300

GUIDELINES TO AN OPTIMIZED APPROACH TO THE RENEWAL OF EXISTING AIR INSULATED SUBSTATIONS

Working Group
B3.03

August 2006

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CONSEIL INTERNATIONAL DES GRANDS RESEAUX ELECTRIQUES
INTERNATIONAL COUNCIL ON LARGE ELECTRIC SYSTEMS
COMITE D'ETUDES B3 : POSTES
STUDY COMMITTEE B3: SUBSTATIONS

Guidelines to an Optimized Approach to the Renewal of Existing Air Insulated Substations

In response to the growing need for an optimized approach to the renewal of existing substations, CIGRE Working group B3-03 "Air Insulated Substations" undertook the task of developing guidelines for the process of evaluating the suitability/condition of existing assets and for methods to optimize its renewal.
The brochure describes the typical reasons for renewal as connecting a new important customer, raised short circuit load, aged equipment condition, new remote control functionalities etc. Each cause leads to a variety of possible solutions, starting from the change of a single equipment up to a total renewal of the AIS comprising several categories of components. The brochure gives general guidance to find an optimised solution by:

- pointing out the importance of combining the actual cause of renewal with an overall condition assessment of the substation in a whole.
- giving advice to an economical evaluation regarding life cycle cost.
- presenting practical examples of renewals carried out.

This technical brochure presents requirements for renewal, condition assessment techniques, as well as qualitative and quantitative risk evaluation methods. The brochure also includes several renewal case studies of innovative efforts across the globe to optimize air insulted substation renewals.

We wish to thank and acknowledge the many scientists and engineers who were involved in this project.

August 2006

Auke Wiersma	Sylvain Laureote
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Guidelines to an Optimized Approach to the Renewal of Existing Air Insulated Substations

Technical Brochure No. 300

PREFACE

The purpose of this technical brochure is to provide a comprehensive and systematic guideline to the renewal of Air Insulated Substations (AIS) to network owners, asset managers and network engineers. A special demand for these guidelines arose from the fact that numerous AIS have a basic plot, which reflects the needs of network and substation design of some fifty years ago. Moreover the lifetime expectancy of the components of an AIS is not uniform: for the civil engineering part (steel-supports, foundations, ducts etc.) one usually counts for a period between 60 to 80 years, whereas major electrical equipment, such as switchgear, transformers, etc. have a life expectancy of about 30 to 50 years. Secondary circuitry, such as control and protection devices could be used for about 20 years but are usually changed under maintenance programs, which in reality means a continuous partial renewal. Each of these categories represents about 1/3 of the total investment of typical AIS.

The brochure describes typical reasons for renewal such as connecting a new important customer, increase in short circuit levels, poor equipment condition, new remote control functionalities etc. Each cause leads to a variety of possible solutions, starting with exchange of a single equipment and going all the way to a total renewal of the AIS comprising several categories of components and using any proven technology including conventional AIS, Mixed Technology, Hybrid and GIS.

The following topic areas will be discussed in this brochure:

- Requirements for renewal
- Condition assessment methods
- Optimized approach to renewal of AIS
- Qualitative evaluation
- Risk evaluation
- Case studies

However, it should be recognized that the process of optimizing the renewal of AIS is very complex with a multitude of aspects and that the present brochure provides guidelines that may have to be tailored for each particular application.

This brochure was written and developed by the members of CIGRE Working Group B3-03 of

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This brochure was developed for the following target groups:

- **Technical Groups** including equipment suppliers, contractors, consultants, maintenance providers, grid planners and grid engineers.

- **Operators** of power systems, generation, transmission and distribution stations and asset and facility managers.

- **Science, Education and Public Groups** including academic and research institutes, young engineers, managers and others not familiar with the work of CIGRÉ.

- **International Organizations** with similar scope.

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1 INTRODUCTION

More and more substations throughout the world are getting older and new ones are difficult to build due to competitive constrains, to stringent environmental regulations and to community acceptance concerns. In the same time the need for power is increasing steadily and short circuit levels rise due to additions of generation to cover the increase in demand for power. Public and private utilities are struggling to utilize existing equipment effectively while they are under increased pressure to control construction and operating and maintenance costs. In the same time they are faced with the task of renewing existing, aging substations to keep them operating safely and reliably.

For the above reasons, the industry is looking for guidelines for the process of evaluating the suitability/condition of existing equipment and for methods to optimize equipment renewal activities.

This technical brochure presents a comprehensive and systematic guideline to the renewal of existing Air Insulated Substations (AIS) to network owners, asset managers and network engineers. This guideline describes the following topic areas to establish an optimum renewal strategy such as replacement equipment wise, partial renewal, total renewal and so on.

- Requirement for Renewal
- Condition Assessment Techniques
- Qualitative, Risk and Economical Evaluation Methods

This brochure also includes several case studies to optimize the AIS renewal from all over the world.

2 Requirement for Renewal

Various requirements can lead to the need of reviewing equipment in substations. Once the decision has been made, an optimum renewal method is studied.

Requirements for renewal can be:

- New regulations, such as meeting new safety codes and environmental regulations etc.
- Customer requirements such as, new connection requirements and power supply capacity enhancements from new power suppliers
- Power system requirements, such as meeting higher short circuit capacity requirements or changes in system control and operating requirements as well as need for reliability improvements,
- Operation and maintenance (O&M) requirements, such as major repair, equipment condition, O&M cost, spare parts procurement, availability of skills,

These requirements for renewal vary both in their cause and in their impact. Some are controllable by the utility; others are controlled by external sources. Further some requirements impact a wide area of society or the entire power system, while others affect only a narrow area like a particular substation or piece of equipment.

The requirements for renewal are categorized in Figure 2.1.

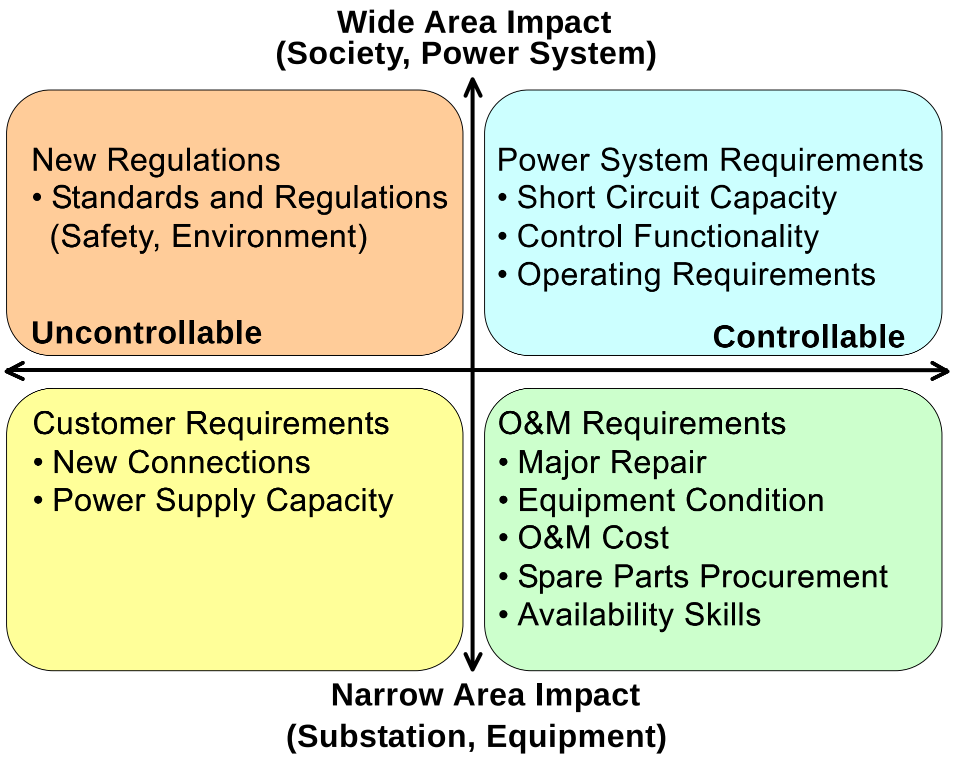


Figure 2.1. - Requirements for renewal equipment

2.1 NEW REGULATIONS

In the past transmission substations were generally located far from demand centers and were rarely restrained by environmental regulation and safety codes during their initial installation.

However, environmental regulations have expanded with recent urban development, requiring adequate countermeasures.

Conversely, distribution substations are generally located near demand centers, often in the center of large cities and have always been restrained by environmental and safety codes. As urbanization continues to increase more advanced countermeasures will need to be applied for both types of substations.

In addition to traditional environmental and community acceptance concerns such as aesthetics, noise, oil spills and EMF greenhouse gases with high global warming potential are now also being considered in some parts of the world as a major concern. Greenhouse gases have been restrained by “the United Nations framework convention on climate change”.

Cigre SCB3 issued "Technical Brochure No.234: SF6 Recycling Guide" and has been working for voluntary restriction, which should steadily be continued and promoted.

Furthermore, additional countermeasures are necessary in order to bring the existing installations to the new safety regulations for protection of the public and the workers at substations.

Examples of countermeasures are:

- Replacing and concealing equipment to improve the aesthetics of existing substations and gain community acceptance for significant additions to a substation
- Replacing and renovating equipment into low-noise level equipment and installation of noise reducing facilities (sound barriers, sound enclosures to meet the requirements of the new audible noise regulations and bylaws
- Installation of new or retrofitting spill containments and associated installations around equipment with large volumes of oil
- Redesigning existing outdoor substations into indoor or underground types to meet aesthetics preservation regulations and audible noise regulations
- Replacing oil-immersed transformers in indoor and underground substations with non flammable liquid to adhere to new, more stringent fire prevention codes
- Replacing, overhauling or repairing old and/or degraded GIS to prevent SF_6 gas leakage in order to meet the guidelines of new environmental regulations
- Replacing aged AIS equipment with GIS and/or hybrid or mixed technology switchgear
- Refurbishing protection devices to meet current technology and safety regulations and new market regulator requirements

These countermeasures may require extensive work and in many cases can not be implemented solely by an electric company.

As a result, countermeasures are difficult to implement in a short period and require careful planning in respect of finance, manpower and manufacturing capability.

2.2 CUSTOMER REQUIREMENTS

New generating capacity created by power suppliers (such as IPP or wind power generators) may cause an increase of short circuit levels beyond the levels for which the original substation was designed and built for. In these situations, it may be necessary to replace existing equipment.

Examples of countermeasures:

- Replacing or refurbishing equipment and buses to correspond to capacity increase
- Reorganising grid configuration to curb the capacity increase

Although these countermeasures may only be necessary on a small number of transmission lines and substations, in most cases they cannot be implemented solely by the electrical utility. Coordination with new generation connection companies is required in most cases.

Furthermore, because in most cases, existing equipment has not been depreciated, they should be examined if they might be used at other substations after confirming the equipment usefulness.

2.3 POWER SYSTEM REQUIREMENTS

A grid capacity increase, inability to meet new and higher short circuit levels, change in the equipment control method or a raise in the operational limits may trigger the need for equipment replacement.
Examples of countermeasures are:

- Separating the grid, installing switching stations and current-limiting reactors and/or fault current limiters to limit grid short circuit capacity increases
- Replacing or refurbishment equipment and buses to satisfy capacity increases and raises in operational limits
- Use of redundant protective schemes for the protection of major equipment and transmission lines
- Installing capacitors or shunt reactors for reactive power compensation

These countermeasures might need to be implemented extensively and may require high investments. However, they allow many optional choices and could be implemented solely by an electric company.

Therefore, it is possible to strategically implement these countermeasures within the financial and manpower capabilities of an electrical utility and with support from manufacturers of the respective equipment.

Substation reliability becomes an important factor in determining substation equipment upgrade or replacements. Substation reliability considerations are required if one or more of the following conditions are applicable:

- The location of the substation next to major power generating station: a failure of equipment to operate may result in loss of the generating station and as a result the loss of revenue and power to major load centres.
- Proximity of the substation to major load centres: Equipment failure such as transformer fire reduces the capacity of the substation and therefore results in loss of revenue and power outage to major load centres.
- Substation location in the system: Transmission substations are normally connected to other major substation, which may be located in different cities, states or countries.
- Equipment failure in one substation may cause system stability issues, which could result in loss of revenue and power blackout in one or more cities.

2.4 OPERATION AND MAINTENANCE REQUIREMENTS

Rationalization of maintenance methods for substation equipment has been rapidly progressing recently, and optimum maintenance methods are chosen on the basis of life cycle cost evaluation and on the RCM (Reliability Centered Maintenance) method. In order to support these, diagnosis technologies have been developed and introduced.

Appropriate applications of these new maintenance methods make it possible to reduce the maintenance cost while preserving the equipment reliability.

On the other hand, both manufactures and electric utilities are drastically reducing their workforce and rationalizing facilities in order to override the liberalization of electric power industry. Therefore, availability of spare parts that were designed more than twenty years ago and preservation and succession of technical workers skill are being considered when maintenance methods are decided.

Examples of factors considered when deciding maintenance methods:

- Major repair
- Condition monitoring technologies, evaluation technologies for deterioration
- Maintenance cost evaluation
- Spare parts procurement
- Preservation and succession of technical workers skills

3 CONDITION ASSESSMENT

3.1 GENERAL CONSIDERATIONS

The need for a condition assessment most commonly arises when there is an obvious or known need to repair, refurbish, or upgrade some element of a substation. A comprehensive condition assessment is then undertaken as an input to the development of the most suitable option for dealing with the substation. Addressing each element of the substation in isolation can be wasteful and not take advantage of synergies.

A comprehensive condition assessment should include the following main items.

- The substation equipment.
- Buildings and civil.
- Site issues.
- Surroundings, neighbors, complaints.
- Fire issues and other major event possibilities.
- History of loading, problems, and failures.

The Condition Assessment should not be limited to the "condition" of the items, meaning the state of deterioration or wear, but should include consideration of matters such as design deficiencies, or outdated policies. For example, inadequate fire segregation, un-duplicated DC supplies.

In other words, a condition assessment should be elevated to a comprehensive assessment of all aspects which relate to "fitness for purpose" of the substation at any given stage in its life. The concept of "state of the asset" Assessment is perhaps more appropriate. It is necessary to do this in order to provide a sound basis for decisions as to the appropriate replacement, repair, or refurbishment options. Common sense, of course, should also apply. If there is one obvious overriding issue apparent, then it should drive the decisions without the need for a lot of unnecessary assessments.

A comprehensive Condition Assessment document should be prepared for each substation, bringing together all aspects so that all issues can be seen together and in perspective. This will facilitate long term decisions aimed at least "whole of life" cost rather than simply short term, quick fix solutions which leave a legacy of problems for the future. This is not to say that all repair or replacement work has to be done at the same time, but that an overall plan is thought out, including the timing of works.

Some facilities within the community are designated as disaster recovery facilities. These include certain hospitals, water pumping stations, sewerage facilities, public communication facilities and similar which are identified as essential to recovery of a city or town after a major or widespread disaster. The substations which supply these critical facilities should be identified and obviously given special attention with respect to condition assessment, particularly those design features required to make it resistant to damage.

The operational condition of a substation as a whole, a functional part of it or a specific piece of equipment is defined by the degree of ability to perform its proper functionality in a reliable manner. Supervising the condition is an important part of the continual operation and maintenance routines in electrical supply networks, using the results of inspection, diagnostic measurements, functionality tests, monitoring results, fault records etc. as sources of information.

Most of this information is collected and used by operation and maintenance staff in order to ensure the system can perform its daily duties.

The fundamental purpose of a condition assessment is to make the relevant part of the information accessible and readable for the decision making process. Usually this is done in three steps:

Step 1: Quantitative Description
Using a suitable template, a formalized description of condition information together with designators for location, equipment and date will form a singular condition report.
Step 2: Rationalization
The condition assessment process can be performed on selected condition reports in combination with information from the asset database, technical information from suppliers as well as from standards and regulations. This leads to a condition statement concerning a type of equipment or an overall consideration of a functional entity within a specific substation, depending on selection.
Step 3: Classification
Decision-making is interested in statements showing the degree of urgency and the action to be taken. Using the results of the assessment, a typical classification can look like:

Class	Classification	Action
1	Fully operational: no performance deficit	No action
2	Operational: light performance deficits	Maintenance measure
3	Reduced operational: performance deficits	Repair or replacement or renewal
4	Critical: performance in danger	Urgent: repair or replacement or renewal

To aid in the creation of a condition assessment process, the next section of this document will provide the condition assessment experience of experts from all over the world. These are broken down by component, showing the properties that may be critical and should be included in condition reporting. It is important to note that technological habits are different depending on the region in question and recommendations may vary by continent to reflect the historical path of the development of the electricity systems. Nevertheless, this document tries to provide an overview referring to locally applied methods and their basic standards.

The extend of each sub-section shows another principle of condition information collection: the level of sophistication is increasing depending on the value of equipment, repair time required, spares availability and specific knowledge needed.

3.2 TRANSFORMERS

Recent economic constraints caused by the deregulated markets have forced utilities to do more with what is already installed. Power transformers are no exception. They are now being operated under increased loads and beyond their standard life expectancy of approximately 25 years, many units reaching the age mark of 40 to 50.

To assess transformer condition, the utility should look at the in-service history of each piece of equipment. The history should contain information on how many through fault currents the transformer was subjected to as well as regular maintenance records. Evaluating the failure history of transformers of same type or construction principle may lead to general conclusions.

Factors that may affect the condition of a transformer are:

- Loading – constant and acceptable loading is better for transformers, overloading may cause unacceptable temperature rise and accelerates deterioration of transformers.
- Oil preservation systems - sealed systems are better than the free breathing systems to avoid an oil deterioration caused by moisture invasion.
- Oil temperature - maintaining a constant oil temperature by switching in and out cooling is better for transformers.

The following international standards are usually applied as a guideline and reference for condition assessment of transformers and other equipment using paper-oil insulation:

IEC 60076-1 (2000-04)	Power transformers - Part 1: General.
IEC 60076-2 (1993-04)	Power transformers - Part 2: Temperature rise.
IEC 60076-3 (2000-03)	Power transformers - Part 3: Insulation levels, dielectric tests and external clearances in air.
IEC 60076-4 (2002-06)	Power transformers - Part 4: Guide to the lightning impulse and switching impulse testing - Power transformers and reactors.
IEC 60076-5 (2006-02)	Power transformers - Part 5: Ability to withstand short circuit
IEC 60076-7 (2005-12)	Power transformers - Part 7: Loading guide for oil-immersed power transformers.
IEC 60076-8 (1997-11)	Power transformers - Part 8: Application guide.
IEC 60214-1 (2003-02)	Tap-changers - Part 1: Performance requirements and test methods.
IEC 60214-2 (2004-10)	Tap-changers - Part 2: Application guide.
IEC 60599 (1999-03)	Mineral oil-impregnated electrical equipment in service - Guide to the interpretation of dissolved and free gases analysis.
IEC 60422 (2005-10)	Mineral insulating oils in electrical equipment - Supervision and maintenance guidance.
IEC 60296 (2003-11)	Fluids for electrotechnical applications - Unused mineral insulating oils for transformers and switchgear.
IEC 60450 (2004 04)	Measurement of the average viscometric degree of polymerization of new and aged cellulosic electrically insulating materials.

IEC 60567 (2005-06)	Oil-filled electrical equipment - Sampling of gases and of oil for analysis of free and dissolved gases – Guidance.

