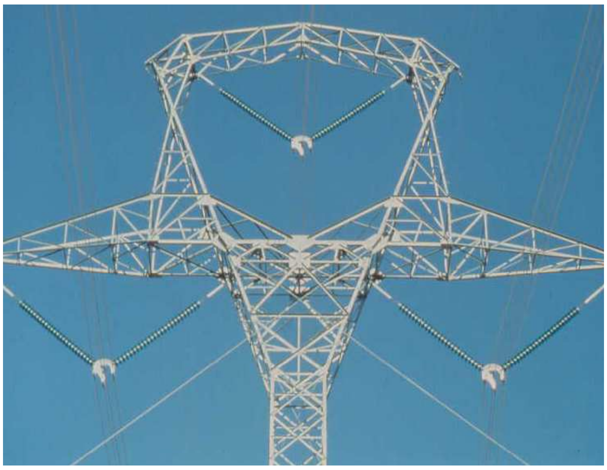
Table 4-4: Influence of Parameters

For voltage uprating projects involving big changes in operating voltage, transmission lines with single conductor present significant difficulties to achieve satisfactory economical outcomes without the consideration of reconductoring with larger conductors and or the installation of bundled conductors. In these cases, the additional wind, weight and ice loads created by the new larger conductors and or conductor bundles may result in mechanically overloaded structures and or structure upgrading which is not economical. For example, a 132 kV transmission line with 3750 mm horizontal phase spacing with a conductor diameter of 25 mm would have a surface voltage gradient of about 12 $kV.cm^{-1}$. This line is under consideration for uprating to 220 kV. In this case the solution would require the installation of additional subconductors to form a conductor bundle to meet a reasonable voltage gradient criteria and practical phase spacing. The installation of additional subconductors may result in the structures being mechanically overloaded making the uprating proposal unviable.

Notwithstanding this, there are many examples in the world where transmission line designs have been implemented in such a way that at some future point in time the line may be reconfigured to allow an increase in the voltage rating. An example of this is the operation of a double circuit 230 kV transmission line with suitable conductor diameter to meet the voltage gradient criteria with a horizontal conductor formation. At some time in the future, the line can be given over to a single circuit 500 kV quad bundle transmission line by aggregating the six twin bundle phase conductors into three phases with four conductors per phase bundles. The initial and final conductor separation is designed to meet both the single circuit 500 kV and the double circuit 230 kV configurations.

Case study 4-17 (USA): 230 kV to 500 kV Voltage Uprating



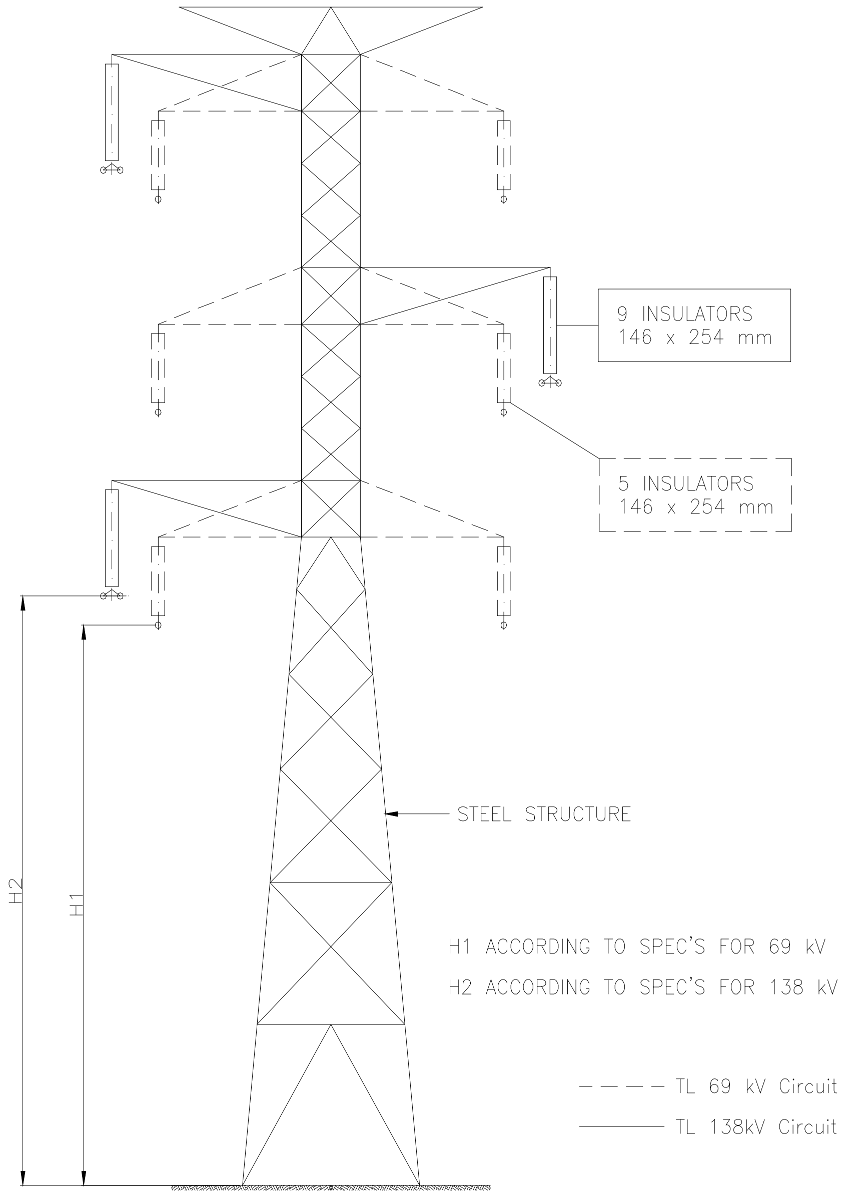


This transmission line was originally designed as a single circuit 500 kV line. It was first built as a double circuit twin bundle 230 kV line shown at the left. Several years later it was converted to the single circuit quad bundle 500 kV line on the right. The conductors from the vertical twin bundle were brought together to form the quad bundle and the insulators in the 230 kV “U-string” assembly were split in the middle of the “U” to form the 500 kV “V-string” assembly.

Case Study 4-18 (Brazil) – Uprating a Double-Circuit 69 kV Line into a Single-Circuit 138 kV Line

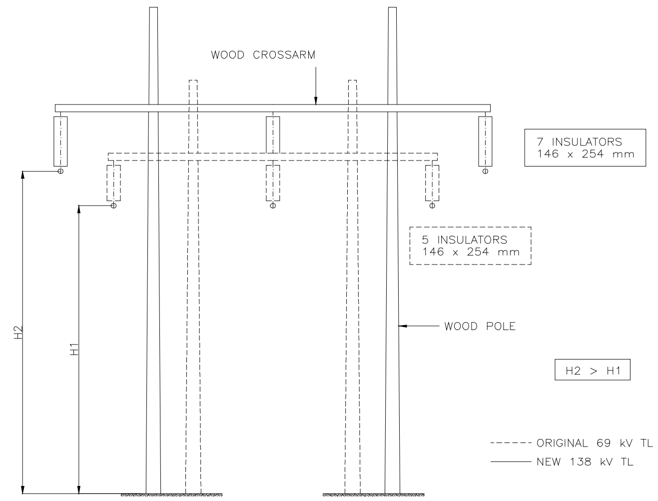
In this case the same conductors of the double-circuit were arranged in twin bundles, and new crossarms were designed for attaching the new insulator strings and clearances. The number of insulator units were increased from 5 to 9

i. 100% increase in line capacity was obtained.
ii. Power increase from 100 to 200 MVA (100%)
iii. Cost: 20% of a new line.



Case Study 4-19 (Brazil) – Uprating a Line using Wood Pole Structures from 69 kV to 138 kV

The figure below shows a case, where a 69 kV line was uprated to 138 kV with live-line replacement of structures and addition of insulator units. The achieved power increase was from 50 to 100 MVA (100%) with a cost of 20% of a new line.



The concern of conductor surface voltage gradient is normally limited to transmission lines with small conductors, insufficient phase to phase distances and or operating voltage over 220 kV as the designed conductor spacing and conductor diameter for lower voltage transmission lines generally result in gradients that are below the criteria threshold. This is illustrated in Table 4-5 for two voltage gradient levels, i.e. 12 kV/cm and 18 kV/cm. The level to be considered depends on regulations and company practices.

Transmission Line Phase to Phase Separation (mm)						
conductor diameter (mm)	**Conductor Voltage Gradient = 12 kV/cm**			**Conductor Voltage Gradient = 18 kV/cm**		
	Nominal operating voltage (kV)			*Nominal operating voltage (kV)*		
	66	***132***	***220***	***66***	***132***	***220***
15	923	*)	*)	205	4210	*)
20	398	13200	*)	133	1220	*)
25	255	3750	*)	109	620	7650
30	199	1830	*)	100	410	3220
35	172	1130	22400	96	315	1820
40	156	790	8300	95	265	1210

*) not practical

Table 4-5: Conductor Surface Voltage Gradient Versus Phase Spacings for a Single Conductor (Calculated with Maximum Operating Voltage for Each Voltage Level)

The table indicates that in case of a voltage uprating of a 132 kV line with a 30 mm diameter conductor to a 220kV line, would require a phase spacing of or 3220 mm with a conductor voltage gradient of 18 kV/cm. If a conductor voltage gradient of 12 kV/cm were required, then a practical phase spacing would require a conductor in excess of 40 mm. It should be noted that conductor motion criteria would dictate that the 132 kV phase spacing should more likely to be about 2100 mm. Therefore, voltage uprating for single conductor lines is very dependent on the maximum allowed conductor voltage gradient, conductor diameter and phase spacing. Practical application of voltage uprating may require larger conductor or bundled conductors.

4.2.2 Increasing Clearances

The first and most elementary consideration for increasing the voltage of a transmission line is to ascertain the phase to earth clearance of the line at the proposed higher voltage of the uprated transmission line. This will determine whether opportunities exist to modify the existing transmission conductor attachment height to accommodate the new voltage rating within the context of a cost effective technical solution.

For example take a 132 kV transmission line with a design ground clearance of 7.5 meters and a 1900 mm long cap and pin insulator arrangement suspended from a crossarm with conductors in a flat formation and the crossarm supported by two poles. Considerations is being given to increasing the voltage rating of this line to 330 kV which requires 9.0 meters ground clearance with an insulator string length of 2900 mm. In this case, the conductor attachment height is required to increase 1500 mm to compensate for the required new ground clearance and an additional 1000 mm to compensate for the additional insulator string length. The aggregation of the required increase in conductor attachment height is 2500 mm and the existing structure and insulator arrangement will be required to be uprated to accommodate this design.

A design option would be to consider a combination of insulated crossarms and the insertion of pole extensions into the existing structures or simply the insertion of pole extensions into the structure to raise the conductor by the required 2500 mm. If this was required for every structure on the transmission line then this may not be considered a suitable technical and economical solution for the particular transmission line.

Case Study 4-20 (Norway): Voltage Uprating of a Transmission Line

Initial and final voltage

i. Initial 300 kV
ii. Final 420 kV

Structure type and modification

i. Portal steel lattice tower. Single circuit, twin bundle.I-strings increased with 3-4 glass insulator units
ii. Tension strings increased with 4 glass units
iii. On some towers I-strings were replaced with L-strings in both outer phases to
iv. limit problem with air clearances during insulator swinging
v. Some tower crossarm reinforcements
vi. Line surge arresters installed in all phases at both ends and in the middle of the 75 km long line for switching surge overvoltage suppression
vii. Composite insulators installed to guide the jumpers through tension towers with short air clearances
viii. New vibration dampers installed

Notwithstanding, there are a number of cases where utilities have successfully increased the voltage rating of existing transmission lines by examining in detail the line sections and selectively applying uprating options to existing structures.

Hence, one of the most significant considerations in increasing voltage rating of an existing transmission line is the capacity of the existing line design and supporting structure design to accommodate the required increased ground clearance within the economic constraints of the existing structure geometry. Other coinciding design verification considerations would include

i. Vertical clearances to existing over crossings of power lines, roads, railway lines, buildings and vegetation;
ii. Horizontal clearances to adjacent structures and existing vegetation clearing envelopes;
iii. clearances to supporting structures;
iv. Clearances for live line maintenance; and
v. Conductor phase to phase clearance.

Case Study 4-21 (Norway) - Voltage Uprating of Transmission Lines

Initial and final voltage

i. Initial 300 kV
ii. Final 420 kV

Structure type and modification

i. Portal steel lattice tower. Single circuit
ii. Both earth wires removed
iii. Tower earthing (in each tower) connected to a parallel line with earth wire
iv. Single conductor 725-A1/S1A-54/19 (Plover) replaced with twin bundle 604-A1/S1A-54/19 (Grackle)
v. Old glass insulators (standard type) replaced by glass fog type and composite insulators (same length as earlier)
vi. Tension strings increased with 4 glass units
vii. In some towers I-strings were replaced with L-strings in outer phases to limit problem with air clearances during insulator swinging
viii. Line surge arresters installed in all phases at both section ends.
ix. Some tower reinforcements

4.2.3 Insulating Crossarms

The replacement of existing insulators with some form of insulating crossarm or modifying the existing insulator arrangement is the most common form of increasing the voltage rating of a transmission line by increasing the conductor attachment relative level to provide greater ground clearance and at the same time increasing the insulator creepage distance and transient voltage flashover distances (see section 4.1.2.3.2). The advent of composite insulators with the ability to apply composite or hybrid insulator sets to fulfil geometrical, electrical and mechanical requirements of a new insulator system with in most cases enhanced performance provide unique opportunities to uprate transmission line voltage ratings with a economical mechanism.

One of the most significant considerations in replacing the existing crossarms or the replacement of existing insulators is a fundamental understanding of the pollution levels and the performance and behaviour of the existing insulation. Notwithstanding this, when consideration is given to modifying the existing transmission line insulation it would be normal that the line would have been in service for a considerable period of time which would suggest that the insulation performance of the line is well known and the consequences of changing the insulation design would be well understood. Other design verification considerations would include

i. Mechanical loads of the insulator arrangement;
ii. Changes in the coupling point of the applied insulator loads and the structure;
iii. Changes in the electrical clearance envelope caused by changes in the insulator swing;

iv. Changes in the conductor attachment fittings and associated loads; and

v. Any changes in structure longitudinal load and restrained insulator movement.

The technical limits of insulator crossarms or insulator modifications are normally determined by the required clearance window, the required coupling and creepage distance of the insulators, and the flexibility of changing the insulator loading structure coupling points.

In the consideration of increasing the conductor attachment height at the structure then an assessment of the foundation capacity and any increased overturning moments of the structure is required.

4.2.4 Structure Extensions

General experience indicates that given the magnitude of the required structural works it is not economical to increase the heights of all structures in a transmission line for thermal capacity uprating projects (see section 4.1.2.3.1). In the case of voltage uprating projects which tend to be traditionally more strategic long term system development projects, it may be considered a viable option to invest in the uprating of the line structures by using structure extensions, which could be body extension or leg extension. The inclusion of a structure extension is more common to suspension structures given the inherent structural and practical difficulty of including a extension into a tension or terminal structure, however, it has been done.

Design verification of increasing conductor attachment heights by the inclusion of an extension would include

i. An assessment of the structural capacity of the existing structure to determine the availability of any marginal capacity [9];

ii. Design of a structure extension to ensure the structure geometry would accommodate the inclusion of such an extension;

iii. Design of structure reinforcement to increase the capacity of the actual structure; and

iv. An assessment of the foundation capacity and any increased overturning moments.

The technical limits of the inclusion of an extension would normally be determined by the structure and foundations ultimate load factor for the defined loading conditions.

Case Study 4-22 (Norway) - Voltage Uprating of Transmission Lines

Initial and final voltage

i. Initial 300 kV
ii. Final 420 kV

Structure type and modification

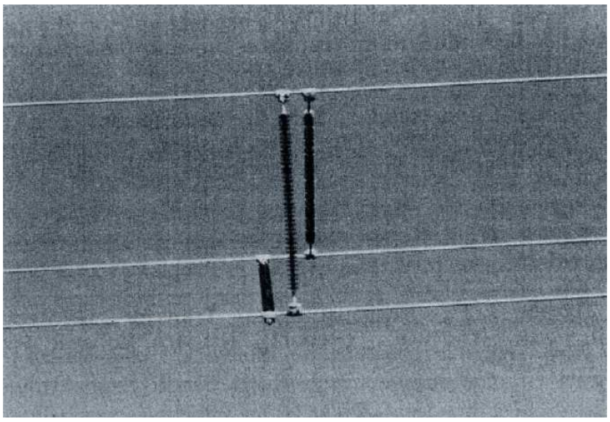
i. Portal steel lattice tower. Single circuit, twin bundle
ii. V-string glass insulators increased with 3-4 units.
iii. V-string insulator extension links replaced by shorter links (shortening equivalent to the length of the 4 insulator units)
iv. Increased insulator strings in tension towers with 4 units
v. Some tower crossarms reinforcements
vi. Line surge arresters installed in all phases at both ends and in the middle of the 75 km long line
vii. Composite insulators installed to guide jumpers through tension towers with short air clearances

4.2.5 In-span Insulator

During the design considerations of in-span clearances and corresponding conductor motion, in some cases sufficient clearances can be maintained without limiting in-span conductor movement.

The availability of light weight composite insulators provides an excellent way to limit and control in-span conductor movement. In these cases, the application of phase to phase conductor spacers allows greater utilisation of existing conductor geometry at existing structures and permits voltage uprating that would otherwise have been excluded from economic and or technical consideration.

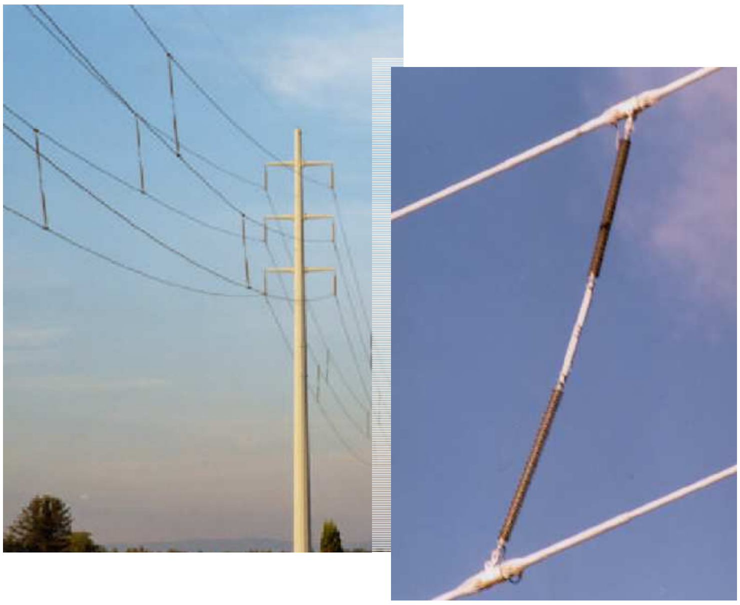
Case Study 4-23 (USA): Use of In-span Insulators on Low EMF Transmission Line



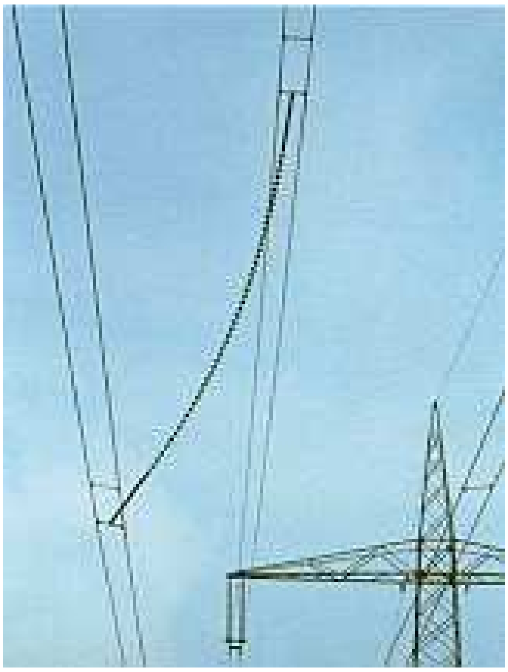
During the development of a low EMF transmission line, one United States utility, constructed a 115kV transmission line with an inverted delta configuration and a 1930mm phase-to-phase spacing. At mid span, three individual polymer insulators interphase spacers were used to maintain phase separation and prevent flashovers due to ice dropping or galloping.

Case Study 4-24 (Canada) – In-span Insulator to Prevent Galloping

A 161 KV Line to an Aluminum Smelter, in Quebec experienced galloping. In-span spacers were installed in 1995-96 and have performing well ever since. Spacer type was articulated (i. e can only take tension, see insert).



Case Study 4-25 (Germany) – Uprating from 245 kV to 420 kV by Changing Insulator Sets and Using In-span Insulator Sets



For system voltage uprating existing tower structures were used. Crossarm dimensions were therefore limited due to restrictions concerning the total line width. Limiting swing of the insulator sets was one of the main aspects to maintain clearances to meet 420 kV insulation levels in accordance with regulations. The former 245 kV insulation consists of double I-string insulator sets with 2 porcelain longrod insulators units in each string.

The first part of the uprating was to use inverted V-string insulator sets and Y-string set configuration to meet the clearance requirements. Twin 30.5 mm diameter ACSR conductor bundle were used. Transmission capacity was uprated from 230 MW to 470 MW per circuit.

The second part of the uprating was the use of composite insulators in-span insulator sets as phase spacers as shown in the photograph

5. Transmission Line Upgrading Options and Case Studies

The main reason for upgrading is increasing the availability of the line. Upgrading is often associated with uprating.

Also the meteorological data collected for many years show that there could be higher ice and wind loads on the transmission lines compared to the loads the lines were originally designed to withstand. Due to this fact, lines need to be upgraded to maintain reliability. New transmission line modelling techniques allow more detailed analyses to assess adequacy of various transmission line components.

Successful upgrading of transmission lines depends on a number of factors that must be considered. These factors can be classified as:

i. Environmental factors;

ii. Operational factors;

iii. Mechanical and Electrical degradation factors.

Some examples of various factors are given in Table 5-1.

Generally the upgrading concerns the whole transmission line or some part of it, but there are some exceptional cases, i.e. upgrading of only one steel structure due to installation of telecommunication equipment.

Unanticipated rapid deterioration of a transmission line component may also require upgrading.

A comprehensive engineering study is required to consider all available upgrade options. Since transmission lines have many different design configurations and material choices, subsequently choices of upgrade solutions are often numerous. An engineering study should consider all choices available and assess their reliability levels, financial costs and practicability (availability of manpower, materials, outage requirements, etc.). When assessing financial cost of a given option, a life-cycle cost analysis should be used to select the most cost effective solution and its timing (i.e. when it should be executed).

The engineering study should take into account further conditions of the maintenance of the line, i.e. whether live line maintenance is required. Such a decision could influence the shape of some components (structures, insulator strings) as described further.

