*भारतीय मानक*

*Indian Standard*

**IS/IEC TR 63463 : 2024**

# एचवीडीसी कनवर्टर स्टेशनों के लिए जीवन विस्तार दिशानिर्देश

# Life Extension Guidelines for HVDC Converter Stations

ICS 29.020; 29.240.10



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NATIONAL FOREWORD

This Indian Standard which is identical to IEC TR 63463 : 2024 'Life extension guidelines for HVDC converter stations' Issued by the International Electrotechnical Commission (IEC) was adopted by the Bureau of Indian Standards on the recommendation of the HVDC Power Systems Sectional Committee and approval of the Electrotechnical Division Council.

This IEC standard was developed in WG 12 of IEC TC 115 which was convened by national mirror committee of India ETD 40 chairperson. This standard was an Indian new work item proposal (NWIP) at IEC level.

The text of the IEC standard has been approved as suitable for publication as an Indian Standard without deviations. Certain conventions are, however, not identical to those used in Indian Standards. Attention is particularly drawn to the following:

a) Wherever the words 'International Standard' appears referring to this standard, they should be read as 'Indian Standard'; and

b) Comma (,) has been used as a decimal marker, while in Indian Standards the current practice is to use a point (.) as the decimal marker.

Only English language text has been retained while adopting it in this Indian Standard, and as such the page numbers given here are not the same as in the International Standard.

For the purpose of deciding whether a particular requirement of this standard is complied with, the final value, observed or calculated expressing the result of a test, shall be rounded off in accordance with IS 2 : 2022 'Rules for rounding off numerical values (*second revision*)'. The number of significant places retained in the rounded off value should be the same as that of the specified value in this standard.

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# INTRODUCTION

In today's complex environment, energy players face growing demands to improve energy efficiency while reducing costs. Energy shortages and increased ecological awareness have resulted in great expectations for grid stability and reliability. Utilities and industries are supposed to find eco-efficient solutions to maintain secure, safe and uninterrupted operations. A number of regulatory changes in the electricity market have led to increased efforts by utilities and grid operators for optimized utilization of their existing networks with respect to technical and economic aspects. As the electric power transmission system ages, the topics of life assessment and life extension have become predominant concerns. At the same time, cost pressures have increased the desire to minimize maintenance. The goals of minimum maintenance and extended life are often diametrically opposed.

The concept of simple replacement of power equipment in the system, considering it as weak or a potential source of trouble, is no longer valid in the present scenario of financial constraints. Today the paradigm has changed and efforts are being directed to explore new approaches and techniques of monitoring, diagnosis, life assessment and condition evaluation, and possibility of extending the life of existing assets.

A major challenge for grid operators worldwide is to ensure sufficient power with quality and reliability. In this regard high voltage direct current (HVDC) systems play a major role in bulk power transmission, system stability, integrating remote renewables and ride through of disturbances. Therefore, HVDC systems represent an indispensable part of the electricity grid in the countries where they are installed.

HVDC has been in commercial use since 1954, and most of the systems are still in operation. However, the early mercury arc valve systems have been phased out and replaced by thyristor valves. This has extended the life of many of the early systems, but the thyristor based systems are also approaching an age where the thyristor valves are likely to require replacement or refurbishment. Operation and maintenance issues of these ageing systems have become a challenge. The situation is further complicated by the fact that all of the HVDC systems are custom built by a relatively small number of original equipment manufacturers (OEM). The HVDC manufacturers have supplied several different generations of equipment and these differences are considered in any life extension assessment.

One major challenge in any refurbishment project is proprietary equipment. Most of the HVDC equipment is composed of unique devices for which replacement/refurbishment by other manufacturers is very difficult. For example, when planning to replace components of a thyristor valve, it is more likely to be only supplied by the original manufacturer which will drive the cost up for such replacement. However, this is still preferred if other component life is much longer, as the alternative would be to replace the entire thyristor valves which will be costlier. Proprietary equipment also causes difficulties in sharing details of equipment to other prospective suppliers for the refurbishment projects.

It is assumed that regular maintenance of HVDC system/component/equipment is being done by the owner as per the OEM recommendation as well as their maintenance practices. Further it is assumed that they are familiar with equipment details and records of equipment failure. They have knowledge of equipment behaviour, its characteristics and its impact on system performance based on international standards. This document deals with life extension of the HVDC converter station.

With the ageing of the equipment, measures to extend the equipment's life is considered by utilities and grid operators. Renovation, modernization and life extension of HVDC stations is usually one of the most cost-effective options for maintaining continuity and reliability of the power supply to the consumers. Implementation of these life extension measures is implemented with minimum impact on the HVDC system and the associated networks whilst maintaining an acceptable level of reliability and availability. If life extension is not economical, the systems are disposed of in an environmentally acceptable way. Also, consideration of environmental issues is made prior to a life extension project to avoid any inadvertent environmental damage.

The cost of outages to carry out a refurbishment is considered as part of the overall cost. This then dictates a greenfield option where a new converter station can be built and only short switch overtime is required. An example of this is the Oklaunion Converter Station (CS) in the USA, where the outage costs tipped the scale towards a greenfield versus a brownfield option for refurbishment. The definition of the interfaces in the case of a brownfield project is critical and more complicated than in a greenfield project.

Most utilities are interested in better understanding and projecting service life of HVDC equipment to help manage risk; however, generic reliability data is inadequate for current decision support needs. It is important to establish industry-wide equipment performance databases to establish a broad-based repository of equipment performance data. With proper care and analysis, this data can provide information about the past performance of equipment groups and subgroups, and the factors that influence that performance. With enough data, projections can be made about future performance. Both past and future performance information can be useful for operations, maintenance, and asset management decisions.

However, for some components it is more difficult than most to determine the useful life and the actual end of life failure modes. The thyristors themselves are an example, as they have been around for some 35 or more years and yet are showing little sign of reaching end of life, except where some design or quality issues have been uncovered.

Life-extension involves any of the following actions:

- Refurbishing the systems or subsystems,
- Selectively replacing ageing components,
- Combination of the above.

In some cases where life extension is not economically feasible, a greenfield replacement can be considered.

The following steps can be taken to arrive at a decision:

- Review the past performance of the major HVDC equipment and systems.
- Identify the future performance issues associated with the ageing of special components of the HVDC systems. The equipment that has not shown performance issues in the past but is still required during life extension, is also considered.
- Determine economic life of various components in the converter station and for making replacement versus life extension decisions. The consideration of economic life will include capital cost, reliability and availability, cost of maintenance and the cost of outages and power losses.
- The usable life of a refurbishment is likely in the average of 15 to 20 year range whereas a greenfield option is likely 30 to 40 years and this can be factored into the evaluation but it is recognized that some components can have a different year range.

One way of going about this activity could be to develop criteria, weightings and methodology for determining near-term action and forecasting the technical and financial effect due to system ageing. This follows an approach based on condition replacement cost and importance of the equipment and components. Assessment of condition parameters could be in terms of equipment age, technology, service experience (e.g. after sales service quality, maintenance costs) and future performance, individual failure rates, and so on. A viable duration for the life extension is determined and usually 15 to 20 years is achievable. Longer durations are more difficult to assess with any degree of accuracy.

Evaluation of the possibility of extending the service life of electrical equipment is a techno-economic compromise which can lead to "run-refurbish-replace" decisions. Once the expected service life period has expired, refurbishment of such equipment falls within the life extension program.

The investment at initial stage is very capital intensive to the utility concerned, as the devices to be installed in the system for residual life assessment (RLA) and condition evaluation purpose, are very costly. However, the decision to refurbish or to replace are generally done based on the study of comparable costs and benefits over the same potential life time of the asset.

Therefore, it can be concluded that the need for life extension and replacement of equipment in HVDC system arises due to:

– Arresting the deterioration in performance,
– Improving the availability, reliability, maintainability, efficiency and safety of the equipment,
– Regaining lost capacity,
– Extending the useful life beyond originally designed life of 30 to 40 years,
– Saving investment on new equipment,
– Not having availability of new spares due to obsolescence.

These objectives help utilities as follows:

– design refurbishment strategies for their existing HVDC systems to extend equipment life,
– evaluate O&M and reliability performance improvement strategies for their existing HVDC systems,
– provide a guideline for determining economic life of various components in the converter station and for making replacement versus life extension decisions. The consideration of economic life are generally capital cost, reliability and availability, cost of maintenance and the cost of power losses.

In order to achieve above objectives this document covers primarily following aspects:

– Key factors/reasons driving need for replacement work e.g.: system concerns such as relevance of link. Technical and commercial feasibility efficiency of the refurbishment planned.
– Failure or life degradation of equipment in the HVDC station.
– Critical equipment or critical interface points in the HVDC station.
– Planning of replacement work: Procurement – utility approach for procurement (OEM/multiple vendor) and reasons for adoption based on type of equipment.
– Plan of execution – scope definition, preparation of technical specification, existing system data requirement, etc.
– Outage planning.
– Performance guarantees
– World-wide experience of system operators.
– This document provides guidelines for the general procedure for performing life assessment (Clause 4). Following this, a more detailed description of performance issues of the thyristor based HVDC systems (Clause 5) is given and the life assessment measures of equipment (Clause 6) and guidelines for accessing the techno-economic life of equipment (Clause 7). Clause 8 deals with the recommendation for specification of refurbishing HVDC system and Clause 9 follows with the testing of the refurbished and replaced equipment. Further, this document will outline environmental issues (Clause 10) and regulatory issues (Clause 8) involved in the life assessment and finalize with a financial analysis of the refurbishment options (Clause 9).