IEEE 1276-2006	Guide for application of High Temperature Insulation Materials in Liquid-Immersed Power Transformers
IEEE C57.91-2004	Guide for Loading Mineral-Oil-Immersed Transformers
IEEE 1538-2005	Guide for Determining of Maximum Winding Temperature Rise in Liquid-Filled Transformers
IEEE C57.100-1999	Standard Test Procedure for Thermal Evaluation of Oil-Immersed Distribution Transformers
IEEE C57.104-1991	Guide for Interpretation of Gases Generated in Oil-Immersed Transformers
IEEE C57.106-2002	Guide for Acceptance and Maintenance of Insulating Oil in Equipment.
IEEE C57.19.100 -2003	Guide for Application of Power Apparatus Bushings
IEEE C57.127-2000	Guide for Detection of Acoustic Emissions from Partial Discharges in Oil-Immersed Power Transformers
IEEE C57.119-2001	Performing Temperature Rise Tests on Oil-Immersed Power transformers at Loads beyond Nameplate Ratings
IEEE 637-2002	IEEE Guide for the Reclamation of Insulating Oil and Criteria for Its Use
IEEE 62.2-2004	IEEE Guide for Diagnostic Field Testing of Electric Power Apparatus - Part 1: Oil Filled Power Transformers, Regulators, and Reactors

Some aspects that need to be considered when evaluating the condition of a transformer are:

- Oil condition and history including moisture, acidity, additives, furans, sludge, electric strength etc. taking into account type of oil and possible contaminants such as PCB, particles.
- Paper condition as evidenced by furans, degree of polymerization.
- Condition of windings e.g. distorted, loose.
- History of loading and temperature, particularly fault history.
- External condition, rust, leaks etc.
- Electrical test results such as dielectric dissipation factor (DDF), partial discharge, resistance and impedance changes.
- Tap-changer condition from inspection and electrical tests.
- Bushing condition from DDF, partial discharge and oil dissolved gas analysis (DGA).
- Condition of cooling system, pumps, and fans.
- Open to air or sealed (hermetic) type of transformer.
- History of failure and repairs, not only for the particular transformer but also for any population of identical transformers.
- Noise issues.

3.2.1 Diagnostic Technologies for Transformers

Diagnostic technologies can roughly by classified into 2 categories that are “Abnormality diagnosis" and "Deterioration diagnosis" as shown by a Japanese example in next table.

Table 3.1 - Diagnostic Technologies for Transformer

Diagnostic Technique	Description	Purpose	
		Abnormality	Deterioration
Dissolved Gas Analysis (DGA)	DGA indicates internal abnormality and determines if an internal inspection or repair is necessary by diagnosed type & amount of dissolve combustible gases. More detail is shown afterward.	X	
Partial Discharge Measurement	High frequency CT and/or acoustic emission (AE) sensor will pick up partial discharge signal that indicates internal abnormality and determines if an internal inspection or repair is required	X	
Insulation Oil Electrification	Static electrification in transformer indicates the possibility of insulation breakdown.	X	
Insulation Oil Characteristics	Withstand voltage test, dielectric test, moisture content		X
Aging Product Analysis	Amount of dissolved aging products such as "CO2+CO" and "Furfural" estimates Deterioration of strength of insulation paper.		X

DGA indicates internal abnormality such as local over heat, partial discharge.

Table 3.2. shows a type of abnormality and associated dissolved gases.

Table 3.2. -Type of abnormal and dissolved gas

Type of abnormality	Dissolved gas
Local overheat of insulating oil	H2, CH4, C2H6, C2H4, C2H2
Local overheat of insulation material	H2, CH4, C2H6, C2H4, C2H2, CO, CO2
Partial discharge in insulating oil	H2, CH4, C2H4, C2H2
Partial discharge in insulation material	H2, CH4, C2H4, C2H2, CO, CO2

Table 3.3. shows an example of DGA criteria.

Table 3.3. - Example of DGA Criteria

Classification	Criteria
Level 1 (Abnormal)	At least one gas meets the condition as follows. H_2 >= 400 ppm C_2H_2 >= 0.5 ppm CH_4 >= 100 ppm CO <= 300 ppm C_2H_6 >= 150 ppm TCG *) >= 500 ppm C_2H_4 >= 10 ppm
Level 2 (Defect)	At least one condition meets with condition as follows. a) C_2H_2 >= 0.5 ppm b) C_2H_4 >= 10 ppm and TCG >= 500 ppm
Level 3 (Failure)	At least one condition meets with condition as follows. a) C_2H_2 >= 5 ppm

	b) C_2H_4 >= 100 ppm and TCG >= 700 ppm c) C_2H_4 >= 100 ppm and TCG increasing rate >= 70 ppm / month

*) Total combustible gas

Life of a transformer depends on deterioration of insulation materials. Although deteriorated insulation oil can be reprocessed or exchanged, deteriorated insulation material like a winding insulation paper is impractical and costly to replace.

Usually strength of insulation paper is deteriorated by cumulative heating during operation, and it may create the possibility of breakdown by mechanical stress under external short circuit conditions and switching surges. .

Although life of a transformer is related to deterioration of strength of insulation paper, it is impossible to determine directly, during operation the aging level of insulation paper.

Therefore, dissolved aging product analysis related to the deterioration of insulation paper is only a useful method to estimate remaining life of transformer.

At present, the amount of dissolved aging products such as “CO2+CO” and “Furfural” is considered for an almost exact estimation of the strength of insulation paper. See Reference [1].

Figure 3.1. shows relationship between “Residual rate of polymerization of insulation paper” and “Amount of CO2+CO produced” and Figure 3.2. shows relationship between “Residual rate of polymerization of insulation paper” and “Production amount of Furfural”.

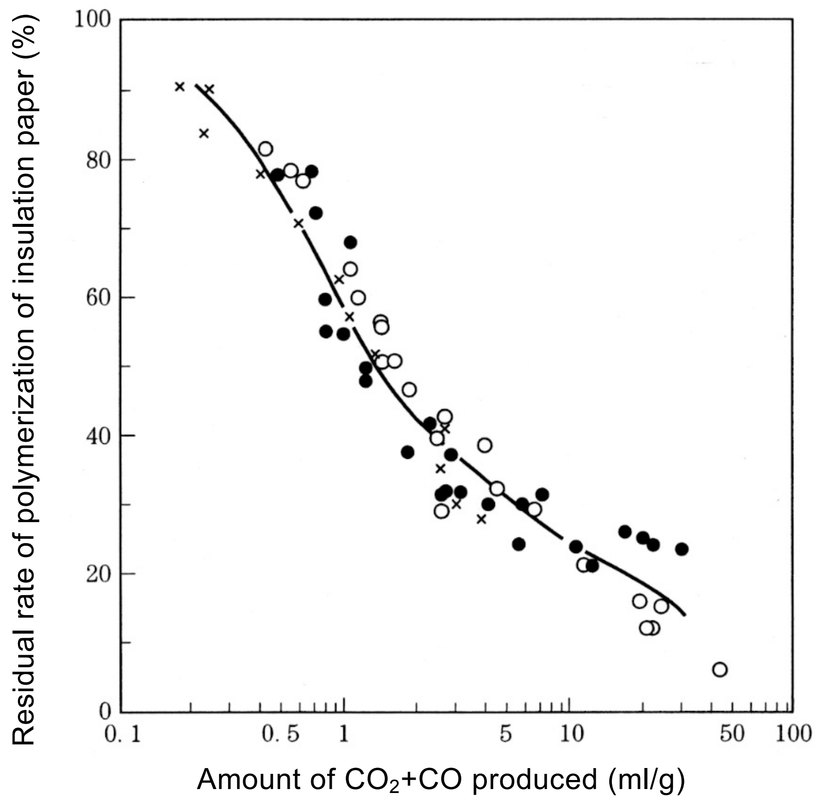


Figure 3.1. - “Residual rate of polymerization of insulation paper” and “Amount of CO_2+CO produced”, Ref. [1]

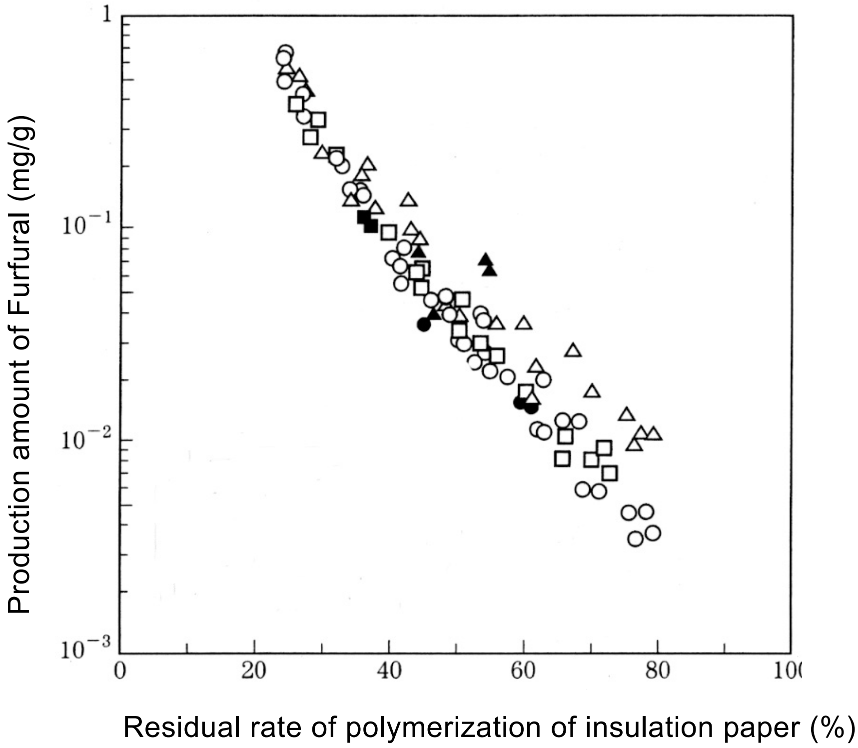


Figure 3.2. - “Residual rate of polymerization of insulation paper” and “Production amount of Furfural”, Ref. [1]

3.2.2 ON LOAD TAP CHANGER

Condition assessment for On Load Tap Changer (LTC) is generally considered based on operation number and operation year because LTC is composed of mechanical components.

A circulating oil filter can significantly extend maintenance cycle and life of LTC’s.

Replacing of diverter switches is considered after every 200,000 operations and replacing the entire LTC is considered after every 800,000 operations based on JEC 2200-1995 on oil filter installed condition.

As for diagnostic technologies, open/ close sequence time measurement is an effective method to evaluate unbalanced/uneven wearing of contacts.

LTC torque measurement and current waveform measurement is an effective method to detect mechanical abnormalities of LTC.A transformer with a load tap changer is susceptible to oil contamination and must be maintained on a regular cycle. The addition of a circulating oil filter can significantly reduce the need for maintenance. Typically, the decision to process oil is based on the dielectric analysis or DGA test of the oil.

3.2.3 PRACTICAL EXPERIENCES

Practical experience shows that Dissolved Gas Analysis (DGA) history will indicate the overall health of a transformer and, based on IEEE C57-104.1991 and IEC 60599 will determine whether an internal inspection or a factory rebuild is required. Poor physical condition such as tank rust or lack of painting can lead to water ingress or leaks. Oil leaks inside the tap changing cabinet and decayed gasket seal material require periodical maintenance.

Over time moisture content will increase in the transformer winding and oil, which will negatively affect insulation. Reprocessing or streamlining the transformer oil will significantly increase the life and health of a transformer. Streamlining will filter carbon and other contaminates and will remove water provided an ice trap machine is present to remove moisture. If desired, new oil can be installed depending on the composition and health of the existing oil. Some users specify oil with inhibitors that will break down over time requiring the oil to be replaced.

An internal visual inspection of the winding core and connections should be performed if oil is removed for processing. Frequently problems leading to failure can be identified before a major failure may occur. Examples are loose connectors, cracks in core supports, core ground strap damaged and possible insulation damage.

All seals and gaskets should be replaced on a regular maintenance cycle to prevent leaks in the control cabinet or CT makeup boxes. Current transformers typically are meggered at the time relay maintenance is performed and should be performed if transformer plates or compartments are opened to replace gaskets and seals.

A condition assessment should also look into solutions that would reduce the stresses imposed on a transformer and, thus extending its useful life. Some of these solutions are:

- Restricted operation (i.e. disabling load tap changer operation, operation at reduced loads, etc.),
- Refurbishment (detanking the core and coils, inspection and retightening of windings, reinsulation of leads, replacing gaskets, replacing control wiring, etc.)
- Reducing fault current through transformers due to external faults.
- Providing better protection against lightning and more frequent switching surges.

3.3 INSTRUMENT TRANSFORMERS

Most commonly used inductive current, voltage or combined instrument transformers can be evaluated using the diagnostic means for paper oil insulated equipment as described above. The basic properties are laid down in the following international standards:

IEC 60044-1 (2003-02)	Instrument transformers - Part 1: Current transformers
IEC 60044-2 (2003-02)	Instrument transformers - Part 2: Inductive voltage transformers
IEC 60044-3 (2002-12)	Instrument transformers - Part 3: Combined transformers
IEC 60044-5 (2004-04)	Instrument transformers - Part 5: Capacitor voltage transformers

IEEE C57.13-2003	Standard Requirements for Instrument Transformers
IEEE C57.13.1-1999	Guide for Field Testing of Relaying Current Transformers
IEEE C57.13.2-2005	Standard Conformance Test Procedure for Instrument Transformers
IEEE C57.13.3-2005	Guide for Grounding of Instrument Transformers
IEEE C57.13.5-2003	Trial-Use Standard of Performance and Test Requirements for Instrument Transformers of a Nominal System Voltage of 115 kV and above
ANSI/NEMA C93.1-1999	Requirements for Power-Line Carrier Coupling Capacitors and Coupling Capacitor Voltage Transformers (CCVT)

3.3.1 COUPLING CAPACITIVE VOLTAGE TRANSFORMERS (CCVT'S)

The age of a CCVT plays an important part in the decision to have it either replaced or continually monitored. The first criteria should be the physical condition of the CCVT base. Holes from rust or broken carrier shorting handle indicate the need for replacement as does any evidence of oil leaks.

A CCVT consists of a capacitive voltage divider with the tap voltage applied to the primary of a step-down transformer. The capacitor divider is made up of many series-connected capacitor elements, connected line to ground. The capacitor elements are housed in porcelain sections; typically 1 section for up to 172 kV, 2 sections for 245 kV, 3 sections for 550 kV and 4 sections for 800 kV. There are roughly 100 series-connected capacitor elements in each section.

A typical CCVT failure mode is one which starts with a single capacitor element failure. The failed capacitor element turns into a short circuit, which results in an increase in the capacitance of the section. The next stage is where elements adjacent to the initial failure start to fail as well. The rate at which subsequent capacitor element failures occur is usually slow, but the possibility of a sudden failure of all elements also exists. If a capacitor section has failed elements, it can generally be detected using a capacitance and dissipation factor measurement. The manufacturer's instruction manual should be consulted regarding the proper measurement techniques. Any unit which exhibits any capacitance changes should be monitored carefully and if the change is 5% or more it should be taken out of service.

A single capacitor element failure in the upward section will also result in a slightly higher output voltage (~1% or less), whereas a capacitor element failure in the reference section will result in a substantially lower output voltage (~10%). As subsequent elements fail, the secondary voltage continues to go up or down. By monitoring this voltage and assigning alarm points it is possible to reduce the probability of a total failure. Capacitive testing of individual sections will discover if any packs are shorted. If units are monitored using Scada or some other system alarms can be used to detect failure of CCVT before a severe event occurs.

3.3.2 POTENTIAL DEVICES (PT'S)

In most cases, oil filled PT's are reliable and do not have to be replaced unless physical damage is obvious. If necessary, oil samples can be taken and DGA analysis can be performed as discussed above. If a DC High Pot test and a DGA test show no degradation there is no need to replace. Experience with failure of solid type PT's may prompt replacement. All solid type PT's 20 years of age or older are to be physically inspected and replaced if any sign of insulation cracking is discovered. Close inspection should be done to insure that the insulation does not separate or curl back from the mounting plate. If separation from the mounting is discovered a DC High Pot test should be performed. If the PT passes the test, a bead of RTV silicone should be applied to reseal the mounting plate. Moisture ingress is the principle mode of failure of solid type PT's.

3.4 CIRCUIT BREAKERS

Most network operators use several generations of outdoor circuit breakers, using oil, air blast, vacuum or SF_6 as arc-extinguishing media. Hence the replacement or refurbishment of circuit breakers is complicated and hard to prioritize.

One must consider the age, performance, and availability of components, especially if the type of circuit breaker is no longer in production. Based on these factors a decision must be made on whether to refurbish/rebuild or replace the circuit breaker. Some circuit breakers are also replaced as a result of increased duty, e.g. increase in short circuit requirements.

Condition assessment for Circuit Breaker (CB) is generally considered based on number of operations and operations per year because CB is composed of mechanical components.

Table 3.4. shows diagnostic techniques for CB's condition assessment.

Table 3.4. - Condition assessment techniques for Circuit Breaker

Type of CB	Condition assessment techniques
General	• Number of operations • Accumulation interrupting current • Open/close characteristic measurement • Minimum open/close voltage (pressure) measurement • Main contact resistance measurement • Current waveform measurement (for motor driving operation)

GCB	• Partial discharge measurement • SF_6 gas analysis
OCB	• Insulation oil test
VCB	• Withstand voltage test for vacuum valve

The basic performance data for new circuit breakers is given by the following international standards:

IEC 62271-100 (2003-05)	High-voltage switchgear and controlgear - Part 100: High-voltage alternating-current circuit-breakers.
IEC 62271-108 (2005-10)	High-voltage switchgear and controlgear - Part 108: High-voltage alternating current disconnecting circuit-breakers for rated voltages of 72,5 kV and above.
IEC 62271-110 (2005-06)	High-voltage switchgear and controlgear - Part 110: Inductive load switching.
IEC 62271-2 (2003-02)	High-voltage switchgear and controlgear - Part 2: Seismic qualification for rated voltages of 72,5 kV and above.
IEC 61166 (1993-04)	High-voltage alternating current circuit-breakers - Guide for seismic qualification of high-voltage alternating current circuit-breakers.

IEEE C37-04 – 1999	Standard Rating Structure for AC High-Voltage Circuit breakers Rated on a Symmetrical Current Basis
ANSI C37-06 - 2000	Standard for Switchgear – AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities
IEEE C37-09 - 1999	Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis,
IEEE C37.010 - 2005	Application Guide for AC High Voltage Circuit Breakers Rated on Symetrical Current Basis
IEEE C37-011 – 2005	Application Guide for Transient Recovery Voltage for AC High-Voltage Circuit Breakers
IEEE C37-012 - 2005	Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers

Air blast circuit breakers have so far shown to reach the highest interrupting currents, however as they age there are ongoing problems with air service monitoring and failed gaskets creating forced outages in some situations. These issues in conjunction with the age of 30 – 40 years have led many network operators to move toward replacement of these breakers.

There is a relatively high inventory of oil circuit breakers (OCB) in use, the oldest having over 50 years of service. The decision to refurbish or replace these circuit breakers depends on the criteria listed above. At this time many companies are no longer refurbishing or rebuilding oil circuit breakers, these circuit breakers will be replaced by modern i.e. SF6 technology.

Oil and airblast are both designs that are no longer being manufactured. Therefore, SF_6 circuit breakers (GCB) will be the replacement option for all air blast and oil circuit breakers, whether in the form of dead tank or live tank circuit breakers. These circuit breakers are proven to be more economical, capable of high current interruption and since they are being manufactured on a large scale, spare parts are more easily obtained.