Environmental Factors	Operational Factors	Mechanical & Electrical Degradation
Climate: i. Overloading due to ice and/or wind ii. Extreme temperatures iii. Ultraviolet exposure iv. Fungi **Pollution:** i. Acid rain ii. Salt spay iii. Fertilizer use iv. Industrial gases v. Lightning strikes vi. Fires **Other External Factors:** i. Vandalism (gun shots, theft, abuse) ii. Wildlife (i.e. woodpeckers, rodents, insects) iii. Mechanical impacts (cars, farm equipment, planes)	i. High temperature operation ii. Increased continuos current iii. Increased fault current iv. Lack of maintenance v. No outage time available for maintenance vi. Installation of telecommunication antennas on transmission structures vii. Higher ground clearance viii. Higher voltage level **External Factors:** i. New obstacles in the vicinity of the line (i.e. roads, buildings)	i. Loosening or breakage of connections ii. Fatigue of materials caused by vibrations iii. Corrosion iv. Material wear v. Degradation of insulation

Table 5-1 : Factors Effecting Life and Performance of a Transmission Line Element

5.1. Structures [10]

5.1.1. Background

The transmission line structure is a key component of a power line. It provides support to other components such as conductors or insulators. At the same time it has the most physical impact on the general public and private property, and it draws most attention when it comes to aesthetics. A newly designed transmission line structure is expected to perform satisfactorily for a very long time, quite often 50 years or more.

During the course of its life a transmission line structure may be expected to carry additional functions or loads in excess of those specified in the original design. This is quite common in current environment in which power operators and system planners demand more utilization from the existing power lines. A lot of effort is being spent on planned transmission structure upgrades.

Another reason to upgrade a transmission line structure might be immediately after a failure due to unexpected weather events or human made causes. In many cases, asset owners will only inventory higher strength suspension towers of a particular design class, for emergency spare towers. Typically, it is the lower strength suspension towers that fail. They will automatically be replaced with the higher strength equivalent towers, thus upgrading the line at the failed locations. If the failed transmission line is redundant or has low priority in the power grid, an upgrade option might be chosen instead of a restoration typically required in emergency situation. In this case the entire line, not just the failed portion, might be considered for upgrading.

5.1.2. Considerations for Upgrading Structures

Successful upgrading of transmission line structures depends on a number of factors that must be considered

Upgrade Studies
It is possible that the original structure capacity was not utilized during installation for various reasons such as unusual terrain conditions, site specific restrictions of availability of materials and therefore has sufficient reserve capacity. In such cases, structure upgrade can possibly be achieved with minimum effort. However, all original design assumptions should be re-examined again.

Availability of Original Design Information.
It is essential to know the assumptions used in design of the original structure such as strength/parameters of materials used and design loads. This will enable a designer to determine the existing structural capacity of the structure and to perform studies necessary to increase it.

Lattice transmission line structures are often of old vintage. Some very old tower designs might have not been well documented. In some cases the properties of the steel material are unknown and member properties not documented making it very difficult for an engineer to model such designs. Material testing and careful engineering assessment might be needed while handling these cases.

Assessment of Field Conditions
A field inspection is necessary to determine the condition of the existing structure which has been exposed to both the environmental elements and the transmission line loads. Such inspection might reveal reduction of capacity of individual structural members which might lead to a lower overall capacity of the structure. It may also trigger a need to replace these members in order to restore the original strength. Steel structures located in high industrial environment might be showing reduction in strength of the members due to corrosion of steel.

Wood poles in particular should be treated with caution since they are products of nature and their physical properties are somewhat unpredictable. Furthermore, these properties change with time depending on environmental conditions. It is necessary to determine physical dimensions of the wood pole and condition of the pole to determine its strength. Wood pole deterioration may occur at higher rates in parts of the wood pole with drilled holes where there is potential for water and humidity to penetrate the wood.

5.1.3. Technical or Practical Limitations

Transmission line structures offer designers multiple choices and large flexibility for performing upgrades. However structure upgrades have also technical and practical limitations, most of which were listed in Section 3.6 of this document.

Additional limitations in upgrading structures include:

i. Variability In Wood Pole Sizes

ii. Unlike other man-made materials, wood poles are products of nature and their supply depends on harvesting patterns used by wood pole producers. Wood poles are a natural product and come in variable sizes. This may lead to some difficulties with matching proper size connectors with a wood pole diameter.

iii. Supply Of Wood Poles

iv. Availability of wood poles, especially in lengths exceeding 30 meters, may be limited.

v. Availability Of Steel Angles Sizes

vi. In some cases, especially when an original transmission line structures are of a very old vintage, it might be difficult to find matching lattice steel members. Reasons for discontinuation of certain sizes might be: new design codes, conversion of measure system (i.e. from British to metric) or different supply sources. This may lead to adjusting the detailing of joints to fit different size members.

5.1.4. Case Studies

<u>Wood Pole Structures</u>
Wood is a common material for building transmission line structures in many countries. Wood poles offer flexibility in designing custom structures whether it is required to match site specific conditions or to provide fast design to address emergency needs. They are easy to handle and assemble in the field.

Upgrades of wood structures might be achieved by:

i. Replacement of wood poles with higher class poles (larger diameter)

ii. Replacement of wood poles with poles of stronger species (i.e. Douglass Fir instead of Western Red Cedar)

iii. Replacement of wood poles with wood engineered poles (i.e. laminated wood products)

iv. Addition/replacement of braces

v. Replacement of wood cross arms by steel arms i.e. or use of reinforcing metal channels to provide higher bending moment capacity or to increase structure height

vi. Use of stay (guy) wires to improve structural horizontal capacity

Steel Lattice Structures

Steel lattice towers have been used successfully throughout the world as a design choice for power transmission lines for almost a century now. They are often considered as good candidates for upgrades.

A number of upgrade options exist for steel lattice towers. They include:

i. Doubling up/duplication of angle sections (often leg members)
ii. Replacement of angle sections with larger section members
iii. Addition of redundant and/or diagonal members
iv. Reconfiguration of low strength sections
v. Addition of guy (stay) wires
vi. Upgrade of bolts to higher grade
vii. Use of tower extensions to raise conductor height
viii. Use of longer length cross arms

Case Study 5-1 (Spain) – Upgrading of 400 kV towers

Localised tornados and heavy thunderstorms have caused tower collapses in different periods of time. Utility decided to ugrade the existing towers to withstand 140 km/h rather than originally used 120 km/h wind speed.

The process included:

i. Study of areas with extra high winds or tornados
ii. Study of line location
iii. Review of Load-Strength diagrams for each tower
iv. Tower redesigning when needed
v. Replacement and/or reinforcement of main legs and angle bars to upgrade the tower

Limitations:

i. Schedule outage time (one month per year)

299 towers were upgraded on 5 different 400 kV OHTLs over 4 years. The upgrade program took 8 years to implement.

Case Study 5-2 (France) – Upgrading of Lattice Steel Towers Following a Major Wind Storm 1999

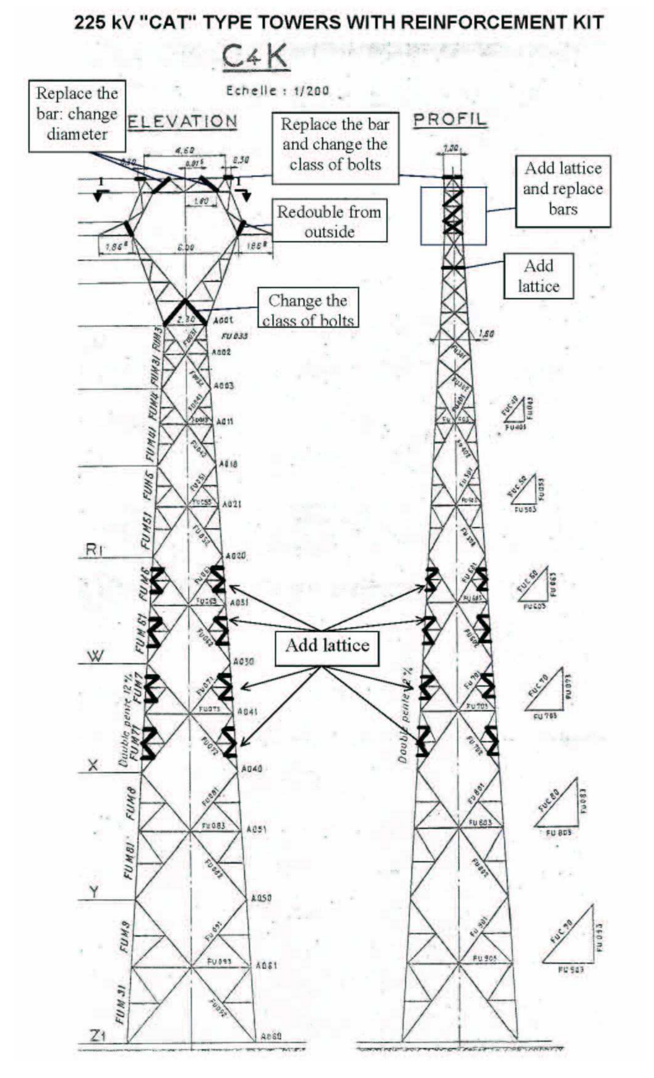
Storms of December 1999 caused unprecedented damage to the French electrical network. The territorial extent of the storms (approximately 2/3 of France) and the violence of the wind were truly exceptional. Wind speeds exceeded 150 km/h and in some areas 180 to 200 km/h. The implementation of "anti-cascade" towers was decided in order to limit the spatial extent of damages to the network in case of exceptional climatic events.

<ins>The strengthening program</ins> concerns approximately 52,000 km of network lines and 18,000 anti-cascade towers to be inserted (either by reinforcement or by replacement) : 1,500 x 400 kV towers, 3,500 x 225 kV towers, 13,000 x 63-90 kV towers.
One of the goals of this program is to reinforce the mechanical strength of existing towers as well as their foundations, and to avoid replacing them. The objective is to control costs and limit the environmental impact of the measure.

Due to the very large number of towers of a given type, the methodology for reinforcing the towers is based on <ins>generic reinforcement solutions, also referred to as "Kits"</ins> : standard strengthening for a given type of support, as opposed to optimized solutions that vary for each support.

The main industrial advantages of such generic solutions are to improve the traceability of the reinforced towers (limiting the types of towers and associated calculation models), to reduce the number of studies required, and improve productivity by manufacturing large series of identical parts and having assembly teams assemble several identical kits.
The technical solutions chosen for reinforcements are mostly traditional, easy to implement, and reduce the required outage time of the installations (add lattice and panel bracing, change the triangulation, increase the size of angles, etc.).

Methodology for reinforcing the foundations is mainly based on micro-pile reinforcement.



Concrete Structures

Case Study 5-3 (France) - Upgrading of Concrete Poles

Various solutions of reinforcement can be considered according to the importance of the loads to be applied to the poles likely to be upgraded:

i. For a light reinforcement: carbon fibre sticking on all the height of the pole (see picture)

ii. For a heavy reinforcement: addition of a new belt on the existing pole. This "belt" can be made up of reinforced concrete or fibre-reinforced concrete systems (with in this case a reduced thickness)

Example of light reinforcement: the concrete pole is reinforced along its profile side to increase the overhead line withstand to transversal loads.
A carbon fibre coating is applied on the total height of the pole

5.2 Foundations [58], [65]

Foundations are located for the most part under ground level. For the availability and proper functioning of the overhead line the foundations are very important. In general when the foundations fail this will have large consequences for the towers. Failure of the foundations will lead to failure of the tower of the overhead line. An additional problem is that restoration of the transmission line takes longer due to the additional time for rebuilding the foundation.

5.2.1 Background

Upgrading foundations as a result of changing circumstances will help prevent foundation failures. There are several causes that can lead to possible failure of the foundations. These causes are:

Catastrophic Events.
Unexpected and extreme weather events can produce extreme loads on the foundation. The following must be considered:

i. Wind loadings;

ii. Snow- and ice load

iii. Landslides;

iv. Snow creep.

Figure 5-1: Foundation Failure after Windstorm

After a catastrophic event design loads are often recalculated. Generally this will lead to improvement of the structure design and also to upgrading of the foundations. Upgrading can be applied to the entire overhead line or for a limited number of towers and foundation in the existing overhead line.

New Standards and Legislation.

Particularly catastrophic events can cause changes in standards. Mostly standards will apply to new towers and foundations, but they can also apply to existing overhead lines. New insights in loadings on overhead lines can lead to changes of existing standards. Also in this case for existing overhead lines the assessment will be done where the changes in the standard will be followed. Changes in legislation for example in case of EMF (see paragraph 5.4.5) can lead to changes in overhead lines and changes in foundations. In some cases these changes can lead to adaptation of other tower configurations and this will have a great influence on the foundations.

Changing the Function of a Tower

Changes of the existing overhead line by for example branches, passage of line to cable can change the function of the tower (e.g. suspension tower may be changed to an angle or dead-end tower). Because of these new loads on a tower the foundation may need to be upgraded.

Changes in Conditions Near Foundations

It occurs regularly that as a result of construction or mining in the vicinity of a tower the soil characteristics around the foundation change. The design conditions are no longer valid. As a result of this foundations may be upgraded of or reinforced. Causes for this are extraction of gas, mines etc in the vicinity of overhead lines or banked-up or additional soil placed on top of the foundation. As a result of these changes there can arise new loadings on the foundation, where recalculation or foundations are necessary (see Case Study 5-4).

Increasing Tower Height.

There are a number of causes for which existing towers must be raised. Raising towers will lead in many cases to recalculation of the foundation of the tower and possibly upgrading the foundation. As a result , the increase wind loads on the conductors of the overhead line will influence on the foundations. Causes for increasing tower height can be:

i. Larger sag of conductors as result of higher operation temperature mostly within the framework of uprating (to see chapter 4);

ii. New infrastructure under overhead lines (roads, railroad tracks, other overhead lines etc);

iii. Placing buildings or other infrastructures under overhead lines.

Uprating and Asset Expansion
Uprating (see section 4) and Asset Expansion (see section 7) often require upgrading of the foundation after the analysis is done and taking in account latest standards.

5.2.2 Verification Considerations for Upgrading Foundations

Successful upgrading of transmission line foundations depends on a number of factors that must be considered.

Upgrade Studies
It is possible that the original foundation capacity was not utilized during installation for various reasons such as unusual terrain conditions, site specific restrictions of availability of materials. In such cases, foundation upgrade can possibly be achieved with minimum effort. However, all original design assumptions should be re-examined again.

Availability of Original Design Information.
It is essential to know the assumptions used in design of the original structure such as strength/parameters of materials used and design loads. This will enable a designer to determine the existing structural capacity of the foundation and to perform studies necessary to increase it.

Foundation designs of some very old tower designs might have not been well documented. In some cases there may be deviation in the construction practice deviates from what you will find on design drawings.

Assessment of Field Conditions
A field inspection is necessary to determine condition of the existing structure and foundation exposed to both the environmental elements and the transmission line loads. It may be necessary to dig near foundation to inspect below ground condition of the foundation. Such inspection might reveal reduction of capacity of the foundation which might lead to a lower overall capacity.

5.2.3 Technical or Practical Limitations

Beside the general restrictions which are described in paragraph 3.6 there will be for the upgrading of foundations several technical and practical limitations. These limitations possibly lead to restriction in the working method, use of equipment, material and tools, and also in the design of upgrading of the foundation. It is possible that the technical and practical limitations make upgrading of the foundation impossible and an entirely new foundation must be chosen. Some examples of the limitations for foundation upgrading are:

Outage Availability

For upgrading foundations normally heavy equipment will be required. In general you can state that the larger the upgrading of foundations, the heavier the equipment will be.

Depending on the size of equipment used for upgrading it could be necessary to deenergize the overhead line. When it is not possible to deenergize the overhead line or the outage time is limited then there decision is made to redesign the upgrading with using smaller equipment. One should also be aware of the time necessary for upgrading the foundation and the outage availability

Figure 5-2: Equipment for upgrading foundations

Construction of Existing Foundation

There are several types of foundations for overhead lines. The use of any particular category of foundation will depend to a degree on both the support type and the geotechnical conditions present. Figures 5-3, 5-4 and 5-5 show some possible types for foundations normally used for towers of overhead lines.

The following types of foundations have been considered:

i. Spread footings;

ii. Drilled shafts;

iii. Piles.

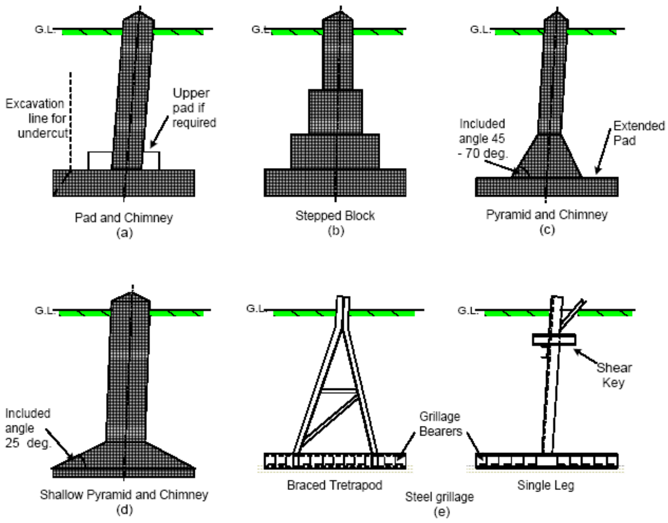


Figure 5-3: Spread Footings Foundations

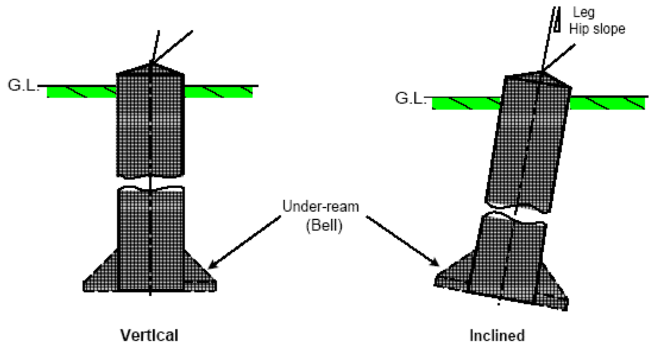


Figure 5-4: Shaft Foundations

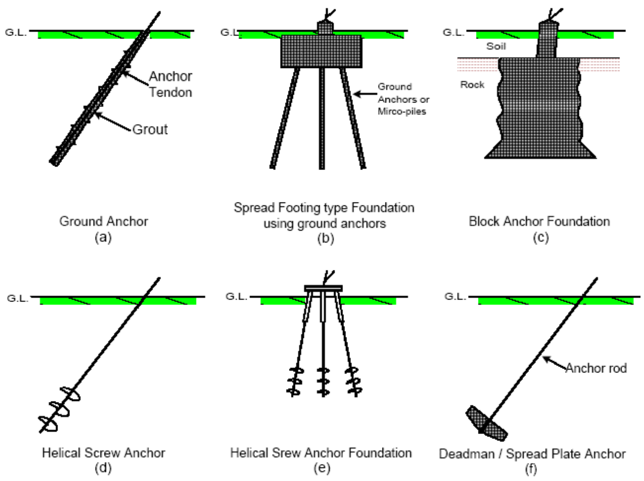


Figure 5-5: Anchor Foundations

Depending on the type of foundation used for the existing tower the solutions for upgrading could be limited. In some cases it could be necessary to use different type of foundations to upgrade the existing foundation. For example a ground anchor (Figure 5-5) in combination with an existing Pad an Chimney (Figure 5-3) foundation is a useable solution.

Permission from Land Owners

Especially when the ground where the tower of the overhead line is built is not owned by the asset owner you have to be aware of the permission of the land owner. It could be a problem when the upgrading of the foundation could limit the land owner for using the ground near to the tower.

Safety Issues

One should be aware of the fact that working on existing foundations will have effect on the stability of the tower. Especially when the upgrading activities will be executed in windy areas or in windy periods of the year the use of temporary constructions could be a necessity. The type of temporary construction could have effect on outage time, but also on permission of land owners.

The use of temporary construction will have great effect on the costs of upgrading the foundation.

Figure 5-7: Use of Temporary Construction to Take Over Foundation Loads

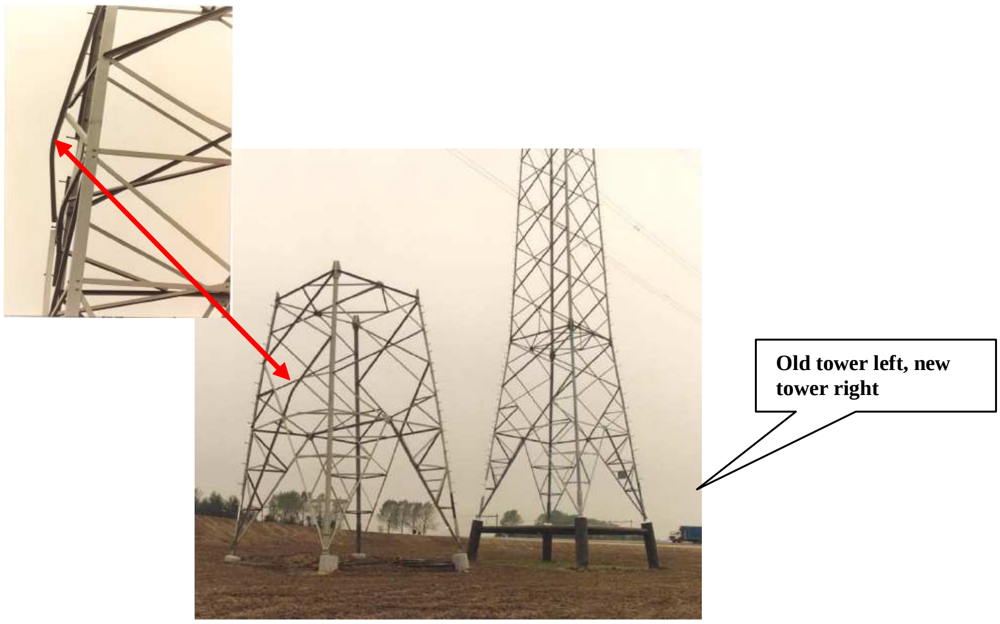
5.2.4 Case Studies

Case Study 5-4 (The Netherlands) – Upgrading Foundations of 150kV Overhead Line Caused by External Forces

Two towers of a 150kV overhead line have to be raised and relocated. It was decided to build two new towers with extra long shaft foundations, because the existing ground level had to be increased by 4 meters. After building the towers a contractor start to bring up the soil. The contractor did not pay attention to compact the soil near to the foundations. The use of very heavy equipment near by caused unexpected external forces on the foundation. The four shafts of the foundation were pressed inward toward each other which caused deformation in the base of the tower.

Solutions:

i. New foundations of drilled shaft foundations with bridging beams;
ii. New base of towers;
iii. Replacing towers.



5.3 Insulator Strings [34]

Insulator strings are a key component of an overhead line; they provide mechanical connection between conductors and support structures and at the same time electrical insulation between live line parts and earthed parts.
Depending on the environmental conditions, newly installed insulator strings can be expected to be in operation for 40 years.