This document is about life extension of HVDC converter stations only. Upgrading the converter stations or operating them beyond their design specifications is out of the scope of this document. However, for both of these OEM can be consulted as these are complex and a custom-built installation and the normal design rules will likely not apply.

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# LIFE EXTENSION GUIDELINES FOR HVDC CONVERTER STATIONS

## 1 Scope

This document provides guidelines for the general procedure for performing life assessment for an HVDC converter station. Following this, a more detailed description of performance issues of the thyristor based HVDC systems is given and the life assessment measures of equipment and guidelines for accessing the techno-economic life of equipment are given. This document also deals with information for specification of refurbishing HVDC system and the testing of the refurbished and replaced equipment. Lastly, this document outlines environmental issues and regulatory issues involved in the life assessment and concludes with a financial analysis of the refurbishment options.

## 2 Normative references

There are no normative references in this document.

## 3 Terms and definitions

For the purposes of this document, the following terms and definitions apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

**3.1**
**life extension**
life assessment of the HVDC and the final result being beyond its original designed life time

Note 1 to entry: As a result of the life assessment, the output could be not to extend the life and this would be outside the scope of this document.

**3.2**
**design lifetime**
time for which the component has been designed to be commercially available or is commercially viable in its original supplied form

**3.3**
**independent expert**
person having an expert knowledge of a part or many parts of a HVDC link and is permitted to be a consultant or not

**3.4**
**maintenance spare**
spare component to replace a component within the system that is expected to wear out or have a limited lifetime, either in terms of operational (or storage) time or usage

Note 1 to entry: These components, known as maintenance spares, can be replaced at predictable and specified intervals.

**3.5**
**strategic spare**
spare component to replace a component that has failed where failure and replacement cannot be predicated and quantified on a yearly basis and be random in nature

**3.6**
**vendor-specific spare**
spare component that is available from the original equipment manufacturer only and for a limited period of time (typically about 15 years)

Note 1 to entry: For example, an HVDC control system has a life of approximately 15 years before a new generation is developed.

Note 2 to entry: If a spare component is purchased at the end of one generation and the spares are not available for the overall lifetime of the control system, a strategic spare parts management is required to ensure the availability of the system.

Note 3 to entry: Thus, the number of spares has a direct influence on the usable life of the equipment.

**3.7**
**resin impregnated paper**
**RIP**
condenser paper in a bushing which is impregnated with an epoxy resin compound

**3.8**
**refurbishment**
replacement, renovation or overhauling of components or equipment or parts of a system in response to wear or end of life

**3.9**
**upgrade**
modification or replacement of parts of an HVDC link to add functionality such as AC system stabilization, overload capabilities, better dynamic performance, increased reliability and availability, lower maintenance, etc.

Note 1 to entry: An upgrade also includes increasing the rated transmission capacity of the HVDC link.

**3.10**
**extension**
HVDC link that is extended to adapt to growing demands, involving additional converters or additional filters, etc.

**3.11**
**greenfield**
developing a brand new HVDC link on a previously free and undeveloped area using all new equipment

**3.12**
**brownfield**
developing an essentially new HVDC link or refurbishing part of HVDC link on an existing site

**3.13**
**refurbishment outage time**
time during which the HVDC project being refurbished is kept out of service and not able to transmit energy

Note 1 to entry: Depending on conditions, the outage time requirement excludes system tests, and post-refurbishment.

**3.14**
**insulated gate bipolar transistor**
**IGBT**
turn-off semiconductor device with three terminals: a gate terminal (G) and two load terminals, emitter (E) and collector (C)

Note 1 to entry: This kind of device is used in voltage-sourced convertor (VSC) HVDC application.

Note 2 to entry: Bi-mode insulated gate transistor (BIGT) and injection-enhanced gate transistor (IEGT) are variants of IGBT. There are several types of turn-off semiconductor devices which can be used in VSC converters for HVDC, too.

Note 3 to entry: For convenience, the term IGBT is used throughout this document to refer to the main turn-off semiconductor device.

## 4 General procedure for performing a life assessment

### 4.1 General

A typical HVDC system consists of the following main equipment and sub-systems integrated for power transmission of the HVDC link:

1) Converter transformer and its associated bushings:

   Primary side AC bushing is rated for system voltages. Secondary or valve side bushings are rated for AC-DC stresses. Further, depending on the connection to the thyristor valve bridge, bushings are used to compose the circuit of star or delta configuration.

2) Valve hall and its equipment:

   This mainly consists of a thyristor valve along with its electronics, optical fiber and valve arresters. It also consists of DC current and voltage measurement devices and other surge arresters inside or outside depending on layout of system.

   There is a valve cooling system either with or without piping and tubing of the valve cooling.

3) HVDC Control and Protection (C&P) system.

4) AC filters and associated AC switchyards:

   Typically, AC circuit breakers feeding the AC filter and converter become critical from a transient recovery voltage (TRV) point of view. Other equipment such as AC surge arrester, AC CT and VT also require replacement during the course of life of the system.

5) DC switchyard and associated equipment:

   In the case of point-to-point transmission with DC line/cable, the DC switchyard consists of DC filters, smoothing reactor, high speed pole isolating/connecting switches, commutating switches with commutating circuits, DC disconnectors, DC current and voltage measurement equipment, etc.

As indicated in list items 2) and 3), depending on the age of the project, thyristor failure rate statistics and the availability of spares (both with owner and OEM) justifies necessary validation. The owner reviews and judiciously decides whether valve replacement (along with all its electronic components within the valve hall considering ageing and performance) is required or not. If needed the same can be done with an integrated approach along with HVDC C&P. This approach with a larger scope provides the advantage of competitive pricing with an incremental cost to the owner. It is noted that in back-to-back HVDC, number of thyristor levels are generally lower as compared to bipolar HVDC scheme. HVDC C&P is vendor-specific firmware, software and hardware and as well as their valve design. Hence, replacement of HVDC C&P and the valve as a package could bring an optimal technical and commercial solution through multi-vendor competitive bidding.

The electrical equipment is stressed during operation, which causes ageing and degradation of equipment affecting equipment performance. The ageing mechanism and cause of failure differs for each class of equipment.

The plan to refurbish an old HVDC plant culminates from the life assessment of the above equipment in station (refer to Annex A). This is critical as it paves the path for prioritizing the equipment replacement, packaging and tendering of the scope of work. This document outlines the failures and ageing pattern of various types of equipment.

Each assessment will be slightly different depending on the needs and expectations of the owner as well as the information available. In many cases, only high-level information will be available, in some cases detailed information will be available. In most cases, only a technical evaluation is required but in others a commercial justification is also required. This document is intended to describe the technical procedure only.

Only the HVDC equipment will be considered in this document, as the AC equipment is outside the scope of this procedure and there are several sources of existing literature already covering this topic. This excludes AC and DC filters and synchronous condenser and SVCs or STATCOM.

### 4.2 Preparation

In preparation for performing the life assessment, it is critical to define the needs and expectations of the owner as much as possible. The next step is to produce a written proposal detailing the scope of work, information available and to be provided by the owner, deliverables and estimated cost. The proposal needs to be discussed with the owner and modified as required and agreed upon. It is also critical to determine the amount of time that a life assessment is good for. It is expected that a life assessment would be conducted shortly before the end of recommended lifetime is reached to evaluate if the system can be used for more years than expected. Taking into consideration the project and scope definition time, it is recommended to conduct life assessments for C&P systems after 15 years, for main components in a more regular basis, starting with the life assessment of C&P systems and then every 5 years.

### 4.3 Team

A team can be established which typically consists of the owners' staff, suppliers' staff and independent experts, or any combination thereof. The team structure is different if only one piece of equipment is being evaluated or if the entire HVDC station is being considered. Formal communication is expected to be through a leader on both the independent experts' and owners' sides only. Formal communication is anything that affects price, schedule or quality. Informal communications are still encouraged.

In general, a specialist or expert is employed for each of the areas, but some areas are critical because of the importance, complexity, or cost:

- Converter transformers and smoothing reactors – Critical because they are normally the highest cost item in a life assessment endeavour and are very complex.
- Thyristor valves – Critical as they are the next highest cost and a very specialized area.
- HVDC control and protection – Critical as they are very complex.
- Valve cooling systems – not as critical but still need proper evaluation.
- Air conditioning for control rooms and converter plant areas.
- Auxiliary systems – Critical, these are usually a source of many operating problems.
- Other DC equipment – includes DC current transformer (DCCT), DC voltage transformer (DCVD), disconnectors and breakers and switches.
- Civil – Ageing of structures and foundations.
- Miscellaneous – Wiring, fire protection, security buildings and ground grid. These items are usually overlooked in an assessment, but consideration of the same items is to be given.