Vacuum circuit breaker (VCB) technology is still mostly considered at the medium voltage class level due to its better performance, reliability, and cost. VCB technology becomes less economical for outdoor applications at a higher voltage in comparison to SF_6. At medium voltage levels, these circuit breakers may require replacement after about 100 full short circuit current interruptions and/or 10,000 mechanical operations. However the number of operations may vary depending on the duty of the circuit breaker and its age.

The following are considerations for outdoor circuit breaker refurbishment or replacement:

- Number of operations together with on no-load, mechanical, short circuit, load currents condition if possible.
- Duty of circuit breaker – general purpose, capacitor switching, reactor switching
- Age of circuit breaker
- Parts and maintenance knowledge availability
- Type of interrupting medium: vacuum (VCB), air blast (ABCB), oil (OCB) or SF6 (GCB)
- Operating mechanisms; spring, pneumatic or hydraulic
- Maintenance history
- Manufacture type reliability experience
- Insulation condition, particularly bushings of dead tank circuit breakers.
- Insulation type.
- Mechanism type and condition
- Contact condition and contact resistance, including diagnostic results such as mechanical contact motion times. Not just of the interrupting and plug contacts, but also of all the bolted and clamped surfaces making up the primary current path.
- Fire. Does the circuit breaker contain fuel and flammable materials e.g. oil, compound, epoxy, PVC, XLPE, paper, wood?
- Condition of auxiliary switches and plug contacts.
- Is there a noise issue with the operation of the circuit breaker?
- Does the circuit breaker have all the operating features and interlocks required of current designs?
- Are the various ratings, voltage, current, interrupting, withstand, duty-cycle, all correct for the application at this site? Has anything changed, e.g. fault level, which would exceed any of the switchgear ratings?

3.5 OTHER SWITCHING DEVICES (DISCONNECTORS, SWITCHES)

Other switching device replacement or life extension is complicated and hard to prioritize. A decision must first be made on whether the switch insulators should be replaced or not. The criteria presented in the previous section should be applied using the following international standards:

IEC 62271-103 (2003-08)	High-voltage switchgear and controlgear - Part 102: Alternating current disconnectors and earthing switches.
IEC 62271-2 (2003-02)	High-voltage switchgear and controlgear - Part 2: Seismic qualification for rated voltages of 72,5 kV and above.
IEC 60265-2 (1988-03)	High-voltage switches. Part 2: High-voltage switches for rated voltages of 52 kV and above.

The following are considerations for switch refurbishment or replacement:

- Number of operations
- Number of energized operations
- Duty of switch – disconnect , breaking parallel, dropping load
- Age of switch
- Parts available to maintain switch
- Type of mechanical operation, hook stick, push pull, torsion, gang operated.
- Physical inspection
- Maintenance history
- Manufacture type reliability experience

Each user may weigh any of the above items differently, making a consensus for maintenance or replacement difficult. Important factors are ease of mechanical operation and hot part infrared scans. Any temperature readings 15 K above ambient needs attention and may require maintenance or replacement depending on the condition of the contacts. Visual inspection for cracks is critical and typically occurs around blade clamps, yokes and counter balance springs.

Several options are available depending on the condition of the operating mechanism and switch bearings. Overheating and wear may require contact replacement only. Hot spots cracks adjustment problems will require that switch hot parts be repaired only. Major operation mechanism fatigue, yoke binding or failure will require switch replacement.

Hand operator or gear operators should be inspected for interference free operation or broken locking device. Replace or repair as necessary.

Interrupter bottles of load break switches should be replaced on a minimum cycle of 20 years to prevent failures and faults during switching.

3.6 INSULATORS & BUSHINGS

Age and manufacture type are the critical indicators when considering replacement of station post insulators.

Insulation material of insulators & bushings are made of porcelain, glass and polymeric material like silicon rubber.

Porcelain and glass are inorganic materials and are considered not to be subjected to age deterioration.

Polymeric material such as silicon rubber are organic materials and have age deterioration characteristics. Inspection technique such as tracking, erosion and hydrophobicity are effective methods to assess the condition polymeric material.

Since bushings contain insulating oil or SF_6 gas the insulation performance depends on moisture in oil or SF_6 gas.

Water penetrates into bushings through the seal portion such as O-rings, gaskets or cracks in cementing. Therefore, monitoring moisture in oil and SF_6 gas and inspection of seal condition are effective methods to assess the condition of bushings.

Insulator design and test standards are designed to prevent brittle stress fractures and prolong life. Typical life can exceed 40 years before the need for replacement. However correct selection of the cantilever strength based on expected short circuit levels and atmospheric conditions plays an important role in the life expectancy of insulators.

The closer the bus loading is to the max cantilever strength the less life can be expected. Wind loading also plays an important role. Areas with continuous wind in excess of 13 km / 8 miles per hour will significantly reduce insulator life. Increase in the short circuit level in the substation might create the need to upgrade the cantilever strength of bus supporting insulators.

Experience and history of similarly aged insulators from similar manufacturers should be recorded and accounted. The number of seismic events both magnitude and duration should be considered as well.

The manufacture type and material are also a major consideration. Station insulators that are cap and pin style have a higher failure rate than solid core, uniform diameter station posts. The reason for the higher failure rate of the cap & pin insulators are that components of these insulators are cemented together and over time this cement weakens and cracks. An active maintenance program will involve sampling insulators and testing for dielectric strength and brittle stress fractures.

For substations near industrial pollution or natural contamination, replacement may be a cost effective option. If washing or the application of silicone grease to insulators is performed on a frequent basis replacement of insulators with resistance graded (RG) porcelain insulators or with silicone polymer ones will increase reliability and reduce maintenance cost.

3.7 REACTORS OR REACTOR BANKS

Air core dry type reactors rarely need to be replaced or repaired and in general have a long service life. However operating environment and service duty, especially prolonged overloading, can have an impact on total service life. A through fault could create suspicion of physical damage such as flash marks or unusual noise. The impedance can be checked to confirm winding integrity and a DC High Pot test can be performed to test insulation capability. A check of the impedance may not fully guarantee the integrity of the windings; especially if a large number of parallel windings are employed. Similarly, a DC resistance check may not detect a broken or open circuited conductor. The change in DC resistance could be very small if a large number of parallel conductors are used to achieve current carrying capacity.

In the case of a dry type air core reactor a High Pot test, whether performed on the factory or the field, will only provide a check on the dielectric capacity of the support insulators; insulation to ground.

Typically two styles of air core dry type reactors are used in an air insulated substation, slotted open coil and encapsulated reactors. Slotted open coil and encapsulated reactors have different points to examine. Slotted open coil reactors will make more audible noise than when installed as new. The amount of sound and vibration may indicate turn to turn failure. Typically visual inspection for flash marks or excessive corona at night indicates the need for maintenance or replacement. Encapsulated reactors last as long as the fiberglass resin and epoxy pint protect the reactor from UV sunlight. Worn fiberglass will lead to insulation break down or failure. If no physical damage has occurred encapsulated air core reactors can be recondition by most manufacturers.

Air core reactor needs to be inspected for visible creaks in mounting hardware, suspension insulators and suspension springs. Any physical damage must be replaced.

The magnetic field, when crossing the winding of the reactor, generates electromagnetic forces. Further, electromagnetic forces are acting on the electrical leads to the reactor and on the spider arms if loaded with current. All of these forces are proportional to the square of the current. In case of single frequency AC current the forces are oscillating with twice the electrical frequency. The oscillatory forces on the winding cause the reactor to vibrate in the axial and in the radial direction. The winding vibrations are further transmitted to reactor components mechanically linked with the winding (spiders, support insulators, support columns, etc.). The extent to which vibrations are initiated depends on the reactor's power rating. While high MVAr shunt and TC reactors may experience noticeable vibrations, other type of reactors, such as current limiting, damping and filter reactors are practically free from vibrations.

The vibrations may cause loosening of bolts and adjacent elements of the reactor and of its support structure if bolts are not properly tightened.

Further, the vibrations of the surface of the apparatus generate acoustic noise which is emitted by the reactor. This noise is tonal in nature and is subject to change with the reactor's load current. However, noticeable variations from the typical noise pattern (e.g. rattling sound) may be an indication of loose parts.

Large post mounted reactors may experience some minor settling during service which can cause hairline cracks at some locations of the reactor, in particular between spider arms and end spacers of the winding and between winding terminations and the adjacent winding end turn. Hairline cracks found during routine maintenance inspection are therefore no sign of performance abnormalities. In case of doubts on cracks which are more pronounced, notify the manufacturer.

Some installations are located in areas of high urban industrial, or ocean based pollution.

Under such adverse operating environments tracking could occur on the surface of an AC-stressed reactor winding. If such conditions are known prior to reactor manufacturing and the voltage drop across the reactors is significant, an anti-tracking coating is applied on the winding surface. The material used for this coating is a single-component low temperature curing silicone elastomer having special hydrophobic properties to prevent water filming on the winding surface. Pollution shields mounted over and/or around the reactors may also be employed.

As a prudent precaution it is recommended to inspect the units occasionally during operation. This may be done at a safe distance in the vicinity of the units.

For large unit-power reactors such as shunt or TC reactors, attention should be paid from time to time to the reactor sound characteristics. - Noticeable variations from the typical noise pattern (e.g. rattling sound) may be an indication of parts which might have become loose. In this case, the reactor and all fastening devices should be inspected and checked for tightness during the next scheduled outage.

In adverse environments, the reactor surfaces should be randomly checked for black "tracking“ marks. If such marks are detected, the reactor should be closely examined during the next scheduled outage. Pictures should be taken and sent to the manufacturer to illustrate the extent of tracking.

3.8 CAPACITORS

The life expectation of a capacitor bank is dependent on the bank’s operation history. As capacitor banks age there is a probability of increased failures due to can rupture, failure of more than one element in a can due to short circuit, gas build-up and leaks which can compromise the dielectric capability of the unit. In the event of can failure, individual units can be purchased to replace the failed can (s) and the bank will return to service. This however will not prevent other capacitor cans from failing. The only way to improve reliability is to economically replace cans or replace externally fused banks that have become problematic with improved technology.

An aggressive program may require replacement of the existing externally fused capacitor bank with fuseless or internally fused capacitor bank. Such a change might be initiated by safety concerns associated with externally fused capacitor banks (exploding fuses or ruptured cans) and also by improved and available technology. Bearing in mind that one of the major advantages of using the fuseless alternative for HV installation instead of external fusing is the elimination of a fault creating source, the external fuse itself. For MV installations, replacement with internally fused banks is preferred as this allows isolation of failed elements; hence the capacitor unit and bank can be kept in service longer.

DGA and Oil temperature measurement are applied to capacitors condition assessment.

Insulation paper of capacitors is gradually decomposed by aging thermal deterioration. During decomposition, CO, CO2, H2 and C2H2 generate and dissolve into insulation oil.. Therefore, CO, CO2, H2 and C2H2 gases are detected by DGA.

Dielectric losses for capacitor banks may increase with aging. Increasing dielectric losses cause heat runaway and leads to breakdown. Therefore, temperature measurements of the dielectric fluid in tanks of capacitors is an effective method to check condition.

3.9 ARRESTERS

The proper placement of arresters in a substation can significantly increase the life of an existing substation. Over time events such as routine switching, fault clearing and lightning can eat away at equipment insulation. To prevent insulation failure or flash over arresters should be liberally applied. There are many guides and philosophies but all paths for a transient to enter the high side or low side buses of the station need to be covered. Sufficient protective margin should be selected to protect substation insulation. Examples can be found at:

IEC 60099-1 (1999-12)	Surge arresters - Part 1: Non-linear resistor type gapped surge arresters for a.c. systems
IEC 60099-4 (2004-05)	Surge arresters - Part 4: Metal-oxide surge arresters without gaps for a.c. systems
IEC 60099-5 (2000-03)	Surge arresters - Part 5: Selection and application recommendations
IEC 60071-1 (2006-01)	Insulation co-ordination – Part 1: Definitions, principles, and rules
IEC 60071-2 (1996-12)	Insulation co-ordination – Part 2: Application guide

IEEE C62.22.1-2003	IEEE Guide for the Connection of Surge Arresters to Protect Insulated, Shielded Electric Power Cable Systems
IEEE 1313.1- 2002	IEEE Standard for Insulation Coordination - Definitions, Principles and Rules
IEEE 1313.2-2005	IEEE Guide for the Application of Insulation Coordination
IEEE C62.11-2005	Standard for Metal oxide surge arresters for A.C power circuit (greater than 1kV)

Some utilities are still using rod and pipe gaps for overvoltage protection of transformers. These gaps provide only limited overvoltage protection and, when combined with aging and increased loading of transformers creates a significant potential for a major transformer failure. An aggressive program for replacement of these gaps with metal-oxide surge arresters should be a priority for the utilities. Also, silicon carbide arresters should be replaced with metal oxide arresters to improve reliability and reduce arrester failure. A substation infrared scan as part of a maintenance program can spot a condition such as low voltage turn on. Any arresters that scan 10 K above ambient should be considered for replacement.

3.10 GROUNDING RESISTORS

Grounding resistors should be checked with an ohmmeter for continuity and impedance value. All connections should be torqued to manufacturer's standards. All insulators and cage containers should be inspected for holes or cracks. Repair or replacement is necessary to properly limit current. Ground resisters are used for a variety of purposes and should not be over looked as minor equipment.

3.11 POWER CABLES AND JOINTS

Condition assessments should include cables and duct lines entering the substation site and should consider the following issues:

3.11.1 GENERAL

Collecting important data of cable and accessories such as, type, manufacturer, age, load, behavior in practice regarding defects, etc is important to diagnosis cables and accessories. The combination of visual inspection and data analysis provides optimal information for condition assessment.

Visual inspection is generally carried out to confirm condition of cables and joints as follows.

- Are the cables and duct line routes accessible?
- Are the routes sufficiently segregated to avoid mutual heating problems and to permit excavation and work on one circuit with adjacent cables in service?
- What is the condition of the cables? Are they damaged, corroded, overheated, and leaking?
- What is the condition of duct lines? Are they damaged, blocked, affected by subsidence? Subsidence can cause a duct to shear and leave the duct offset either side of the break.
- Are the cables oil filled? This is a further fuel risk.
- Do the duct materials contain asbestos?
- Are the cables adequately supported on the ground, on cable trays or brackets?
- Are the cables adequately clamped to prevent undue movement and provide support to vertical sections? Are the clamps of the correct type to hold the cables firm without cutting into the sheath?
- Are the cable sheaths all earthed?
- What is the condition of the cable terminations?
- Are all the cable openings fire stopped?
- Are all ducts sealed at the entry point?
- Are the cable routes and locations properly documented 'as installed 'within the substation? This is a vital requirement because of the congestion of cables entering a substation but is often overlooked or poorly done.
- Is there too much congestion of cables under switchgear or in cable chases behind switchgear? This is often a safety-related issue for staff working on one cable ' buried

‘ in a mass of others.

Power cables are operated closer and closer to their designed parameters due to increased demands on utilities to increase efficiency.

Under these circumstances monitoring and periodical testing and analysis of power cables is essential to assess their condition and to evaluate their available useful life.

Most common causes of power cable failure/degradation are external mechanical damage, overheating, moisture penetration, poor accessory installation, etc. All of these will cause electrical failure of the primary cable insulation.

Overheating of cables accelerates the aging process and can lead to cable or core movement beyond the design parameters of the system. As paper insulated cables age due to overheating, they become quite fragile when they are exposed to the high/very high temperature.. In addition, mechanical impact, or an attempted movement, may be sufficient to crack the increasingly delicate paper insulation layers and cause failure. The newer XLPE insulated cables also suffer problems when overheated eventually resulting in a breakdown of the polymer chains. With the insulation at any one of these stages of deterioration, any additional stresses imposed by voltage peaks, impulses, and spikes will initiate the breakdown of the entire thickness of insulation.

Deterioration of the primary insulation is the most severe type of aging damage, but the most common aging damage occurs to the outer parts of the cable, as they are in contact with the external environment.

For the polymeric sheathing materials, such factors as UV radiation and chemical reactions, are the most significant, while for the metallic layers, corrosion and electrolytic action are a danger. The breakdown of the external cable protection then leads to damaging effects onto the primary insulation and eventual cable failure. Degradation by UV radiation will not usually occur if sheath is black color. Corrosion of metal sheath is not quite common unless you have DC in the neighborhood.

When a substantial level of PD appears on the cable insulation, the XLPE cable may breakdown and eventually fail.

It is important that an appropriate assessment shall examine in accordance with the characteristics of cables and the differences of laying method of cables.

Table 3.5. shows characteristics of cables and Table 3.6. shows the comparison laying methods of cables.

Table 3.5. - Characteristics of Cables

Type of Cable	Insulator Material	Characteristics
XLPE	XLPE	Low impact on environment, no need of secondary equipment, Large transmission capacity, Small dielectric losses , Difficult to diagnose
Oil Filled	Insulation paper & Oil	High reliability for long-term use, Easy to diagnose, Larger dielectric losses, Maintenance required

Table 3.6. - Comparison Laying Methods of Cables

Laying Method	Characteristics
Direct burying	Low investment costs, Short installation period, More vulnerable to damage, Difficulty in replacement, installation of additional circuit and withdrawing
Ducts	Easier maintenance, replacement, installation of additional circuit and withdrawing, Relatively high investment costs, Limitation of span length
Tunnel	Best for multiple laying, Easiest maintenance, Easy to control temperature of cable, Highest investment costs, Long installation period

Traditionally, field diagnosis was performed using DC voltage, which has been effective for oil-impregnated paper insulated cables. However, with the introduction of solid-dielectric insulated cables such as XLPE it became evident that the results of the DC field testing of XLPE insulated cables were not satisfactory. Gross on-site damage of cables and major jointing or termination errors were not always identified. In addition, breakdown and damage have occurred in apparently sound accessories that made it necessary to replace the cables.

The criteria used to select potential testing methods can be summarized as follows:

- The ability to detect defects in the insulation that will be detrimental to the cable under service conditions without creating new defects or causing aging,
- The complexity and practicality of the testing method,
- The commercial availability and costs of testing equipment,

Power frequency AC testing reflects service conditions more closely by producing realistic capacitive voltage distribution and voltage levels. In addition to withstand testing, AC excitation also makes it possible to perform broader partial discharge (PD) diagnostic testing. The drawback of AC testing is the large output that is required from conventional portable transformers. This is due to the high capacitive current generated by cables. In such case, Very Low Frequency (VLF) AC testing or DC testing are applied.

Different condition assessment techniques are applied to Oil Filled cables and XLPE cables.

3.11.2 OIL FILLED CABLES

Oil Filled cables have more than 80 years field experience, and have a proven high reliability for long-term use from operation historical perspective.

Diagnostic technologies for condition assessment have been developed for a long time, and some technologies have been established and applied for practical use in the field.

3.11.2.1Dissolved Gas Analysis (DGA)

DGA indicate internal abnormality such as local overheating, partial discharge.

Table 3.7. shows an example of DGA criteria in Japan.

Criteria are different from transformer's one due to a structure difference and electrical field design difference.

Table 3.7. - Example of DGA Criteria in Japan

Dissolved Gas	Criterion	Remarks
H2 (Hydrogen)	500 ppm	• H2: Corona discharge • C2H2: Arc discharge • CO, CO2: Local heat of Insulation material • CH4, C2H6, C3H8: Low temperature decomposition of oil • C2H4, C3H6: High temperature decomposition of oil
C2H2 (Acetylene)	TRACE	
CO (Carbon Oxide)	100 ppm	
CO2 (Carbon Dioxide)	1,000 ppm	
CH4 (Methane)	200 ppm	
C2H6 (Ethan)	200 ppm	
C2H4 (Ethylene)	200 ppm	
C3H8 (Propane)	200 ppm	
C3H6 (Propylene)	200 ppm	
TCG (Total Combustible Gas)	1,500 ppm	Overall analysis of total combustible gas

3.11.2.2Insulation Oil Tests

Insulation oil tests are major assessment method for oil filled cables.