5.3.1. Background

Upgrading of an insulator string is achieved either by strengthening of its mechanical resistance or by improving of its electrical resistance (insulation performance). Although the methods of strengthening of mechanical resistance are limited (strengthening of the weakest component in string or multiple strings), the possibilities of how to improve electrical performance vary. The major challenge is to improve the pollution performance.

A pollution flashover of a transmission line is initiated by deposits of airborne contaminant particles on the line insulators surfaces. Under dry conditions, these deposits are harmless however, when they are wetted by light rain, fog or high humidity events, the salts in the contaminants dissolve, forming a conducting film on the surface of the insulators. This film reduces the leakage distance across the insulator surface and compromises the insulators withstand power frequency voltage capacity. If the withstand capability falls below the designed stress level, a pollution flashover will occur.

The contaminant particles may be of natural origin or they may be generated as a result of industrial, agricultural, or construction activities. Transmission line flashovers occur due to a range of containments such as sea salts, road salts, cement dust, fly ash, potash, limestone and gypsum and may arise from a changing environment where the transmission line is located.

Depending on the frequency and the amount of rain, a varying amount of the contaminants could be collected on an insulator before they are cleaned by natural rain washing event. During the period between the natural washings, if the insulator contamination level reaches the critical value, the moisture the light rain or high humidity event could cause a flashover.

A contaminated insulator flashover is more damaging to a transmission line reliability than a lightning or a switching flashover. Generally, a transmission line can be successfully reclosed after a lightning or a switching flashover, but a contaminated insulator flashover is frequently followed by additional flashovers if the atmospheric moisture producing condition persists and may not be able to be reenergized until the pollution is removed from the insulator.

The transmission line pollution performance is a function of the pollution level of the environment which may range from light to very heavy and determines the minimum nominal specific creepage distance for the insulator. The insulator pollution performance is therefore a function of the creepage distance and also the shape of the insulator.

Upgrading a transmission line pollution performance may consist of replacing the insulators with increased creepage distances and or introducing insulators with deep ribs such as a fog shape designs. In some arid countries an aerodynamic flat profile shape has been found to be satisfactory to minimize pollution flashover events. Upgrading of insulator strings is also required in cold climates where freezing rain could cause icicles and salt to form between various insulator units thus bridging the gap and reducing leakage distance

Other mitigation techniques consist of the application of hyperphobic silicone greases, recurrent insulator washing or the use of semiconducting glazed insulators or installation of polymetric or composite insulators .

Some of the methods of insulation performance improvement are listed bellow:

i. Increasing the arc distance (i.e. by increasing the number of insulators or length of insulator);

ii. Increasing the leakage distance (i.e by increasing the number of insulators or providing a different shape of insulator; or

iii. Changing the pollution characteristics of the insulator (i.e. different shaped insulators for fog or desert environments or different insulation materials such as non ceramic materials).

Choosing one of the above mentioned methods or their combination depends on physical state of the whole line (clearances), progress in new material investigation, expenditures and experience of particular utility.

5.3.2. Verification Consideration

Although new computing methods and latest investigation application help designers to specify all possible loads and stresses on components, experience from operation remains one of basic sources of data when considering upgrading of some components.
Designers should take into account:

i. Environmental conditions stated in original design

ii. Residual parameters (esp. mechanical and electrical strength) of original components

iii. Experience from operation (negative impacts of line on its surrounding or vice versa)

iv. Records of failures and other events from extreme loading (critical loads)

v. Possible causes of future deterioration (vandalism, birds, industrial pollution etc.)

vi. Availability of the market

vii. Traditional solutions in particular place or country

viii. Inventory considerations

Because upgrading of insulator strings affects other parts of a line (structures, conductors), consideration should also involve impact on all these components and their condition (i.e. exchanging of insulator strings on old conductors, on conductors with optical fibres).

Verification of Parameters
Many utilities have their own standards which according to coordination of insulation levels specify parameters of components in insulator strings (called classification of insulator strings). Such standards help designers to choose the proper components.

Mechanical Resistance
When crossing any highway, railway or waterway multiple suspension insulator strings or increasing the strength class of the insulator is often used to reduce the probability of failure. Deterioration of certain parts of the fittings can lead to possible failure at the coupling.

Pollution Resistance
This means the ability of an insulator to resist contamination in the ambient air. In some arid countries an aerodynamic flat profile shape has been found to be satisfactory to minimize pollution flashover events. The mitigation techniques consist of the application of hydrophobic silicone greases, recurrent insulator washing or the use of semi conducting glazed and polymeric or synthetic insulators with good hydrophobic properties.

Radio and TV Interference Resistance
Lowering of number of connections can decrease possible sources of radio and TV interference. In addition loose hardware and unshielded hardware parts can cause interference. The addition of hold down weights on lightly loaded insulator strings can reduce radio and TV interference.

Verification of Used Insulation Material
The main advantage of glass insulators is that they maintain their mechanical connection even after failure of the glass. They have a long history of satisfactory experience. The ceramic insulators are produced from the stable material (ceramic porcelain) and have been used for many years. Both are quite easy to add to or to change out using live line techniques. Their disadvantage is that they are heavy and fragile
The composite insulators are the newest type of insulators. Their usage is growing because of the following:

i. Light weight compared to strength;

ii. Less sensitiveness to the mechanical impact;

iii. High bending strength (that’s why their main usage as post insulators); and

iv. Exceptional resistance to flashover in contaminated areas due to the hydrophobic characteristics of some composite materials.

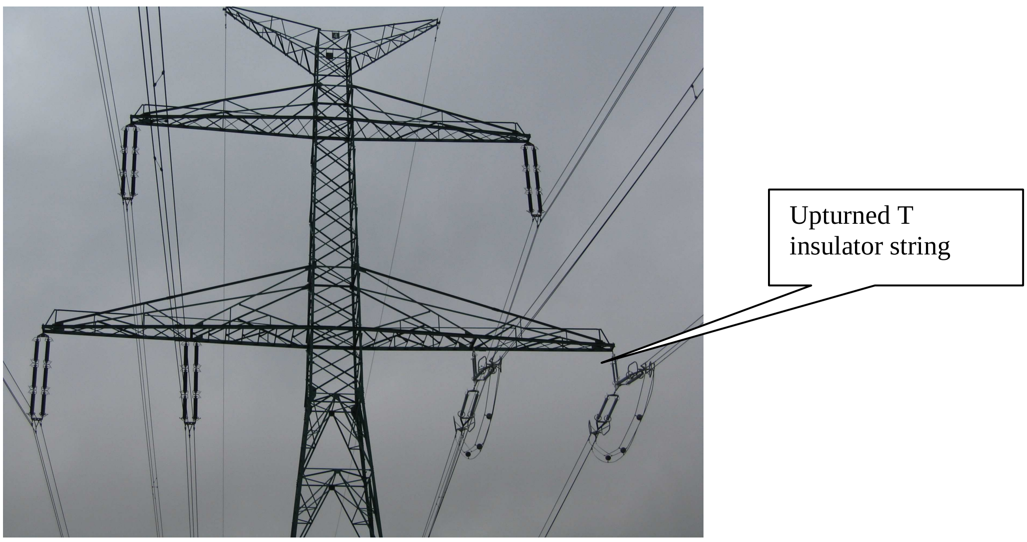
5.3.3. Technical and Practical Limitations

New types of insulators allow a variety of modifications for upgrading (V-strings, T-strings). Also the variety of possible insulation materials, i.e. glass, ceramic or composite helps meet different requirements for shape and strength.
Continued invention of new composite insulation materials has resulted in inadequate experience with many of these materials, which limits the assessment of their long-term experience. Accelerated laboratory and field tests are necessary for performance and lifetime estimation of these types of insulators.
Demands for minimizing of operation outages are practical limitations that effect planning of upgrading the lines. Live line maintenance technique is one of the solutions for upgrading insulation without taking a line outage.

5.3.4. Case Studies

Case Study 5-5 (Czech Republic) – Installing Upturned T-Insulator Strings

A double-circuit 400 kV line crosses the polder (dry area with barriers against floods). Due to this fact actual clearances have to be increased to fulfil the requirements for system security whenever the maximum level of flooded area occurs.
The project dealt with replacing of former double insulator string with ceramic insulators (the length 4982 mm). The new insulator string in the shape of "upturned T" was installed. The vertical length of this insulator string is about 1,9 meters (1927 mm exactly), which resulted in increasing of distance phase to earth in 3055 mm. This distance enabled to increase the thermal rating of the conductor to 80°C.
Replacing of one insulator string lasted half a day. Replacing four insulator strings lasted two-days.



Case Study 5-6 (USA) – Electrical Upgrading, Replacement of Glass or Ceramic Insulators with Non-Ceramic Insulators.

The need to reduce line relay incidents caused by contaminated insulator flashovers and the maintenance cost to wash glass or ceramic insulators in high contamination areas may justify the replacement of the glass or ceramic with a suitable non-ceramic (polymer) insulator.

One Pacific Coast utility has replaced both 138kV, 230kV, +/-500kV DC and 500kV AC ceramic insulators with silicone based non-ceramic insulators in high contamination urban areas with the results of eliminating washing on these lines since 1985. In addition, no reports on insulator flashovers due to contamination have been reported on the towers with the non-ceramic insulators.

Above, typical insulator washing on +/- 500kV DC and 230kV lines

At left, change out of 230kV ceramic insulators with Non-ceramic insulators. Since installation no washing has been required.

5.4 Upgrading or Improving Electrical Characteristics

The electrical parameters that provide opportunities to upgrade a transmission line are improvements in lightning performance or outage rate; improvements in insulator pollution performance; improvements in corona, radio & television interference and audiable noise; reductions in earth potential rise; reductions in electric and magnetic field (EMF) levels and reductions in induction in adjacent long parallel metallic infrastructure such as pipelines and or metallic telecommunications. These upgrading strategies are discussed in detail in the following sections.

Reducing the levels of EMF of a transmission line may not be considered as upgrading the electrical characteristics of the line as the outcomes do not reduce the probability of failure. However these changes will produce a more environmentally friendly line. Notwithstanding this, the opportunity will be taken to briefly discuss in the following section strategies to reduce EMF.

5.4.1 Lightning Performance

The determination of the lightning performance of a transmission line requires an intricate mathematical study based on probability involving non linear complex electromagnetic behaviour of the interactions of the lightning, conductors, insulators, the structure and the earthing.

Minimizing the probability of outages due to lightning is a critical aspect of transmission line design and is normally undertaken at the conceptual stage so the structure configuration, insulation levels and earthing may be coordinated to achieve the desired level of lightning protection.

The major factors that affect the lightning performance of a transmission line are;

i. The keraunic level or ground flash density;

ii. Stroke current magnitude and wave shape;

iii. The structure height;

iv. The presence of one or more overhead earth or shielding wires;

v. The geometry of the overhead earthwire relative to the phase conductors;

vi. The conductor phase to structure clearance;

vii. Midspan clearance between conductors and overhead earthwires;

viii. The insulator arcing distance;

ix. Whether the structure is conductive or non conductive;

x. For non conductive structures such as wood whether the fittings and crossarms are bonded or earthed or are unearthed; and

xi. For earthed structures the structure earth resistance.

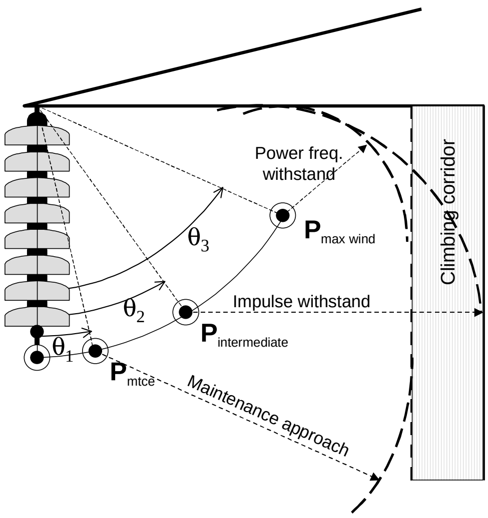
With the exception of the intrinsic keraunic level, stroke current magnitude and wave shape, upgrading the lightning performance of a transmission line may be achieved by modifying one or a number of the mentioned factors. Opportunities to improve the lightning performance of transmission line will focus on the three principle lightning flashover mechanisms as follows,

i. Insulator and or structure flashover for lines without overhead earthwires;

ii. Shielding failures for lines with overhead earthwires; and

iii. Back flashovers.

Firstly, insulator and or conductor to structure flashover arises from either a direct transient lightning strike on the conductor and or for lines generally above 300 kV switching transient over voltage flashovers. In either case, transient over voltage performance of a line may be improved by installing insulators with longer insulator arcing distance and or increasing the conductor to structure clearance. In most cases, the original conceptual design of conductor, structure, insulator geometry has been optimized and any transient voltage upgrading opportunities for transmission lines without overhead earthwires will most likely require a complete reconfiguration of the insulator and crossarm arrangement as additional clearances are not likely to be practicable or possible. It may be effective to add additional weight at the bottom of the insulator string to reduce insulator swing and increase conductor to structure clearances. For transmission lines without overhead earthwires, improvements in transient voltage performance for at least lightning strikes may be achieved by improving the shielding of the conductors by the installation of overhead earthwires or the installation of surge diverters. This will be discussed in detail as follows. In the meantime, a typical suspension insulator string illustrating, maintenance approach distance, lightning withstand clearance and power frequency clearance is shown in Figure 5-7**.**



<u>wind on conductor</u>

condition 1
100 Pa wind – θ_1 = 20 degree swing
maintenance approach distance to climbing corridor

condition 2
300 Pa wind – θ_2 = 35 degree swing
impulse clearance to structure

condition 3
500 Pa wind – θ_3 = 60 degree swing
power frequency clearance to structure

Figure 5-7: Example of Swing Conditions for Clearance Criteria

Secondly, a common outage cause for transmission lines with overhead earthwires is a lightning shielding failure where the lightning strikes the conductor directly without being intercepted by the overhead earthwires. Typical shielding arrangements with single and double earthwires are illustrated in Figure 5-8**.** For transmission lines with existing overheads earthwires the lightning performance will be improved by reducing the shielding angle. This would normally be achieved by redesigning the overhead earthwire and conductor geometry and this may include changing the structural attachment point of the conductor or earthwire or changing the insulator design. Differing shielding angles by differing overhead earthwire attachments resulting in superior lightning performance are illustrated in Figure 5-9.

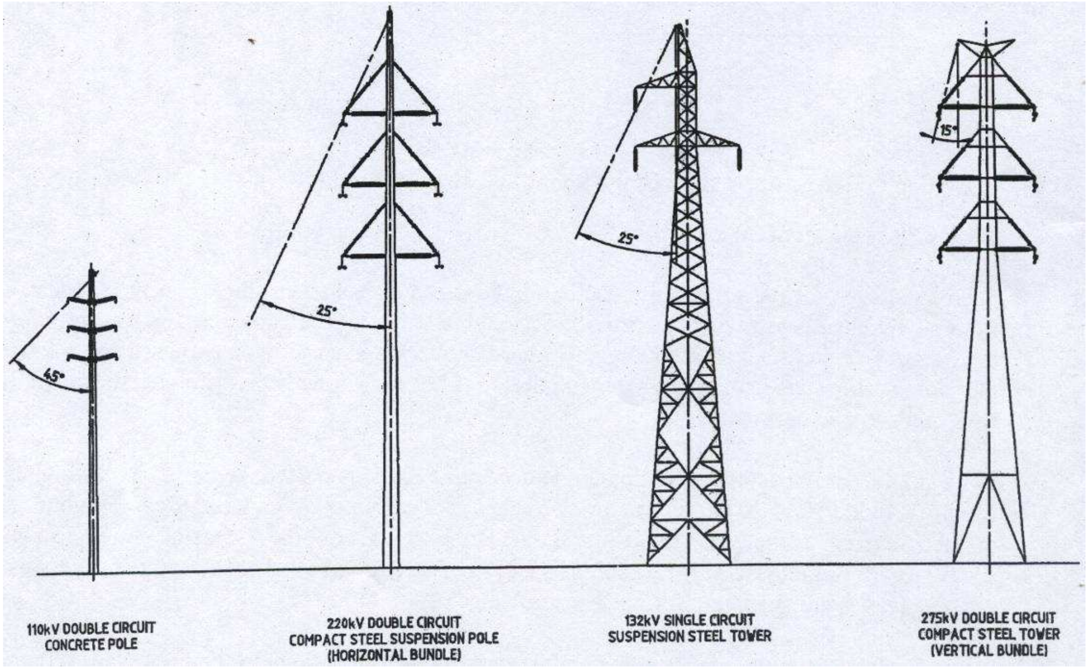
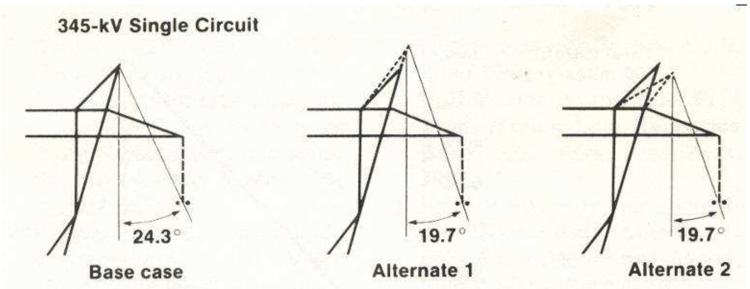


Figure 5-8: Typical Shielding Arrangements for Single and Double Earthwires



Scheme	Shielding Angle	Tripouts/100 miles/year Shielding Failure	Back-flash	Total
Base case	24.3°	0.03	0.54	0.57
Alternate 1	19.7°	0	0.58	0.58
Alternate 2	19.7°	0	0.53	0.53

Figure 5-9: Typical Shielding Failure Rates for Varying Shielding Angles [51]

Similarly, installation of overhead earthwires for transmission lines without overhead earthwires, will result in a significantly improved lightning performance. The number of overhead earthwires is a function of the required outage performance and the available marginal structural capacity. Double circuit transmission lines and transmission lines with flat conductor configuration without overhead earthwires will in general require the installation of two earthwires to achieve a satisfactory outage performance. The installation of one or two overhead earthwires to reduce shielding failures will contribute additional wind structural loads to suspension, tension and termination structure and additional tension loads to tension and or termination structures. In this regard, structures may require substantial modification and structural capacity assessments to accommodate the additional overhead earthwires. Additional foundation loads is also a fundamental consideration.

It is also important to mention that any changes in clearances may eliminate opportunities to carry out live line maintenance.

The installation of surge arrestors for transmission lines with or without overhead earthwires is an effective technical mechanism to improve transient voltage performance and is used widely in some countries. The installation of arrestors for some transmission lines with optimized design may provide the only option to improve transient over voltage performance. This may also be the only viable solution for transmission lines with an unacceptable level of switching transient over voltage flashovers. The outage rate of the transmission line is a function of the number of arrestors installed per kilometer and the earthing resistance of the arrestor. For example a 66 kV transmission line without overhead earthwire, a structure earthing resistance of 5 ohms with an expected 35 strikes per 100 km.year and arrestor installed with a separation of 200 m would result in an outage rate of 0.15 per 100 km.year. Increasing the arrestor separation to 500 m would result in an outage rate of 4.9 per 100 km.year. Clearly this example illustrates that arrestors are novel technical solution to improve the over voltage performance, nevertheless the overall effectiveness of the solution would be the subject of a cost benefit analysis.

The final mechanism discussed is the back flashover and is the predominant cause of lightning induced flashovers on transmission lines. The sequence of a back flashover event leading to an insulation failure is,

i. Lightning strikes an earthwire at or near a structure;

ii. Current flows in the overhead earthwire(s) towards the structure either side of the lightning strike;

iii. The current flows down one or more structures;

iv. The current in the overhead earthwire induces voltages in the phase conductors;

v. The current which flows down the structure is reflected at the earth;

vi. The reflected current establishes a voltage on the structure;

vii. The current which flows to the other structures via the earthwire is reflected at each structure and earth;

viii. When the voltage across any part of the transmission line insulation exceeds its electrical insulation strength, there will be a back flashover from conductor to the structure; and

ix. Often there will be a number of simultaneous back flashover failures.

A typical example is shown in Figure 5-10 where the structure earthing was very high and the lightning current flashed over to an adjacent fence.

Figure 5-10: Typical Evidence of Structure Potential Rise and Flashover to Adjacent Metallic Fence

Reduction of the incidence of back flashover is achieved by one or all of the following strategies,

i. increasing the insulator arcing distance and or increasing the conductor to structure clearance thereby reducing the probability of back flashover;

ii. reducing the structure earth resistance as illustrated in Figure 5-11 thus reducing the structure voltage to earth and the voltage across the insulators and reducing the probability of back flashover;

iii. reduce the conductor earthwire separation which improves the coupling and increases the conductor voltage relative to the earth thereby reducing the voltage across the insulators and the probability of back flashover.

The most common and generally the most cost effective strategy is reducing the structure earth resistance.

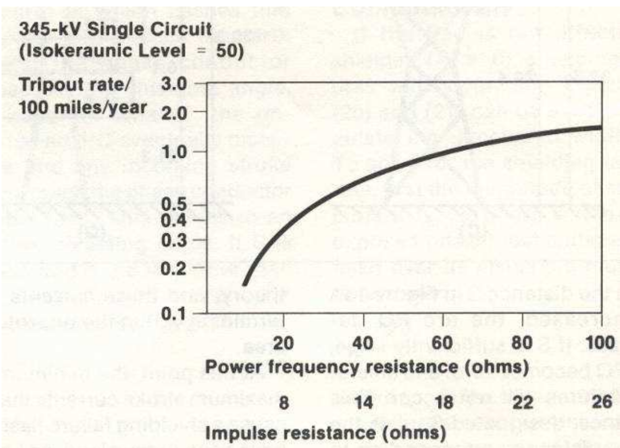


Figure 5-11: Typical Outage Rate as a Function of Structure Earth Resistance [51]

5.4.2 Corona, Radio & Television Interference and Audio Noise Mitigation

Corona discharges form at the surface of conductor or hardware when the electric field intensity on the surface exceeds the breakdown strength of air, and the air then ionizes. Corona results in losses which are cumulative with the length of line. Corona does not normally occur below 200 kV. Several conditions control the breakdown strength, the air pressure, the electrode material, incident photo-ionizations and the type of voltage.

The presence of small protrusions such as water droplets, snow flakes, contamination or protrusions or sharp points on the insulator or hardware surface may produce strong local enhancements of electric field. The ionization of air generates light, audible noise, radio noise and in some extreme cases conductor vibration.

Minimizing the likelihood of corona is a critical aspect of transmission line design and is normally undertaken at the conceptual stage in the selection of conductors, the bundled diameter and configuration for multi-phase conductors and the insulators fittings such as grading rings.

Corona activity may result in radio and television interference. The primary concern for interference is for amplitude modulated signals. Frequency modulated and television broadcasting signals are much less affected by the activity.