### 4.4 Assessment process

A kick-off meeting with the team is recommended to obtain the information and discuss the format in which it is provided, as well as any software required to open the files and interpret the results. These are provided in a standard format such as using common word processing software wherever possible.

Several visits to the station(s) are carried out for discussions with the maintenance staff. Also, discussions are carried out with the operating staff to determine if the equipment is meeting their expectations. It is also determined whether there are any additional requirements that the existing equipment cannot provide and possible benefits.

The following are part of the analysis:

– Operating problems or changes in the mode of operation,
– Maintenance records for the last 5 years,
– Any modifications performed and why,
– Any failures and failure reports,
– Original quality or design issues,
– Any equipment replaced and when,
– Spare or replacement parts or obsolescence for major or critical equipment. An example is the number of thyristor failures per year, spares on hand and whether they are still available from a supplier.
– Status of spares – questions to consider are whether they are usable? Have they been maintained? Have they been in service and removed because they were of technical issue such as gassing of the converter transformer which were then repaired and returned to the replacement stock inventory? Have they never been in service?
– Technical skills of staff to continue operating and maintaining the equipment. Is additional training required?
– Normal life of each piece of equipment.
– Drill down to the smallest subsystem or components possible to check if it is possible to replace only some components and not the larger equipment subsystem or system. This could save a lot of cost but requires that detailed information be available.
– Criticality of the HVDC link to the system and consequences if it is unreliable or out of service.
– Risk assessment – is there a way to prevent or mitigate a risk? What needs to be done if the risk occurs?
– Some equipment does not have a history of problems and failures, but consideration is given that such issues will occur if the life assessment is long enough and is considered as a contingency.
– Replacement costs, wherever possible, are obtained from a supplier. Where this is not possible, estimated costs based on previous experience are required.
– An implementation schedule will also likely be required. Wherever possible the schedule is obtained from a supplier. Where this is not possible, a rough schedule based on previous experience is required.
– Environmental effects of the terminal and the surrounding site is considered.

As equipment is costly it is beneficial to use an independent expert to review an assessment provided by a supplier.

Regular status update meetings between the owner and the involved parties are generally held to ensure everyone is on track and to disseminate any new information, if available.

In order to make a future failure estimation, the asset owner could also use mathematical tools to analyse the historical records of the failure rate data of the existing high voltage equipment. Statistics and statistical tools could be applied to describe and analyse the failures for the decision-making process. Cigre TB 706, guidelines for the use of statistics and statistical tools on life data, provides more details on this topic.

Additionally, in general for the new system, a condition-based maintenance database is established to have a clear picture of the system at any time. In the case of replacement of components or refurbishment of systems, necessary sensors are built to facilitate such condition-based maintenance. Furthermore, with this database it would be possible to calculate the future failure probability of the equipment. As a result, it will be possible to get a clear picture of which equipment is expected to be renewed in what timeframe.

### 4.5 Deliverable

The deliverable is usually a report with a range of options for comparison, recommendations and conclusions. A preliminary copy of the report is reviewed with the owner incorporating any comments or concerns. In some cases, the owner will request additional work in a specific area requiring additional analysis, modifying the report and another preliminary meeting.

Eventually a final report will be issued. The owner will then combine this with the commercial analysis and make a final recommendation for brownfield or greenfield.

In the event that the owner also wants a commercial analysis, it is necessary to understand these requirements and follow the standard way or format in which the company produces the information and if the project is to be financed by a bank what is necessary for the bank to carry out its risk assessments.

### 4.6 Life assessment timetable

Life assessment generally begins 5 years (refer to Figure 1) before the time indicated in Table 1 [1] or if there are high failure rates or maintenance issues.

The reality is that there is no piece of equipment where a firm number is accurate. The idea of coming up with a number is that if this piece of equipment has not caused any major problems up to the relevant point in time, a life assessment is generally done to determine the remaining life, refurbishment and replacement of that piece of equipment, subsystem or system, or if replacement is done, then the entire HVDC project is sometimes the best option. Only major items are considered in this document, and not subcomponents.

[1] Reproduced from CIGRE Technical Brochure No. 649 with the permission of CIGRE.

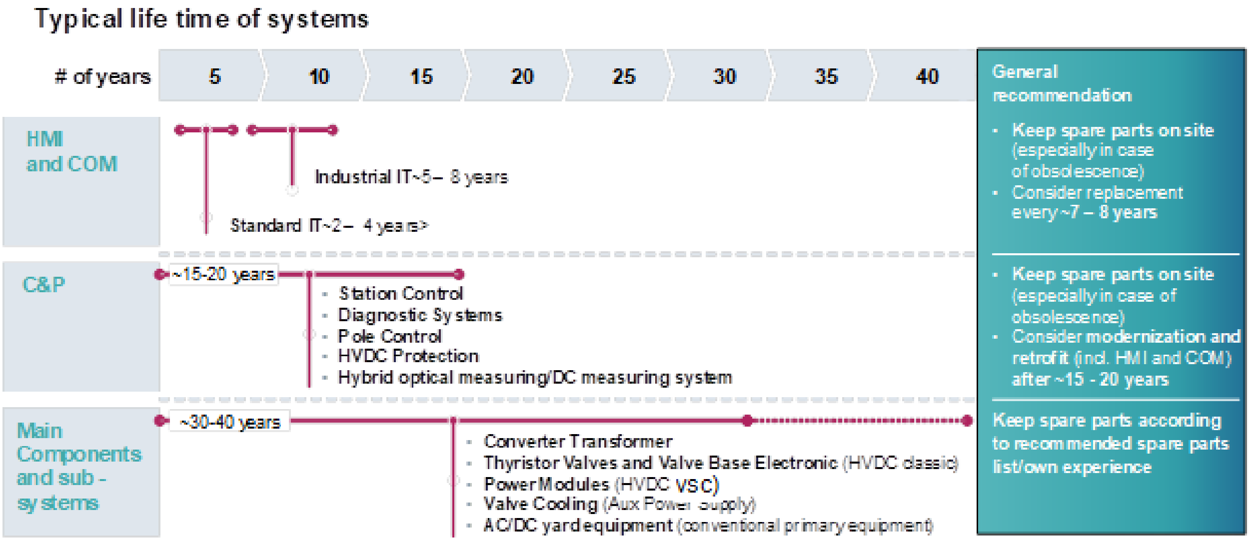



**Figure 1 – Typical lifetime of systems/equipment in HVDC stations**

The necessity to renew the different systems of an HVDC can be generally divided into four stages of the complete lifetime.

1) SCADA / HMI: 8 to 10 years
2) Control and protection: 15 to 20 years
3) Auxiliary system (heating, ventilation and air conditioning, cooling water control, auxiliary power etc.): 10 to 20 years
4) Main components: 30 to 40 years

As it can be seen that Stage 2 and Stage 3 are overlapping, it would make economic sense to combine the replacement of the control and protection system and the subsystems.

**Table 1 – HVDC equipment lifetimes (typical)**

| HVDC equipment lifetimes | | |
|---|---|---|
| NOTE Excludes design and production run quality issues | | |
| HVDC station design life 30 to 40 years | | |
| **Equipment** | **Lifetime (years)** | **Comments** |
| | | |
| **Converter transformer** | 40 | Depending on load factor |
| AC Bushings | 25 to 30 | |
| DC Bushings | 30 to 35 | |
| Tap changer | 30 | Vacuum type tap changers generally have longer life span with higher number of operations as compared to oil filled tap changers. A refurbishment decision can be judiciously taken by the owner based upon the actual condition of tap changers. |
| Coolers | 25 | |
| **Thyristor valves** | 35 | |
| Thyristors | 35 | |
| Valve reactors | 30 | |
| Tubing | 25 | |
| Fiber optics | 35 | |
| Damping capacitor | 30 | |
| Damping resistor | 30 | |
| Electronic cards | 25 to 30 | |
| Coolers | 25 | The efficiency of the cooling system to be evaluated after 15 years. |
| | | |
| **Control & Protection** | | |
| HVDC Controls (digital) | 15 to 20 | |
| HMI | 7 | |
| **Other major equipment** | | |
| DC smoothing reactor (oil) | 35 | Bushings have a shorter life |
| DC smoothing reactor (dry type air core) | 35 | Dry type air core reactor is simply called air core reactor |
| | | |
| Optical DCCT | 30 | Electronics have a shorter life |
| DC voltage divider | 30 | |
| DC surge arrestors | 35 | |
| DC insulators | 35 | |
| DC wall bushings | 30 to 35 | 30 OIP, 35 RIP – DC bushings have more insulation |
| DC switching equipment | 35 | |
| DC Bus work, structures | 50 | |
| Ground electrode | 40 to 50 | Normal design life |
| Civil work | 50 | |
| Communications systems | 15 | |
| Source: CIGRE Technical Brochure No. 649. | | |

# 5 Thyristor based HVDC systems performance issues

## 5.1 General

HVDC technology has experienced enormous growth worldwide in the past 50 or more years, and many HVDC systems are currently in operation. As these systems age, asset management questions of what to refurbish, what to replace and the scope of equipment repair and replacement is becoming increasingly important to extend the life of all HVDC links.