Table 3.8. shows an example of insulation oil tests criteria in Japan.

Table 3.8. - Example of Insulation Oil Tests Criteria in Japan

Test Items	Criterion	Remarks
Dielectric Breakdown	-----	Criterion depends on system voltage Insulation deterioration & contamination
Volume Resistively	10^{13} Ohm cm	Insulation deterioration & contamination
Dielectric dispassion factor	2%	Insulation deterioration & contamination
Acid Value	0.02 KOHmg/g	Chemical deterioration
Moisture in oil	10 ppm	Seal performance & Insulation deterioration

3.11.3 XLPE CABLES

XLPE cable has approximately 40 years field experience, and has a lot of advantages such as low impact on environment (less oil) and easy maintenance compare than oil filled cable as indicated Table 3.11.1.

The use of XLPE cable has been increasing rapidly since 1970's. In some parts of the world (i.e. Europe or Japan) XLPE cables cover up to 80% of T&D cable network.

As for diagnostic technologies for condition assessment, many research and development have been conducted recently, but only few effective methods have been applied to practical field so far.

DC leakage current measurement and dielectric spectroscopy (dissipation factor measurement method) can be applied for medium voltage cables to detect water-tree degradation.

Partial discharge measurement is applied at the commissioning test. This test is difficult to be applied during field operation due to possible background noise.

Recently other diagnostic techniques became available in the field.

Some of these techniques are:

- Ultrasonic detection of PD in cable accessories, (sensitivity of Ultrasonic detection might be affected by external noise.)
- Direct, capacitive or inductive couplers (sensors) installed on or near the cable accessory to locate and measure PD in cable splices and terminations,

New technologies such silicone based fluid injection can extend operating life of power cables. The silicone based restoration fluid is injected into cables at a transformer or other termination point. It diffuses into the insulation, purges water and inhibits the growth of future water trees. It prolongs cable life by a significant number of years and increases dielectric strength.

Other technologies that have been developed include "DC Superposition Method"," AC Superposition Method" and "Residual Charge Method". See Reference [2].

3.12 STATION SERVICES EQUIPMENT

Condition of the AC and DC station services equipment plays a vital role in the safe and reliable operation of substations. Output of power transformers, proper operation of critical protection schemes, etc. depend on this equipment.

The most important components of AC & DC station services are: the station services transformers, automatic and/or manual AC & DC transfer schemes, battery chargers, batteries, and AC & DC distribution panels.

Station services transformers range from 75 kVA to more than 1000 kVA. Most of the station services transformers have no load tap changers and have no forced cooling. Regular oil sampling is sufficient to provide information on the condition of these transformers. A major role in proper functioning of these transformers is held by the high voltage fuses installed on the primary of these transformers. Visual inspection and thermo vision will provide information on the condition of these fuses.

Automatic transfer schemes comprise circuit breakers and a control scheme, which provides the transfer function when supply voltage disappears. Experience shows that automatic transfer schemes need periodic inspection and maintenance in order to perform their function. Even with this periodic maintenance the automatic transfer function may not be performing properly due to mechanical problems with the circuit breakers of the transfer scheme. Utilities should assess and evaluate the alternative of replacing aging automatic transfer schemes with automatic transfer schemes with emergency by-pass features or with simpler, more reliable manual transfer schemes.

DC batteries have to be checked periodically to make sure that they will perform their function when they are called upon to do so. Vast majority of DC batteries in substation are wet, flooded lead-acid batteries with an expected life span between 10 and 15 years.

The condition of a wet, flooded battery can be evaluated by established testing methods. A general rule is that when a wet, flooded battery has an actual output of less than 80% of its initial output the rate of decline of the battery is increasing and that the battery is close to its end of life.

If tests indicate that a wet, flooded battery is not able to hold the charge then this should trigger the assessment for replacement of the battery.

Some utilities have introduced Valve Regulated Lead Acid (VRLA) batteries as the emergency DC source in substations. It is a attractive alternative to the wet flooded battery due to its smaller foot print, no need for special ventilation and less maintenance. Operating experience however has shown that VRLA batteries have a much shorter life than the wet, flooded batteries. Some utilities reported that they had to replace VRLA batteries after ten years of operation.

Battery chargers are usually extremely reliable pieces of equipment. Their reliability relies on their simplicity and on the use of proven electronic components and rectifying schemes.

Utilities add over years loads to the DC system which were not considered during the initial design phase of the system (i.e. addition of high voltage breakers, disconnect switches, protections, inverters for supply of essential AC SS loads, etc.). A review and verification of the capability of the DC batteries in a station to carry the actual DC load is advisable whenever a significant load is added to the DC system.

3.13 PROTECTION & CONTROL SYSTEMS

Protection systems comprise relays, current transformers, voltage transformers, wiring and cabling, batteries and DC supply circuits, circuit breakers, and software.

Assessments of protection and control equipment is based on equipment type, equipment age and due system growth or substation expansion.

Protection systems are critical to the power system in a number of respects:

- System security.

- Reliability of supply.
- Safety of staff and public.
- Preventing major damage.
- Controlling Earth potential Rise.

Protection is a specialized engineering field. Consequently condition assessments should be carried out by persons qualified and experienced in this field.

Electromechanical type protective and control relays have been used for many years for the protection and control of substations. These relays have limited functionality and require larger panel space than the Intelligence Electronic Devices (IED's). With many electric utilities moving toward substation automation and integration, the electromechanical type equipment is replaced with a multi function IED's. The IED's can provide flexible relay settings, fault recording capabilities, metering, and alarm. The IED's have the capabilities to communicate with other relays and can be accessible by the protection and other engineers. To improve substation protection, operation and to simplify protection, control and metering schemes, the electromechanical type equipment have been replaced with new IED's.

Older relays become unreliable and have a high maintenance cost. Spare parts become unavailable. Replacing aged equipment will prevent an unnecessary generation loss due to equipment failure.

System growth may require substation expansion or equipment upgrade. The new additions may change the existing zones of protection that may require additional protective relays. New substations additions may require improvement in substation reliability by adding redundant protective relays. To meet system growth, protection and control equipment must be added or replaced with newer type equipment.

Modern technology has produced digitally based protection relays which have much shorter lives than the industry has been used to with previous electromechanical relays. The best of the current relays appear to have life spans of only 15 to 25 years with many being much shorter. Support for the relays in terms of spares and software may not even be available for this length of time. Thus the life of these relays will be half or less of the life span of most other equipment in the substation and replacement at least once during the life of the substation will be required. Therefore condition assessments will need to determine the expected life of relays as well as the remaining life for both old and new technologies.

Points to address in assessing protection systems are as follows:

- Is the concept design of the protection schemes in the substation satisfactory? Does it comply with policy requirements? Is there coverage for all faults? Is Back-up protection provided correctly?
- Are the relays and relay panels housed in a secure location, not subject to damage from power system failures?
- What is the condition of each relay or each relay type?

- What is the failure or defect history of each relay type represented in the substation?
- Has the functional testing and maintenance of the relays and complete systems been carried out correctly and on time?
- Are there suitable test links provided?
- Is the labeling of relays, test links and other components satisfactory?
- Are terminals and wiring terminations in good condition?
- Is the wiring insulation in satisfactory condition? Old insulation types such as cotton and vulcanized India rubber (VIR) will generally be in poor condition.
- Is there segregation of secondary circuits?
- If screened secondary cables are used, is the screen to earth connections correctly configured?
- Are the relay settings correct and is there engineering documentation in the substation as to the required settings? Are the CT and VT ratios to be used also documented?
- Software is a big issue. Are the software versions installed in each relay clearly documented and is the back up copies available, properly identified, and securely stored?

SCADA control systems and alarm systems should be assessed by people who are qualified and experienced in that field. Modern digital systems will have even shorter life spans than protection relays. A key requirement of SCADA systems is to be secure against false or spurious trip or close outputs.

Software is a critical issue here also. Correct documentation and back up of the software version installed and of any upgrades is essential. Condition assessments should cover this issue.

3.14 EARTHING GRID

The functions of a substation earthing system are:

- To provide a safe and sound return path for fault currents.
- To control Earth Potential Rise during system faults to an acceptable level.
- To provide lightning protection.

The earthing grid is fundamental for protection of all insulation in a substation, limiting neutral shift and earth potential rise. Nuisance failures of low voltage communications, electronics and relays can be linked to earth grid failure. Integrity of the earthing grid is not only necessary for protection of the equipment but for achieving safe touch and step potentials for personnel protection. This is not limited to the operating personnel within the substation but also concerns the possible threat to the neighborhood. Due to the strong relation to health and safety regulations there is a variety of standards with national additions describing the properties of earthing systems in substations. The following table gives an illustrative choice and should be counterchecked for national applicability:

IEC 61936-1 (2002-10)	Power installations exceeding 1 kV a.c. - Part 1: Common rules.
HD 637 S1 (1999-05)	Power installations exceeding 1 kV a.c.
IEEE 80-2000	Guide for safety in AC substation Grounding

Items to address in assessing the earthing system in a substation are:

- Does the installation comply with the drawing? In particular, have there been any additions or changes to the substation which have been done without the design process being updated.
- Have fault levels changed from what was the basis of the design.
- Have protection clearing times changed.
- Has the type or configuration of fencing or gates changed?
- Has pipe work and plumbing been installed in accordance with the original design or has anything changed.
- Have there been any changes to the surroundings. E.g. new buildings or structures near the substation. In particular, pools.
- What is the condition of electrodes and connections? Is there a corrosion problem?
- Are all earth mats at operator positions installed and correctly bonded, if national regulations require those?
- Is the building structure bonded to the earth grid?
- Are all cable sheaths bonded to the earth grid?
- Is all equipment correctly bonded to the earth grid?
- Is there a properly documented drawing showing all the earthing requirements for the specific substation.

More and more theft situations of earthing system copper are reported by utilities. Periodic visual inspection of presence of above ground earthing conductors has to be performed and missing earthing conductors replaced.

The above items should be verified by inspection first. Then, in most cases an injection test will be required to prove by measurement that the earthing installation is performing as designed. Each connection and string in the earthing grid should be tested for impedance and high current ability. Failure of a connection or increased resistance should be compared to previous readings to confirm degradation.

A typical method can be to inject 200 to 300 amps of AC current from the connection to be tested to a known location on the earthing grid and measuring the voltage drop. Any voltage drop value greater than 1.5 Volts is considered bad. Any voltage drop reading greater than 1 Volt but less than 1.5 Volts is suspect. After all connection measurements are made a percentage of connection readings above 1.5 Volts will require an earthing grid overlay. A utility may use a formula of failures plus suspect readings above 20 % as a realistic criterion for earthing grid improvement. Note that this is an illustrative example: required methods vary with network configuration and national regulations.

3.15 Substation Fence

General condition of substation fences can be assessed based on their location and their purpose. Many fences are decorative in nature and require more attention and maintenance. Support poles must be plum and capable of supporting fence loads for all design conditions. Corrosion of posts should be repaired and inhibited against further rust. Fences shall be checked regularly for excessive gaps between the bottom of the fence and finish grade. Large gaps have to be fixed to prevent animals, unauthorized personnel and children of gaining access into a station. These gaps have to be filled and any other holes should be repaired. Connections to the ground grid and bonding straps should be inspected to prevent touch potential hazard to the public. Integrity of the station fence grounding grid should also be checked periodically. It is not unusual to find that thieves have removed entire pieces of fence grounding. To mitigate this situation, replacement of copper conductors with aluminum or aluminum clad steel wire is an alternative.

3.16 Site Issues

A condition assessment should include the substation site and cover the following issues:

- Is the site of adequate size for the substation installed on it?
- Is there satisfactory access for loaders, cranes, vehicles, and equipment? In particular, access for transformer floats should be level, provide for unloading on site, not in the street, provides adequate road turning radius, and provide adequate crane height.
- Have there been any changes that affect access?
- Are the ownership and tenure of the site satisfactory? Freehold title is the preferred tenure method. Leases and easements are less satisfactory and if they are used should not be limited in time; even 99-year leases run out.
- Is there satisfactory access for cables, duct lines, and overhead lines?
- Is there a buffer zone around the substation?
- Are security issues adequately covered?
- Are there noise issues?
- Are there nuisance to neighbors issues?
- Are there intrusive lighting issues?
- Are the ground conditions stable?
- Are there drainage or subsidence issues?
- Is the site clean, tidy, and adequately landscaped, grass mowed, etc?
- Are there any risks imposed by adjacent properties, such as fuel storage, petrol stations, and trees?
- Is the site in a flood plain and if so is it sufficiently elevated?
- Is the site at risk from bushfires?

3.17 Buildings

There is a wide range of building types used in substations, from the large fully enclosed building in a city business district housing all equipment, to the control building in an outdoor type substation. Even in outdoor substations the building will house critical protection and control equipment, without which the substation cannot operate. The design and condition of the building can therefore be a critical item in the assessment of the substation (it is often overlooked).

Points to address in assessing a substation building are as follows:

- What type of building is it? Reinforced concrete, brick or block work, steel framed, steel clad, light construction, etc.
- What is the design life of the building and its current age?
- What type of foundations are installed and what are the ground conditions? Is it built on rock or on piers to rock or solid ground? If not it may be subject to movement, subsidence, cracking, or even collapse.
- Is the construction strong enough to withstand stress, e.g. from earthquake, impact, pressure load from electrical faults and similar?
- Is the structural design such that a failure of one part of the building will not cause a cascade failure of other parts?
- Condition of the structure. Is there evidence of subsidence, movement, cracking, damage?
- Roof. A key requirement for a substation is that the roof should prevent water entry into any electrical area as this could cause failure of the electrical equipment.
  - Type of roof e.g. concrete, steel sheet, fiber cement sheet, aluminum sheet, tiled.
    - A concrete slab roof is sound provided it is tied in to the wall structure. However, if it depends on a membrane for waterproofing this is poor as the membrane has limited life.
    - A Pre-cast Beam roof will usually not be tied into the wall structure and will depend even more on a membrane for waterproofing.
    - A Fiber Cement sheet roof will be easily damaged by large hailstones and any damage will let water in.
    - A Tiled roof will also be damaged by large hailstones or similar objects.
    - A Sheet Steel roof if well constructed will be resistant to damage and water ingress but at best will require replacement at about 25 years.
  - Structure of roof. E.g. Steel framed, Timber framed.
    - A Timber framed roof will be a fire risk, from internal equipment failure, from external sources such as a transformer fire or a bushfire, or even from wiring in the roof space. Once fire takes hold in the roof space it will generally burn out completely, collapse, and render the whole substation unusable. Fire rated ceilings provide only partial protection.
    - A Steel Framed roof is a good option for a substation provided there is no fuel source below it or nearby. Exposed Steel framing does not have a fire rating.
    - The roof structure should be adequately tied down to resist extreme wind loadings.
  - Gutters and down pipes.

- All roofs should overhang the walls. Internal gutters will invariably lead to water ingress as they will block up with debris or hail and flood. All gutters should be external to the walls so that overflow will not let water into the building.
- Similarly, all down pipes should be external. Internal down pipes will inevitably block up or leak, and let water into the building.

The most suitable arrangement is to have no roof gutters but to use ground level dish drains below the roof edges. This avoids the inevitable build up of leaves and debris in roof gutters.

3.18 FIRE PROTECTION SYSTEMS

Fire is usually a significant issue in regard to the design and condition of a substation. This is due to the presence of large quantities of insulating oil and, sometimes of other flammable materials. Total loss of the substation, extended supply interruptions, risk to the safety of people, and spread of fire to adjacent premises is possible unless adequate control measures are taken.

Substations are designed to cater for the loss of any one of the major equipment without causing loss of supply. Containment of a fire to the one equipment is therefore vital in preventing total loss of the substation.

Fire protection in substations must be evaluated specifically in transformer areas and the control room. A fire in the control room may result in the loss of the entire substation. Modifications to the control room may be required to prevent fire initiation and to provide means to protect against fire.

Once again, the assessment of the risks associated with the substation and the need for remedial work must include an assessment of design features as well as an assessment of the condition of the substation.

Following are the key issues to be addressed in an assessment with respect to fire:

- Where are the possible sources of fire:
  - Failure of electrical equipment, particularly oil filled equipment.
  - Hot connections, particularly heavy current carrying connections.
  - Work activities such as welding.
  - Fires in adjacent premises.
  - Bushfires.
- What fuel is present and where is it, e.g.
  - Oil in transformers and switchgear.
  - Oil stored on site such as in drums.
  - Bituminous insulating compounds in bus bars, end boxes, CT chambers.
  - Oil in capacitors.
  - Cable insulation and sheathing such as PVC and XLPE.

  - Any timber in the building structure or equipment. Timber framed roofs are particularly bad as there is usually no segregation in the roof space and it is generally impossible to fight a fire in the roof space.
  - Materials or waste temporarily stored on site.
  - Vegetation. Often architectural considerations lead to landscaping with vegetation too close to the building.
  - Leaves in roof gutters.
  - Timber fences.
- Fire Segregation. Is there adequate segregation between items of equipment to prevent a fire in one item spreading to damage adjacent equipment or buildings within the substation? Radiant heat can damage or set alight adjacent equipment and buildings.
  - Adequate separation between transformers or fire walls between transformers.
  - Switchgear rooms and similar separated into fire segregated rooms.
  - Fire stopping of openings between compartments in the building. Often overlooked is the need for fire stopping of cable openings between floors.
  - Cable risers require particular attention because of the fast rate of fire spread vertically. They should be fire stopped at every floor and / or fitted with sprinklers.
  - Coating of cables in chases and similar.
  - No windows or openings facing major fire sources such as transformers.
  - Basements in which large quantities of power and P&C cables are installed generally can not be segregated into individual spaces and should be fitted with sprinkler systems.
  - Bundling around transformers and similar items to prevent spread of burning oil.
- Escape and Rescue: Two paths of escape are necessary from any part of the substation so that escape is still possible if one path is blocked by fire or failed equipment. Escape routes and passageways should be clear, well marked, signed, lit, and unencumbered at all times.
- Sealing of the substation or building against vermin is important as rats can chew insulation off cables, causing extensive damage, causing faults and fires.
- Active Fire Suppression systems. These include water sprinklers, water deluge systems, and gas systems. Condition assessments should include inspection and testing of these systems and verification of their maintenance and testing records. Fire Extinguishers should be within use-by date. Further, a design assessment of whether fire suppression is required where not already installed should be carried out.
- Fire Detection and Alarm systems. Similarly an assessment should be made of the suitability and condition of alarm systems. Are they working?

Housekeeping is vitally important to prevent the build up of items or waste in a substation which could provide additional fuel, start a fire, obstruct escape or rescue, or obstruct fire fighting actions. Another housekeeping issue is to make sure that fire doors are not chocked open as often happens.

It should be noted that all fire related measures need to take into account local regulations and legislations, which may differ from country to country.

3.19 STRUCTURES AND FOUNDATIONS

Substation foundations and structures should be periodically evaluated in terms of their existing condition, current state of repair, and integrity. Following ranking of the condition of these elements could be used:

Good Condition – the element is intact, structurally sound, and performing its intended purpose and there are few or no cosmetic imperfections. There is no need for repair.