Audible noise arises from corona discharges and consists of humming, crackling, frying or hissing characteristics. The intensity of the corona noise is influenced by the weather conditions and the noise increases during periods of rain, snow and fog. The noise level is inversely proportional to the square of the separation distance and as one moves away from the transmission line then the level of noise reduces significantly.

Technical Brochure 147 [52] indicates that from surveys carried out that corona noise is not a major problem for existing transmission lines.

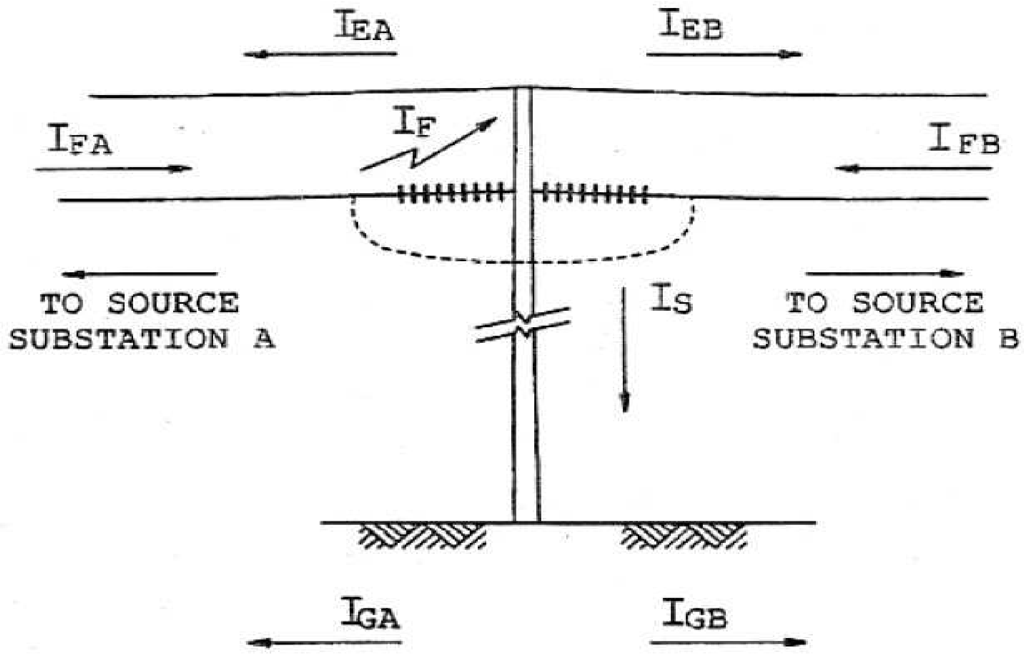
Nevertheless opportunities to upgrade the performance of the transmission line may arise as corona may occur on contaminated insulators, or as a result of looseness or protrusions in hardware, or on imperfect or damaged conductor surfaces or from inappropriate insulator fitting designs and grading rings.

5.4.3 Reductions in Structure Earth Potential Rise

Transmission lines are normally earthed at every structure location to provide a local low impedance circuit to the body earth for transient earth fault currents. Low impedance earthing is necessary to minimize the possibility of elevated touch and step voltages in the vicinity of the structure in the event of an earth fault. High touch and step voltages may result in unsafe structure voltage and a risk of electric shock and the possibility of electrocution. The structure earth potential arises from a fault current flowing to earth via the structure and hence the magnitude of the potential rise is a function of the fault current and the structure earth resistance.

Low impedance earthing also minimizes the risk of structure voltage rises exceeding the flashover voltage of an insulator string causing and indirect lightning strike outage or backflash over as mentioned in section 5.4.1.

Allowable step touch potentials are generally defined in various jurisdictions through standards, regulation and or codes and one such example is IEC 60479 [53]. IEC 60479 defines the physiological effects of body current as a function of duration of current flow.



IF = IFA + IFB
= IEA + IEB + IS
IS = IGA + IGB

Where:

IFA, IFB	=	Contribution of fault current from source substation A and B respectively.
IF	=	Fault current.
IEA, IEB	=	Contribution of fault current in the continuous earthwire flowing to source substations A and B respectively.
IS	=	Structure fault current.
IGA, IGB	=	Contribution of fault current in the ground flowing to source substations A and B respectively.

Figure 5-12: Typical Transmission Line Earth Fault Structure Current Paths [54]

The design of the transmission line earthing system will depend on the structure earth resistance criteria and will vary with the soil resistivity along the route of the line. Two methods are commonly used to achieve an effective earthing system for a transmission line, the provision of a continuous earthwire and the placement of locally buried structure earth electrodes having a low earth resistance. The earthwire provides an alternative return current path to the source reducing the magnitude structure earth fault current and hence the structure earth potential rise. Typical earth fault structure current paths are illustrated in Figure 5-12**.**

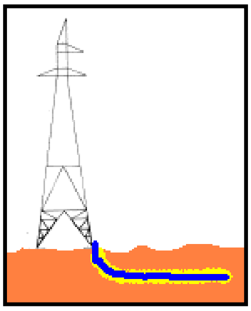
Upgrading to reduce structure potential rise may consist of installing additional structure earthing, installing buried grading rings at step locations to reduce step touch potential, installing larger overhead earthwires to reduce the current flowing in the structure, the application of insulating paints and or epoxies to structure touch locations and or the installation of high speed protection schemes to reduce electric shock duration.

There are basically three types of methods to upgrade structure earthing and are counterpoise, metal cladding and deep drilling. All the methods use a galvanized steel or copper rod that is placed in a hole at various depths in the ground and lengths from the structure leg and each method will be discussed in more detail.

The aim of implementing structure footing improvements is to achieve a low resistance connection between the structure and a earth. The soil type and resistivity are basic determining factors and influence which of the method of earthing is economical and technically feasible. Counterpoise and metal clad methods can only be applied in normal ground soil conditions and the deep drilling is normally applied in rocky terrain as the rocky terrain will make it very difficult to apply the first two methods. In areas where there is basically only rock alternative methods like line surge arrestors may be considered as the only feasible option to improve lightning performance of the line.

Counterpoise is the method that is mostly used for the earthing of structures. The method consists of a metal strap or copper rod that is connected to the structure leg at the bottom and is buried in the ground in a trench at an average depth of 0.5 m. It is buried normally at an angle of 45^0 and the distance is dependent on the soil resistivity and the required structure earthing. A typical counterpoise earthing arrangement is illustrated in Figure 5-13.

Figure 5-13: Typical Counterpoise Earthing



Metal clad earthing consists of either copper rods or galvanized steel rods connected to the structure at the structure leg foundation interface. The rods are buried in a trench of about 0.5 meters deep and are then horizontally buried for about 7 meters long before it is buried in vertical holes. A typical metal clad earthing arrangement is illustrated in Figure 5-14.

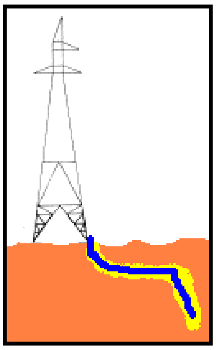
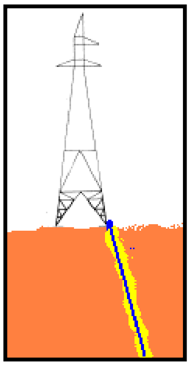


Figure 5-14: Typical Metal Clad Earthing

In some circumstances soil resistivity is very high requiring special techniques such as deep drilling. Deep drilling method is the placing of a copper or steel rod in a hole bored and varies in depth depending on the soil type and resistivity. A typical deep drill earthing arrangement is illustrated in Figure 5-15.

Figure 5-15: Typical Deep Drill Earthing



Case Study 5-7 (South Africa): Apollo – Verwoerdburg

The Apollo - Verwoerdburg transient line outages mostly occurred due to lightning strikes. The line tower earthing resistance was measured and found to be very high. The line was running over a rocky hilly terrain and the normal metal cladding method to improve the tower earthing could not be used. It was therefore decided to apply the deep drilling method. The copper rods were placed in holes drilled up to a depth of 25 meters. It was filled with a mixture of normal soil and bitumen. The performance of the line improved considerably after this method to improve the tower earthing was applied.

Case Study 5-8 (South Africa): Arnot – Vulcan

The Arnot – Vulcan 1 line traversed over a area of normal ground with limited rock. Although the area is fairly flat lightning strikes did cause a number of outages. The metal cladding method was used to improve the line faults as the metal strips were easily buried in the ground as well as the 3 metres at the end of the earth strap that was buried vertically The ground is mixed with gypsum and used to fill the trench and hole in which the earth strap was laid.

Case Study 5-9 (South Africa): Marathon – Acornhoek

The Marathon - Acornhoek line is running over mountain areas and lighting caused transient flashovers was a major issue of concern. In the mountain areas the soil was not deep and as a result it was very difficult to bury any rods in the ground. The best methods that had to be used is the deep drilling as the earthing will be improved due to the depth that the earth rod is buried in the rock/soil.

5.4.4 Reductions in Electric and Magnetic Field Levels

Electric and magnetic fields (EMF) from transmission lines and concerns over suggested health effects has emerged as a major public policy issue for utilities world wide. CIGRE has considered the subject and the debate and published in 1999, Technical Brochure 147 [52].

The strength of the electric and magnetic fields depends on both line voltage, line current and on the conductor geometrical parameters. The electric field decreases rapidly with lateral distance from the line and is further reduced by grounded objects like trees, lamp posts, buildings and other structures. The magnetic field also decreases rapidly with lateral distance from the line.

Minimizing the electric and magnetic fields is a critical aspect of transmission line design and is normal undertaken at the conceptual stage in the selection of transmission line phase conductor geometry. For existing transmission lines existing conductor and structure geometry presents major technical constraints to retrospectively modify the design to reduce the electric and magnetic field.

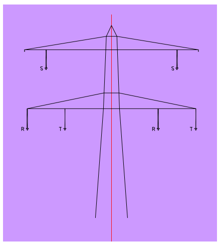
Nevertheless, increasing the line height and or using a triangular phase configuration are the most effective ways of reducing the maximum electric fields at ground level. Opportunities to minimize magnetic fields also include increasing line height, using triangular phase configuration, phase reversal for double circuit transmission lines, screening conductors and employing split phasing. In some case right of way width may be increased to allow lower EMF fields at the edge of the right of way.

Case Study 5-10 (The Netherlands) – Redesign 380 kV Overhead Line as Part of Reduction EMF

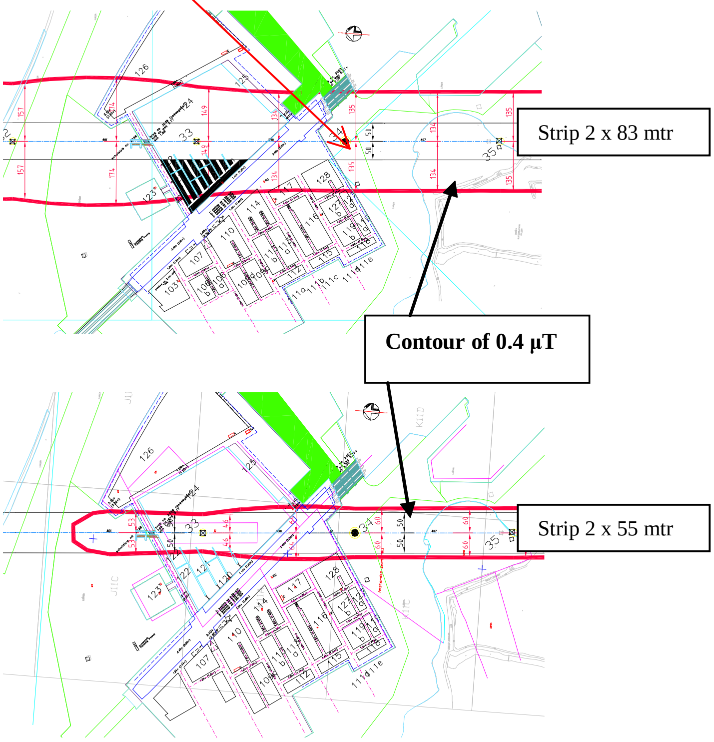
A local government decided to create a new residential area near to the city. Through the area there is a 380kV 2-circuit overhead line, lattice towers, type Donau. The local government asked for a solution with the smallest strip under the overhead line with a maximum EMF of 0.4 µT.
It was decided to split one of the 3-bundle phases in a circuit into two 3-bundle phases. This solution had the most effect on decreasing the EMF of the overhead line.

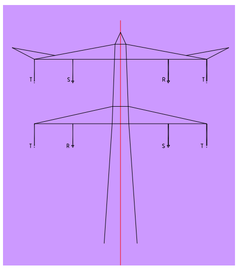
Activities to be done:

i. Upgrading foundations;
ii. Upgrading structures;
iii. Replacing bolts;
iv. Installing 3-bundle conductors



Existing tower configuration





New tower configuration

5.4.5 Induction Mitigation

As human habitation development continues particularly in urban fringe areas and restrictions are placed on the flexibility to select linear routes for infrastructure, the likelihood and community pressure for cohabitation of linear assets will increase. As a result, it has become common for transmission lines, pipelines, conveyors, rail traction systems and metallic telecommunication networks to coexist in infrastructure corridors.

There are three electromagnetic interference mechanisms between transmission lines and coexisting long conductive infrastructure and are inductive, conductive and capacitive coupling. The induced voltage due to inductive and conductive coupling is directly proportional to the transmission line current. The induced voltage due to capacitive coupling is proportional to the operating voltage of the transmission line. The level of induced voltages is influenced by the transmission line and other infrastructure separation distance and parallel length. Other factors include,

i. The earthing of the parallel infrastructure and the transmission line;

ii. Soil resistivity;

iii. Conductivity of the parallel infrastructure;

iv. Cathodic protection equipment install on the parallel infrastructure;

v. The presence of shielding of the parallel infrastructure

vi. The presence of isolating joints in the parallel infrastructure;

vii. The level of insulation on the parallel infrastructure.

The opportunities for the implementation of mitigation strategies on existing transmission lines are limited. Some options to be considered are magnetic field shielding [55], relocation structure earthing as the structure earthing should be separated from the adjacent infrastructure as far as practical, minimizing earth currents by introducing conductor transpositions and or the isolation of shielding earth wires and finally the reconfiguration of the transmission line phase conductor geometry.

6. Transmission Line Refurbishment Options and Case Studies

The main reason to consider refurbishment of a transmission line is to restore one or more components to their intended design life. Refurbishment is intended to decrease the probability of failure of the transmission line without changing the consequences of a failure, thus the risk of operating the line will decrease.

The reason that there is a need for refurbishment is that all components of a transmission line continue to age and are subjected to harsh or changing environmental conditions that degrade components. Conductors are susceptible to corrosion, fatigue, wear, overstress, vandalism improper installation, etc. Insulators can age and loose their electrical and mechanical properties due to pollution, corrosion, vandalism etc. Structures can degrade due to overstressing, corrosion, vandalism, natural biological causes (for wood structures), etc. Foundations need refurbishment due to chemical attack, natural freeze-thaw cycles, erosion, environmental changes, initial construction flaws, etc (see Table 5-1).

Refurbishment of components is normally carried out after inspection (either before or after failure of a component) and when analysis has indicated that a defect can cause accelerated aging of a component that increases the probability of a failure of the transmission line. The refurbishment activities can be limited to a single structure or conductor span or to the entire transmission line.

6.1 Structures [10]

6.1.1 Background

Transmission lines and their structures can be exposed to harsh environmental conditions that affect their performance; i.e. industrial areas with pollution, mountainous terrains with avalanches, flat plains with high winds to name a few. These environmental conditions are responsible for gradual deterioration of structural strength of transmission line structures. With passage of time, the structures will require refurbishment in order to restore their original condition and strength.

In general, structural deterioration can be caused by:

<u>Natural Causes:</u>

i. Ice or wind storms causing structural overloads leading to member deformations

ii. Avalanches and earth slides causing member deformations

iii. Aeolian vibrations, vortex shedding, conductor galloping causing structural fatigue, deformations and wear

iv. Corrosion

v. Biological causes (i.e. fungi)

vi. Wildlife (damages by animals, birds and insects)

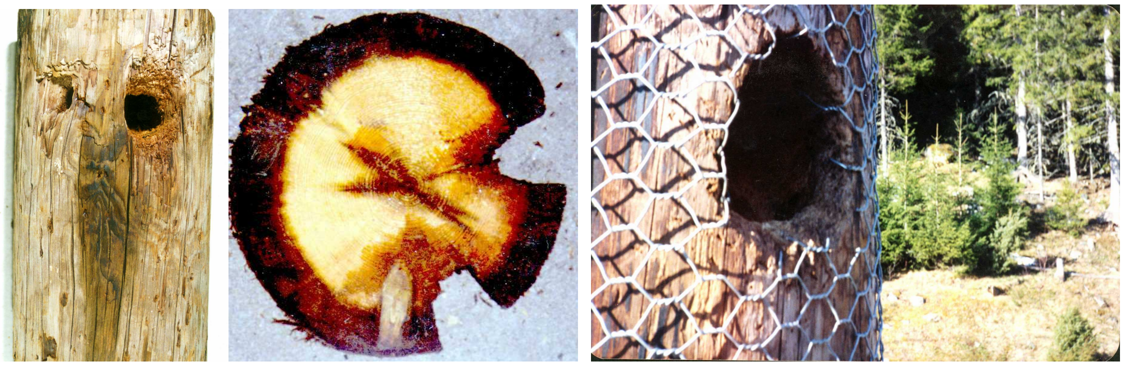


Figure 6-1: Damage Due to Woodpecker

<u>Man Made Causes:</u>

i. Vandalism (i.e. gun shots, member cuts or robbery)

ii. Improper manufacturing, shipping or on site assembly

iii. Industrial pollution causing corrosion

iv. Vehicular impacts

In some cases, failure of a whole structure may occur as a result of a catastrophic climatic event such as a high wind storm (tornado or high intensity winds) or severe icings. Other might be caused by human activities such as vehicular accidents, farming activities, or vandalism. In rare cases failures might be caused by poor design or manufacturing error. These failures can sometimes go unnoticed and be spotted during the course of regular maintenance inspections. However, they can also generate much attention if the scale of the failure is large enough to affect many customers or to cause casualties. In most cases these failures are met with a very swift action by the asset owner.

There are several methods of structural refurbishment. The type of method chosen depends on the type of structures involved (steel, concrete, wood structures) and the level of damage and deterioration. In addition, in some cases preventive measures can be adopted to avoid further damage (i.e. vandalism).

Generally speaking, structural refurbishment involves:

<u>For all Types of Structures, either:</u>

i. Complete structure replacement, or

ii. Replacement/repair of damaged parts or components

Complete structure replacement might be required in cases where the number of damaged parts is high or when refurbishment work needs to be done in a short period of time due to external factors such as availability of line outages. Sometimes, the total replacement even can be advisable if the partial substitution of parts of the structure would be more expensive in economic terms than the installation of a new structure. In other occasions, the total refurbishment of a steel structure becomes necessary if corrosion level is too extensive.

Partial replacement of structural members can be done if deterioration is localized and it does not affect the overall strength of the structure. Normally, this type of refurbishment will be made when there have been deformations caused by ice or wind loads or vandalism. To prevent the theft of metal structural members, it is possible to use welds on the tower bolts, use of anti-theft bolts or installation of barriers to prevent access to the structure.

Member replacement or reinforcement is also sometimes required if steel tower members are excessively corroded and have lost cross sectional area or if there are cracks due to degradation caused by vibrations.

A typical refurbishment method used on steel towers involves painting of metal parts to control corrosion The painting is used in cases where generalized corrosion exists without excessive material strength loss that would put in danger the structural capacity of the structure. Further information on corrosion evaluation can be found in Appendix 2.

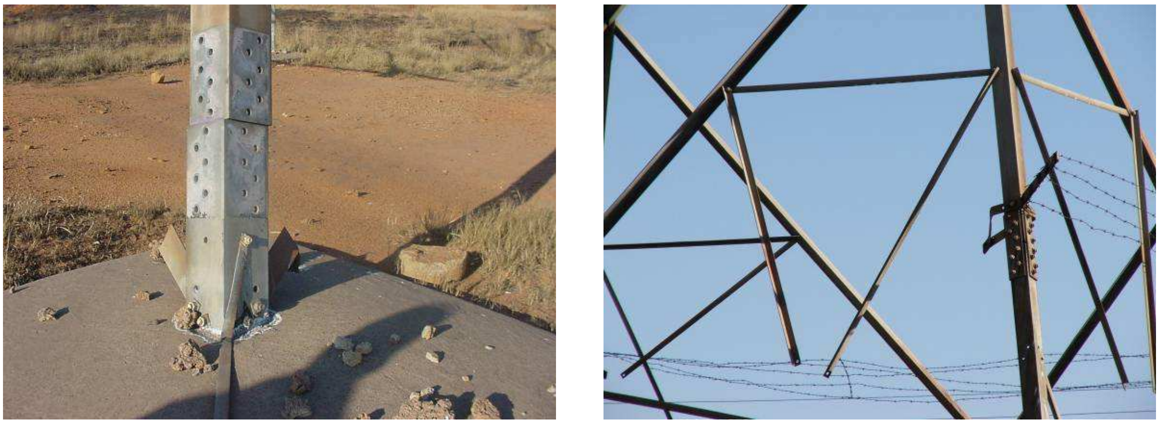


Figure 6-2: Theft of steel parts

Refurbishment of wood pole structures typically falls into these two categories :

<u>Ground Line Reinforcements</u>
Wood pole structure reinforcements are required at a ground level where wood pole decay commonly occurs. They involve:

i. Pole stubbing – involves driving a short wood pole next to a damaged pole and joining the two using metal bands;

ii. Metal reinforcement channels – vertical metal channels (usually made of galvanized steel) driven to the ground next to a damaged wood pole and join together using mechanical fasteners. This solution can also be used for both increasing a structure height and upgrading capacity.

iii. Pole wraps – composite material used to wrap around a damaged part of a wood pole connecting strong, "healthy" parts of a pole and attached to the pole using resins.

Above Ground Reinforcements

Above ground reinforcements are more costly than the ground level reinforcements since they usually involve the use of a pole crew with a bucket truck. The options involve:

i. Fillers to fill the voids caused by wildlife (i.e. woodpeckers) and to restore strength of the pole

ii. Pole caps to prevent wood pole from splitting

iii. Anti-splitting bolts to prevent cracking of wood poles

iv. Doubling-up wood structure members, i.e. installing additional cross braces

v. Use of composite pole wraps (similar to those used for ground line repairs)

6.1.2 Verification Considerations

Structure refurbishment involves in most cases a like-for-like replacement of a structure or its member without affecting original capacity. Refurbishment is often performed by maintenance staff without involving a structural engineer.

Asset owners that use advanced asset management systems have proper tools to deal with deteriorating structures. They use analytical tools which can tell them when to refurbish transmission line structures or their components in the most cost effective way.