An HVDC system will likely have a computerized maintenance management system (CMMS) which will contain more detailed records than that which is necessary for reporting to CIGRE or internally to high level management within an organization. It is important that the root cause analysis reports from the field experts can be stored in the CMMS system. Modern day CMMS also have asset management systems integrated into them to assist with life assessment decisions.

The following is some information about the collection of data from HVDC schemes throughout the world from those HVDC schemes that have submitted the information. This information can be useful for benchmarking or for discussions with staff from HVDC schemes that are similar.

## 5.2 Survey of availability and reliability of HVDC systems in the world

### 5.2.1 General

CIGRE SC B4 collects operational performance and reliability data of HVDC systems in commercial service in the form of annual reports. Such reports are prepared in accordance with a standardized protocol published in accordance with CIGRE Technical brochure 590 "Protocol for reporting the operational performance of HVDC transmission systems". Also refer to IEC TR 62672.

Performance data includes reliability, availability and maintenance statistics.

Reliability data is confined to failures or events which result in loss or reduction of transfer capability. Statistics are categorized in order to indicate which type of equipment caused the reduction in transmission capacity.

Advisory Group B4.04 of CIGRE Study Committee B4 (DC systems and Power Electronics) summarizes the performance statistics for all reporting schemes every two years in a CIGRE paper entitled "A Survey of the Reliability of HVDC Systems Throughout the World".

High levels of equipment reliability for individual HVDC links are also visible from the CIGRE performance reports. The CIGRE performance report also contains sections with the yearly number of forced outages and duration of forced outages (in equivalent outage hours) for each equipment category.

Converter station equipment is classified into six major categories: AC and Auxiliary Equipment (AC-E), Valves (V), Control and Protection (C&P), DC Equipment (DC-E), Other (O) and Transmission Line or Cable (TL).

### 5.2.2 AC and auxiliary equipment

This major category covers all AC main circuit equipment at the station (from the incoming AC connection to the external connecting clamp on the valve winding bushing of the convertor transformer). This category also covers low voltage auxiliary power, auxiliary valve cooling equipment and AC control and protection. It is subdivided into following subcategories:

– AC filter and shunt bank AC-E.F

Types of components included in this subcategory would be capacitors, reactors, and resistors which are included in the AC filtering or shunt compensation of the converter station.

– AC control and protection AC-E.CP

  Assigned to this subcategory are AC protection, AC controls, and AC current and voltage transformers. AC protection or controls could be for the main circuit equipment, for the auxiliary power equipment or for the valve cooling equipment.

– Converter transformer AC-E.TX

  The converter transformers and any equipment integral to the converter transformer such as tap changers, bushings or transformer cooling equipment is assigned to this subcategory.

– Synchronous condenser (compensator) AC-E.SC

  The synchronous condenser (compensator) and anything integral or directly related to the synchronous machine such as its cooling system or exciter is included in this subcategory.

– Auxiliary equipment & auxiliary power AC-E.AX

  This subcategory includes auxiliary transformers, pumps, battery chargers, heat exchangers, cooling system process instrumentation, low voltage switchgear, motor control centres, fire protection and civil works.

– Other AC switchyard equipment AC-E. SW

  This subcategory includes AC circuit breakers, disconnect switches, isolating switches or grounding switches and AC measurement equipment.

The classification of other groups can be found in IEC TR 62672.

## 5.3 Operating history

Records of equipment operating history are an integral part of equipment maintenance, and are required to verify the suitability of maintenance practices, in order to achieve the design life of the HVDC equipment.

Equipment operating history generally contains basic equipment technical data, maintenance intervals, detailed records of maintenance activities completed during the scheduled outages, components replaced to keep the equipment operational, forced outages caused by the equipment, results of scheduled inspections and diagnostic tests and results of tests done after replacement of components. The data also includes the root cause analysis reports for each forced outage and the corrective actions taken.

The data collected is used to assemble equipment condition assessment reports which assist in identifying any requirements to increase and change maintenance, repair or replace equipment.

## 5.4 Major equipment/system/sub-system failure/refurbishment summary

Modern thyristor based HVDC links are designed to last at least 30 to 40 years.

Not all equipment used in the converter stations will have a lifetime of the full 30 to 40 years. Therefore, if running the equipment to failure is not an option due to expensive consequential equipment damage and long unplanned outages, midlife replacement and refurbishment of HVDC equipment is a valid option.

The major HVDC equipment requiring life assessment activities are: converter transformers, valves, valve electronics, controls and protection, valve cooling, AC filters, DC filters, smoothing reactors and circuit breakers.

For HVDC links constructed in the 1970s (early thyristor links) the following life assessment activities were undertaken:

- Valve controls and valve electronics upgrade: between 16 and 44 years in service after commissioning. Some systems are still in service.
- Control and protection system upgrade: between 26 and 42 years. Some systems are still in service.
- The replacement of thyristors in some projects was completed after 21 to 30 years of thyristors in service.
- Cooling systems have been upgraded or replaced after some 25 years of service.
- Replacement of oil filled smoothing reactors (with air core or oil) and oil filled direct current transformer (DCCTs) after some 35 or more years of service.
- Refurbishment of converter transformers after about 30 years of service.

For the HVDC links constructed in the 1980s, the following life extension activities were undertaken:

- Control and protection system upgrade: between 23 and 35 years. Some systems are still in service.
- Valve cooling system upgrade: after 24 years in service.
- Valve upgrade (together with valve cooling) after 25 to 31 years in service. Some valve systems are still in operation.

### 5.5 Life assessment and various options for a refurbishment project

As mentioned in 4.6 various components of the HVDC system have different design life. In order, to maintain the performance of the HVDC link at an acceptable level, the components can be replaced as they approach the end of their design life.

Therefore, the refurbishment options fall into two categories:

- Selective repair and refurbishment or replacement of HVDC equipment;
- Complete replacement of HVDC converter stations.

a) Selective repair and refurbishment or replacement of HVDC equipment

   As some components (e.g. controls) have a much shorter design life than the major components like converter transformers, selective refurbishment will be required during the expected lifetime of the project (30 to 40 years).

   It is very important that equipment can be repaired as spare parts remain available, and the knowledge base (engineering and technical staff) is retained.

   Equipment replacement is required if spare parts are not available (OEMs are no longer in business). The parts are phased out, discontinued, cannot be remade or they are reverse engineered locally, or the knowledge base is lost (maintenance personnel familiar with the equipment have retired).

   Selective equipment replacement is an excellent method to achieve the design life of the HVDC link if other components that are not refurbished or replaced can last until the end of HVDC converter station extended life.

b) Complete replacement of HVDC converter stations

Complete converter station replacement is required when the majority of the equipment is at the end of its design life; the HVDC link is still required for power transfer, or AC system performance improvement. This can ultimately be a combined economic and/or technical decision to determine the scope of replacement.

The advantage of complete replacement would be a much larger design life and a system which has been uniformly engineered and supplied by a single supplier whereas the disadvantage would be the higher cost. Complete system replacement would mean longer shutdown of the HVDC system. Depending on the staging of the replacement and the placement of the new station, outage times can be minimized as a new station can be built next to the existing (running) one. However, for that, additional space is necessary.

Complete replacement of HVDC converter stations is also an opportunity to increase the steady state power transfer capability, dynamic power transfer capacity of the link or where a lengthy outage to the existing converter stations is not acceptable. In some cases, this is an opportunity to switch from LCC technology to VSC technology.

In any case, actions for extending converter station life can be addressed before HVDC link reliability and availability are impacted.

Irrespective of the choice of replacement technology (LCC or VSC), the following options can be considered for determining the economic impact.

1) Build a greenfield new station near the existing station, then transfer over.
2) Build a new station near the existing station but use some of the components of the original converter.
3) Build the new station at the same location.

The economic impact of replacing the LCC converter with a VSC converter will depend on what option is chosen for replacement. Issues related to replacement of LCC converters with VSC converters are discussed in Annex B.

- OPTION 1 – Build a greenfield new station near the existing station, then transfer over.

  In this option a new station using all new equipment is built near the existing station. This option will result in the shortest outage time. The existing system will continue to transmit power while the new station is being built. Once the new station is ready, an outage of 3 to 6 months will be required to commission and integrate the new station into the system. This option will result in a minimum amount of revenue loss.

- OPTION 2 – Build a new station near the existing station but use some of the components of the original converter.

  In this option, an additional several weeks will be required to move the equipment from the old converter to the new converter. This time will be in addition to the commissioning period as required in option 1. The additional outage time required will depend on what components are being reused.

  For example, if the auxiliary equipment (battery banks, etc.) are to be reused, the existing system would be shut down much earlier than if only the smoothing reactor, etc. is to be reused.

  The cost of buying new equipment vs loss of revenue resulting from additional outage are generally taken into account in deciding if some components of the old system are used or not.

- OPTION 3 – Build the new station at the same location.

In this option, the old system would be shut down completely from the time the removal of the existing equipment starts until the new system is in operation. If the existing valve halls cannot be reused, the old buildings would be demolished and a new building built at the same location. This will result in outage time being the longest of the three options. This duration is estimated to be at least 5 to 6 months to remove the existing facilities and building a new building and equipment takes an additional time in the range of 28 to 32 months.