Fair Condition – the element shows early signs of wear, failure, or deterioration, although it is generally structurally sound and performing its intended purpose. Examples of fair condition of an element would be crumbling of concrete surfaces or sings of rust on steel structures,

Poor Condition – the element no longer performs its intended purpose, It is missing or it shows signs of imminent failure or breakdown. Such a condition of an element requires major repair or replacement. Examples of a poor condition of an element is unusual and excessive deflection of a steel structure or deterioration of a foundation to the level that rebars are exposed and are visibly rusting,

Critical Condition – the element shows advanced deterioration that will result in its failure if not corrected within two years, and/or the element poses a threat to the health and/or safety of the user. Example of a critical deficiency would be tilting of foundations due to excessive loading or poor drainage conditions,

3.20 DOCUMENTATION

The proper documentation is part of the asset, not just an optional extra. The documentation of all aspects of the substation is vital for many reasons:

- Maintenance.
- Safety.
- Refurbishment and additions.
- Identification of problems during operation,
- Repair.

However, documentation is often poor and incomplete.

Condition assessments should include a review of all documentation for the substation. This should include the following:

- Complete and accurate drawings showing all aspects of the substation as designed and as built.

- Operating Manual for the substation.
- Operating Instructions for all items of equipment.
- An Inventory of equipment.
- Age of all items of equipment.
- Anticipated service life of all items of equipment.
- Maintenance requirements and instructions for all items.
- Protection and control circuit functions.
- Relay setting instructions.
- Ratings of all equipment and cables.
- Loading of all equipment and cables.
- Fault levels, both design levels and actual levels.
- Records of failures, defects and problems.
- The intended service life of the substation.
- Tenure documents for the site and any associated easements.
- Known or possible infrastructure projects which could affect the substation. E.g. expressways, railways.
- Test records
- Maintenance records.
- Inspection records.

All documentation should be indexed, up to date, and accessible,

3.21 STRUCTURING OF COMPONENT CONDITION INFORMATION

Whatever information is collected, it has to be qualified by an appropriate header in order to allow evaluation and generating reports in many ways. From a practical point of view this header should follow the information hierarchy as it is expressed by the ISO-layer model (Figure 3.3).

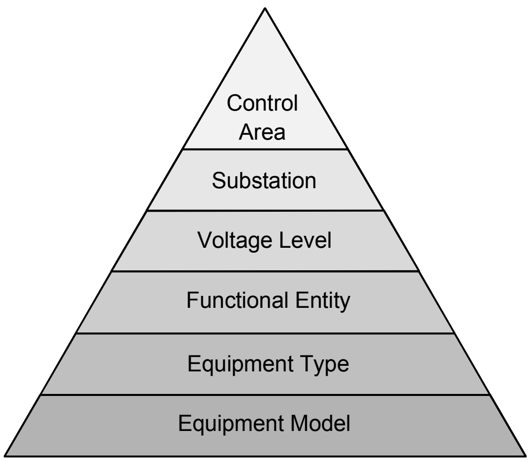


Figure 3.3. Substation information designation

Following a top-bottom approach, in the case of substation information this may be:

- Designation of the control area to describe the interconnected network region.
- Name of the individual substation to provide a layer, where all information concerning the substation as an entire entity can be stored (GPS-position, environmental information, property data, shared buildings, location of closest hospital, emergency evacuation instructions, etc.).
- Voltage level as a designator to collect all equipment, which is in connection with the same technical quality of circuitry.
- Functional entity to distinguish by function. This may be done bay-wise and/or by separating high-voltage primary-, control-, protection- and auxiliary-equipment.
- Naming of the equipment type can follow the outlines in the precedent sections.
- Designation of the equipment model and operating designation number (unique designation throughout a utility given to each element installed in the utilities substations) allows to identify the individual component, naming manufacturer, model-name, serial-number, date of installation etc.

Having structured the condition report data in such a way, queries of all kind can be performed. Both the sums of reports concerning one substation or the sum of reports concerning a specific model of equipment can be viewed. Condition assessment requires a second component, which lays the basis for decision-making: all the technical and operational information must be classified. The general process is depicted in Figure 3.4.

Classification uses all available information, which can be related to the statements of a single condition report, giving an overview on the overall condition of the substation or parts of it or giving an overview on condition of equipment of the same family or model to lead to an optimal decision. Related documents from standards and regulations, fault statistics and the asset data base can be linked. These services can be provided by a Knowledge Management Tool.

On the other hand weighting of facts depends on the asset management principles of the operating company. Usually performance indicators are given by the asset owner, describing a sustainable value of the assets, quality of supply and risk management. Superimposed are legal obligations given by society.

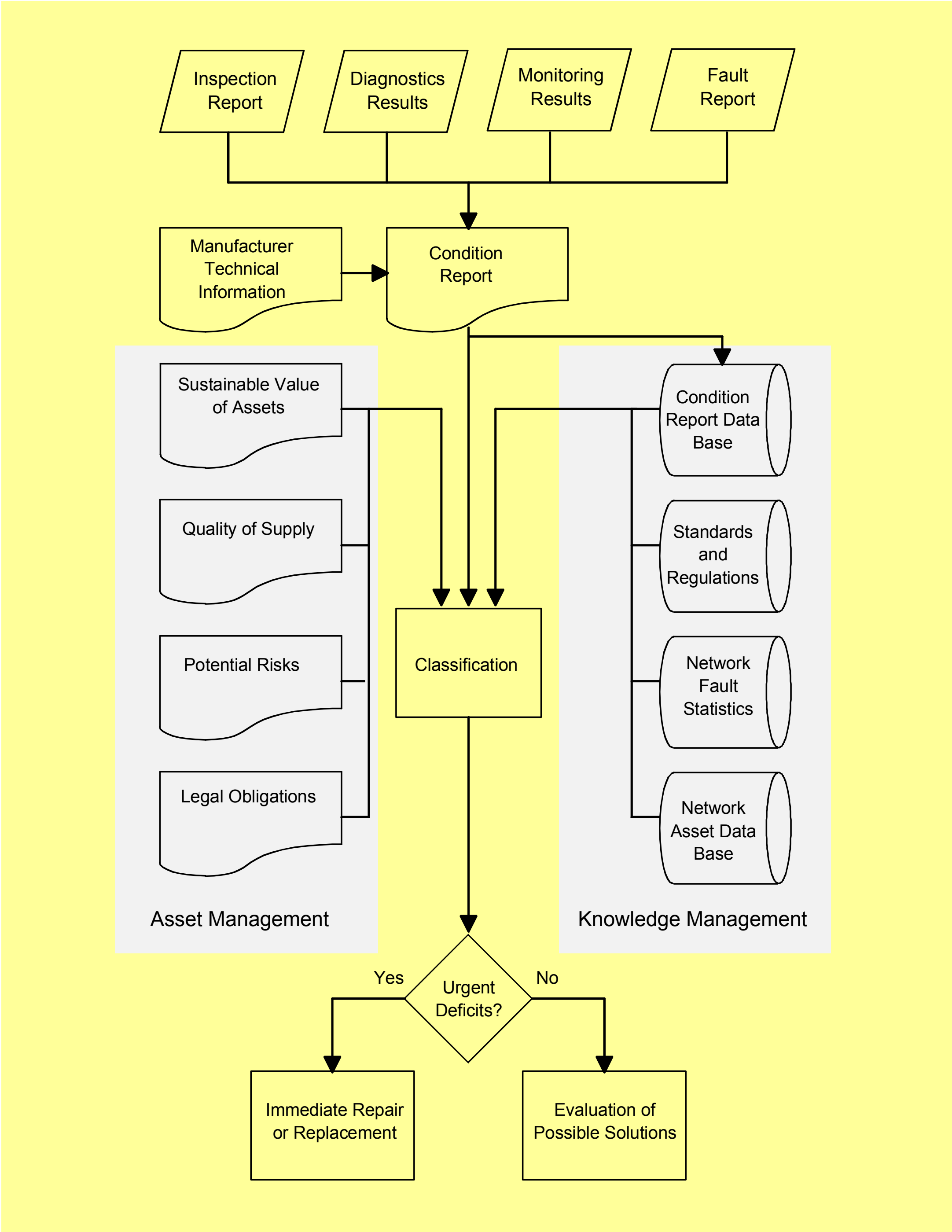


Figure 3.4. Classification Process

4 Possible Solutions

There are different possible solutions to choose. Many factors may have diverse influences:

- The available budgets. The amount of money is decisive to choose the solution.
- The company strategy
    - Voltage level
    - Maximum allowed risk
    - For some utilities capital expenditures can be more valuable than operational ones, or vice versa.
- The arrival of new technologies
- The equipment condition
- The way of working inherited

4.1 Do nothing at least for the moment

In a corrective maintenance strategy, replacement or repair is performed only if a failure occurs in the case of equipment where investment costs are low and a fault will have only minor consequences.

Some utilities are complaining about the increasing pressure of cost savings, therefore they have to set priorities and invest in replacement/refurbishment of the most critical equipment.

In this step, the company evaluates the substation condition, and then decides what to do.

This strategy will be mainly used in systems with lower voltages. Only severe failure on certain type of equipment will influence the procedure.

The expenditure in operation and maintenance will be low, but if a failure occurs the expenditure in operation could be very high.

4.2 Perform planned Maintenance on an existing equipment

There are different options to perform the maintenance, all of them are included under preventive maintenance (Figure 4.1), and this term refers to any activity that is designed to:

- Predict the beginning of component failure
- Detect a failure before it has an impact on the equipment function
- Repair or replace the equipment before failure occurs

It is possible to distinguish two features, an activity to be performed, and a frequency at which the activity is performed.

Preventive maintenance frequencies can be varied according to the deterioration and failure rates, the operating strategy, the cost of performing the activity and the penalty associated with asset failure. Decision models for timing of inspection, repair and replacement based on asset failure data can be useful.

Time based maintenance strategy featuring predefined interval rooted in empirical feedback, where components are replaced after a specified period of use, has been practised as the usual maintenance strategy in electrical power systems for many years. This approach generally produces satisfactory results. It will not, however, be the most cost-effective option in all cases, since the equipment will not usually remain in operation up to the end of the expected lifetime.

For some years, nevertheless, there has been an increasing shift away from time-based maintenance and towards <u>condition based maintenance</u>. Use of condition based maintenance allows expenditures to be targeted to the most critical equipment or those components requiring immediate repair/replacement. In addition maintenance actions are taken only when they are needed, reducing the unnecessary repair/replacement costs, and the system outages.

Condition based maintenance is driven by the technical condition of the equipment. Under this approach, all major parameters are considered in order to determine the technical condition with maximized accuracy. For this reason, detailed information via diagnostic methods or monitoring systems should be available. The analysis of the equipment behaviour under fault conditions is important to decide a correct maintenance plan.

Condition based maintenance can be qualified according to the parameter that is considered to be more important. Two new subtypes can be distinguished:

- Combination of the condition of the equipments with their importance in the grid and the risk level after failure. In this context, there are numerous different parameters to be considered, e.g.:
    - Unavailability of the substation
    - Failure rate of the equipment
    - Substation configuration
    - Interrupted energy
    - Kind of customers, social impact
- Combination of the condition of the equipments with the cost of the works and the financial impact in case of interruption in supply to customers.

Another approach to maintenance is <u>predictive maintenance</u>. It is based on the same criteria as condition based maintenance and it is designed to detect potential maintenance problems and stop them from happening.

Finally, another option is to improve the maintenance plan in order to extend equipment life, postponing the renewal of the equipment. There could be different reasons for choosing this approach:

- There are other priorities to renew.
- It requires an unacceptable down time for operation.
- The utility prefers to wait for a partial or total renewal of the substation, in order to save money, minimise down time, etc.

In this case, there are little capital expenditures but maintenance expenditures will increase.

In every case the utility needs to train their employees and to improve maintenance practices in order to decrease maintenance costs, Nowadays the problem is that maintenance budgets for substations are being reduced, and many utilities are losing experienced personnel. As a result, the utilities need expert assistance to help them assess the condition of equipment, train maintenance staff to perform inspections and train staff to use inspection data in a manner which drives maintenance decisions.

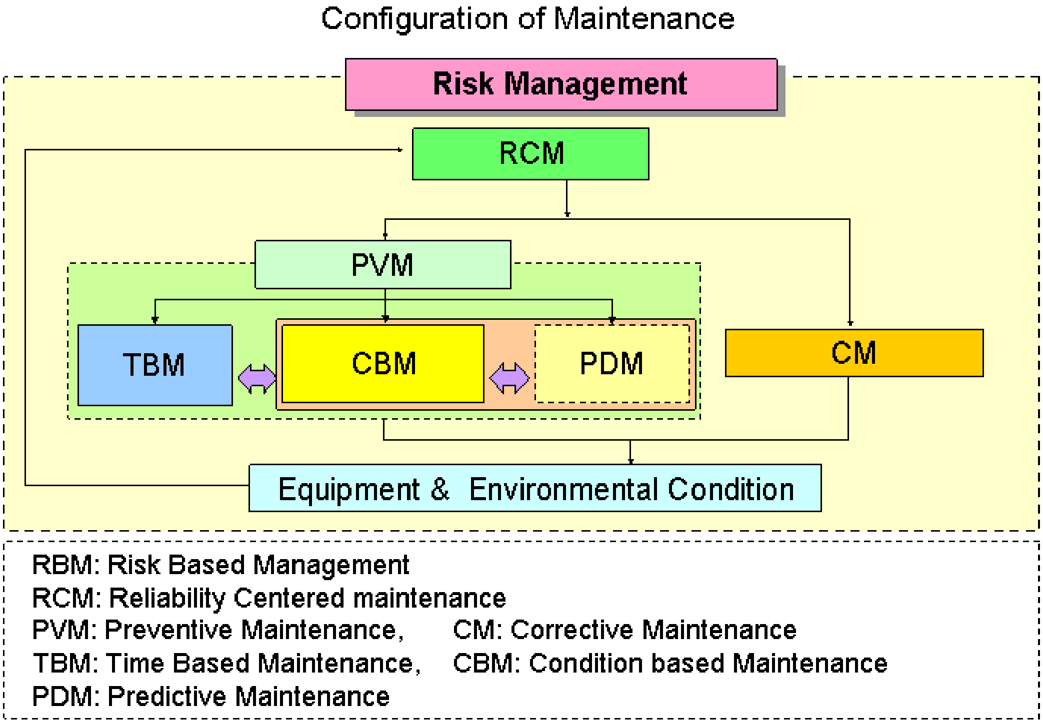


Figure 4.1 Configuration of maintenance.

4.3 REPLACE EQUIPMENT WISE

When the problem is located on a single piece of equipment:

- When any equipment (circuit breaker, measure transformer, switch, protection & control equipment) fails, the company has to replace it quickly, in order to restore supply. In this case, the cost is not important, the aim is to minimise downtime and to avoid blackout.
- The utility's strategy could include a renewal plan in order to replace an entire generation of equipment (due to obsolescence, defective generation etc). The company can plan the supply, installation and commissioning in order to reduce the corresponding expenditures for operation and maintenance:
  - Utilising existing shut-downs.
  - Doing other maintenance works at the same time.
  - Depending on the bus configuration (circuit breaker and a half, bypass switch) it is possible to minimise considerably the downtime.

This solution is the best option if the condition of the other equipment is adequate. However, if in a short period of time it is necessary to replace other equipment, the expenditures will be increased. From an operation point of view, it will need additional down time for installing and commissioning From an engineering point of view, it will generate several editions of the drawings, and construction and erection will be more expensive.

The condition of the equipment has to be determined, and the importance of the equipment for the network as a whole established, e.g. the influence of equipment failure on the reliability of supply. Both information inputs must be combined and evaluated in order to specify the optimum sequence of maintenance work for the individual device or to decide the equipment replacement.

4.4 PARTIAL RENEWAL OF THE SUBSTATION

Some examples for this approach are:

- Renewal of secondary systems (the primary equipment life expectancy is about double than secondary system).
- Migration to digital control systems.
- Renewal of auxiliary systems.

The supply, installation and commissioning of the equipment requires planning to ensure adequate integration with other site activities and to prevent areas of conflict occurring. The work can be divided into a number of easily managed work packages. To utilise existing shut-downs has the advantage to reduce downtime.

This option could be more expensive because it requires progressive modifications in order to obtain a total renewal of the substation and it is difficult to get a uniform solution.

4.5 TOTAL RENEWAL OF THE SUBSTATION

The condition of obsolescence of the substation can force the decision for a total renewal of the substation. There are two basic strategies:

- Remove and rebuilt everything.
- Progressive changes, one bay or a set of bays may be renewed keeping the other ones untouched.

The first one provides a uniform solution, less expensive than the progressive change since there is no specific cohabitation interface to be solved and a single installation and commissioning process is required.

The second one is the most common and requires setting up a migration strategy, defining the different steps to be followed to match the objectives.

The advantages of this method are:

- Adaptation to yearly budgets.
- Rapid installation of each bay keeping the voltage in the other bays.

As disadvantage it will require down time of the entire substation (depending on the bus bar configuration) for erection and commissioning.

If it is necessary the scope of the project can include the upgrading of the substation This could be done in two different ways:

1) Increase the capacity of the equipment. This solution refers to replacement of circuit breakers, conductors, transformers, etc.

2) Increase the nominal voltage of the substation. In this case conductors, bus bar, relays, control buildings remain, but other pieces of equipment have to be replaced, e.g. surge arresters, power and measuring transformers and switches.

5 Optimized Approach to the Renewal of Existing Air Insulated Substations

The preceding sections of this brochure have given an overview of the possible requirements for the renewal of a substation, have provided quite a lot of information for a systematic assessment of the substation's condition and have outlined the possible span of countermeasures to be taken. To give some information on factors, which are the drivers for finding the adequate and optimized solution is the purpose of this section.

As mentioned earlier there are numerous external factors aside the asset related internal requirements, which contribute to decision demand and decision making. Figure 5.1 depicts these factors, without claiming to be complete, and explains the way these factors interact.