This can be well illustrated by an example of a wood pole which deteriorates gradually over its life span. Due to the fact that many transmission line designers use deterministic design approach with generous safety factors, wood poles might often be over-designed. This means that a controlled deterioration of a wood pole parameter (i.e. effective pole diameter after excluding voids) can be permitted. The asset management tool can be used to predict the most economic time for replacement of a wood pole based on the expected rate of deterioration and as confirmed by regular maintenance inspections. Some utilities have also used steel poles to replace deteriorated wood poles.

If metal structure painting is considered as a refurbishment option, site inspection followed by an engineering assessment will be required to determine if the structure involved is suitable. It is necessary to determine the state of corrosion of the zinc-coat galvanizing and the remaining thickness of metal to make sure that the structural integrity of the metal tower is maintained. Replacement of an excessively corroded member maybe required in some cases if the member metal loss is significant. A total structure replacement should be considered when metal loss is excessive and many members are affected.

6.1.3 Technical or Practical Limitations

Technical and practical limitation during refurbishment of existing transmission lines are similar to those discussed in Sections 3.6 and 5.1.3 of this document.

6.1.4 Case Studies

Case Study 6-1 (Spain) – Painting of 400 kV Towers

A line with 32 years in mountainous and humid area. Inspection detected extensive corrosion. A special corrosion study was performed in order to determine the losses of material. The study concluded that material was not significant as to effect the strength, so painting was decided. 85 towers were painted in 15 days. Two layers of paint was applied.

Case Study 6-2 (Spain) – Replacement of 220 kV Towers

A line with 50 years in mountainous and humid area. Inspection detected extensive corrosion. Special corrosion study was performed in order to determine losses of material. Study concluded that there were high quantities of lost material in different bars, legs and bracket plates. Therefore replacement of towers was necessary.

.

Limitations:

i. Limited outage time (one month per year)
ii. No road access in mountains

40 towers per year have been replaced.
Erection of new towers was carried out by cranes and by a helicopter

Case Study 6-3 (South Africa) – Painting of 400 kV Towers

The six 400kV lines emanating from a Nuclear Plant had to be repainted every 5 years due to a severe marine corrosive environment. Previous coating systems were primarily epoxy based. Preparation of the steel members and application of coatings were not always consistent which was one of the main contributing factors. The decision was made to consider alternative coating systems. The coating system used was a non-drip, water dispersed acrylic polymer system with a high degree of elasticity. This allowed for the complete encapsulation of the steel members, nuts and bolts as well as foundation caps, which inhibits any further moisture ingress and hence corrosion.

Case Study 6-4 (USA) – Reinforcement of 230 kV Wood Pole K-Frame

A line patrol identifies that a 56 year old wood pole located in a remote mountainous area has been severely damaged by woodpeckers and decay, and is in danger of failing. The line is critical to system reliability. It is not practical to schedule an extended outage in the near future to enable the necessary repairs to be performed using de-energized work practices. The damaged structure is located in an environmentally sensitive area on federal lands therefore, special access roads would need to be permitted and constructed to enable line trucks to drive to the structure in order to replace the pole. For these reasons pole replacement was deemed to be cost prohibitive. Hence, a follow up inspection was performed in which detailed measurements were made that were then used as input for structural analyses to assess the feasibility of restoring strength to the damaged pole using a field applied composite reinforcement technology. The assessment indicated that adequate strength could be restored using a patented composite repair consisting of a fibreglass wrap coupled with a phenolic resin system designed specifically for restoring strength to wood poles. The pole was then thoroughly treated with preservatives to minimize further decay, and a repair was then designed and installed over a four day period with the line energized at a substantial cost savings relative to pole replacement.

Case Study 6-5 (The Netherlands) - Painting of Tower Members [Part 1]

Together with its Service Providers, NUONº Asset management has developed a company policy with respect to painting (or not painting) the towers of High Voltage OH-lines. To that purpose a framework of business values has been used to take into consideration economics, safety, service quality, legal aspects, regulatory aspects, technical aspects, uncertainty (rigid and flexible solutions), sustainability, reputation and strategic aspects.

1.1 STRATEGY

The strategic interest is mainly to keep the Rights-of-Way (RoW) of the existing OH-lines (50 kV up to 420 kV), because of the fact that:

i. The costs of a new HV or EHV-connection based on OH-lines in the straight trajectories of the old OH-lines is much cheaper than those of cable connections, especially when deviations from the straight trajectories are required
ii. Most OH-lines are expected to show adequate capacity for the coming decades, so that maintaining the existing OH-line structures will lead to the lowest life cycle costs
iii. For the heavy loaded OH-lines the strategy is to maintain the existing RoW so that it in the near future will be possible to up-rate the towers, to replace the towers or to replace the whole OH-line
iv. It will be impossible to acquire new trajectories for OH-lines, hence good stewardship for the existing RoW is a must
v. OH-lines show to be far more flexible in case of catastrophes, emergencies and/or an urgent need for a higher ampacity.

Based on this policy, utilities face the societal pressure to remove OH-lines and to install cables in stead of OH-lines. As such it will be very difficult for utilities not to accept these societal developments, and the strategy has to be adapted slightly in that sense that under societal pressure the goal is not to keep the old OH-line, but to force the society to bear all costs for the new cable connections. However, as the perception of the authorities is that the OH-lines are old and approaching the end of their technical lifes, they may claim that a re-investment for the OH-line is anyway coming soon, so that the costs for the new cable have to be covered, at least partly, by the utilities. Hence, from the point of view of the utilities it is very important to avoid any impression that OH-lines are indeed in the last stage of their technical life. NUON's policy is based on this philosophy.

1.2 TECHNICAL ASPECTS

Apart from some very old (black steel) OH-lines, NUON's towers consist of members that are dip-galvanized. By painting the dip-galvanized members a protection system is achieved for a period almost twice as long as the sum of the protection periods of galvanizing and painting individually. The paint coating lasts for 10 to 15 years and has to be repaired in order to keep the second protection layer intact. But even without repair of the paint coating the protection will last for 50 to 65 years in an environment that can be classified as mild to industrial; i.e. after 50 to 65 years one may expect 5% of the total surface to show corrosion. In case of heavy industries or very close to the coast the protection period of the combination of galvanizing plus paining is less.

As soon as a member is eroded by corrosion, its strength will decrease, but the members are designed and specified with quite some margin. In the Netherlands a specific OH-line from 1964 has, on purpose, not been painted after erection and from time to time the decrease in strength of the members is verified without any serious consequences so far. In 1997 investigations predicted that replacement of the towers or, at least, quite a number of members will be necessary in 2013. Five years later, the actual decrease in strength was exactly as predicted. The conclusion is that, without repair of the painting, towers in an environment with heavy industry can reach a technical life of 50 years.

Case Study 6-5 (The Netherlands) - Painting of Tower Members [Part 2]

Attention however has to be paid to specific items like bolts, corrosion between members, tensile corrosion, failures from the steel rolling process, connection to the foundations, etc.
From a technical point of view, one could promote a policy not to repair the painted layers, thus avoiding costs and increase the availability of the OH-line. Such an approach is elaborated in Denmark by designing towers that can be regarded as well-adapted to the environment and optimized for minimal maintenance activities [63].

1.3 LEGAL ASPECTS

The Dutch law, regulations and/or standards do not explicitly require painting or repair of painting for steel towers of OH-lines.

1.4 REPUTATION

It has been investigated by asking colleagues who are not experts in the field of OH-lines, to judge the condition and impression of a number of OH-lines in the Netherlands and Germany, by visiting OH-lines that were well-preserved as well as OH-lines that show corrosion, including the OH-line that is not painted on purpose. The general impression is that only very approximate to the towers one can detect the corrosion, but at a distance corroded towers show to be less dominant from a visual point of view (and therefore more acceptable than, for instance, fresh painted towers). They also looked for other infrastructural applications of steel members, as the OH-line of railways, where many steel structures are very rusty, but without giving a bad impression. By the way, uncontrolled vegetation or a mess in/round towers gives an impression worse than corrosion.

So, the conclusion is that for the reputation in front of people in general it is not necessary to paint the towers of OH-lines.

But, another aspect of reputation is related to the impression that authorities may have, as they, under certain circumstances, may want to get the OH-line removed. In such a case the authorities will probably know whether towers are corroding or poorly maintained (in their minds). This impression, correct or not, may damage the company’s strategy. Therefore, it is in the interest of the utility’s reputation to keep the OH-lines visually in a good shape, albeit not for the public but for the authorities.

1.5 SAFETY

Safety here is not meant to cover the risk of collapsing towers, as that aspect is dealt with under the technical aspects. Safety is meant for the workers in the OH-lines: linesmen, supervisors, painters. These workers use platforms, ladders, special bolts to mount the tower, etc.

It has to be clear that a policy to repair painting or not, has to be independent from the policy to keep the safety precautions in good order. It has been estimated that the impact of the policy with respect to painting will have only a marginal influence on the need to replace the platforms, bolds, ladders, etc. Conversely, the choice not to paint the towers improves the safety in a small degree as less activities (and traveling) are needed.

1.6 SUSTAINABILITY

Two aspects are relevant with respect to preserving the steel members of OH-line towers: zinc and its derivatives contained in the soil around towers and the residues, as grit, used to remove the old layers of paint.

Case Study 6-5 (The Netherlands) - Painting of Tower Members [Part 3]

Although in the past much attention has been given to zinc spoiled in the soil, nowadays biological experts know that the toxic influence from zinc in the soil will disappear within five weeks.

To prevent that grit is spoiled to the environment, measures are taken to catch as much grit as possible and to clean (recycle) the grit in a sustainable way. Such countermeasures are very expensive, and from an economic point of view it has to be prevented that towers need to be cleaned in this way.

1.7 ECONOMICS

To compare several policies different scenarios have been studied and economically simulated. For two representative existing 150 kV OH-lines the following scenarios have been compared:

A. Paint very 13 years
B. Paint every 18 years
C. No painting but replace the towers (OH-line) after a total life of 55 years
D. No painting and replace the OH-line by a cable in the same RoW after a total life of 55 years.

The net present value of the costs during 55 years for the four scenarios have been calculated based on a WACC-rate of 4%, 6% and 8%. Scenario B (with a lower frequency of painting, but higher costs for painting) shows to be a little more expensive than scenario A. Scenario D (replace by cable) shows to be more than twice as expensive as scenario C (replace by OH-line) and for all WACC-rates the most expensive scenario.

Interesting is to notice that depending on the WACC-rate scenario C (replacing in stead of painting) is more or less attractive than the scenarios A and B. For rates higher than, say, 7% it is attractive not to paint but to replace the OH-lines, of course under the assumption that it will be possible (in the future) to replace the OH-line by a new one. As this assumption is very questionable, and the alternative replacing by cable far more expensive, it is recommendable to preserve the towers by regular painting.

1.8 CONCLUSION

i. Based on strategic considerations, economic evaluations and the impact of reputation, it is concluded that the best policy is to preserve the towers, the OH-line and the RoW by frequent painting, thus avoiding any claim that the structures are obsolete and at their end-of-life.
ii. This policy is not necessary from a technical, sustainable or safety point of view.
iii. One could consider to preserve only those OH-lines or towers close to an area where the societal pressure to remove the OH-line is expected to exist.
iv. The Danish policy to erect new well-designed OH-lines, that are maintenance-free and that are planned to be replaced after 55 years, is supported under the condition that the replacement policy is supported by the authorities.

Case study 6-6 (France) - Refurbishment of Wooden Poles

A visual examination is sufficient, in the vast majority of appraisals, to establish a global diagnosis of the support with a satisfying degree of confidence.

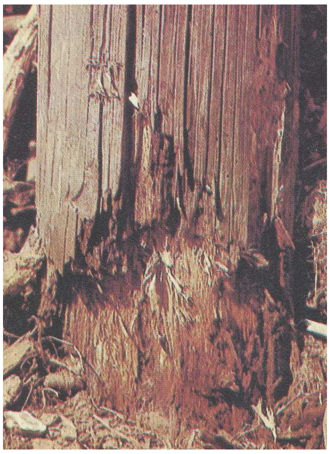
The survey is carried out from the ground; it consists in a visual inspection of the part of the pole above ground level followed by a control of the embedding.
The control of the embedding can be carried out with non-destructive tests operated during overhead line visits. For example, the use of Polux tool which identifies 4 levels of risk of degradation. These levels are directly translated into periods of time within which maintenance is necessary: 10, 5, 2 years. Alternatively, it may lead to a decision to replace the pole. Moreover, the tool can give information as far as any major risk regarding the climbing.

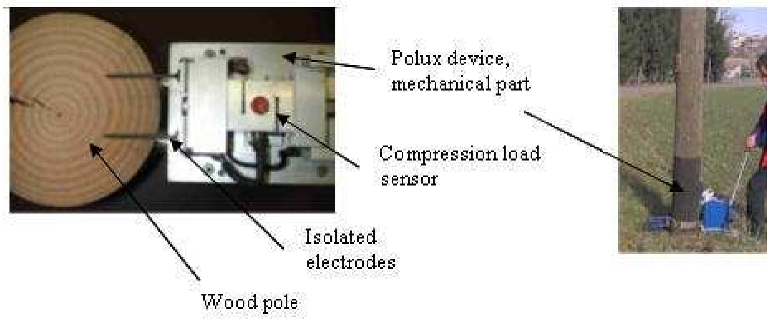
The Polux technology has been developed in a large R&D project supported by EDF (Electricité de France), the Swiss Federal Institute of Technology located in Lausanne and the CBS-CBT timber-engineering group. The physical principle of the Polux device is the measurement of two physical basic wood properties at the pole's ground line (GL) level:

i. The GL local compression strength F, translating the residual wood density, directly correlated to the pole's residual Cantilever bending strength
ii. The internal wood moisture content which relates the decay process (active or non active) obtained through the wood bio-degradation equation giving COs and HsO.

Repair works generally consist in replacing the pole. Exceptionally, in case of local damage (e.g. hole dug by a green woodpecker), a repair by carbon fibre is carried out.

Control of embedding with the support of a dedicated tool: on this picture, the polux device, used to analyse the residual wood properties





Typical deterioration of a wooden pole: caused either by natural ageing of external aggression (engines, tools used in the vicinity of the pole, woodpecker)

Case study 6-7 (France) - Refurbishment of Concrete Poles

Inspection:
A visual inspection is carried out in order to define the types of pathology of the concrete (cracks, micro-cracks, corrosion of the reinforcing steel,...).

Additionally, measurement of concrete carbonation depth gives an indication on the ageing state. A carbonated concrete does not ensure anymore a protection of the reinforcing steel against corrosion.

The rate of carbonation depends on porosity and moisture content of the concrete.

Carbonation can be visualized by using phenolphthalein.

Refurbishment:
Repairs works must be adapted to the assumed pathology. They are generally based on the methods used in the Buildings and Civil Works industry.

Typical pathology on concrete poles : outer part of concrete damaged as a consequence of a corrosion process on steel reinforcing bars

scaffolding installed to facilitate the repair works on a damaged pole

6.2 Foundations [58], [65]

6.2.1 Background

Various reasons can cause deterioration in a foundation or is constituent materials and therefore it could be necessary to refurbish foundations.

Cracking in concrete is influenced by many factors, which both effect the size and extent of the cracks formed. The nature of cracks, whether active, i.e. increasing in length and width or inactive i.e. with insignificant change in length and width is critical in possible repair options.

Cracking due to the following causes is possible in concrete foundations:

i. Early-age cracking;

ii. Reactive aggregates;

iii. Salt crystallisation;

iv. Sulphate attack;

v. Freeze-thaw;

vi. Corrosion;

vii. Ground settlement and;

viii. Inadequate design and/or poor construction;

ix. Lightning currents as a result of poor earthing of the tower.

Figure 6-3: Cracking of concrete foundation

Early-age Cracking

Early-age cracking can provide a path for ingress of aggressive agents e.g. chlorides. The different types of early-age cracking that can occur are:

i. Drying shrinkage;

ii. Plastic settlements;

iii. Plastic cracking;

iv. Thermal cracking.

Chemical Attack

There are different chemical reactions which can cause cracking of concrete foundations. Some types of chemical reactions are:

i. Acid attack
Acid attack is only likely to occur when concrete is in contact with low pH water;

ii. Alkali aggregate reaction
Alkali aggregate reaction may occur due to alkali silica, alkali carbonate or alkali silicate reaction, of which alkali silicate reaction is the most common;

iii. Carbonation
Carbon dioxide present in the atmosphere dissolves in the concrete pore fluids to produce carbonic acids;

iv. Chloride attack

Chloride ions from groundwater or unwashed marine aggregates can react with the cement paste. The products of the reaction are not expansive and therefore cracking of the cement paste does not occur. However the chloride ions can diffuse through the concrete and initiate corrosion of embedded steelwork;

v. Efflorescence
Efflorescence is the deposition of salts on the surface of concrete. The resulting evaporation on the surface results in crystallisation of the dissolved salts;

vi. Salt crystallisation

Concrete saturated with salt solutions can suffer from crystallisation damage during periods of alternative wetting and drying;

vii. Sulfate attack

Sulfate salt solutions in the groundwater react with hydrated calcium aluminate in the cement paste.

<u>Adfreeze</u>
The adfreeze phenomenon occurs in northern countries where a combination of extremely low temperatures and ground conditions give rise to frost heave problems sufficient to cause the collapse of a tower.

<u>Reinforcement Corrosion</u>
Reinforcement corrosion can be caused by the following factors:

i. Porous concrete cover;

ii. Chemical attack;

iii. Loss of alkanity in the concrete, and

iv. Cracking.

Irrespective of the cause, the degree of corrosion will always be exacerbated by inadequate concrete cover. Any reduction in reinforcement area may have significant structural consequences.

The cracks associated with reinforcement corrosions normally run parallel to the direction of the reinforcement.

Muff/ Reveal and Cladding Concrete

Muff/reveal concrete is used to form a watershed or finish to the top of a concrete foundation particularly the chimney. Cladding concrete is generally added as a protection encasing tower steelwork that may either be buried, or subjected to flooding, etc.

If the finishing concrete is of a poor quality material then shrinkage cracks can form. Depending on the porous nature of the muffing concrete, the muff may act as a reservoir for aggressive agents attacking the tower stub/leg.

Steelwork Corrosion

The corrosion of tower/stub or grillage steelwork including guy foundation anchor rods and helical screw anchor shafts occurs in a similar manner to that described for reinforcement corrosion.

As previously stated oxygen and moisture must be present for corrosion to occur. The exceptions to this rule are the presence of chlorides in groundwater and anaerobic bacterial corrosion. in certain soils

Figure 6-4: Corrosion of Stub and Tower Bracing Member

Design and Construction Errors

Design and construction errors potentially cover a wide range of items. Those errors that have a long term detrimental effect on the foundation and could prevent the foundation from being refurbished or upgraded. Many of these errors are not discovered until a failure occurs.

Changes in Environment

Changes in the surroundings of towers may cause changes in the foundations which require refurbishment. When the soil near the foundation is raised (i.e. due to building roadways, dykes, etc.), these changes should be analyzed to insure proper function of the foundation. In some cases soil near the foundation is removed or washed away. If possible the soil should be replaced, whether or not the soil is replaced, the foundation should be reanalyzed for the new conditions.

Figure 6-5: Changes of Environment (e.g Raising Soil Around Foundations) will Lead to Refurbishment of Foundations or Soil near Foundations

6.2.2 Technical or Practical Limitations

Technical and practical limitation during refurbishment of existing transmission line foundations are similar to those discussed in Sections 3.6 and 5.2.3 of this document.

6.2.3 Case Studies

Case Study 6-8 (Canada) - Refurbishment of Concrete Pile Foundations of 500 kV AC Transmission Line

500 kV AC transmission line, 210 km of total line length with individual lattice steel guyed and self supporting towers and 490 individual foundations - built in 1979.

Deterioration of concrete pile foundations has been discovered during a regular field inspection. Further inspection has revealed extensive deterioration of foundations as follows:

i. 35 foundations with various degrees of cracking and spalling - in need of repair
ii. 57 foundations with severe crumbling concrete - in need of replacement

Work constraints:

i. Refurbishment had to be done with line being energized.
ii. Existing tower locations had to be maintained.
iii. Due to difficult terrain conditions construction work was limited to a few winter months

Solutions:

<u>Repair</u>

Cracking: Chipped to sound concrete, wire brushed, re-profiled using Fastcrete and Xypex sealer.
Spalling: Loose concrete removed, wire brushed, re-profiled using non-shrink grout and Xypex sealer.

<u>Replacement</u>

Installation of a new steel box foundation on four helical screw piles approx. 2.5 m away from the existing foundation and transfer of the existing tower to the new base

Case Study 6-9 (The Netherlands) – Refurbishment of Concrete Foundations of 150 kV Overhead Line

In the overhead line there were many foundations with deformation. The deformation of the foundation of tension towers was large. After analysing some foundations the conclusion was that the reinforcement in the top of the foundations was missing. The decision was made to refurbish all foundations of the overhead line.

Limitations were:
i. Limited outage time;
ii. Environment of towers;
iii. Time of the year

Because of the limited outage time it was decided to use a special temporary constructions to replace the foundation support during refurbishment.

Case Study 6-10 (USA) – Replacement of Corroded Anchors on 500 kV Line [60], [61]

Sixteen years after construction, anchor rods in two parallel 500 kV lines began to fail due to corrosion occurring at 2-5m below ground; within twelve months of the first failure two additional failures occurred. The lines were constructed using guyed-delta towers and a total of approximately 6400 anchors were installed to support the towers. The combined length of the lines is about 800km. Replacement of all the anchors was not economically feasible; however, no test method was available at the time that could be used to detect which anchor rods may be at risk of failure. Therefore, a research project was initiated which led to the successful development of an ultrasonic nondestructive evaluation (NDE) technique that could distinguish severely corroded anchors from intact rods. The inspection technique was then applied to identify rods requiring replacement and an inspection program was initiated that requires reinspection of all anchor rods every five years. A rigorous program for managing the cathodic protection system for the line and maintaining sacrificial anodes was also implemented. Anchor rods found through NDE to be severely corroded were replaced with pier foundation tie-downs to support the guy wires. The asset owner is investigating the potential for using a new composite anchor rod for future replacements due to their lower cost relative to the pier foundations.

Anchor rod with grout exposed from erosion

Ultrasonic NDE sensor placed in anchor rod eye

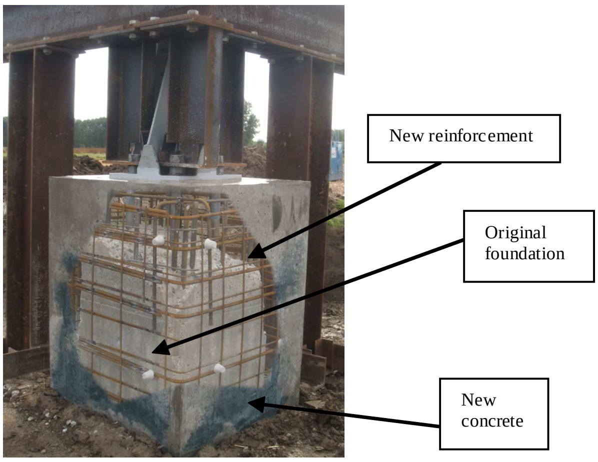
Pier foundation replacement for corroded anchor rods

Failed anchor rod (5m below ground)

Case Study 6-11 (The Netherlands) – Refurbishment of Concrete Foundations (ASR) of 150 kV Overhead Line

In this overhead line there were many foundations with deformation. In 1995 the foundation of one tower had been refurbished. After a new line inspection in 2005 the conclusion was that further investigation was necessary. It was found that in the concrete there were traces of alkali-silica reactivity (ASR).
Limitations were: Limited outage time, access to towers, and time of the year.
Because of the limited outage time it was decided to re-use a special temporary constructions to take over the foundation loads.