The final choice is determined by the following factors:

- Availability of land nearby

The availability of land depends on the location of the existing station. If the station is located in an open area outside the populated area, it is likely possible to purchase land adjacent to the existing station. However, if the station is located inside a populated area, it is likely not possible to obtain land for building a new station.

- Cost of outages

The cost of outages is determined by the function of the HVDC system in the overall power system. In cases where the HVDC system is transmitting power from a dedicated generating station to the load centre with no parallel transmission system, the cost of outages will be higher than the cases where a parallel transmission system is available.

In other cases where an HVDC system was built to transmit power from a dedicated thermal generator, the cost of outage is much lower if the generators are refurbished/replaced at the same time.

- Feasibility of using the old equipment

Major equipment like converter transformers, smoothing reactors and bus work have a much longer design life than the rest of the equipment. These components are allowed to be reused for the refurbished system provided the system rating has not been increased.

If old equipment is reused, on-site spares (e.g. spare converter transformers) can be available to reduce the outage time in the event of failure.

- Feasibility of using the existing valve halls

Most HVDC systems that require complete refurbishment/replacement are more than 40 years old. Even though the number of thyristors required have been reduced to less than 50 % it does not automatically mean that the new thyristor valves can be installed in the old valve halls.

The feasibility of fitting new valves in the existing valve halls needs to be evaluated with the vendors before going to valve refurbishment.

If the standard design of valves will not fit in the existing valve halls it becomes necessary to custom design the valves if the existing valve hall can be used. This will result in additional cost.

### 5.6 Methods for assessing reliability, availability and maintainability of existing components

CIGRE's survey of the reliability of HVDC systems throughout the world enables HVDC link asset owners and operators to compare the performance of their own HVDC link against the performance of similar HVDC links in the world. It is recommended for owners seeking to assess the reliability, availability, and maintainability of components, to actively participate in the CIGRE HVDC survey.

The goal is that the accumulated data from several systems would establish a basis against which performance of individual HVDC links could be judged.

Performance of any HVDC system can be evaluated using data on energy availability (EA), energy utilization (EU), forced energy unavailability (FEU), scheduled energy unavailability (SEU) and thyristor failure rates, as well as examining equipment categories causing forced outages or reduction of HVDC system capacity.

In the CIGRE survey and statistics carried out by Advisory Group B4.04, the following definitions are used:

- Outage – The state in which the HVDC system is unavailable for operation at its maximum continuous capacity due to an event directly related to the converter station equipment or DC transmission line is referred to as an outage.
- Scheduled outage – An outage, which is either planned or which can be deferred until a suitable time, is called a scheduled outage. Scheduled outages can be planned well in advance, primarily for preventive maintenance purposes, such as annual maintenance programs.
- Forced outage – The state in which equipment is unavailable for normal operation but is not in the scheduled outage state is referred to as a forced outage.
- Forced outages can be caused by trips – sudden interruption in HVDC transmission by automatic protective action, manual emergency shutdown, or unexpected HVDC equipment problems that force immediate reduction in capacity of HVDC stations or system but do not cause or require a trip.
- Energy availability (EA) – A measure of the energy which could have been transmitted except for limitations of capacity due to outages is referred to as energy availability.
- Energy unavailability (EU) – A measure of the energy which could not have been transmitted due to outages is referred to as energy unavailability.
- Energy utilization (U) – A factor giving a measure of the energy actually transmitted over the system.

For example, comparing the performance of one HVDC link against similar pairs.

Scheduled equipment unavailability (SEU) has less significance than forced equipment unavailability (FEU) in comparing different systems since scheduled outages are allowed to be taken during reduced system loading conditions or when some reduction in power transfer capability is acceptable. Discretionary outages for maintaining redundant equipment are also considered within the SEU category. As each system follows different maintenance practices, the scheduled energy unavailability (SEU) can vary considerably between systems. For example, some systems shut down the entire system for two weeks every year for scheduled maintenance whereas other systems perform maintenance only once every four years for a week.

### 5.7 Basis for replacement/refurbishment of equipment

HVDC converter station equipment (and subsystems) is complex and has varying design lifetimes. Each piece of equipment, system or subsystem is generally assigned a "normal" lifetime which, as it approaches, could trigger a life assessment.

The criteria for equipment replacement and refurbishment are related to the risks the asset owner is ready to take and potential lost revenue which is correlated to equipment performance.

For example, capacitors can be replaced after design life is exceeded. However, they can also be replaced after the number of failures exceeds a percentage of installed capacitors per year (e.g., 2 %). The latter option implies a number of filter bank trips or loss of redundancy (maintenance outage), which are the consequence of failed capacitor cans.

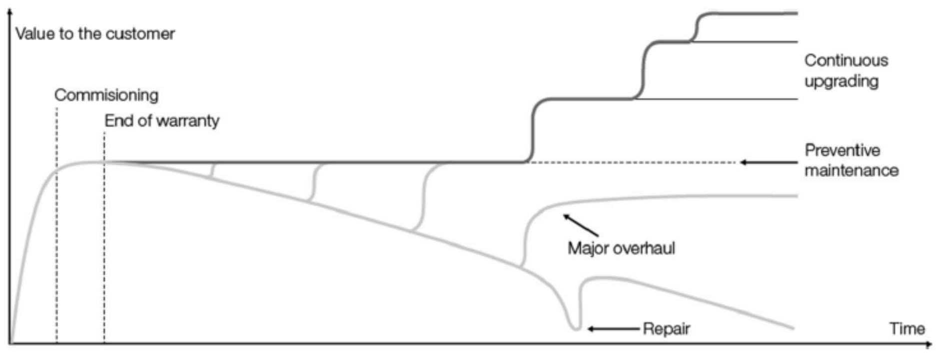



**Figure 2 – Typical equipment performance curve**

Figure 2 shows equipment performance with the passage of operational time based on equipment failure rate and ageing. The curve also shows the requirement of major overhaul and additional investment/effort in order to achieve the same value to the customer as well as indicating the importance of the HVDC link by carrying out suitable upgrades.

A conservative approach would be not to run the equipment beyond the manufacturer's recommended design life. An assumption is that the spare parts and skilled maintenance personnel are still available.

The following conditions could require equipment replacement or refurbishment even before the design life is exceeded:

– Poor performance of equipment. An unacceptable number of HVDC trips caused by this equipment reducing HVDC availability, or long scheduled outages required to keep the equipment in a serviceable condition.
– The type of equipment is not manufactured any more (for example circuit breaker) and there are no spare parts available. It is possible to postpone the replacement of the whole equipment fleet, say of circuit breakers, by replacing one or more circuit breakers, and using the parts from the units removed from service as a source of spares. In some cases, the parts can be reverse engineered by the utility if it has the knowledge or by other firms such as tap changer parts which specialize in this field.
– Engineering and maintenance staff retiring and the knowledge base of how to maintain some equipment is being lost and the supplier also cannot support maintenance of the equipment.
– The results of equipment condition assessments showing poor or deteriorating equipment conditions (for example very low degree of polymerization paper inside converter transformers), could justify earlier replacement, even before equipment design life is exceeded.
– Failures of the same type of equipment at other HVDC links, could justify unscheduled equipment condition assessment, and if required, early replacement.
– Manufacturer instructions to remove equipment from service due to a production defect (e.g. use of unsuitable material for components during production) could result in early equipment refurbishment.
– Under direction from an outside regulatory body (safety or environmental issues for example).

- Technical obsolescence – older software versions are no longer supported by the OEM and the new software requires new hardware.
- High cost of operations maintenance and administration. OP-EX stands for operating expense. COMA – stands for cost of operations, maintenance and administration.

### 5.8 Performance after replacement and refurbishment

Reliability performance data collected for CIGRE reporting purposes (data on energy availability, energy utilization, forced and scheduled outages and other data in accordance with the reporting protocol per IEC TR 62672) can be used to evaluate success of equipment replacement.

Performance improvement is generally visible by comparing HVDC reliability data and loss of redundancy data (number of forced outage events and the equivalent forced outage hours relevant to replaced equipment category) two years before replacement and two years after replacement.

However, if the equipment was performing well and had enough spare parts (for example the control and protection system) but was replaced with the new model due to obsolescence, then good performance in the future will be the sign of successful equipment replacement. If equipment is replaced as a result of condition assessments identifying poor or deteriorating equipment, prior to the equipment affecting performance indicators, there could be an expectation of a reduction in maintenance and that is generally reflected in maintenance records and maintenance hours required.

## 6 Life assessment and life extension measures of equipment

### 6.1 General

This Clause 6 discusses the life assessment and life extension measures of the HVDC equipment from a technical point of view based on the premise that all types of the equipment have been properly maintained by following the maintenance instructions recommended by their original equipment manufacturers (OEM). The AC switchyard equipment is not covered in this Clause 6, except for the converter transformers.