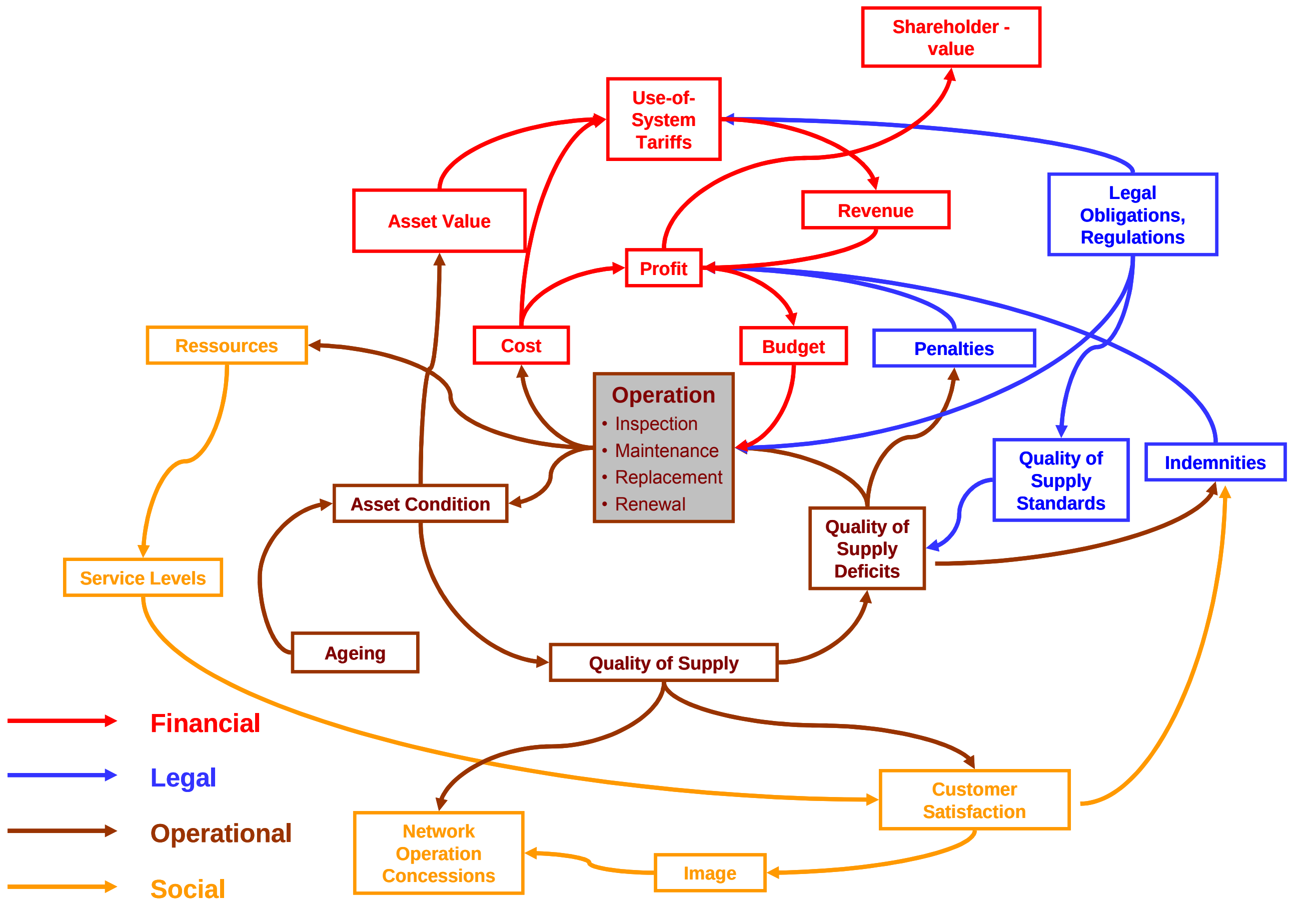


Figure 5.1. - Interacting Factors Related to Network Operation

Around the primary cycle of network operation, which determines cost, asset condition and quality of supply, there are other cycles in effect, which describe the influence on or coming from financial, social or legal factors. As a trivial example, inferior service levels or quality of supply may lead to indemnities, can damage the company's image and thus influence profits or can even set the network operation concession in danger.

In the end, the way to an optimized solution to network upgrading requirements has to take into account more than an asset condition related factors, which have broadly been discussed in section 3. Basically, the optimization process follows the principle qualitatively depicted in Figure 5.2.

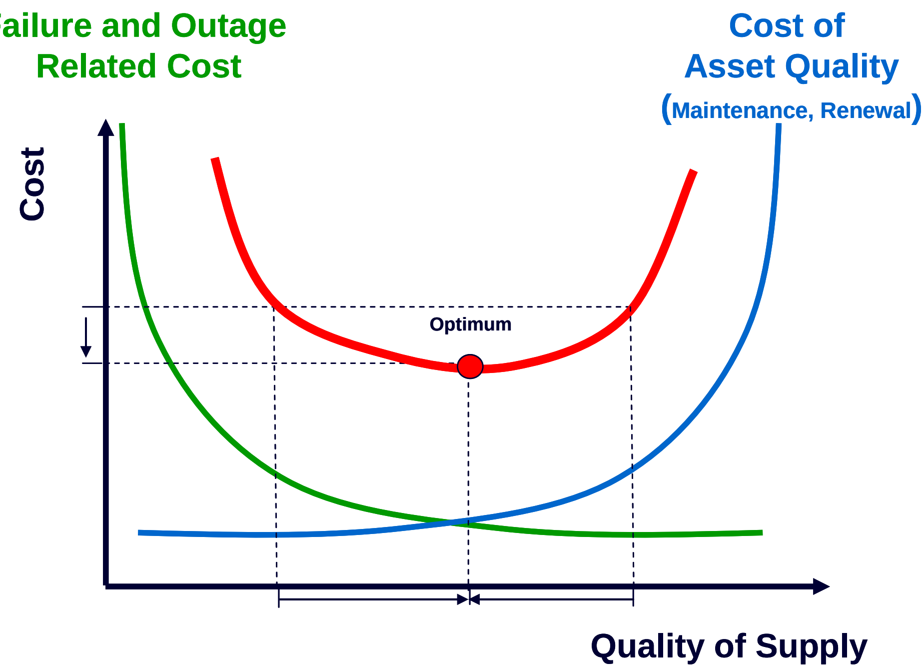


Figure 5.2: Simplified Optimization Principle

The optimized solution can be found at a minimum of cost taking into account all necessary effort for upgrading and all risk related cost. Evaluating the asset related cost is a routine task in asset planning, whereas taking into account of social and legal factors depends much on situational judgement or even on the company's ethic standards.

5.1 QUALITATIVE EVALUATION FOR SAFETY, ENVIRONMENT, COMMUNITY ACCEPTANCE, CUSTOMER SATISFACTION, BRAND NAME AND REGULATIONS

In evaluating the optimum solution one should consider both economical and non-economical factors, taking into account life cycle phases as described in IEC. While the economical factors could be easier to fit in a mathematical model, the characteristics and interpretation of the non-economical factors are more difficult to address and translate in an economical value. Thus, these values are more subjectively interpreted.

Some of the qualitative values are safety, environment, community acceptance, and company brand name. The weight given to these factors will depend on the particulars of the political and social environment of the utility.

This section attempts to describe the qualitative values and how to apply them in evaluating the optimum renewal solutions for existing air insulated substations.

5.1.1 SAFETY

Safety is an important factor since substation safety could affect both the public through the boundary lines of the substation as well as substation working personal. Safety of a solution should be assessed in the construction phase as well as during the operation and maintenance of the substation. For construction phase, the solution should be assessed from safety of constructability point of view to ensure that the installation could be safely built.

In the case of finding the optimal solution for substation renewal it is important to address the following questions (ref. IEEE 1266):

- Is the existing installation in compliance with the latest applicable safety codes (if the asset is considers safe to operate and maintain, continued maintenance will keep the asset at safe operating level during its extended life).
- If not in compliance with latest safety codes, is it within acceptable safe limits
- Unsafe – corrective action is recommended

For comparison between solutions, risk level should be taken in consideration, as well as company liability. For different solutions one can assign different weighting factors (of course with justifications).

5.1.2 ENVIRONMENT

Existing substations have the potential to exert a significant impact on the environment. The environmental impact of existing substations may be on the rise due to changes in local land use, operation of aging equipment, changes in environmental laws and regulations and changes in community perception of substations (Ref. CIGRE Brochure 221)

Environmental evaluation is as important as safety evaluation and it may have a great impact on community acceptance even if all the work is done within the current boundaries of renovated substation.

Most of the elements of the environmental evaluation could be converted in dollars. For example:

- Noise mitigation needs. For instance it the solution contains a new transformer and it addressed change of end of life existing unit with need of increasing capacity of the substation, it is possible that the new unit is noisier than the existing one and it may require special noise mitigation measures, such as sound enclosure, barriers, special landscaping, etc (ref. CIGRE Brochure 221). On the other hand, if a quieter transformer is purchased, the initial capital investment may be higher.
- Aesthetics. If the considered solution will change the aspect of the existing substation to the point of being noticeable, additional aesthetic measures such as taller fences, landscaping, solid structures, etc. may have to be incorporated
- Spills. If the existing substation did not have provision for spill containment, the change of an exiting transformer with a new one even if identical in size will in most cases

trigger the need of retrofitting a spill containment, mainly due to changes in environmental regulations over the years.

- Pollution. In some cases the solution may have to provide special insulation levels due to high pollution level. For instance if over the years a new industrial plant or a highway was build in the vicinity of the substation, pollution consideration need to be taken into account.

Other environmental elements are more difficult to transform in economic evaluation and need to be address qualitatively. One of these elements is the EMF level. Will be discussed under community acceptance

5.1.3 COMMUNITY ACCEPTANCE

A strong factor in evaluating solutions for renewal of existing air insulated substations is the community acceptance. Most of the time there is need for approvals for changing elements in an existing substation. These changes can be subjected to extensive review for community acceptance (ref IEEE Std. 1127)

The bus and associated equipment in an air-insulated substation are exposed and directly visible thus modifications are hard not to be seen. Most of community acceptance elements have been covered under environmental compatibility.

One area that is perhaps most difficult to evaluate is the EMF levels. Although the substation existed before, the community will tend to use the modification opportunity to bring up EMF issue. A solution, regardless how good it is may be negated due to community acceptance. To overcome this community involvement at the planning stage is recommended. Some solutions will be easier to sell than others and this factor should be considered during evaluation.

5.1.4 COMPANY BRAND NAME

The company brand name is a delicate subject. It reflects the public opinion on the economical and social performance of the company. All companies spend quite an effort to develop and sustain a unique brand image with a positive appearance to the public. For a network operating company the essential target groups are network customers, regional political organisations and representatives, investors and – not to be neglected – the employees of the company. Usually network operators show themselves as innovative, reliable and aware of their public responsibility. Particularly those operators, which work on periodically renewed regional concessions, demonstrate their solidarity with the operating region being aware that they are a quite important part of the regions infrastructure and competitiveness.

Thus a distinct deficit in the quality of supply can become an image-relevant matter. If there is a specific substation or a group of substations bound to the matter, this usually leads to a strong support for renewal.

5.2 Risk Evaluation

A goal of a Risk Evaluation is to find out the common optimum from several aspects, but because of the complexity of the relations, mostly it is not possible to find a single total optimum. These aspects have been discussed in the previous sections of this brochure:

- system: influence on quality of supply,
- equipment: technical condition of the equipment (regarding regulations and legal requirements),
- finance: life cycle costs, initial capital investment cost
- society: public opinion, brand name community acceptance.

If a risk assessment has be applied it is presupposed that the further view is only necessary under consideration of system questions regarding the system development. These system questions summarize the requirements of the system, which is the basis for the future network planning. For example:

- Are there intentions to change the feeding nodes of the system?
- Are there any plans for making changes in the rated voltage?
- Are there any plans to change the power flow?
- Have there been any changes regarding the technical requirements (capacity, reliability, customer requirements, etc.)?
- Are there any foreseen changes in the previously assumed maximum system short circuit levels, due to new generation connections?

The above mentioned questions can be extended due to the requirements of the companies.

If one question is answered with "yes" it means that a refurbishment activity should not be undertaken and a more complex analysis performed.

5.3 Definition of risk

In general risk can be defined as the result of two parameters: probability and consequence, so the definition is:

$$\text{Risk} = \text{probability} \times \text{consequence}.$$

The probability arises from the failed equipment, which is in service, whereas the consequence is caused by this outage, for example: replacement cost, non-delivered energy or personal injuries and so on. Risk maps are used for the visualization of the result of the risk assessment according to Figure 5.3 based on the probability and consequence with different classes, which start from "very low" to "very high".

This figure helps to identify the risks in the system, for example an outage with a high probability of occurrence and high consequences should be indicated in the right top corner. In addition tolerance lines or areas can be drawn in the risk map according to Figure 5.3, where three different areas:

low – medium – high risk

are marked. If any risk is calculated above this line, special measures have to be taken to reduce the risk.

One group that tends not to be taken in consideration is the "low probability - high impact" risk. The best way to address the issue of infrequent, long duration interruptions is to ensure that the issue is given explicit consideration during the normal planning process. These infrequent events could also occur for reasons outside the system itself. One example of this kind of event could be the fire in the substation control room that may cause a total station outage. It is recommended that utilities conduct individual reviews for system critical substations to determine their vulnerability to a prolong outage due to a single event. Once the vulnerabilities are identified, measures to reduce the impact of these events need to be developed and implemented

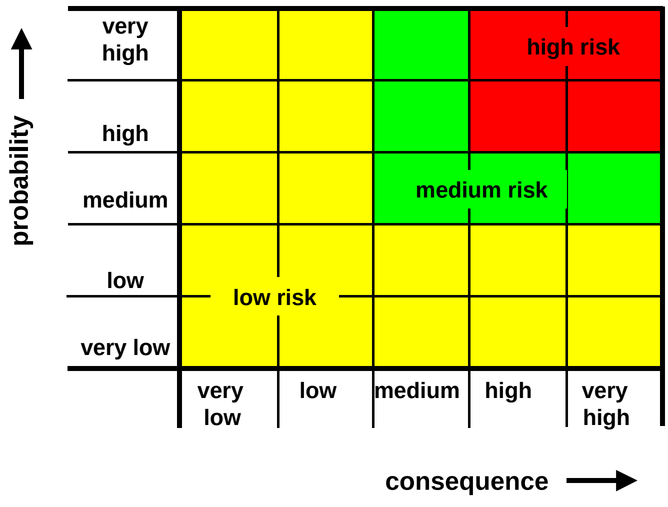


Figure 5.3: Risk map with tolerance lines or areas

5.4 RISK ASSESSMENT

The fundamentals and thus the processes for the evaluation of the outage risk of an equipment and installation are discussed in Reference [3]. In addition to the risk definition according Fig. 5.3, the measures to avoid the risk is taken into consideration using the further described method.

Basis of the evaluation is the determination of the outage probability of the equipment. For this reason it is necessary to determine the failure frequency of an equipment in dependence on the time after the commissioning or the last maintenance activity. In parallel, a calculation of the non-delivered energy, which is caused by the outage of the equipment, has to be performed by a reliability calculation. During the consideration of both procedures the different requirements of the company regarding the equipment (e.g. technology) and the supply quality (e.g. availability of energy), have to be taken into consideration. In the next step the probable outage costs are determined and compared with the expenses regarding the possible countermeasure scenarios. It has to be differentiated between the following maintenance strategies [4]:

- Extension of the lifetime by service, e.g. more intensive service in order to extend the life of the investment.
- Renewal by replacement: all components of an asset are replaced and the system remains unchanged.
- Renewal by refurbishment: some components of an asset are exchanged, so that the installation can be regarded as "new"; the system remains unchanged.
- Upgrading or renewal: the system is enhanced in some way, e.g. by increasing the current capacity or short-circuit strength.
- Redesign of the system: re-configuration of a part of a system, e.g. change of the nominal voltage or the configuration of a substation, e.g. splitting the HV buses.

Finally there should be an assessment under consideration of the "sociological effects" (e.g. social consequences, public image of the company, frequency of outage etc.). Also, in the two last cases requirements of the company regarding finances and the environment are to be included during the consideration. If a decision is finalized, considerations are necessary regarding the realization of the maintenance measures. The basis for the risk assessment is to consider the outage probability of an equipment during the next year in connection with the resulting financial expenses. The maintenance costs for different scenarios of the equipment respective to. The restoration of the system functionality have to be compared. Maintenance makes sense if these costs are lower than the probable outage costs.

5.5 INFORMATION FOR A RISK-ASSESSMENT

For the evaluation of the risk assessment the outage as well as the maintenance costs have to be compared.

The probable annual costs, which result from the outage of the equipment, can be calculated according to the failure rate of the equipment (minor as well as major). Additionally, the costs due to the non-delivered energy and the expenses, which are caused by the contracts with customers or requirements of the regulator, have also to be considered. The following information should be available:

- repair costs of the faulted equipment
- liability costs due to third party damages
- possible damages of further components
- failure rate of equipment
- costs and amount of non-delivered energy
- customer contracts, requirements of the regulator

In case of outage costs calculation, in general, it has to be differentiated between two failure scenarios which lead to a various financial assessment:

- major failure: instantaneous unplanned outage of the equipment with and without energy interruption(e.g. flashover inside the circuit breaker due to lightning strike)
- minor failure: failure, which can be repaired by a planned maintenance and does not lead to an outage of the supply.

As a consequence of different maintenance scenarios the expenses for these scenarios can be estimated and compared with the probable outage costs in case of a fault. The following information is important for an evaluation:

- maintenance measure
- maintenance costs and time interval
- investment costs for a new equipment
- usual life-time
- depreciation method
- interest rate
- disposal costs.

In addition the environmental and social influences have to be considered for the final decision. However, these effects are generally not financially assessable and they depend on the company requirements. Among other, the following information is of interest:

- personal injuries in case of an outage
- damages of the property in case of an outage
- social aspects of the customer (interruption of supply)
- public image of the company
- land use
- electric and magnetic fields
- pollution
- right of ways.

5.6 ECONOMICAL EVALUATION USING QUANTITATIVE CRITERIA

If risk evaluation shows the need of intervention, the asset manager usually has the freedom to decide among several possible solutions. These solutions can be evaluated regarding the cost and the effect on the quality of network performance associated with a particular solution. The same principles are valid for all other renewals due to the condition of assets within substations.

In order to get sustainable results the total cost of ownership, i.e. Life Cycle Cost (LCC) must be reconsidered. Following IEC 60300 three life cycle phases will be regarded:

- Acquisition including all processes from planning, design, procurement, site preparation, construction to testing and commissioning.
- Ownership including operation and maintenance.
- Disposal including decommissioning, waste treatment, and site restoration.

Within normal cost evaluation the cost of acquisition is usually well defined, whereas the cost of ownership (operation and maintenance) strongly depends of the structure of the operating company and the environment it is operating in. While evaluating these costs the following aspects of modernisation should be regarded:

- Operational Expenditures
  - Impact of remote operation: reduction of local switching.
  - Impact of fault localisation: automatic readout delivered to maintenance management in conjunction with workforce management.
  - Impact on facility and vegetation management.
  - Impact on labour requirements: ease of operation, reduction of qualification.
  - Impact on electrical losses: important regarding power transformers.
  - Simplification of substation primary circuit: allowing reduced redundancies due to higher reliability of equipment (impact on cost of acquisition as well), quicker restoration of normal operation.
- Maintenance Expenditures
  - Impact on preventive maintenance: reduction of building maintenance, extension of equipment inspection and maintenance cycles and reduction of maintenance extent.
  - Reduction of outage periods.
  - Impact on corrective maintenance: reduced number of incidents due to higher reliability.
  - Impact on labour requirements: faster repair and modular repair.
  - Impact on outage penalties

According to the LCC model, cost of disposal should include the planning of decommissioning, demolition, collection of recyclable materials, deposition of wastes and site restoration.

Practical experiences over decades have shown that the infrastructure of Air Insulated

Substations (buildings, support structures, roads etc.) often will be reused for the renewed substation.

In general the determination of a life cycle is difficult for AIS due to the rather different periods of use of its components. Referring to Cigré report 176 [4] and experience, one usually counts lifetime spans as follows:

Infrastructure (buildings, support structures, foundations, roads, fences etc.)	60 – 80 years
Conductors, insulators	30 – 70 years
Circuit breakers, disconnectors	30 – 50 years
Power and measurement transformers	30 – 50 years
Control and protection devices	20 – 30 years
SCADA, Intelligent Electronics Devices (IED)	15 – 25 years
Secondary equipment and circuitry	10 – 45 years

Thus, all possible solutions of renewal should be evaluated for that period of time, in which all of them end at an equivalent state. Further, this evaluation should be in concordance with the company's long-term network development plan.

If all alternatives have acquisition cost, which come up at same time, it is a common approach to compare these and the cost of ownership for a fixed period (e.g. 10 years) on an actual value basis.

If the distribution of cost over time is non-uniform, the cash-value-method will be applied. Cash-value is defined as the difference between benefits and costs related to a certain moment of time. All values future to this moment of comparison will be discounted with a company-internal interest rate. As in most cases particular benefits can not be related to a certain substation, comparison can be reduced to an evaluation of costs:

$$\mathbf{CV} = \sum_{k=1}^{n} \mathbf{C_k\, q^{-k}}$$

CV	cash value
k	number of years counted from the year of comparison
n	number of the last year of comparison, i.g. end of life cycle
C_k	annual cost in year k being sum of all cost within the year at the end of the year
q	interest factor = 1 + p / 100
p	interest rate in percent

By the use of this method all cost - at what time ever they appear - can be normalised to the year of reference (Figure 5.4) giving a comparable value for solutions with different developments over time.