Activities during refurbishment included:
i. Excavation including the control of ground water;
ii. Place temporary construction;
iii. Remove concrete;
iv. Make new reinforcement;
v. Concrete placing;
vi. Remove temporary construction;
vii. Backfilling excavation.



Case Study 6-12 (USA) – Foundation Refurbishment after Landslide

Steel pole structure No. 58/1 on the Curecanti – Rifle 230 kV line in Grand Mesa National Forest, Colorado, USA, was installed in 1984 to replace a lattice tower destroyed by a landslide. A continuing landslide, which affected the entire surrounding landscape, over a period of 19 years, slowly tilted the approx 14 meter deep reinforced concrete drilled shaft foundation approximately 6 degrees from its original plumb position. During that period, the 28 anchor bolts each with a 1335kN capacity, that secured the pole base were adjusted a total of 200 mm to compensate for the pole's changing position – 100 mm on the uphill side and 100 mm on the downhill side. Figure 1 shows a close up of how much the anchor bolts have been adjusted to compensate for the shifting ground.

Figure 1: A close up of Structure showing how much the anchor bolts have been adjusted to compensate for the shifting ground due to landslide

To correct the situation, a base leveler was designed to compensate for angle difference between the pole and the top of the foundation. The leveler is a wedge shaped steel tube with 100 mm thick flange plates that attaches directly between the existing foundation and the structure base. Figures 2-4 show the installation of leveler and the installation of the structure on the new level foundation.

Figure 2: Crew Members remove bolts and place PVC pipe segment over the bolt threads to protect them from damage when structure is lifted off the foundation.

Figure 3: A crane Lifts the Structure, with conductors attached, off its foundation

Figure 4: Structure is manoeuvred onto the leveler

6.3 Insulator Strings [56], [57], [34]

6.3.1 Background

An insulator string provides the required mechanical connection between support structure and the conductor of a line as well as required electrical insulation between these parts. An insulator string comprises components – insulators and fittings - assembled in one or more parallel chains.

Insulator strings are exposed to mechanical and electrical stress. Deteriorations of this component of an overhead line can cause:

Mechanical Failures:
Each insulator string is characterized by its guaranteed mechanical strength. This parameter results from mechanical strength of each component in chain or chains. Lower mechanical strength could be a consequence of:

i. Ageing of material

ii. Reduction of original dimensions (different kinds of corrosion)

iii. Poor manufacturing

iv. Vandalism

In addition to their mechanical connection insulators are key components that provide electrical insulation. There are three types of insulator materials available:

i. Glass insulators

ii. Ceramic insulators

iii. Composite insulators

Each of these materials has advantages and disadvantages. Designers pay great attention to all possible factors that could cause damage or limit expected lifetime of the chosen material. While glass and ceramic materials have a long history, composite materials have been used for a relative short time (~ 30 years).

Figure 6-6: Deformation of Insulator Pin

Fittings (hardware of insulator strings as well as end fittings of insulators) are usually made of ferrous metal or aluminium alloy. Corrosion is the cause of metal parts deterioration and hot dip galvanizing is typically used to resist or prevent such deterioration. The aluminium alloy hardware can wear out due to vibration, loss of material strength or electrolytic corrosion that can result in failure.

Figure 6-7: Corrosion on a Support Insulator

Electrical Failures

Electrical resistance of insulator string is determined by leakage (creepage) distance and the shortest air gap between steel parts of insulator string. Electrical failures result either from over voltage or decreasing of dielectric strength because of pollution or environmental conditions (i.e. fog, ice, etc.). Required leakage distances are provided in standards (i.e. IEC 60071), for areas from light to heavy pollution. Long term operation of insulators in heavy polluted areas can cause degradation of insulator surface (see Figure 6.8).

Figure 6-8: A new ceramic insulator on the left and a ceramic insulator after 30 years in operation on the right – glazing of the surface is damaged, the surface is rough and different kinds of fungi contribute to it's deterioration. Consequently leakage distance of such insulator has decreased due to increased conductivity of the surface and a number of flashovers have occurred.

Refurbishment of an insulator string can be carried out by replacing a faulty component (unit/units) or the complete insulator string.
Decision which of these methods to use depends on many factors such as:

i. Type and shape of insulator string (suspension, dead end, V-string, T-string etc.)

ii. Whether component of the same parameters (mechanical and electrical) is available

iii. Whether there is a need to use component with improved characteristics

iv. Available time (outage of the line) and budget

v. Availability of special techniques for changing out insulators (i.e. live line maintenance)

Figure 6-9: Replacing Faulty Glass Insulator on 400 kV Suspension Insulator String with Special Equipment, the Line is Out of Operation

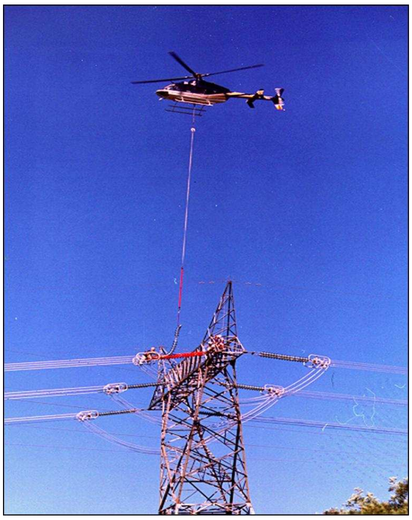


Figure 6-10: Replacing Faulty Insulator in a Dead-End Insulator String, Live Line Maintenance is Used

6.3.2 Replacement Considerations

To consider refurbishment the following needs to be taken into account:

i. Remaining lifetime of components in insulator string. Although there are several live line testing procedures for glass and ceramic insulators, a visual check remains the basic method to decide whether some component is reliable or not. Different kinds of laboratory tests can be used to determine which of the components is the weakest link and what are the signs of their deteriorations.

ii. Remaining design life of other components of an overhead line. Refurbishment of more than one line component at a time could be more effective and save money as well as time.

iii. Actual environmental aspects. In many cases original environmental aspects has changed (i.e. increasing of pollution level, humidity) or some aspect originally not predicted is becoming more important (i.e. bird's excrement).

iv. Historical records of particular type of insulator. Then the decision whether to use a component with the same characteristics or improved characteristics.

v. New technologies and insulator designs (i.e. additional zinc or corrosion interception sleeves on the pin, non-ceramic insulators, etc.).

vi. Standardization of insulator and hardware designs. Availability of different types of insulators and hardware (i.e. older designs may not be available). Standardization of insulator strings saves time and money and reduces the variety of spare parts.

Reducing the number of connections and quantity of parts in insulator strings are a goal for designers and suppliers. New materials are being developed to provide higher mechanical resistance and improved metallic resistance to corrosion.

6.3.3 Case Studies

Case study 6-13 (USA) - Refurbishment of Cap and Pin Insulators

Cap and pin insulators have a limited service life, mainly due to corrosion of the galvanized steel pin. These pins are very susceptible to corrosion in marine or polluted environments due to the high electric fields at the energized end of the string. The corrosion will result in loss of pin diameter (see Figure) and strength and possible cracking and puncture of the insulator between cap and pin.

Contaminated and wet insulators display a biased leakage current having DC component. This DC component causes electrolytic corrosion and reduction of pin diameter, as shown in the figure

During normal inspection and maintenance, degraded insulator strings can be removed and tested to determine the amount of mechanical and electrical (M&E) degradation. When the M&E properties of the insulators fall below acceptable levels, insulator strings on the transmission line, or effected portions of the line, should be replaced. If the line has been in service for some time the hardware as well as the insulators may need to be replaced due to wear and corrosion. In many cases it is not possible to replace an insulator and hardware assembly with an identical assembly, as most manufactures have changed their products since the original was installed (possibly 40 to 50 years ago).

Case study 6-14 (Czech Republic) - Refurbishment of Long Rod Insulators

Loss of mechanical resistance at ceramic insulator

The first crack initiates on the perimeter of the insulator head mounted in the metal armature close to the upper end. This peripheral crack grows into the bulk of the ceramic up to complete peeling off of a slice of material. Then the new crack initiates in the remaining part of the insulator head and the process repeats itself until the lower part of insulator head cementing is reached and final insulator failure occurs.

6.4 Conductor and Conductor Fitting Refurbishment

6.4.1 Background

As far as phase conductors and earth-wires are concerned there is very rarely any need just for upgrading. If phase conductors have to be changed it is then customary to consider also up-rating options, i.e. trying to increase the power transfer by adopting a new type of conductor with higher ampacity ratings. This was addressed in clause 4.1 of this brochure. However, there may be some cases where conductor upgrading may be necessary.

Phase conductor or earth-wire refurbishment, on the other hand, is much more common. The most usual reason for that is corrosion caused by different causes. The following deals with conductor refurbishment, its reasons and remedies (the word conductor refers to both phase conductors and earth-wires).

6.4.1.1 Reasons for Refurbishment

Corrosion

As mentioned above, the most common reason for conductor refurbishment is corrosion. The corrosive atmospheres are in coastal areas with salty, high humidity winds and farmlands where fertilizers and pesticides are used.

The conductor corrosion increases with smaller external conductor diameter, fewer number of strands layers and smaller diameter for wire strands. Therefore earth-wires are usually more susceptible to corrosion than the phase conductors

In the case of ACSR conductors corrosion leads to loss of steel galvanization in steel core wires. This is followed by galvanic corrosion between steel and aluminium wires attacking most aluminium strands in the inmost layers. Another mode of failure affecting all kinds of conductors is crevice corrosion that may occur beneath connectors, clamps, XLPE-insulation on covered conductors etc. Crevice corrosion usually attacks locally but in some cases it may diverge along the conductor if its spaces and crevices are not filled with grease.

Figure 6-11: Broken Wires Due to Corrosion and Corrosion Fatigue Beneath a Damper

Mending of the decay may be carried out by repair rods, but ac-corrosion and arcing may occur also beneath the rods due to their inability to short-circuit the coupling between the damaged and undamaged wires.

A combination of repair rods and shunting or a repair sleeve compressed outside the decay will take care of the mechanical and electrical properties of the conductor. However, there is a possibility that the continual corrosion will expand.

If the conductor is not greased and the local corrosion has diverged, conductor replacement may be the best remedy. The decayed part of the conductor can also be removed and replaced by a section with a conductor segment and two joints or replaced by a repair joint with prolonged central piece.

Vibration

There are three different conductor motion forms: aeolian vibration, subspan oscillation and galloping. All of them may cause deterioration of the conductor thus leading to the need for conductor refurbishment.

Aeolian vibration can cause fretting which in turn opens cracks leading to fatigue in places where there are mass discontinuities and high stresses such as: suspension clamps, supporting clamps, splices, spacer clamps, damper clamps, clamps of aircraft warning markers etc. When a bare conductor is corroded the conductor tension and dynamic stress (due to conductor vibration) is very often increased thus leading to accelerated degradation due to corrosion fatigue. In case of AAAC conductors, inter-granular corrosion can also be found.

Abrasion and wear may occur at loose hardware on conductors subjected to vibration and when the conductor is in contact with tree branches.

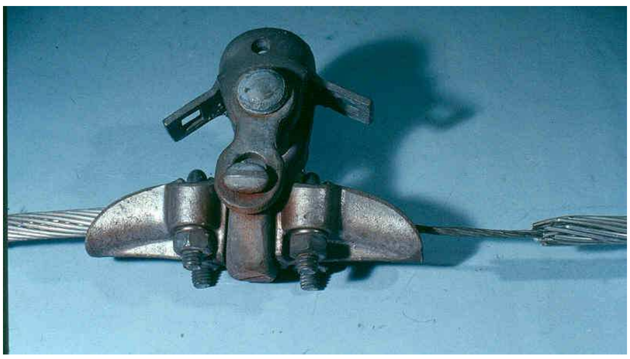


Figure 6-12: Fatigue has Lead to Broken Wires in a Supporting Clamp Due to Vibration

Figure 6-13: Wear and Broken Wires Due to a Loose Damper

Mending of the damages due to vibration depends on the extent of the problem. In minor problems the use of repair rods for repairing broken wires is adequate while in some cases replacing the conductor may be the best solution. In all cases, however, the cause for damages must be removed. Attention should be paid to proper damping of the conductor by e.g. vibration dampers, installation of bundle conductor spacers at irregular distances, removal of spacers, decreasing the conductor tension or other methods.

<u>Other Reasons</u>

Besides the reasons mentioned above for conductor refurbishment there are a number of other causes which can lead to conductor refurbishment:

i. Swinging jumpers may lead to fretting, abrasion and fatigue adjacent to the anchoring device.
Swinging can be controlled by using additional insulator strings, weights etc.

Figure 6-14: A Swinging Jumper has Lead to a Broken Conductor Adjacent to a Dead End Tension Joint

ii. Clashing conductors may lead to electric arc burn. This may occur in strong wind, during galloping or ice shedding.
Phase spacers are used to eliminate conductor clashing.

Figure 6-15: Clashing Conductors or Lightening Strokes may Lead to Electric Arc Burn

iii. Lightning strikes, either direct or indirect, may give rise to electric arc burn which can be due to improper arcing and over-voltage protection or faulty conductor selection.
Lightning problems can be avoided by the proper selection of arcing devices and, e.g. in case of OPGW, by choosing a conductor suitable for heavy lightning density areas.

iv. Earth faults and short circuits, for instance due to insulators with unsatisfactory insulation level.
These problems can be resolved by paying attention to insulator selection and lightning protection and the use of armour rods to protect the conductor in the strike area near the clamp.

v. Bird caging and loose wires
Permanent deformation and "bird cages" are probable in locations where icing and overturned trees may occur. Proper conductor selection regarding strength can reduce permanent deformation caused by icing. Tree clearing along the line is essential to avoid falling trees on the conductor.

These kinds of damages may also occur when pulling the conductor from the reel or due to conductor turn. Bird-caging during the pulling phase is due to bad manufacturing of the conductor or bad installation methods. Good quality control in both cases is most important.

If an dead end clamp or compression joint doesn't fit to a greased ACSR-conductor, the Aluminium strands may have a permanent deformation due to sliding upon the steel core.

Figure 6-16: Bird Caging Adjacent to a Joint

vi. Ice and wind loading

Even if the design criteria have been fulfilled, it is possible that a failure will occur during the conductor's design working life. The loading is variable and may exceed the design limit load or the strength can decrease due to deterioration. Increasing climatic loads due to climatic change may lead to accelerated degradation and the need for upgrading.

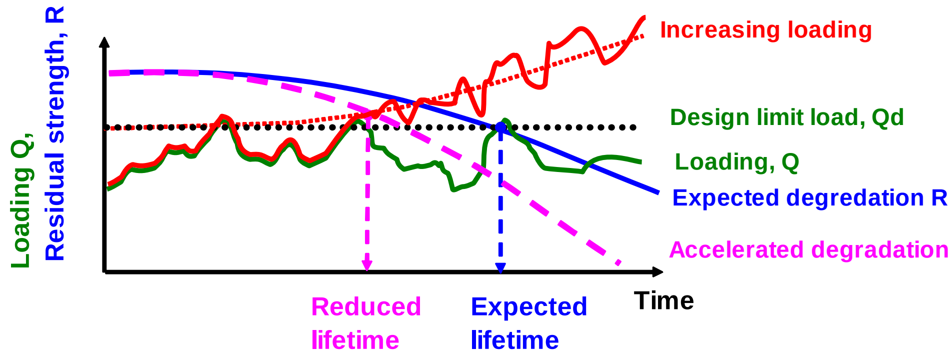


Figure 6-17: Reduced Life Time and Need for Upgrading Due to Climatic Change

vii. Overheated joints deterioration is caused by improper installation with relation to cleaning, greasing, symmetry, electrical tape, inadequate compression etc. This problem can only be eliminated by good workmanship and quality control. The consequence of deterioration is that the joint becomes warm which further increases the rate of oxidation. Over a period of time, the joint resistance will increase resulting in excess current flow in the steel core of the conductor. In general the forms of damage can be seen as:
   a. Overheating
   b. Micro arcing within the joint and between the wires
   c. Mechanical failure of the conductor
   d. AC Corrosion between wire strands in the conductor

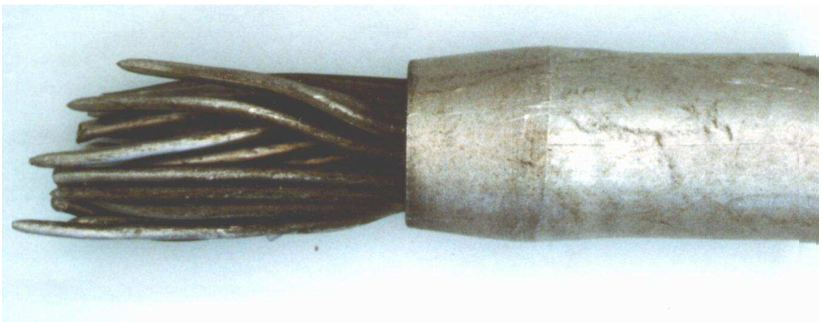


Figure 6-18: Overheating and Broken Conductor Adjacent to a Defect Joint

viii. Damage to conductor during stringing can be caused in many ways. Before pulling the conductor from the reel, one should be sure that there are no protruding nails which would scratch the conductor. Tension stringing methods should be used [64]. Pulling the conductor over rocks or fences should be avoided. Use grips with smooth jaws. Stringing sheaves should be free running, smooth and have the largest diameter practical and consistent with the conductor diameter, weight and span length. Neoprene or Urethane lined sheaves provide additional protection for the aluminium surface.

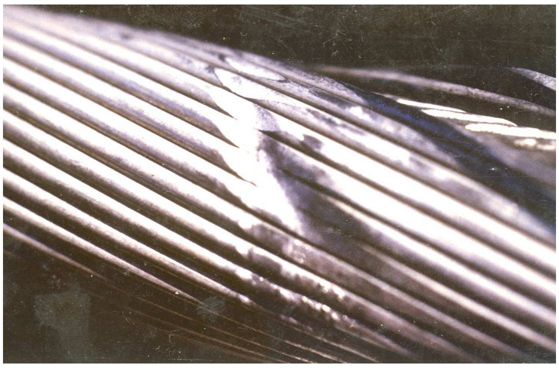


Figure 6-19: Damage has Occurred When Pulling the Conductor from the Reel During Installation

ix. Foreign flying objects, vandalism (i.e. shooting), trees, blasting etc will cause local tear. Local impacts due to firing by shotguns are common in popular hunting grounds. Bare conductors, are to a limited extent, affected by the hail of bullets. When XLPE-covered conductors have punctures caused by shotguns, phase to phase contact may lead to continuous arcing and to accelerated galvanic corrosion.

Figure 6-20: Foreign Flying Objects, Shooting, Fallen Trees, Blasting etc. will Cause Local Tear

x. Forest, sugar cane etc. fires may overheat the conductor or cause flashovers between conductors leading to arc burns.
Good vegetation management should be the answer to these problems. In some areas fires are monitored and the lines are de-energized to prevent flashovers.

xi. Annealing due to high temperatures adjacent to faulty joints or long lasting short circuit currents due to improper adjusted short-circuit and earthing protection.
The effects of elevated temperatures due to normal current and due to short circuits are cumulative regarding the mechanical strength of the conductor. Therefore attention should be paid to the lifetime temperatures experienced by the conductor.

xii. Small scratches, impacts and wounds are ordinary damages which the asset owner is not concerned. Unfortunately, a small local scratch can cause loose wires and launch fretting and ac-corrosion along the conductor. Fretting and corrosion released by wounds during installation can notably decrease conductor's useful lifetime.
Great care should be taken during the installation phase to avoid any damages to the conductor that might also be a cause of corona.

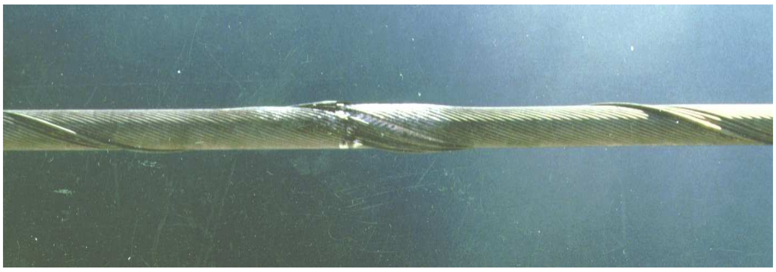


Figure 6-21: Local scratches occurred during installation has led to loose wires and triggered fretting and ac-corrosion along the conductor. The conductor had to be replaced after 15 years of service. Normal lifetime in this area is 50 years

6.4.2 Methods of Damage Detection

There are several techniques used in conductor inspection regarding damages caused by corrosion, wind, lightning etc..

<u>Conductor Corrosion</u>

i. Visual inspection (helicopter/ground/support)

ii. Overhead line corrosion detector - eddy current

iii. Overhead line corrosion detector - steel core

<u>Wind induced and Lightning Originated Damage</u>

i. Visual inspection (helicopter/ground/support)

ii. Camera and/or video photography (helicopter/ground/support)

iii. Radio frequency/microwave emission (corona) detector

iv. Infra red (IR) thermography

v. Gauges

vi. Radioactive isotopes

<u>Conductor Fittings</u>

i. Visual inspection (helicopter/ground/support)

ii. Camera and/or video photography (helicopter/ground/support)

iii. Infra red (IR) thermography

iv. Joint resistance measuring

v. Boroscope and steel sleeve locator for joint inspections

The above methods are presented in more detail in Technical Brochure 175 [47].