The first and most important part of the life assessment procedure is to inspect the site works. During the inspection any visual defects or damage to equipment are noted. Discussions are conducted with the operating teams and maintenance teams on site to note their observations and suggestions. Station maintenance, availability and reliability and equipment failure logs are reviewed. Changes in the system as compared to the system during design of HVDC system can be noted and its effects on the HVDC system determined. Availability of spares in store as well as whether spares are still available for purchase from the manufacturer are noted down. Recurring problems due to design defects are also noted down. In the case of control and protection systems' components, cards and relays can be checked to check if they have become obsolete. Operating systems are checked for the supplier support availability. Modifications from original design are also noted.

Site testing involving testing of different equipment to determine the health of the equipment is an important part of life assessment. This includes measuring parameters like resistance; capacitance, inductance, tan delta as well as dielectric withstand tests. The scope of testing is limited by the site conditions, available test equipment on site as well as requiring the shutdown of the plant for testing. In some cases, special test facilities (mobile testing system) are also brought to the site for more detailed testing. The test results show not only the health of the equipment, but also present parameters of existing equipment which are needed in case of refurbishment of other equipment.

In general, the health of the existing equipment can be ensured to define the exact scope of the planned refurbishment.

This can be done via visual inspection, check of sequence of events recorder (SER) and transient fault recorder (TFR) messages, and the knowledge of abnormalities observed during maintenance outages.

Most converter stations employ some kind of computerized maintenance management system (CMMS). It can be part of a larger system, a standalone system or a home-grown system. There is continuing pressure to reduce maintenance costs and outage times and some utilities have moved to reliability centred maintenance (RCM) systems and away from time-based systems. RCM generally relies on doing maintenance based on levels of inspections, importance of equipment, is condition based and relies on appropriate and timely maintenance intervention. This has the effect of improving reliability and availability and reducing maintenance costs. This can be a hard sell to existing converter station staff who are used to a time-based system.

During the warranty period of the OEM, maintenance requirements can be followed and well documented to prove that the maintenance has been completed. After this period condition-based maintenance or RCM can be adopted.

It is very important to have good maintenance records to analyse the equipment performance with the root cause analysis of any failures. Complete systems have been replaced by utilities because the root cause of the problem was not identified and thus the problem was still there after replacement. Trend analysis is also very important as a bad reading or information, or statistical analysis can skew an analysis with very little data. Good records are also very important to assist in justifying any refurbishment or replacement as it can be readily shown how much improvement is possible and what the benefit could be in increased revenue.

## 6.2 Spares

The number of spares that are available especially for items such as the DC controls can impact the usable life of the equipment. Spares can be broken down in many ways, one way is as follows:

- RAM and performance guarantees spares – Spares required to meet the RAM, and performance guarantees requirement of the contract, usually 2 years.
- Initial spares – Spares for the first 10 to 15 years to get a record of the failure rates and then to order more. The supplier will usually guarantee availability of spares for that period.
- Insurance spares – Spares to cater for infrequent failure (e.g. DC wall bushing).
- Consumable spares – Items to be consumed due to normal failure rates (e.g. fan, motors).
- One-supplier items – Some items are only available from the OEM, control cards are an example whereas AC filter capacitors are available from many vendors on relatively shorter notice, and thus stocking levels will likely be different. In most instances exact replacements are generally available; however, in certain instances a re-design of the bank is required.

Some utilities are starting to specify that enough spare parts be supplied to last the 35 to 40 year life of the project. This could help ensure the viable life of 40 years of these types of devices.

## 6.3 Converter transformers

### 6.3.1 General

An HVDC converter transformer is, in many ways, similar to an AC transformer. This Subclause 6.3 will only focus on the differences between them from a life assessment and extension point of view.

### 6.3.2 Life assessment

The life of HVDC converter transformers is expected to be around 40 years, but it can differ greatly depending on many factors.

Life assessment of a converter transformer is similar to that of an AC transformer. In addition, special consideration for the converter transformer includes the following:

- DC bushings. The oil end of a DC bushing (including the condenser core) is an integrated part of the transformer insulation structure. The condenser foils are aligned with the DC barriers such that only a bushing with the exact make, type and model can be used for replacement. Thus, lack of spare DC bushings can be a major factor limiting the service life of the converter transformer. The life of a DC bushing is expected to be 30 to 35 years, but its remaining life is hard to predict. It is advisable to periodically perform the capacitance and power factor tests and other tests recommended by the OEM in order to identify signs of potential failure. It is possible to take oil samples, but it is not generally recommended by the bushing manufacturers considering that it would risk contaminating the oil and is likely to require the replacement of a nitrogen gas cap. This is generally done only when absolutely required and following the OEM's instructions. In some instances, a valve is provided at the bushing flange, which makes this a lower risk operation.
- Tap changers. The tap changer of a converter transformer operates much more frequently than that of an AC transformer. For example, a typical HVDC scheme can have more than 5 000 tap changer operations per year at the inverter and many more operations at the rectifier. Because of such a high number of operations, regular inspection and necessary overhaul are required in order to keep the tap changer operating reliably. The condition of the tap changer can be determined by reviewing its maintenance records. Its operating characteristics can be easily monitored in real time thanks to advances in technology. The number of operations and the measurement of the amount of wear on the arcing contacts are indicators of end-of-life (EOL) or a need for refurbishment. The diverter conservator filling or removing of oil while in service is an indication of an oil seal or O-ring failure between the main tank and the diverter vessel.
- Core and windings. A converter transformer is more prone to internal failure due to its additional complexity (e.g. DC cocoon insulation, DC bushing as part of the insulation structure, etc.) and special service conditions (e.g. AC and DC voltages/currents, harmonic currents, etc.). Oil gassing is an indication of potential internal failure. Online hydrogen monitoring can give a quick indication of any gassing concerns which would then be followed up with oil sampling and dissolved-gas analysis (DGA). It is noted that DGA is not a substitute for condition assessment and the information from DGA merely provides a high-level indication of a potential problem and when to conduct a more detailed assessment. Testing of a converter transformer for a condition assessment generally follows the manufacturer's instructions. This could include frequency response analysis, core vibration tests, partial discharge tests as well as the periodic dielectric tests. When a failed converter transformer is repaired in the factory, this could provide an opportunity to assess the condition of the unit and extrapolate this information into the other transformers, as they are usually similar in design.

### 6.3.3 Refurbishment/Replacement

The replacement or refurbishment of a converter transformer is similar to that of an AC power transformer. In addition, special consideration for the converter transformer includes the following:

- DC bushings. If a DC bushing fails, it can be replaced with a spare having the exact make, type and model as previously described. Because DC bushings are very expensive as compared to AC bushings, it is more economical to refurbish a DC bushing by replacing its core and/or seals if required, but it would be done by the OEM. The current revision of the IEC/IEEE 65700-19-03:2014 converter transformer standard requires the manufacturer to provide sufficient information so that replacement bushings can be obtained if the OEM is not available or no longer in business. In some cases, the utility or contractor is capable of replacing seals, processing, and testing.

- Tap changers. Spare/replacement parts for older tap changers are difficult to find and/or costly to procure. Some utilities have refurbished the tap changers using reverse engineered parts. In other instances, the entire tap changer has been replaced with the assistance of the transformer manufacturer. Retrofitting of vacuum type diverter switches and tap changers is offered by many suppliers and can be considered if full replacement is warranted. This can help reduce maintenance costs and frequencies.
- Core and windings. It is sometimes economical to replace either the windings or the core, but not both. A business case analysis is generally conducted taking into consideration any design improvements and the associated benefits. The remaining life of all other components such as the bushings, tap changers, etc. can also be included in the analysis. It is possible to repair a tap changer lead or other connections in the field depending on internal access. These are generally done by the OEMs or under their supervision. Loose core laminations can be fixed to some degree and loose blocking can be repined, again depending on access. In the event of having loose core laminations, online degassing allows the converter transformer to stay in-service until a scheduled shutdown. This was successfully done by one utility for several years. An online multi-gas analyser can be added during the degassing or to the transformer of concern in order to provide instant notification of any changes to the gassing pattern.

## 6.4 HVDC control and protection

### 6.4.1 General

HVDC control and protection (C&P) systems usually covers bipole control functions, pole C&P functions and group C&P functions of the HVDC system. The control and protection functions are closely integrated, and therefore always designed, installed and replaced/upgraded together. Valve base electronics (VBE) provides monitoring and protection for each valve and serves as an interface between the VG control and thyristor valves. The pole/group controls and VBE are covered separately. Older HVDC systems used analog controls, however with only a couple of exceptions the analog controls have already been replaced with digital controls.

### 6.4.2 HVDC converter controls

#### 6.4.2.1 General

Digital C&P systems have been commonly used in modern HVDC systems. Their control and protection functions are realized with programmable controllers each consisting of highly integrated modules such as CPU modules, I/O modules, communication modules, interface modules, etc.

#### 6.4.2.2 Life assessment

Rapid advances in technology, design, hardware, and software as well as changes in system requirements tend to make the service life of digital systems relatively short. The service life of digital systems is typically 15 years. It is noted that C&P hardware is bought by supplier around 2 to 3 years before planned commissioning to perform factory system test (FST) before the delivery.