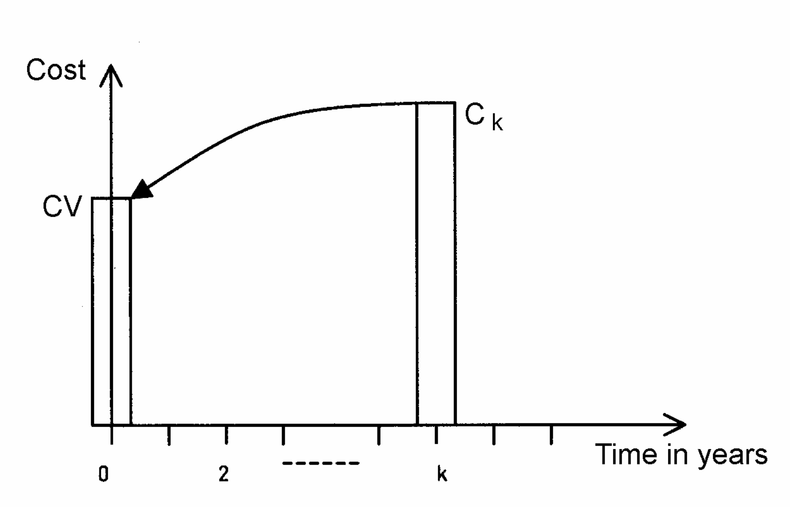


Figure 5.4. - Normalisation by cash-value-method

Being applied to cost of acquisition only, this method has a tendency to favour decision towards postponement of renewal. Therefore the correct costing of operational and maintenance expenditures is of high importance.

5.7 CLOSING REMARKS

Like every technical infrastructure Air Insulated Substations - for the benefit of a constant quality of supply - need appropriate renewal, which must meet the requirements of the liberalized market concerning the effectiveness of asset utilization and cost control. It is the intention of the authors of this brochure to give general guidance for the case of existing substations.

A systematic approach was chosen, firstly describing the typical reasons for renewal and pointing out that for all further considerations, a thorough condition assessment is crucial to obtain all relevant information for an optimized solution. A lot of effort of all participating experts has been devoted to offer an international overview of equipment related important aspects to be taken into account. The listed items may sometimes reflect a regional emphasis but state the actual trends. Hence, compilation of facts gives the user of the brochure a solid base to develop his own checklist.

Several times the importance of a well-structuralized documentation of substation assets is pointed out as the key to a successful asset-management. This documentation should comprise not only technical information from cradle to almost grave but also locational, environmental, safety-related and societal information.

Those who expect a straight forward, flow-diagram-like description of the approach to an optimized renewal will search in vain. On one hand the reason is found in the multitude of possible solutions, which reach from corrective maintenance – keeping the substation alive – up to the complete rebuilding. On the other hand the forces driving or limiting decisions are of various nature: ranging from the company's own financial possibilities, the rules of regulation to social and legal pretensions. Thus, the purpose of the brochure is realistically limited to a description of these factors and their interdependence, giving some additional help for the individual evaluation of a comprehensive solution.

In practical life most companies follow either a strategy of successive replacement of substation components or they tend to stretch out the utilization of equipment up to the moment of a complete renovation of the whole substation. Typical examples for both strategies are shown as case studies in the following appendix.

6 REFERENCES

[1] Okubo, H.; et al.: “Asset Management of Oil-Immersed Transformers”, Electric Technology Research Association, Vol. 54, No. 5, 1998

[2] "Underground Cables and Its Maintenance Technologies", Electric Technology Research Association, Vol. 40, No. 3, 1984

[3] Balzer, G.; Schorn, C.: “Risk Assessment of High Voltage Equipment”, CEPSI 2004, Shanghai, Oct. 18-22, rep. 102, M3

[4] CIGRE, Report 176: ”Aging of the System –Impact on Planning”, Working Group 37-27, December 2000

7 Appendix A – Case Studies

A1. Replacement of 245-kV Circuit Breakers - Germany

The substation existing 245kV circuit breakers were approaching the end of their useful life and maintenance costs were high, being above average for their class of equipment. Conversion of the 245-kV section of the substation to 400-kV was anticipated within the next 12 years according to long-term network development planning. Consequently an intermediate solution was needed.

1.1 Condition Assessment

The existing circuit breakers still had sufficient breaking capacity and were of the two pressure-type with separate 15 bar SF_6 tanks. Operating and Maintenance records showed that the old circuit breakers had a normal reliability, but a relatively high maintenance effort was needed due to short overhaul intervals and frequent exchange of expensive high pressure gas circuit parts.

1.2 Alternatives Considered

The alternatives were to replace the circuit breakers with either new units or ones that were in adequate condition. LCC evaluation showed that the most favorable solution for the required 12 year lifespan was to use 25 year old puffer-type circuit breakers , which were available from previous conversions. As part of the installation the circuit breakers were overhauled to ensure they would not require further major maintenance for the next 12 years.

1.3 Summary

Replacement was performed at about 40% of the cost of installing new circuit breakers. The solution provides equal life-time expectancy for all 245-kV switch bay components prior to their conversion to 400 kV in about 2017. The photos below in Fig. A1-1 show the installation before and after replacement of the circuit breakers.

Before Replacement

After Replacement

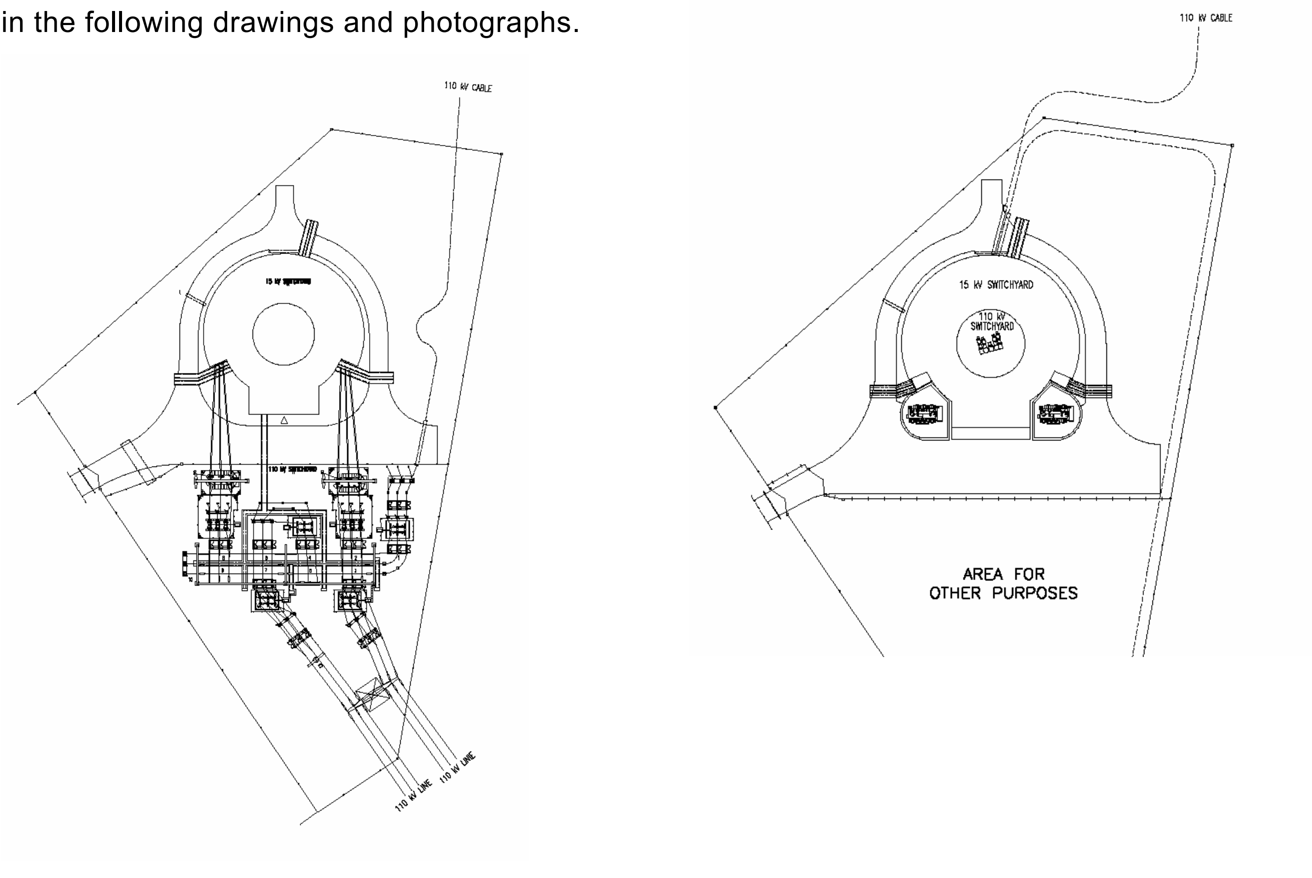
Figure A1-1: 245-kV Switch Yard Circuit Breaker Replacement

A2. Substation Renovation - Poland

Substations require modernization following long term operation due to normal wear and tear of equipment as well as increases in rating flows and short circuit levels in network parameters resulting from development of the power system. The modernization can be carried out using current structural solutions and replacement of existing HV apparatus with new equipment that has upgraded technical parameters.
However the modernized facility may be entirely rebuilt using completely different solutions from those routinely done before. A good illustration of this is the replacement of a classic outdoor AIS installation with an SF_6 insulated switchyard that requires much less space. In this way part of the site may be reserved for another use, e.g. a commercial one, thereby enabling the modernization costs to be balanced.
The following are two good examples of reduction of the area occupied by a substation resulting from modernization cases that were undertaken in Warsaw, the capital of Poland.

2.1 Warszawa-Batory 110/15 kV Substation

The Warszawa-Batory 110/15 kV substation consisted of an outdoor 110 kV switchyard and a 15 kV indoor switchyard. Modernization included major repair of the substation building and replacement of the 15 kV switchyard. The new and former substation solutions are presented in the following drawings and photographs.



(a) Before Modernization (b) After Modernization

Figure A2-1: Layout of Warszawa-Batory Substation

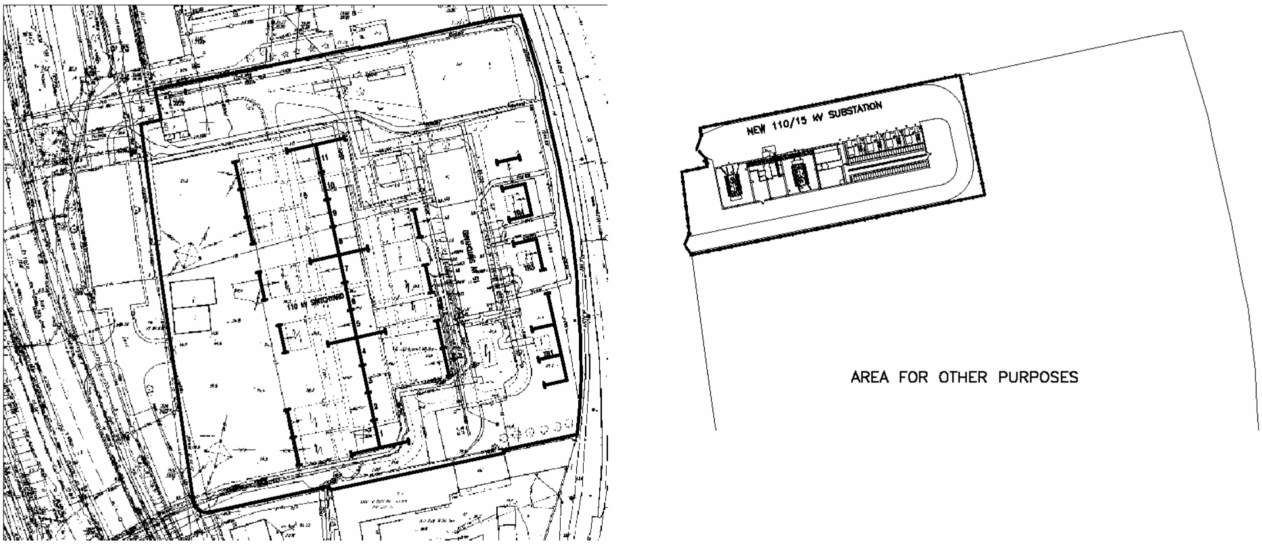
The outdoor 110 kV switchyard was completely dismantled and replaced with SF_6 switchyard located in the spare part of the existing building. To accommodate power transformers, chambers were erected adjacent to the existing building. In this way a new, fully indoor substation comprising new equipment came into being, while allowing 50 % of the area that was formerly occupied by the substation to be dedicated to other purposes.

Figure A2-2: Part of Warszawa-Batory Substation before Modernization

Figure A2-3: Warszawa-Batory Substation after Modernization.

2.2 WARSZAWA-ZACHODNIA 110/15 KV SUBSTATION

The second example is the Warszawa-Zachodnia 110/15 kV substation with outdoor 110kV and 15kV switchyards. Its modernization included construction of a new 110/15 kV indoor substation with new equipment on part of the former substation site. The original substation, with a record of 50 years of operation, was dismantled. Importantly, this allowed the recovery of almost 90% of the area formerly occupied by the substation which can now be used for other purposes.



(a) Before Modernization (b) After Modernization

Figure A2-4: Layout of Warszawa-Zachodnia Substation

Figure A2-5: Part of Warszawa-Zachodnia Substation before Modernization.

Figure A2-6: Warszawa-Zachodnia Substation after Modernization.

A3. LONG-TERM EXTENSIVE SUBSTATION RENEWAL PROJECT - ISRAEL

The development of a Transmission & Distribution system may include periods of intensive building of substations due to increased load requirements and system expansion. The result is that a significant number of substations are built in a relative short period of time, using similar concepts and technologies.

After decades of service, the utility has to deal with renewal of this group of substations.

In order to allow resource planning (equipment procurement, design, construction) and correlation with system development (extension of existing Substations) renewal has to be based on a long term extensive plan.

IE faced such a situation and decided to adopt a systematic approach to the problem.

The task was assigned to an interdepartmental group including engineering, asset management and operation staff. This group proposed a 10 year renewal plan, comprising approximately 300 projects with a value of more than $30M.

The projects were defined on an equipment basis but were grouped on a site basis and coordinated with other substation development projects. It was obvious that executing more projects in a substation together was beneficial, even if some projects were postponed or advanced. Virtually all installations and substation systems were covered, including fire protection and water supply infrastructure and protection and control systems.

It should be mentioned that the utility is the asset owner operator and maintainer. The project strategic guidelines as outlined by management were:

- Minimizing costs.
- Minimizing system impact (non supplied energy).
- Security of company personnel and the general public.
- Mitigating environmental impacts.

3.1 REQUIREMENTS FOR RENEWAL

Since the renewal was planned on an equipment basis, requirements were based mainly on equipment condition assessment. In addition, upgrading of switchgear due to changed system requirements such as short circuit capacity, load currents, reliability and stability was also taken into consideration.

In several instances the requirement for renewal came from the community or environment (road changes, visual impact, fencing, etc.) In many cases the benefits of modern technology were the incentive for equipment renewal.

3.2 CONDITION ASSESSMENT AND RENEWAL SOLUTIONS

The work was performed in accordance with the following steps (see flowchart, Fig. A3-5):

- An extended data base was created for equipment and systems, recording the age, fault history, maintenance cost, spare parts availability, etc.
- Criteria were defined for both replacement and upgrading as follows:
    - For high voltage and medium voltage equipment the criteria were based on age,

fault frequency, reliability and LCC.

- For protection and control equipment the main criteria were; system stability (busbar protection, circuit breaker failure protection, teleprotection) and technology upgrading.

The benefits of digital technology (information, self testing, and versatility) together with lack of requirement for spare parts and repair skills (as is the case for electromechanical relays) may fully justify replacement:

- The age criteria (12-15yr) was almost strictly applied for stationary DC batteries because of their high impact on the substation reliability.
- The recommendations of the asset manager were decisive for auxiliary plant, installations, and infrastructure, subject of course to a feasibility and economic check.

3.3 Project Definition and Management

By applying the renewal criteria to the equipment database, the amount and definition of projects was established.

- A first-time schedule and a cost evaluation were prepared.
- The projects were divided into three priority groups according to system requirements and the severity of impact of a fault.

For instance DC batteries older than 15 yrs, or lightning arresters, and voltage or current transformers with serious problems were placed in a priority group proposed to be included in the renewal plan for the coming year. The process of priority analysis is to be repeated each year on the remaining group of projects, while updating data.

3.4 Refurbishment Criteria – Examples

3.4.1 HV Circuit Breakers

a) System requirements (short circuit breaking capacity, suitability for single phase reclosing)
b) Availability and cost of obsolete (high cost maintenance) technology spare parts, LCC (CB operated by central compressed air plant).
c) "Ageing" criteria. This criterion analyses the fault frequency. A sustained increasing fault frequency indicates the entrance of the equipment into the "aging" period and its replacement is recommended.

3.4.2 MV Outdoor Switchgear

Age, spare parts, technology (bulk oil MV circuit breakers are recommended to be replaced by vacuum or SF_6 units).

Figure A3-1:
Old Outdoor Bulk Oil MV Switchgear

Figure A3-2:
New Indoor SF_6 MV Switchgear

3.4.3 HV Protection

a) System requirements (speed reliability).

b) Repairing skills and spare parts.

A recommendation was made to replace EM distance relay from the older generation.

Figure A3-3:
Old EM Protection Panel

Figure A3-4:
New Digital Transformer Protection Panel

3.4.4 MV Control and protection Technology.

The modern one-box digital feeder protection became obviously cost attractive. Refurbishment is generally recommended when switchgear is replaced.

3.5 SUMMARY

For centralized utilities (responsible for asset ownership, operation and management) a long term renewal plan with periodic revisions is the best way to obtain cost effective results.
The same strategy may be valid for other types of substation management, but technical and economical goals must be appropriately defined.