6.4.3 Refurbishment Considerations for Conductor

The most significant consideration when planning conductor refurbishment is the extent of the work. To make that decision it is important to take into account all the existing information, i.e.:

i. Inspection data

ii. Laboratory test data

iii. Existing experience of similar incidents

iv. Climatic conditions along the line

v. Refurbishment method: change of conductor section / repair by changing smaller stretches or using e.g. repair sleeves

Other considerations would include:

i. Costs

ii. Optimal timing of the work

iii. Can the job be postponed to a more favourable date

iv. Is there redundancy in the grid to do the job

v. Basic reason for the damage and method to avoid the same damage from happening again

vi. Possible use of a different type of conductor instead of the existing one, e.g.:
   a. AAAC instead of ACSR
   b. Aluminium Clad Steel instead of galvanized steel
   c. OPGW instead of ADSS optical cable
   d. Greased conductor instead of ungreased
   e. Conductor with better self-damping properties or mechanical characteristics
   f. Bundle instead of single (or vice versa)

vii. It would be useful to refurbish other line components at the same time: insulator strings, clamps etc.

viii. If the problem has been extraordinary, should monitoring devices be installed to try to prevent future troubles

ix. Working method: is there a possibility to do the job live or should the line be de-energized

x. Expected residual lifetime of the line: is conductor refurbishment worth while if the line is coming to its end of life

xi. Needs for up-rating the line: why not up-rating the line if the conductor needs to be replaced in any case (which would lead to considerations presented in section 4.1.1)

xii. Other lines in similar conditions: should same kind of refurbishment be simultaneously done on other lines in the same situation

6.4.4 Refurbishment Considerations for Conductor Fittings

Normally refurbishment of conductor fittings is not a major problem but in cases involving fittings in tension, i.e. mid-span joints and tension clamps. Dealing with these fittings the following items will be considered:

i. Failure of fittings in tension may have severe consequences regarding safety of people, therefore the works will be done as soon as possible if there is any danger of conductor falling down

ii. When problems begin to occur all the fittings should be rapidly inspected to clarify the cause and extent of the problem and make refurbishment decisions accordingly

As to non tension fittings (i.e. replacing spacers and vibration dampers or installing phase-to-phase spacers), this work can be scheduled to the most convenient time regarding power transfer, other maintenance works, resources etc. However, it should not be postponed too long as these problems have been known to drop conductors if left unattended.

Figure 6-22: Wear at Suspension Bolts

6.4.5 Case Studies

Case Study 6-15 (Canada) – Aerial Damper Change-out on Energized 500 kV DC Line

Spacer damper units were failing on two Manitoba Hydro's Radisson-Dorsey ± 500 kV dc line. Each line consists of a positive and negative pole strung with twin bundled 1843 kcmil 72/7 ACSR Nelson conductors using spacer-dampers to maintain a separation of 0,6 m between subconductors. The 898 km long lines have been in service since 1969. While the lines remained energized, MH refurbished these units and installed additional dampers.

The problem with the dampers was that the elastomeric bushing separating the clamp arm from the damper body was at the end of its useful life. In addition, the fasteners showed excessive corrosion damage. MH determined it needed to rehabilitate the existing spacer dampers by replacing the failed bushings with upgraded fasteners, and by replacing bolts and washers for the connections between the clamp arm and conductor, and between the clamp arm and body. MH also determined it was necessary to modify the positioning and number of spacer-dampers to optimize the range of damping capability.

Since it was mandatory that the lines remained energized at all times, MH was constrained to use hot-line techniques during the rehabilitation work. Due to bad terrain conditions the work procedure used a helicopter modified with a fully insulated, electrically nonconducting fiberglass boom.

On a typical day, 720 dampers were removed and 800 installed.

Case Study 6-16 (USA) – Refurbishment of Overhead Ground Wire Hardware

Since overhead ground wire suspension assemblies are much shorter than phase insulator and hardware assemblies, wind induced wire motion, normally causes greater motion and therefore more wear on the overhead ground wire assemblies.

During normal inspection, several assemblies were found to have severe wear. These assemblies were replaced and tested. The results indicated a change out of all assemblies in areas of high nominal wind speed

7. Asset Expansion

Although constructed for the transmittal of electrical energy, transmission line assets can provide the owner additional potential revenue. Transmission towers have been used to accommodate cellular telephone antennas and to carry fibre optic cables along the right of way. In certain cases the utilization of transmission towers are the only way to install telecommunication equipment or fibre optic cables (FO) due to the absence of permission of other land-owners. This may be the best way to reduce the expenses of complicated installations or avoid environmental restrictions.

Several strategic topics will need to be addressed prior to considering the installation of such devices, such as the structure and foundation capacities, compromising the electrical performances of the transmission lines and restriction in work (maintenance) practices.

7.1 Telecommunications Equipment

7.1.1 Background

Cellular telephone antenna sites have become increasingly difficult to obtain. This has made use of overhead transmission line structures preferred sites for use as antenna support structures. The structures are already built and the public more readily accepts alterations to existing structures rather than the installing new structures. Joint use also increases the value of the existing infrastructure and provides an income flow to the utility owner. This section evaluates the impact of installing antennas and associated equipment on transmission line structures.

Figure 7-1: Direct mount of telecommunications antenna to a double circuit 230 kV lattice tower between shield wire and top conductor arm. Note location of communication control building and coax cable installed on cable ladder.

A minimum of three antennas located 120° apart are required for each carrier. There may be as many as four antennas located in each sector. Amplifiers may be required for each antenna. One or two coax cables are attached to each antenna and run down the structure to a control cabinet or enclosure which can be located on the ground (Figure 7-1 close to the tower or inside the main legs) or on a special platform. Service voltage electricity supply is necessary (usually supplied from an external source).

Figure 7-2: Worker on pipe extension to a double circuit 115 kV lattice steel tower with antenna mount platform

7.1.2 Considerations for Adding Telecommunications Equipment

i. The optimal elevation of the antennas is determined by the cellular engineer to obtain maximum signal coverage. Antennas can be mounted below or above phase conductors or on the top of a tower above the earth wire (if any). If the elevation is below the top of the structure, the antennas are mounted directly on the structure. If the elevation is above the top of the structure, an extension is designed to support the antennas at the required elevation (Figure 7-2);

ii. It is very important to perform a complete structural analysis of the tower, reviewing the added loads caused by wind and ice loads on the cell antennas;

iii. The review of electrical clearances (relative to safety distances) between the live parts (conductors, fittings, etc) and towers to permit the safe installation and maintenance of antennas without requiring live line procedures to be used;

iv. Where enclosures with electronic equipments, air conditioned equipments, etc should to be located? On the ground? On a platform installed on the tower?;

v. Installation of work platforms or ladders to facilitate the maintenance activities by telecommunications technicians;

vi. The source electricity source supply for cellular equipment and how to protect the lower voltage system against overvoltages and surges due to short circuits or lightning strikes;

vii. Supply electricity equipment can be fed from the low voltage network which is the most common case or from the medium voltage network;

viii. Environmental issues required by regional jurisdictions due to antenna is a source of EMF of high frequency and depending on a regulation their installation may require a special permission which is usually proceded by the environmental impact assessment;

ix. A formal contract or agreement between the asset owner and the telecommunications company is required. This agreement should take in considerations different issues such as:
   a. Detailed responsibilities of each party;
   b. Detailed design of cellular system and structural modifications to tower structures;
   c. Safety procedures for employees of both companies including radiation exposure;
   d. Detailed procedures for operating both companies systems taking each other's equipment into consideration;

x. The safety of radio base stations (RBS) is an important issue. Lightning and earth potential rise must be taken into consideration during the engineering process. International Telecommunication Union (ITU) developed two recommendations in this field:

   K56 (07/2003): Protection of radio base stations against lightning discharges;
   K57 (09/2003): Protection measures for radio base stations sited on power line towers;

   K56 provides a quantitative procedure in order to protect radio base stations for wireless access network against lightning discharges;

   K57 specifies measures to be taken with respect to safety and risk of damage to equipment through the simultaneous effects of lightning stroke earth potential rise, when power line towers are used for locating radio base stations;

xi. Operators of overhead lines don't usually own the land areas under transmission lines. These are the property of land owners. For a certain compensation the access to overhead lines is guaranteed, but this doesn't usually include the right of leasing a tower to a third party for a business not connected with transmission of electrical power. Thus an agreement with a land owner can be necessary, in particular when a container is situated on a floor;

xii. Reengineering of the ground system of the existing tower or separate grounding system for antennas installation;

xiii. Special measures (if necessary) to protect the installation against vandalism.

7.1.3 Technical and Practical Limitations

i. Lack of lower voltage electricity supply for cellular equipment;

ii. Legal issues (Licensing or environmental concerns);

iii. Location and height of a tower (May not provide coverage for cell system);

iv. The presence of nesting endangered birds on the tower could dictate when the installation or the maintenance of antennas can take place.

7.1.4 Case Studies

Case Study 7-1 (USA) – Adding Cell Site Systems to Transmission Structures

Since the introduction of personal cell phones in the USA in the late 90's, the use of existing transmission structures has been utilized for location of antennae. Typically, they have been located above the conductors due to the need for height. One arrangement is shown in Figure 1 (typical steel pole and tower). Another arrangement to achieve additional height is to use an auxiliary "pole extension", which extends above the structure (Figure 2). In some cases, there is significant structural reinforcing to incorporate both types (as shown in Figure 2 for the tower). Evaluation of the structures is required, as are detailed engineering design plus specialized crews for construction

Figure 1

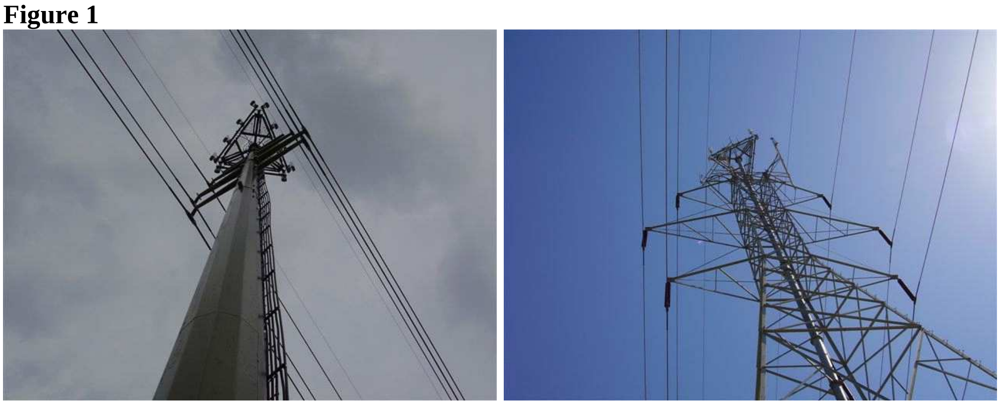


Figure 2

Case Study 7-2: (Poland) – Antennas Installation on a 400 kV Tower

A telecommunication operator was interested in installation of antennas on a 400 kV tower. The operator of a line accepted this location on a condition to locate antennas below the attachment points of phase conductors and in a distance of at least 3.5 meter from live parts. The control container was located on a height of 17 meter. The tower construction was checked for additional loads which resulted in local reinforcement of the tower body. Special platform to carry the container was designed as well as four triangular shaped smaller platforms to enable installation and maintenance of antennas. The tower is typically equipped with climbing steps on one leg, but special ladder was provided for antennas operator staff. In the bottom part this ladder is protected (a key locked cover) from climbing by unwanted persons. Electricity supply is provided by the low voltage cable. The installation has its own grounding system.

7.2 Fibre Optics

7.2.1 Background

The routing of transmission lines throughout various geographic areas facilitate the development of a telecommunication network based on the use of optical fibre. The fibre can be used for internal services of utilities (protection systems, data transmission, etc) or can be leased or sold to telecommunication companies.

There are different kinds of technologies like OPGW (Optic Fibre Ground Wire), ADL (All Dielectric Lashed cable) and ADSS (All Dielectric Self-Supporting cable), MASS (Metal Aerial Self Supported cable), OPPC (Optical phase conductor).

7.2.2 Considerations for Adding Fibre Optics

i. Review the structural capacity of towers, in particular to review the additional loads due to ice and wind pressure caused by the addition of fibre optic cables;

ii. Review foundation design and capabilities due to increased loading;

iii. Review electrical clearances between conductors and fibre optic cables because of different characteristics of the previous ground wire and the new fibre optics cable whether metallic or synthetic;

iv. The electrical distances between conductors and Fibre Optic (ADSS) in order to avoid electric-magnetic influences on FO material (deteriorations);

v. Installation of a platform to carry out maintenance activities at termination boxes if they are off the ground;

vi. Low voltage supply electricity shall be provided to electronic equipment enclosures if amplifiers are required;

vii. Contract agreement between the asset owner and other users (telecommunications companies, utilities, etc) of FO is needed. This agreement should take into considerations different issues such as:
   a. Detailed responsibilities of each party;
   b. Detailed design of fibre optic system and structural modifications to tower structures;
   c. Safety procedures for employees of both companies;
   d. Detailed procedures for operating both companies systems taking each other’s equipment into consideration;

viii. Review the lightning and short circuit current design if metallic ground wire has been replaced with synthetic FO;

ix. Review design considerations relative to short circuit current due to changes of ground wire sections, relative to resistivity, and permitted temperatures of materials;

x. Modifications to towers required due to changing of suspension fittings to dead-end fittings in long tangent sections;

xi. Design required protect FO against vibrations;

xii. If planned outages are not permitted, live line procedures can be used but could be limited relative to economic issues;

xiii. Life expectancy of various types of technology and materials of FO;

xiv. If OPPC is used for telecommunication it may also be used for temperature, ice and vibration monitoring of conductor.

7.2.3 Technical and Practical Limitations

i. Long planned outages when installing the Fibre Optic. Live line working techniques could be applied to mitigate outages;

ii. Long spans in case of ADSS cable(Carrier fibre may be tension limited);

iii. Tower configuration in the case of ADSS cable (Need to review electrical and ground clearances.

7.2.4 Case Studies

Case study 7-3 (South Africa) - Optical Cable Installation [Part 1]

10 000 kilometres of optic fiber telecommunication network was installed on existing Eskom power lines over 14 months. Three basic technologies were employed: OPGW (Optic Fiber Ground Wire), ADL (All Dielectric Lashed cable) and ADSS (All Dielectric Self-Supporting cable).

ADL, both hand and motor lash techniques, was used on 275 and 400 kV transmission lines. In the former technique the lash machine, with its lashing tapes installed, is placed on the earth conductor and pulled along the span with an insulated hand line from ground level. The optic fiber cable is laid out at ground level and is fed up into the lashing machine. The machine is relatively light (30kg) and can be handled by a line worker on the earth peak of a transmission tower. The basic principle of motor lash technique is identical to hand lash except that the remote controlled machine is equipped with a petrol motor that is able to propel it along the span. Due to clearance requirements between earthwire and phase conductor the work could be done live with motor lash technique on 400 kV lines and with hand lash technique on 275 kV lines.

Case study 7-3 (South Africa) - Optical Cable Installation [Part 2]

Ten percent (10%) of the roll out consisted of replacing existing earth wire with OPGW (Optic Fibre Ground Wire). This was mainly done where existing mechanical integrity of the earth wire was suspected and needed replacing. The tension stringing technique was used the existing earth wire as a pulling bond. Installation under de-energised conditions indicated that the tension and resultant sag could be suitably controlled, suggesting that live installation using tension stringing technique would be possible. However, the risk and probability of the existing earth wire failing mechanically was considered unacceptably high and as a result no live stringing of OPGW was actually performed.

The remainder (10%) of the rollout consisted of ADSS (All Dielectric Self Supporting) optic fibre cable.

This was mainly installed on distribution lines (132 kV and below). Consideration has to be given to the placement of the ADSS cable relative to phase conductors. Unacceptably high electric field strengths will result in damage to cable through leakage currents and tracking. Wind performance and sagging characteristics are different to that of the phase conductors and also affects the optimal attachment position on a tower. Electric field modelling indicated that changing the phasing on a double circuit line had dramatic effect of the resultant electrical field at a suitable attachment point from a mechanical point of view.

Technology comparison

	ADL - Hand	**ADL - Aerial**	**OPGW**	**ADSS**
Total cost as % of OPGW base	45 %	60 %	100 %	70 %
Roll out speed per 8 h day	8 km per day using 3 hand lash machines	25 km per day using 3 motor lash machines serviced by 1 helicopter	4,5 km per day using single winch and tensioner	12 km per day using single winch and tensioner
Life expectancy	8 – 10 years	8 – 10 years	30 – 40 years	10 – 15 years

* The above figures are average values and can vary with fiber count, supplier and manufacturer of cable and installation specifics.

Conclusions

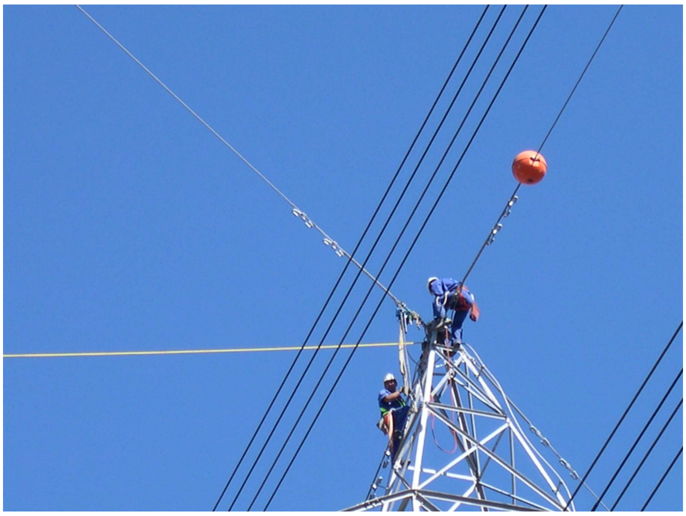
ADL can be installed fast, efficiently and cost effectively on existing earth wires of overhead transmission lines. The work can be safely performed under energized conditions subject to structure dimensions and conductor characteristics. Life expectancy and operational durability will be proved with time.

OPGW is a time consuming and relatively expensive installation. Life expectancy and operational integrity is expected to be far superior to both ADL and ADSS installations. Installation under live conditions can be problematic with a certain degree of risk to the transmission system.

ADSS is a fast and cost effective technique to establish telecommunication infrastructure. It is relatively simple and can be performed under live conditions with minimal risk to the system.

Case study 7-4 (Spain) - Optical Cable Installation

In the last three years approximately 4000 km of optical fibre cable OPGW with different numbers of fibres have been installed on existing transmission lines of 400 and 220 kV. The existing earth wire could be used as a pulling wire for the stringing of the OPGW when its state of maintenance is acceptable and can be used when it is strong enough. Fittings are changed and, in some occasions, the structures have been reinforced. The crossing of existing distribution lines is one of the most important problems to be solved during the stringing since the distribution companies do not accept outages of their lines by supplying problems to their customers.



Workers hooking an optical fibre cable

A planned outage is required to install optical fibre cable on existing overhead transmission lines but, sometimes it is impossible to get it due to restrictions of the network. In that cases (approximately 30%) the optical fibre installation was performed by live line techniques. This method consists of stringing of the OPGW to a tension of 80% of the final tension to maintain, at any moment, the necessary safety distances according to the corresponding regulations.

Workers installing optical fibre cable by live line methods

Appendix 1:

Some Additional Effects of Increasing Conductor Temperatures

High Temperature Effects on Galvanized Steel Core [42], [43].

High temperature operating of conductors with steel cores can be limited by corrosion and the adherence of zinc plating to steel core wires. Some observations regarding high temperature operation of galvanized steel core wire are:

i. The steel wires of ACSR conductors will run hotter than the aluminium wires. Temperature gradient between the steel core and outer aluminium wires can be as high as 10% for new conductors and 20% for old conductors, depending on conductor stranding, age and ambient conditions.

ii. It is found that the temperature has a marked effect on the rate at which zinc corrodes in water. The corrosion rate in distilled water reaches a maximum in the temperature range of 65-75 ^{o}C. This variation in the corrosion rate with temperature is attributed to changes in the nature of the protective oxide film. At lower temperatures the film is found to be very adherent and gelatinous, while at temperatures around 70 ^{o}C, it becomes distinctly granular in character and coating formed at temperatures around 70 ^{o}C is more porous than others thus permitting greater access of dissolved oxygen to the metal.

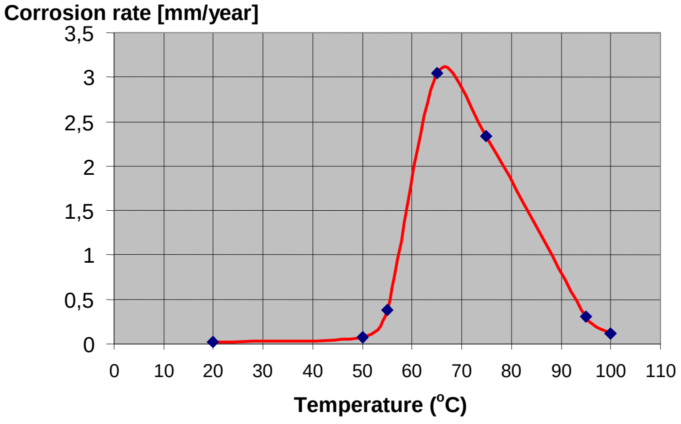


Figure A1-1: Dependence of Corrosion Rate of Zinc on Temperature with Moisture

iii. The zinc plating does not adhere well to the core wires at temperatures in excess of 200 ^{o}C. Operating temperatures above this value will reduce the life expectancy of in-service conductors due to impaired corrosion resistance and fatigue resistance from subsequent pitting of the steel strands.

iv. Temperatures near 400 ^{o}C cause the zinc surface layer to alloy with the underlaying steel, forming brittle compounds which have a tendency to flake and spall. This will tend to lower the corrosion resistance of the galvanized wire. Furthermore brittle cracks in the zinc alloy layer will greatly increase susceptibility to fatigue in the underlaying steel. Additionally, this temperature causes a reduction in hardness and tensile strength.

Effect of Elevated Temperature on Current Carrying Connectors [42],[44]

With the pressure to increase the use of existing line capacity it is vital that the effect of the increased current on connectors is known. The main consideration for connectors when evaluating elevated conductor temperature operation is its impact on connector long–term life expectancy. High temperature excursions on connectors increase their electrical, mechanical, and thermal stresses. Failure of connectors can be precipitated by high current and/or high temperature operation. Such failures can be difficult to predict and find, and they are always expensive to repair with extensive field work and loss of transmission capacity. Since the final stage of failure is decoupling of the conductor, there are also safety and economic issues to consider.

High Temperature Effect on Ferrous Conductor Hardware

Non current carrying ferrous conductor hardware which surrounds, or partly surrounds a conductor, is subject to hysteresis and eddy current losses due to magnetic flux associated with conductor current flow. These losses result in a heat gain within the hardware, and hence increased operating temperature. The localized loss of conductor strength due to hardware operating at a temperature greater than the conductor's allowable temperature for annealing, is confined to the conductor directly under and adjacent to the hardware.

Smaller parts of ferrous hardware have relatively low mass in comparison to their surface area and usually operate at temperatures well below the conductors allowable annealing temperature regardless of current. Larger parts of ferrous hardware have a mass to surface ratio which can result in hardware temperature greater than the conductor's allowable annealing temperature at higher currents. Hardware large enough to produce localized conductor temperatures of concern is usually confined to suspension and anchor clamps.

High Temperature Effects on the Protecting Properties of Grease [45],[46]

In coastal and industrial locations conductors are subject to various degrees of deterioration in their mechanical and electrical properties and it has been found that coating them with suitable grease can substantially improve their lifespan under such conditions. If little or no oil or grease is left over a period of time conductors are found to deteriorate to some extent in corrosive atmospheres. Some of the required properties therefore are that the grease must:

i. Not flow at the temperatures that the conductor is likely to reach in service (ambient + conductor temperature rise under normal, short- circuit and increased operating currents).
ii. Not migrate to the bottom of the conductor, which might increase corona losses.

iii. Be sticky so that it does not come loose with temperature fluctuations.
iv. Be resistant to weather and atmospheric pollution without altering its properties.