The digital system usually comes with full redundancy and comprehensive self-monitoring functions. A single mode failure does not normally result in a system outage. This combined with a shorter service life makes the digital system virtually immune from the various performance related issues resulting from component ageing and failures.

After 10 years of operation or as needed, a digital system is assessed for its remaining life with a focus on the following potential limiting factors:

- Spares. Most of the parts in a digital system are single source items, i.e. they are available only from the OEM. The various functional modules are an example. Lack of spare parts in stock and inability to procure them will result in the EOL of the digital system.

- Programmable tools. The programming tools for a digital system are usually desktop and laptop computers each having a licensed software platform. They have a similar life as the controls.
- Knowledge base. Enough trained engineering and technical staff are required to maintain, troubleshoot, repair, and reprogram a digital system. In some cases, they are also required to modify the software to accommodate station equipment upgrades.

#### 6.4.2.3 Refurbishment/Replacement

As digital controls have a much shorter life than thyristor valves, it is therefore reasonable to expect that the digital controls can be replaced twice during the service life of the associated thyristor valves. The second control replacement is expected to be done along with the thyristor valves. Efforts are made to avoid replacing digital controls more than twice. This requires that the life of the initial control system be extended as much as possible. However, there are limited life extension measures that can be taken, which are expected to include the following:

- Purchase enough spare parts/components including programming tools and compatible computers after 10 years or receiving the "last buy notice".
- Update the obsolete components such as computers and operating systems including the workstations.

Sacrificing part of the control redundancy in return for spare parts helps extend the life of digital controls but has significant impact on the system reliability and operation & maintenance (O&M) costs if the converter stations are unmanned or supported by external engineering and technical resources.

### 6.4.3 Valve base electronics (VBE)

Many of the previous discussions on the life assessment and life extension measures of pole/VG controls can be extended to the VBE, but with the following special considerations:

- The VBE and its associated thyristor valves are usually replaced together because of their integrated nature. In other words, the life of the VBE is expected to be the same as that of the associated thyristor valves, i.e., typically 35 years. In rare occasions, the VBE and thyristor electronics of light triggered thyristor (LTT) valves have been replaced along with the associated controls by the OEMs, although it might not be necessary. Pole/VG controls, on the other hand, are not an integrated part of the associated valves and therefore can be upgraded separately.
- The VBE in the modern HVDC projects has been built using individual modules/PCBs consisting of programmable logic devices and microcontroller chips. Accessing and modification is not considered for the VBE software once commissioned into service. The life of the associated thyristor valves is not expected to be limited by VBE. This requires that enough spare parts be available for VBE repairs.
- Depending on the availability of the spare parts, the employer is allowed to decide to replace the VBE either at the same time as the replacement of control and protection (C&P) or by itself. Both options have been used in different projects. When VBE is replaced, the interface between VBE and C&P and between the VBE and gate control units can be given special attention. If the VBE and C&P are replaced at the same time by the same vendor, the interface issue between VBE and C&P disappears.
- Whenever VBE is replaced, tests can be performed to verify the correct function of the gate control units and to ensure that the thyristors are protected. The testing setup includes an actual thyristor module.

## 6.5 Thyristor valves

### 6.5.1 General

Each thyristor valve consists of thyristor level components (thyristors, damping/grading resistors and capacitors, thyristor electronics, DC grading resistors, fibre optics, etc.), saturable reactors, cooling circuit components (heatsinks, tubing, electrodes, etc.) and valve arresters, and other electric components such as grading/compensating capacitors depending on the system design. The capacitors in the valves are permitted to be named differently in different projects. There are two types of thyristors used in LCC valves: electrically triggered thyristors (ETT) and light triggered thyristors (LTT). Most of the valve components are highly customized and usually can only be purchased from the original manufacturers.

### 6.5.2 Life assessment

The design or expected life of thyristor valves is typically 35 years. The upgrade history of the HVDC projects installed during the life assessment indicates that thyristor valves have been replaced after 25 to 45 years (approx.) in service as at 2022, and there are over 20 projects where thyristor valves are still in service after 30 years of age with an average of 37 years. The oldest water-cooled valves still in service are 45 years old.

The overall life/condition assessment of the valves is generally performed after 25 to 30 years in service or even earlier considering the long lead time of a valve replacement project, which can be up to 7 years (from planning to commissioning). Condition assessment of each individual type of component is typically scheduled using the life assessment timetable in 4.6 or on an as needed basis.

All the individual valve components can be easily replaced unless they are part of the valve structure. Most of the random component failures are associated with thyristor levels and do not cause forced system outages (i.e. pole or group outages) due to redundant thyristor levels. Thus, the remaining life of thyristor valves largely depends on the stock of spare components, their future consumption rates that could accelerate due to ageing, and the ability to acquire spare/replacement components either from the OEMs or other suppliers. Lack of spares for any type of highly customized valve component can result in the end of life (EOL) of thyristor valves. This is generally the focus of valve life/condition assessment. In addition, the valve base electronics (VBE) is an integrated part of the valves and is a factor limiting their service life (see 6.4.2 for more details).

When assessing the valve components, more attention is generally paid to the following:

- Thyristors: Thyristors can age based on O&M practice or suffer pre-mature failure if OEM recommended practice is not followed or there is a change in system parameters from original design parameters. Thyristors can age as indicated above, resulting in abnormally high failure rates or increased leakage currents. The former will quickly deplete the stock of spare thyristors and the latter cause valve failure due to the resulting uneven voltage sharing among thyristor levels. The thyristor ageing conditions can be easily identified by reviewing the thyristor replacement records and performing leakage current measurements in the reverse and forward directions at a DC voltage big enough (e.g., 300 V or higher) within a certain time window (e.g. 8 h) after the converter unit is blocked. The measurements do not need any special equipment, just a DC voltage supply and an ammeter.
- Thyristor electronics in ETT valves. Older HVDC schemes each consist of a huge number of ETTs and analog electronic cards providing control, protection and monitoring functions for thyristors. They are expected to become increasingly prone to random component failures due to ageing. Life assessment focuses on the availability of enough customized spare parts for card repairs and trained technical staff who know how to repair and troubleshoot the electronics cards and associated test equipment for the remaining life of the valves. In addition, the electronics cards, especially the power supply related, can suffer solder fatigue and the resulting failure can cause fire. Once this kind of problem is identified, the cards are refurbished by re-soldering the vulnerable solder joints and cracked connections.

- Saturable reactors. Saturable reactor cores in service are continuously subjected to an intensive cyclic mechanic stress resulting from magnetic field. This combined with the ageing of bounding material can cause core delamination which in turn can produce red dust (mainly iron particles) or lead to extensive core destruction. After 25 years of operation or earlier, all the reactors are generally checked for red dust and some that have failed for other reasons are disassembled and inspected, ideally by the OEMs.
- Test equipment. Support for the test equipment coming with older thyristor valves is likely not available from the OEMs. It is important to ensure that enough spare parts and knowledgeable staff are available to repair and troubleshoot the critical test equipment such as the thyristor electronics test equipment, valve test equipment for valves, etc.
- Cooling circuits.

Water leaks cause forced outages at best and catastrophic flashover or fire. Frequent water leaks, normally indicate that the O-ring seals have reached their EOL and can be replaced. The leaked water trapped around the ageing O-ring seals can cause corrosion on the heatsinks. Plastic tubes/pipes and connectors are inspected for cracks and discoloration after 20 years in service or earlier, and some samples are sent to a chemical lab for testing and analysis.

- Capacitors. Capacitor failure rates are usually very low, whether in older or modern valves. Older thyristor valves consist of various oil contained capacitors or capacitor modules. Their failures can cause fire. After 25 years in service, all the capacitors are generally inspected for oil leaks and tested for electrical properties.
- Fibre optics. The fibre optic light guides and their connectors deteriorate over time. They are generally tested after 30 years in service. The internal conditions of light guide channels are visually inspected. The dust in the channels can cause flashover if water or moisture gets in. The material around the fibres can become brittle or fall off due to excessive UV light from partial discharge, leaving the fibres without coating and protection.
- Risk of fire. Older thyristor valves are prone to fire because they were constructed with a large amount of flammable material. There have been three projects where a valve group was destroyed by a valve hall fire. Fires can happen for various reasons: component ageing, loose connections, water leaks and human errors. Risk of fire is expected to increase as components age.

### 6.5.3 Refurbishment/Replacement

Thyristor valves are one of the most expensive pieces of equipment in HVDC converter stations. It is of great financial interest for the owners to extend the service life of thyristor valves based on their life/condition assessment results. Typical valve life extension measures are expected to include:

- Acquire enough spare components from the OEMs, different suppliers or other utilities whose HVDC systems were built using the same valve technology. It is possible for other manufacturers to make replacement thyristors for older HVDC schemes assuming the availability of enough technical data. It is noted that the importance of matching thyristor properties, most of all turn-off properties such as Qrr, (recovery charges) amongst the series-connected thyristors needs to be addressed. Also, when a different manufacturer supplies replacement thyristors it is much less risk to replace thyristors one complete valve at a time, compared with mixing different manufacturers within the same valve.
- Purchase enough spare parts once receiving the last buy notices from the OEMs.
- Refurbish the valves by replacing the ageing components whose failures can cause forced outages, flashover/fire or valve failure, which include ageing tubing, ageing/leaky thyristors, ageing oil contained capacitors and ageing gapped valve arresters if their replacements can be obtained from the OEMs or other manufacturers.
- Refurbish the ageing valve components. Only the repairable valve components can possibly be refurbished, which include the thyristor electronics and reactors depending on what and where the issues are.
- Ensure that enough spare parts and technical staff are available to repair and troubleshoot the critical test equipment and refurbish/rebuild the test equipment if needed.