Project definition flow chart

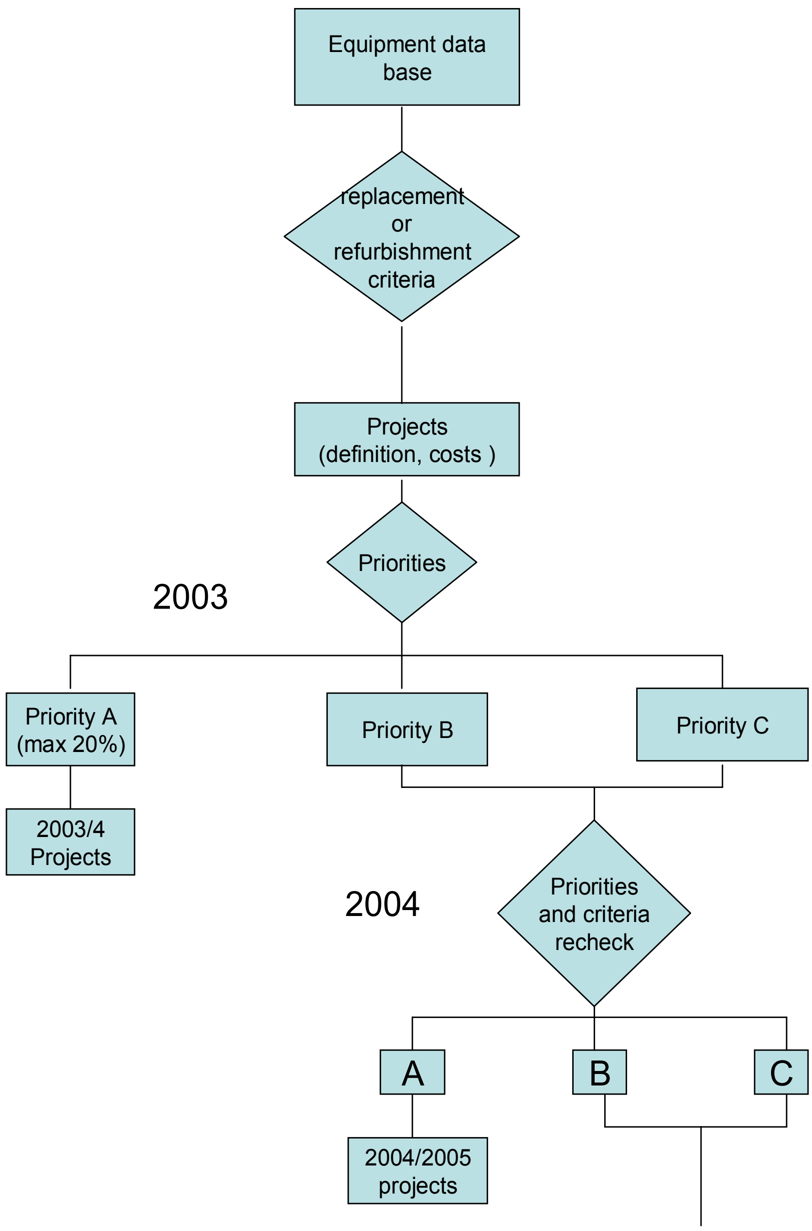


Figure A3-5: Project Definition Flow chart

A4. Total Renewal of an AIS Substation - Israel

4.1 Introduction

Berot substation was commissioned in 1968 as a 2 x 30 MVA, 161/24 kV AIS substation, connected to the grid by two overhead circuits. Several years later two 30 MVA transformers were added.

This case study presents the main development and the renewal project undertaken during 2003-2005 in several stages, at the end of which the substation is in its final configuration. The development project comprised the increasing in transformer capacity from 4 X 30MVA to 4 X 45 MVA and the addition of two overhead 161kV circuits.

Figure A4-1: Substation General View

The renewal and development projects involved renewal of almost every item of equipment as well as all substation systems. It can therefore be classified as a total renewal. The project was implemented with a minimum of supply outages, using company staff for design and erection. Exceptions included civil engineering, where the work was performed by a contractor, and some commissioning of equipment and systems, which were performed by the manufacturer's specialists.

7.1 4.2 Requirements for Renewal.

- System development resulting in an increase in short circuit level and required substation busbar load current capability
- Requirements of increased transformer capacity from the distribution system.
- MV Switchgear condition and technology.
- HV Switchgear condition and technology.
- New technologies for control, protection and communication systems.
- Condition assessment of infrastructures (fence, buildings, drainage, etc.).

4.3 Basic Considerations

As mentioned above, the substation needed a significant extension, because of network requirements (increased short circuit level, two additional lines and additional transformer capacity). It was decided to use the project as a good opportunity to revise all substation components and systems by condition assessment and to define a total renewal project for the substation.

For an in-service installation a basic requirement is to mitigate the down time of the system or parts of it during the implementation of the renewal project. Therefore, there is a significant advantage in performing several projects simultaneously. For instance, if the replacement of a circuit breaker is a system requirement, than it might be worthwhile to execute at the same time projects such as renewal of protection and control systems, earth grid improvement, changes to remote control, etc., even if for some of them there is no immediate requirement.

The advantage of shortening the down time and using the same work team must be weighed up against the early investment cost. The decision shall be made on an economic basis only.

4.4 Condition Assessment

Condition assessment of the following types of equipment indicated that there was a necessity for renewal:

- HV Air blast Circuit Breakers
- MV bulk oil Circuit Breakers
- EM protection in outdoor protection cubicles, in the MV switchgear
- EM relays

Figure A4-3:
a) Old Air Blast CB b) New SF_6 CB

The main reasons were:

- Poor performance, with an increasing trend of faults
- The amount of maintenance
- Lack of skills
- Lack of spare parts
- Condition Assessment

4.5 Possible Solutions

A clear result of the condition assessment of MV switchgear was the requirement for a total replacement.

Since the standard technology adopted by the company for 24 kV MV switchgear is indoor GIS switchgear, a new building for housing the switchgears was required. On the other hand, the extensive changes in the substation control, protection and auxiliary circuits required substantial modification of the existing control building.

Two alternative solutions were analyzed:

- A new common building for all control and protection auxiliary plant and the MV switchgear.
- Extension and modification of the existing control building, and a new building for MV switchgear only

The comparison of the two solutions showed a clear advantage for the first one.

Figure A4-4: Old Control Building

Figure A4-5: Old MV Switchgear

Figure A4-6: New Control & MV Building

4.6 SUMMARY

Executing a total renewal project on an operating substation must be well justified from the point of view of the transmission (or sub-transmission) and distribution systems needs.

Design and construction work on a total renewal are generally greater than in a new equivalent substation project and, if land is available (which was not the case in this project), an alternative solution of a new nearby substation should be considered and compared with the total renewal option.

All civil works should be executed by the same contractor and building permits, including environmental aspects, should be obtained before any work starts on site.

Project management is a critical issue and should be assigned to people familiar with the substation technology and experienced in managing complex projects.

A5. UPGRADING AN EXISTING 275KV GCB TO ACCOMMODATE SYSTEM CHANGES - JAPAN

5.1 INTRODUCTION

Following changes in system demand it became necessary to modify an existing gas circuit breaker (GCB) to cope with an increase in short circuit current level. The GCB involved had been in service for over 20 years. The specification of this GCB is as follows.

- Year of Manufacture: 1980
- Rated Voltage: 275 kV
- Rated Current: 4000 A
- Rated Short Circuit Current: 40 kA
- Rated SF6 Gas Pressure: 0.5 MPa/gauge
- Driving Unit: Pneumatic drive rated 1.5 MPa

5.2 CIRCUIT BREAKER SELECTION

We estimated the existing maximum short circuit current capability of this GCB and also established that the maximum required value would be up to 42kA over the next 20 years. It was also assumed that the remaining life of the circuit breaker was 15years.
Studies were undertaken and necessary interruption tests were carried out in the factory to obtain capability data. An example of this data is shown in Fig. A5-1.

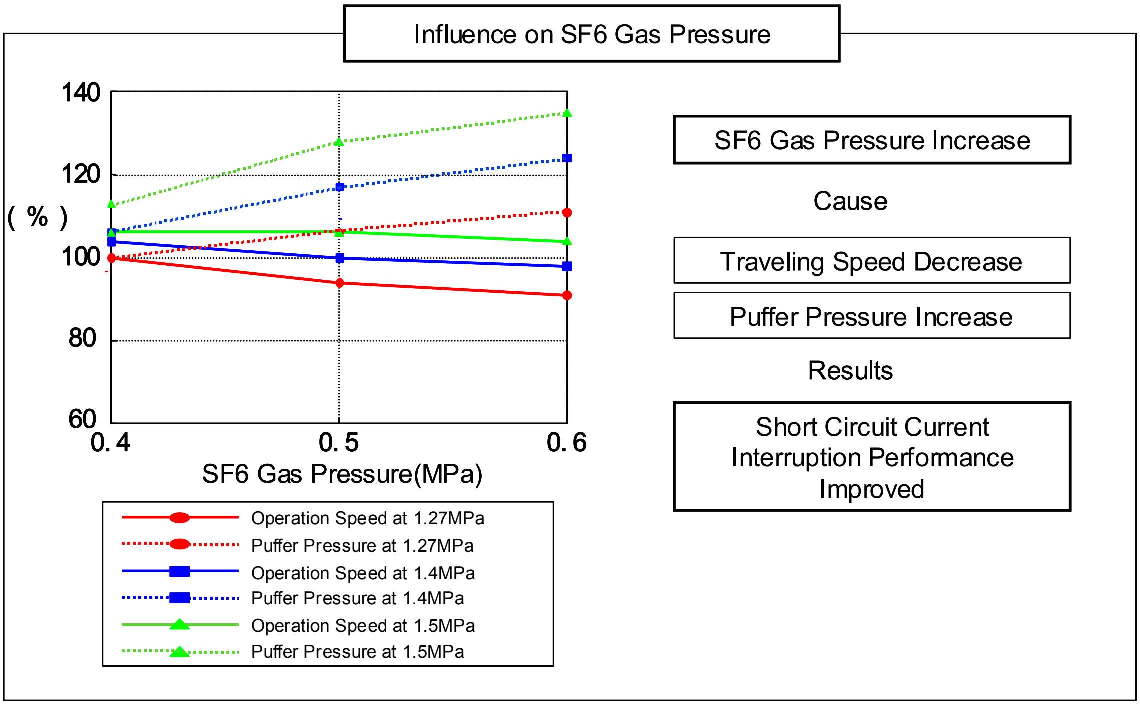


Figure A5-1: Effect of Increasing Circuit Breaker SF_6 Gas Pressure

5.3 Summary

After review of the data the countermeasure adopted to meet with increased system requirements was to raise the GCB SF_6 gas pressure from 0.5 MPa/gauge to 0.6 MPa/gauge. This increased its short circuit current rating from 40kA to 44kA and its new specification is now as follows:

- Year of Partial Modification: 2002
- Rated Voltage: 275 kV
- Rated Current: 4000 A
- Rated Short Circuit Current: 40 kA to 44kA
- Rated SF6 Gas Pressure: 0.5 MPa/gauge to 0.6 MPa/gauge
- Driving Unit: Pneumatic drive rated 1.5 MPa

This was found to be the most cost effective countermeasure for this particular case.

A6. EHV AIS Rehabilitation Projects - Japan

A rehabilitation project for an Air Insulated Substation located in the northern suburbs of Metropolitan Tokyo was competed recently. This substation was first commissioned in 1959 and its main features are listed as follows:

- System Voltage: 275kV as primary voltage and 154kV as secondary voltage

- Number of Transformers: 5 main transformers
- Total Capacity: 1,542MVA
- Number of transmission lines: 6 bays for 275kV system and 8 circuits for 154kV system
- Bus configurations: Double busses with four bus tie circuit breakers
- Rated Short Circuit Current: 50kA at 275kV

6.1 Condition Assessment

The main objectives of the project were to maintain system reliability, to improve safety during maintenance, and to augment the system capacity. These objectives and reasons for the project are detailed as follows:

- To replace steel structures.

  The steel structure for the double deck bus system (physically an upper and lower level bus configuration) was aged and did not satisfy current seismic standards. Very strict maintenance safety working conditions had to be applied to prevent contact with energized circuit components.
- To replace main circuit equipment.

  Ratings of main items of equipment, such as bus capacity, short circuit current and power system operation, etc did not meet the requirements of the power network.
- To install new equipment within the space occupied by the existing equipment.

  There was no space for new equipment in the substation as there was no spare space available.

6.2 Scope

The scope of the project was to replace all the existing 275kV circuit equipment with air insulated bus composed of aluminum rigid tube and with gas insulated equipment.

- 275kV double buses (from the double deck strain bus to the suspended aluminum rigid tube bus)
- 275kV transmission out let switchgear (conventional gas insulated components)
- 275kV transformer switchgear
- 275kV protection relay system

6.3 Summary

An economical and technical evaluation was carried out between a combined system comprising air and gas insulated components and a fully gas insulated system. As a result of the evaluation study, the air and gas insulated component combined system was selected as the optimal scheme for the project.

- Economic evaluation.
  - The combined system is more economic than the fully gas insulated system.
  - A fully gas insulated system reduced the required equipment installation space, but there was no useful way in which to use the incomplete spare area.
- Technical evaluation.

- There were no significant advantages for maintenance work if the fully gas insulated system was selected for the project.

Figure A6-1:
The Original 275 kV Substation Comprising Double Deck Bus Configuration

Figure A6-2:
The Completed Rehabilitation Project with Suspended Aluminum Tube Bus System

Figure A7-2: Number of Circuit Breakers

A7. Strategic Maintenance and Replacement of Air Blast Circuit Breakers - Japan

A comprehensive 275kV and 500kV Air Blast Circuit Breaker (ABCB) maintenance plan was devised for the bulk power transmission network in Japan. Preventive maintenance of 500kV ABCBs and progressive replacement of 275kV ABCBs was coordinated, based on a life cycle maintenance cost assessment.

This maintenance plan provides a solution for rising preventive maintenance costs and shortages of important maintenance / replacement components for aging equipment.

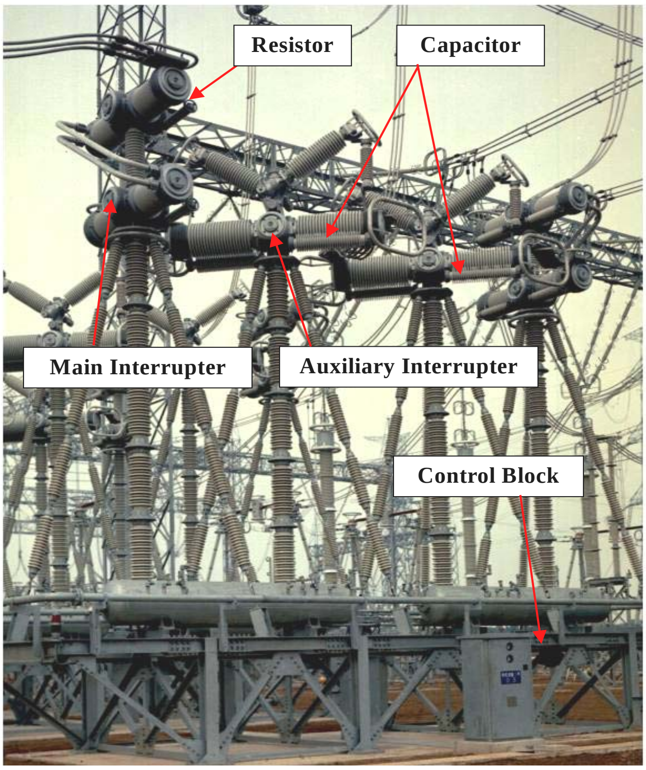


Figure A7-1: Air Blast Circuit Breaker

Fig. A7-2 shows the number and the years since commissioning of ABCBs in the EHV transmission network. Of the in-service circuit breakers in the 275kV & 500kV systems 7% are ABCB, with over 25 to 40 years operating experience.

7.1 Condition Assessment

Major inspection of ABCB units is carried out approximately every 12 years, based mainly on consideration of the life cycle of packing. As the length of service increases, the number of parts to be replaced during major inspection is increasing significantly. Since it is not very realistic to get a long outage period from the viewpoint of system operation and availability, components such as the main interrupter, auxiliary interrupter, control-block, and so on, are pre-assembled in the maintenance provider's factory and replacement

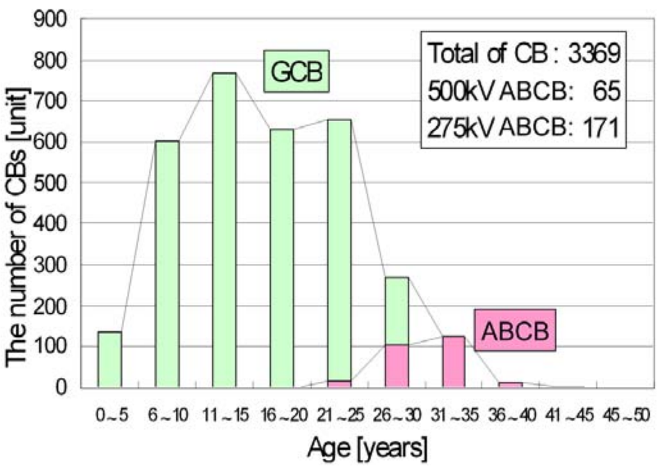


Figure A7-2: Number of Circuit Breakers

is carried out on-site in the shortest timeframe. This approach to major maintenance shortens the inspection duration from 8 days to 3 days.

7.2 ISSUES CONSIDERED

Gas Circuit Breakers (GCB) have been manufactured since 1974, and ABCB have not been manufactured since 1982. Consequently, it is anticipated that the factory spare parts will run out within 5 to 10 years. In addition, it is estimated that such parts cost five times more than the original components if they are manufactured today and that the overall inspection cost will consequently be doubled. Moreover, it is a fact that some of main components can no longer be manufactured due to the abolishment of production facilities.

GCBs are the current mainstream of circuit breakers and have a maintenance-free feature that basically means they do not require a major inspection for a longer period than the conventional equipment, thereby reducing the maintenance cost. Given this fact, the life cycle cost assessment of 275kV & 500kV ABCB was conducted assuming progressive replacement of the GCBs. The results of the assessment are shown in Fig. A7-3 and indicate that:

- It is cost-effective for 275kV ABCB to be replaced with a new GCB.
- 500kV ABCB should be maintained with proper preventive measures.

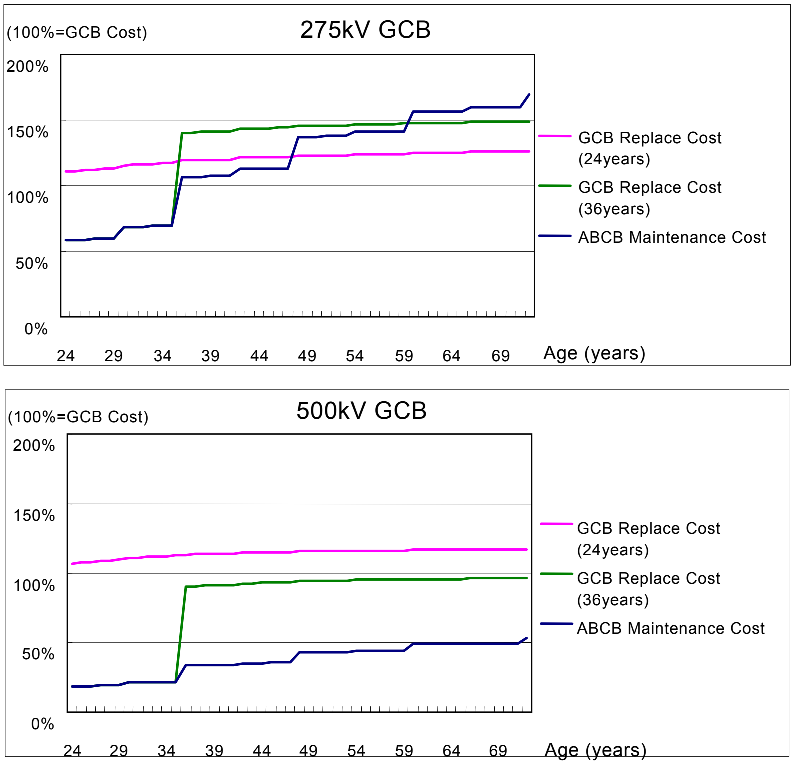


Figure A7-3: Results of the Assessment (ABCB)

The results also suggest some parts of the 275kV ABCB can be utilized for maintaining 500kV ABCB and, according to provisional calculations, components required for major inspections will be available until 2024, on condition that 30% of the parts from the replaced 275kV ABCB can be used for the maintenance.

7.3 SUMMARY

An outline of strategic maintenance and replacement of 275-500kV ABCB aimed at reducing costs was briefly introduced. The maintenance cost comparison based on life cycle cost assessment has resulted in reduction of the operating cost of EHV class circuit breakers, as well as increasing the availability of spare parts for 500kV ABCB over the next 20 years.