Requirements for approval of greases are covered by an identification test, measurement of drop point, penetrability test, flow test, measurement of acidity/ alkalinity index, weathering test and corrosion test.

Appendix 2:

An Example of the Analysis and Evaluation of Corrosion from RED Electrica, Spain

The galvanized coating is the most typical protection in towers against corrosion. It ensures 20 to 25 years protection for angle sections and bracket plates in non-aggressive environments and some 15 years for bolting. In marine or highly polluted (basically industrial) environments, the time this protection is effective can be substantially reduced.

Once the galvanized zinc-coating disappears, a corrosion process starts that may be rather significant both as relates maintenance costs and the likely repairs due to irreversible structural deterioration.
Although many factors determine tower structures corrosion, in a specific environment, those more significant are described next:

i. Relative Humidity

Relative humidity allows to determine up to what point the atmosphere is near or far from its saturated condition. It is stated as the ratio (in %) between the steam partial pressure in the air (P_{H2O}) and the air saturation pressure in steam (Ps), at the same temperature.

$$HR = 100 \times P_{H2O} / P_s$$

It has been shown that corrosion rate increases with the higher relative humidity. For corrosion to be significant, relative humidity has to exceed 80% and the atmosphere polluted by agents that attack the existing metal or paint coat.

ii. Wetting Time (rain, dew, fog, etc.)

During rainfalls, metallic surfaces are covered by a continuous or discontinuous water layer of different thicknesses. It is hard to determine whether rainfall, dew or fog are more harmful. Dew or fog can induce more damage that rainfall, for the same exposure time length, since rain can wash out the different pollutants from the exposed surfaces.
Corrosion can be rather higher when metals are seen wet to the naked eye than if they are exposed to a humid but condensation-free environment, even for HR = 90% value.

iii. Atmospheric Pollution

Atmospheric pollutants are a rather significant factor in corrosion.
SO_2, is quite often found in the atmosphere and the content varies widely subject to the type of industries, geographical season of the year, etc.
Steel deterioration is much faster when SO_2 concentration exceeds 0,1 mg/m^3, an amount that can be easily reached. SO_2 must be combined with moisture to attack metals. In dry atmospheres, it would be harmless. For corrosion to take place, the SO_2 + moisture binomial is required. When RH reaches 80% and SO_2 concentration stands at 0.10 ppm., SO_2 is absorbed at the rate of 0.1 mg/m^2 per hour.
Solid particles are also a significant factor in metal corrosion, specially, when SO_2 concentrations are present in the atmosphere. Carbon particles develop a

large corrosion effect and that of fertilizers applied to farmland is quite negative for structures preservation.

In marine environments, chlorides that make up seawater particles carried by air streams are another pollution agent that must be taken into account. This pollution is found near coastal areas.

As already mentioned, for corrosion to be significant relative humidity must be high. The chloride ion effects start at about 70% of relative humidity (RH) and increase significantly for RH values above 80%. The Cl pollutant action is usually matched to a high RH, common in areas close to the sea.

iv. **Temperature**

Corrosion in metals exposed to atmosphere is affected by temperature changes. The electrochemical reactions rate is increased as temperature rises. But, at the same time, evaporation of water overlaying the metal is accelerated while the concentration of oxygen and other corrosion gases decreases. Usually, corrosion decreases, as ambient temperature increases, since the liquid laying on the metal is evaporated and, therefore, the wetting time, which is a basic variable, decreases. But, if the amount of liquid is large, the corrosion rate increases since the solid-liquid diffusion ratios increase, too. For instance, the iron corrosion rate is increased about 25% when temperature goes from 5 to 25ºC.

Corrosion is stopped at temperatures below 0ºC. But this temperature is dependent on the solute concentration in the wetting liquid, since the larger the solution concentration is, the lower the freezing point will be.

Atmospheric corrosion can be defined as the sum total of partial corrosion processes that take place each time an electrolyte layer develops on the metal surface. It can be said, therefore, that atmospheric corrosion is a discontinuous process and its effects can be determined through Barton's Law:

$$E = \sum_{1}^{n} \tau_n . v_k(n)$$

where:

E: Is the cumulative effect of atmospheric corrosion.

τ : Is the wetting time. During this time, the metal surface is covered by a water film that allows atmospheric corrosion to take place.

v_k: Is the mean corrosion rate during each wetting period. This term shows the amount of metal oxidized by unit of surface and can be stated as a function of penetration (mm/year or micron/year) or weight change by surface unit (g/m^2).

Wetting time (WT) is defined as the annual number of hours when relative humidity exceeds 80% and, at the same time, temperature rises above 0ºC.

If a continuous recording of relative humidity and temperatures is available, WT will be directly determined from the thermohygrograms. Otherwise, the WT value can be estimated based on the annual relative humidity mean values supplied by the respective Weather Bureau.

Later on and based on the wetting time, the atmosphere will be classified as shown in ISO 9223, where only exposure to outdoors weather is taken into account.

As the mentioned Barton Law shows, atmospheric corrosion is decidedly influenced by those parameters that change significantly wetting time and the ones that directly affect the corrosion rate value, during each wetting period. Those parameters either modify the electrolyte composition (atmospheric pollution) or the chemical and electrochemical reaction rates that take place during the corrosion process (temperature).

The atmospheric corrosion rate of metals in general and, more specifically, that of steel is a hard to find value. A value that is determined by the physical properties of the water film overlaying the metallic surface and the nature and concentration of the water dissolved atmospheric pollutants.

Additionally, while exposed to the atmosphere, the steel corrosion rate is somewhat attenuated by the more or less protective layers built up on the surface by the corrosion products (rust). The protection extent and properties of those layers are related to the annual number of wetting hours the metal has to stand.

The pollutants effect, mainly, SO_2 and chlorides, is quite significant since these are factors that multiply the corrosion rate. For instance and depending on SO_2 concentrations, a change ratio of 2 is found when switching from a rural to an industrial atmosphere. As concerns chlorides pollution, the amount of corroded metal is deemed to increase between 1.3 to 8 times when the atmosphere changes from rural to marine.

As for other effects, the corrosion rate is also affected by the orientation, temperature changes, and initial exposure conditions.

Concerning the corrosion rate, it is very normal to classify the atmospheric environment in the geographical zone the electric power transmission line alignment goes through based on one of the following environment types:

i. DR.- Dry rural environment
ii. HR.- Humid rural environment
iii. DU.- Dry urban environment
iv. HU.- Humid urban environment
v. DI.- Dry industrial environment
vi. HI.- Humid industrial environment
vii. MR.- Marine rural environment
viii. MU.- Marine urban environment
ix. MI.- Marine industrial environment

The estimated deposition rates of SO_2 and chlorides (CI) in mg/m^2.day are found based on the above classified environments and the class of atmosphere is determined, according to ISO-9223, through the pollutants deposition rate

In order to detect losses in structural components "Structural Risk" will be deemed present when a number of conditions are found in exposed structures related to both the facilities condition and long-term corrosion prospects. A structure will be regarded at risk when the amount of material lost that it can hardly meet the project's strain-stresses requirements.

Both deterioration quantifying and its possible trend are a basic requirement that shows which lines and when they must be protected and allows to set priorities. Generally speaking, it is thought, as stated at this paragraph end, that a "Structural risk" exists when the thickness decrease is larger or equal to 1 mm. When this value is reached, the structure is out of the design boundaries, since the thickness of bars subject to mechanical stresses range between 5 and 13 mm. A 1 mm. thickness decrease implies, therefore, a strength capacity reduction ranging about 20 to 7.7%.

Thicknesses will be measured on different structural members once the overlaying rust has been removed.

Whether a full or partial replacement is required will be determined through evaluation of any design thickness decrease.

The Military Standard, MIL-STD 105D, known as "Tables and procedures for inspection sampling by attributes" will be applied to find out how many towers must be inspected.

The towers to be inspected will be determined based on the following formulae:

$$x = \alpha . RND$$

where:

- x = number of towers to be inspected
- α = number that consists of digit "1" followed by as many zeroes as there are digits in the number of the first tower in the inspected stretch.
- RND = generator of random numbers

Unified terminology and the selection of the locations will be needed where values will be read, the main points will be measured in any selected tower.

An ELCOMETER 245F, 145 or similar instrument must be used to read thicknesses values. Generally speaking, zero adjustment and instrument calibration against preset standards must be allowed by the instrument. Also, the possible reading values have to range at least from zero to 500 μm.

The thicknesses measuring instrument has to meet the ISO 2178 and ISO 2064 standards and special attention must be paid to:

i. *Avoid border effects*: Values must be read at least 20 mm from borders, edges, holes or internal angles.

ii. *Foreign particles*: Any foreign particles that can prevent the closest possible contact between the sensor point and the surface to be measured must be removed. Bristle brush thoroughly the surface to be measured reaching down to the attached underlayer. The sensor tip will be also regularly cleaned.

iii. Before values are read in a tower, the instrument must be calibrated using appropriate gauges (of thickness close to the theoretical values to be read). The instrument must be calibrated while the sensor is in a horizontal position, since most values will be read while the sensor is in that position. The instrument calibration must be controlled by rotating the sensor at 90º intervals.

Once the correct values from the respective towers are recorded, a number of statistical processes will be carried out to determine, generally speaking, the following:

a) If the found data are representative
b) A measured estimate value to determine a confidence interval for the read values.

Based on the field values read at each tower, the following must be determined:

a) The arithmetical rate of the thicknesses values read at each tower.
b) The typical deviation of the values read at points based on the formulae

$$S = \sqrt{\sum_{i}^{n} \left(\frac{x_i - \bar{x}^2}{(n-1)} \right)}$$

where:

x_i = value at each measured point in the tower
$\bar{x}$ = arithmetical mean of those values
(n-1) = number of elements in the sample

Rather than "n", (n-1) is used, since for "small" samples, a better reading of the deviation is shown by n ≤ 30.
The average value of the mistaken reading will be determined by the typical deviation that will be applied to estimate the red values reliability.

Besides, based on the thickness mean value per tower, the following will be determined:

i. Data Adjustment to a Normal Distribution

Different hypothesis will be compared to decide whether the found data match any distribution pattern and are therefore representative for the inspected stretch, or are scattered and do not match a distribution type.
In here, the Shapiro and Wilks contrast comparison formulae will be applied, since, generally speaking, samples will be small in the n ≤ 30 will be used.
The applicable formula is:

$$\omega = \frac{1}{\sum_{i=1}^{n} (x_n - \bar{x}^2)} \left[\sum_{i=1}^{h} a_{in} (x_{(n-1+1)} - x_i \right]^2$$

where:

ω = statistical value to be determined
n = number of towers where values have been read
h = n/2, if "n" is an even number, and (n-1)/2 if "n" is an odd one
a_{in} = tabulated value. Constant

A significance level (α) must be applied for computation, i.e., a probability level whereby events that show a probability to take place below that level are deemed negligible. Here, 0.05 has been set.

Based on this significance level, a number of ω values have been tabulated. If the tabulated ω value based on α and "n" is less than that found through the formula, the normality hypothesis will be accepted, e.i., data will be deemed to match a normal distribution and, therefore, its arithmetical mean value is applicable throughout the inspected stretch.

Otherwise, the likelihood of data being rather scattered and not stretch-representative, based on the sample confidence interval, will be taken into consideration.

ii. Confidence Interval

An interval will be taken into account where a specific percentage of the read values are found, to achieve, in this way, a homogeneous base for the read values.

If a probability to find the read values in an interval to be determined is set at 90%, this will be computed through:

$$x^{-} \pm \frac{z\sigma}{\sqrt{n}}$$

where:

- n = number of elements
- $\bar{x}$ = read value found for the stretch
- σ = typical deviation
- z = constant. Statistical value determined based on the probability percentage defined for the problem. For a 90% confidence level "z" has been set at 1,64.

Based on the above, the interval where 90% of the read values will be found, is estimated through:

$$x^{-} \pm \frac{1{,}64}{\sqrt{n}}\sigma, x^{-} + \frac{1{,}64}{\sqrt{n}}.\sigma$$

Based on the previous measurements and taking account environmental issues a range of values has to be defined in order to get the decision of painting (low value of corrosion) or total replacement (high value of corrosion) because of when damage is so extensive, painting might not be financially convenient.

References:

[1] CIGRE Technical Brochure No. 244 (2004), "Conductors for the Uprating of Overhead Lines", SC B2 WG B2.12

[2] D. Sánchez, C. Alonso, "Increase in Transmission Capacity in High-Voltage Power Lines on the Levante (Eastern Spain) Coastal Path", CIGRE Paper B2-206, Paris 2004

[3] F.G.A Albermani, S. Kitipornchai, "Assessment and Upgrading of Transmission Towers", CIGRE Paper SC 22-102, Paris 2000

[4] G.Brennan, "Methodology for Assessment of Serviceability of Aged Transmission Line Conductor", Master of Engineering Thesis, University of Wollongong, 1989

[5] "Guidelines for the Design and Maintenance of Overhead Distribution and Transmission Lines", Electricity Supply Association of Australia, Guideline C(b)1

[6] "Loss in Strength of Overhead Electrical Conductors Caused by Elevated Temperature Operation", Electra No. 162, October 1995, SC 22 WG 22.12

[7] CIGRE Technical Brochure No. 273 (2005), "Overhead Conductor Safe Design Tension with Respect to Aeolian Vibrations", SC B2 TF B2.11.04

[8] "Design Criteria of Overhead Transmission Lines", IEC Publication 60826

[9] CIGRE Technical Brochure No. 178 (2001), "Probabilistic Design of Overhead Transmission Lines", SC 22 WG 22.06

[10] CIGRE Technical Brochure No. 230 (2003), "Assessment of Existing Overhead Line Supports", SC B2.08.01

[11] "Design and Installation of Micropiles and Ground Anchors for OHL Support Foundations", Electra No. 222, October 2000, SC 22 WG B2.07

[12] CIGRE Technical Brochure No. 141 (1999), "Refurbishment and Upgrading of Foundations", SC 22 WG 22.07

[13] F. Kiessling, D. Hussels, C. Juerdens, J. Ruhnau, "Upgrading High-Voltage Lines to Increase their Capacity and Mitigate Environmental Impacts", CIGRE Paper 22-208, Paris 1998

[14] T. Kikuchi, W. Oba, Y. Kojima, Y. Asano, S. Matsui, "Compact Transmission Lines for Increasing Voltage while Keeping Existing Equipment Intact", CIGRE Paper 22/33/36-03, Paris 1998

[15] M. Ammann, P. Dallèves, K.O. Papailiou, M. Leva, S. Villa, "A new 400 kV Line with Compact Towers and Composite Insulated Crossarms", CIGRE Paper 22/33/36-06, Paris 1998

[16] D. Loudon, K. Halsan, U. Jonsson, D. Karlsson, L. Stenstrøm, J. Lundquist, "A Compact 420 kV Line Utilising Line Surge Arresters for Areas with Low Isokeraunic Levels", CIGRE Paper 22/33/36-08, Paris 1998

[17] "Real Time Line Monitoring", Electra No. 197, August 2001, SC 22 WG 22.12

[18] "The Use of Weather Prediction for Transmission Line Thermal Ratings", Electra No. 186, October 1999, SC 22 WG 22.12

[19] "Survey of Properties and Uses of Novel Conductors", SC22 Meeting, Paris 1998, SC 22.12

[20] R. Stephen, "Description and Evaluation of Options Relating to Uprating of Overhead Transmission Lines", CIGRE Paper B2-201, Paris 2004

[21] M.J. Tunstall, S.P. Hoffmann, N.S. Derbyshire and M.J. Pyke, "Maximising the Ratings of National Grid's Existing Transmission Lines Using High Temperature, Low Sag Conductor", CIGRE Paper 22-202, Paris 2000

[22] K. Adachi, T. Kumeda, K. Nagano, "A Method for Expanding the Current Capacity of Overhead Transmission Lines", CIGRE Paper B2-209, Paris 2004

[23] D.A. Douglass, Y. Motlis, T.O. Seppa, "IEEE's Approach for Increasing Transmission Line Ratings in North America", CIGRE Paper 22-302, Paris 2000

[24] "Description of State of the Art Methods to Determine Thermal Rating of Lines in Real-Time and their Application in Optimising Power Flow", CIGRE Paper 22-304, Paris 2000

[25] R. Stephen, D. Muftic, "Determination of the Thermal Rating and Uprating Methods for Existing Lines", CIGRE Paper 22-305, Paris 2000

[26] B. Cauzillo, L. Paris, G. Pirovano, "Ampacity Assessment of Overhead Line Conductors as a Compromise Between Safety and Deregulated Market Requirements", CIGRE Paper 22-206, Paris 2002

[27] S.P. Hoffmann, A.M. Clark, "The Approach to Thermal Uprating of Transmission Lines in the UK", CIGRE Paper B2-317, Paris 2004

[28] T.O. Seppa, M. Clements, S. Damsgaard-Mikkelsen, R. Payne, N. Coad, "Application of Real Time Thermal Ratings for Optimizing Transmission Line Investment and Operating Decisions", CIGRE Paper 22-301, Paris 2000

[29] T. O. Seppa, H. W. Adams jr., N. Coad, D. A. Douglass, "Use of On-Line Tension Monitoring for Real-Time Thermal Ratings, Ice Loads, and Other Environmental Effects", CIGRE Paper 22-102, Paris 1998

[30] H.L.M. Boot, F.H. de Wild, A.H. van der Wey, G. Biedenbach, "Overhead Line Local and Distributed Conductor Temperature Measurement Techniques, Models and Experience at TZH", CIGRE Paper 22-205, Paris 2002

[31] F. Soto, D. Alvira, L.Martín, J. Latorre, J. Lumbreras, M. Wagensberg, "Increasing the Capacity of Overhead Lines in the 400 kV Spanish Transmission Network: Real Time Thermal Ratings", CIGRE Paper 22-211, Paris 1998

[32] CIGRE Technical Brochure No. 207 (2002), "Thermal Behaviour of Overhead Conductors", SC 22 WG 22.12

[33] R. Stephen, K Yeomans, "Statistical Signatures for the Determination of Transmission Line Safety", Elektron, Official Journal of the South African Institute of Electrical Engineers, November/December 1993

[34] CIGRE Technical Brochure No. 306 (2006), “Guide for the Assessment of Old Cap & Pin and Long-Rod Transmission Line Insulators Made of Porcelain or Glass: What to and When to Replace”, SC B2 WG03

[35] R. J. Carrington, "New Technologies for Transmission Line Uprating", Presentation to overhead lines seminar, March 1998, Hobart, Tasmania

[36] R. Stephen, "Real Time Monitoring Methods", Presentation to overhead lines seminar, March 1998, Hobart, Tasmania

[37] J.C. Poffenberger et al., "Overhead Conductors in the United States", Paper presented at the open conference, Rio de Janeiro 1983

[38] "Probabilistic Determination of Conductor Current Ratings", Electra No. 164, February 1996, SC 22 WG 22.12

[39] "Increasing the Transmission Capacity of Overhead Lines – High Surge Impedance Loading technique", Electra No. 221, August 2005, SC B2 WG B2.06

[40] O. Regis jr., S. J. Gusmão Cavalcanti, A. Pessoa Neto, L. A. de M. Cabral Domingues, F. Chaves Dart, M. J. Albuquerque Maia, "Expanded Bundle Technique: The Application of HSIL TL Concept to Increase the Capacity of Overhead Lines", CIGRE Paper 22-207, Paris 1998

[41] CIGRE Technical Brochure No. 278, (2005), "The Influence of Line Configuration on Environment Impacts of Electrical Origin", SC B2 WG B2.06

[42] "Guide for Determining the Effects of High-Temperature Operation on Conductors, Connectors and Accessories", IEEE Standard No. 1283-2004

[43] L.L Shreir, "Corrosion, Volume 1, Metal/Environment Reactions", Newnes-Butterworths, 1977

[44] R.G. Stephen, "Electrical Aspects of Overhead Transmission Lines", CIGRE WG 22.12, 1997

[45] Michel Dutournier, Michel Paris, "New Test Standards for Protective Coatings for Aluminium-Based Bare Overhead Conductors", Revue de l`aluminium No. 526 , March 1983

[46] "Conductors for Overhead Lines-Characteristics of Greases", CENELEC standard EN 50326:2002

[47] CIGRE Technical Brochure No. 175 (2000), "Management of Existing Overhead Transmission Lines", SC 22 WG 22.13

[48] P. Buckland & N. Hastings, “The Replacement Decision for Linear Assets”, ICOMS 2001, Melbourne, May 2001

[49] CIGRE Technical Brochure No. 294 (2006) “How Overhead Lines are Redesigned for Uprating/Upgrading – Analyses of the Answers to the Questionnaire”, SC B2 WG B2.06

[50] CIGRE Technical Brochure No. 299 (2006) WG12, TF6 “Guide for the Selection of Weather Parameters for Bare Overhead Conductor Ratings”, SC B2 WGB2.12

[51] Simpson, K.D. & Wisniewski, J.B. “Lightning Performance of Transmission Lines,” Paper presented at Sargent & Lundy Eighth Biennial Transmission and Substation Conference, Nov 1984.

[52] “High Voltage Environmental Concerns, Procedures, Impacts and Mitigation,” CIGRE Technical Brochure 147, 1999.

[53] “Effects of Current Passing Through the Human Body,” IEC 60479

[54] “Guide to Protective Earthing,” Electricity Council of New South Wales, 1992.

[55] "Guidelines for Mitigation Techniques of Power-Frequency Magnetic Fields originating from Electric Power Systems," CIGRE Technical Brochure under preparation by SC C4.2.04.

[56] “Failure Rates of Ceramic & Composite Insulators on the Transmission Power System in the Czech Republic”, Paper presented at INMR Conference, Sept. 2005

[57] STRI Guide “Failure Rate of the Insulators” CIGRE Technical Brochure

[58] Technical Brochure No. 141 (1999) “Refurbishment an Upgrading of foundations”, SC22 WG22.07

[59] R.E. Randle & L.K. Troutman, "Case Study in Evaluating Today's Line Rating Techniques", American Society of Civil Engineers Electrical Transmission in an New Age Conference Proceedings, September 2002

[60] Miler et al, 2006, "Corrosion Detection Techniques for Buried Steel Components", ASCE Electrical Transmission Conference, pages 261-273 (Birmingham, Alabama USA 2006)

[61] Lachance et al, 2006, "2005 Update on Inspections of Anchor Rods on NYPA System", International Conference on Overhead Lines, pages 141-147 (Ft. Collins, Colorado USA 2006)

[62] White, John E., et al., "KCP&L Reconductors Energized 345kV Line", Transmission & Distribution World, September 2003.

[63] "New type of Tower for Overhead Lines" , Henning Oebro, e.o., CIGRE SC B2 Session 2004, report B2-305

[64] IEEE Std. 524, IEEE Guide to the Installation of Overhead Transmission Line Conductors.

[65] CIGRE Technical Brochure No. 308 (2006), "Foundation Installation – An Overview", SC B2 WG07