## 6.6 Valve cooling system

### 6.6.1 General

De-ionized water (DIW) is used for cooling of all modern HVDC valves. The cooling systems using air or oil as a cooling medium are not discussed here as they are not used in modern days.

The valve cooling system varies in design from project to project, but in general it is either a single-circuit system where DIW or DIW-glycol mixture is used as the valve cooling medium depending on the climate or a dual-circuit system where DIW is used as the valve cooling medium. Typical cooling circuit components outside the valve hall include piping (pipes, fittings, expansion joints, etc.), valves, pumps, expansion tanks, pressure relieving devices, ion exchangers, strainers, meters, sensors, pressure and level switches, indoor heat exchangers, outdoor coolers, fans, etc., noting that indoor heat exchangers exist only in the dual-circuit system.

Older valve cooling systems are equipped with analog control systems, whereas newer ones use PLC-based control systems.

### 6.6.2 Life assessment

Most of the valve cooling system components described above have a life typically ranging from 15 to 25 years assuming that they have been properly maintained by following the OEM's instructions. However, this does not necessarily mean that the valve cooling system would likely be replaced before the thyristor valves. The cooling components are replaceable or repairable items and are usually not prone to technical obsolescence. The availability of spare/replacement parts or components is not normally of much concern.

Typically, the ageing components are usually identified during maintenance or become noticeable from their increasing failure rates.

A valve cooling system needs to be assessed for efficiency after 20 years of operation or as needed during the hottest summer days. If the efficiency is found to have reduced, it would mostly likely be attributed to the conditions of the heat exchangers and coolers.

The PLC based valve cooling controls typically have a lifetime of 15 years. However, it is not uncommon for many of the individual parts to be replaced over time to allow the controls to continue until the entire cooling system can be refurbished or replaced.

### 6.6.3 Refurbishment/Replacement

A complete replacement of the cooling system alone during the lifetime of the thyristor valves is much more expensive than if it is done along with the HVDC controls or thyristor valves. It could likely be avoided through the following life extension measures:

- Periodically check the stock of spare parts/components and replenish it as needed.
- Clean/refurbish/replace the heat exchangers and coolers if needed.
- Refurbish/replace the cooling controls, which can be done by the owner without involving OEMs.

## 6.7 DC equipment

### 6.7.1 General

DC switchyard equipment includes oil-filed and air-core smoothing reactors, DC voltage and current measurement devices, surge arresters, support insulators and bus work, and DC switches. These system components are not highly integrated with the HVDC converters and controls, and therefore can be replaced/upgraded without difficulty when deemed necessary. All of them are relatively low-maintenance or maintenance-free items except the oil-filled smoothing reactors. The key to extending the life of the switchyard equipment is to have enough on-site spares for the equipment or spare/replacement parts for equipment repair/refurbishment.

### 6.7.2 Oil-filled smoothing reactors

#### 6.7.2.1 General

Smoothing reactors (SR) are required for LCC based HVDC schemes with transmission lines, but they are not necessarily required for some back-to-back HVDC links. Oil-filled SRs found their use in the early HVDC schemes, either mercury-arc or thyristor valve based. Most of them have been replaced with dry type SRs.

Oil-filled SRs are similar to HVDC converter transformers or AC power transformers in many ways. Presented below are some major differences that are generally considered for life assessment and extension.

#### 6.7.2.2 Life assessment

The average life of oil-filled SRs is expected to be around 35 years, but it could be shorter or longer depending on many factors.

Life assessment for oil-filled SRs is similar to that for converter transformers in 4.6, but more attention is paid to their oil-impregnated paper (OIP) DC bushings. No statistical data are available to establish the lifetime of the OIP DC bushings for SRs, but according to the DC bushing manufacturers, it could be 25 years for the OIP type and 30 years for the resin-impregnated paper (RIP) type. These numbers represent not the actual lifetimes of DC bushings, but they suggest when it would be prudent to perform an assessment. The failures of DC bushings were fairly common in the past, but they can only be replaced with the exact make, type and model as DC bushings are not interchangeable at high voltages as described in 4.6. This combined with the lack of spare/replacement DC bushings is a major issue that can result in the end of life of SRs.

#### 6.7.2.3 Refurbishment/Replacement

The following can be part of the consideration when it comes to decision making on replacement or refurbishment:

- Insulation or core refurbishment of oil-filled SRs is possible, but it is most likely not an economic choice considering that air-core SRs are much lower in capital and maintenance costs.
- If the supplier provided sufficient information so that any DC bushing manufacturer can supply the bushings, it is possible to replace the DC bushings, DC barriers and DC bushing leads, but this is risky, very expensive and can mostly not avoid the need for replacement.
- If lack of spare DC bushings is the only issue, the option of replacing some of the oil-filled SRs with air-core SRs can be considered, but ultimately the decision will be based on an economic analysis taking into account the plan for major system upgrades/improvements.

Other life extension measures are similar to those for the converter transformers.

#### 6.7.3 Air-core smoothing reactors

##### 6.7.3.1 General

Air-core SRs have been commonly used in the modern HVDC schemes. They are much simpler in design than oil-filled SRs as they can be just an epoxy impregnated, fiberglass-encapsulated wound coil. They are relatively maintenance free.

##### 6.7.3.2 Life assessment

The life of air-core SRs is expected to be around 35 years. Their actual life could be very much different depending on environmental conditions (e.g. farming, coastal, heat, ultraviolet exposure, etc.).

Air-core SRs are generally assessed by following the OEMs' inspection and maintenance instructions after about 30 years of operation or as needed to determine their remaining life. Factors to consider include:

- Support insulators are critical for mechanical and dielectric support. It is possible to check the support insulators after 25 to 30 years, to remove a couple of them from service and test both mechanically and electrically. Failure of the grout between the metal flange and the porcelain is a common cause of problems.
- Deterioration of the SR's outer coating can result in premature failure of the SR.
- If an air-core SR has a noise shield that was not originally required in the factory but was installed later in the field, it can cause an increased temperature in the SR coil, thus accelerating its loss of life. This has been a cause of premature air-core SR failures.

Air-core SRs would likely survive an additional 10 years or more if their outer coating is still in good condition and their noise barriers are factory installed.

##### 6.7.3.3 Refurbishment/Replacement

The life extension measures for the reactor coils are pretty much limited to refurbishing their exterior coating whenever needed. Some air-core SRs have "black pots" on them but no failures have been reported to date. The addition of corona rings can help to eliminate the black spots. If the outer protective coating has deteriorated to a degree such that the insulation and aluminium conductors are visible, it would be cause for immediate replacement. The support insulators can be checked after 25 to 30 years in service. Depending on the result of their condition assessment, a replacement can be considered.

With enough on-site spare coils or redundant units, the approach of "run to failure" can be an option to fully utilize the life of air-core SRs considering that their failure modes are unlikely catastrophic. More frequent inspections and thermal scans can help to identify signs of imminent failure.

#### 6.7.4 DC voltage dividers

##### 6.7.4.1 General

A DC voltage divider (VD) for high voltage measurement consists of multiple sections mounted on top of one another. Each section is built with resistors and capacitors enclosed in a porcelain or composite housing. It can be either oil-insulated or gas-insulated.

##### 6.7.4.2 Life assessment

The life of VDs is expected to be 30 years, but it can be much longer. There are HVDC projects where the VDs were more than 40 years old at the time of replacement.

Overall, the VDs are very reliable devices. Degradation of the capacitance of a VD will likely occur near the end of life (EOL) of the VD. Each section of a VD is normally a sealed unit. If there is a filling port on it, an oil sample can be taken for dissolved gas analysis. Care can be taken to avoid contaminating the oil with moisture or other foreign substances.

When fibre optics is used to send the signals to the control room, the associated electronics will likely require repair or replacement prior to the EOL of VDs. Replacement of VDs can be avoided by carrying enough spare parts or sourcing identical replacements as required.

#### 6.7.4.3 Refurbishment/Replacement

The following are taken into consideration in decision making on refurbishment or replacement:

- If a VD suffers an oil leak and it is not near its EOL, the unit can be refurbished. This is likely a cost-effective alternative at higher voltages, but less likely at lower voltages.
- When a VD is approaching its EOL, degradation of its capacitors would likely occur. If so, replacement of the VD is considered as it is a relatively low-cost device.
- Any replacement decisions generally consider the advantages of moving from oil to gas/solid insulation filled units.

### 6.7.5 DC current transducers

#### 6.7.5.1 General

DC current measurement devices have evolved significantly over the past 50 years. The oil paper insulated Kraemer style DC current transducers/transductors/transformers (DCCT) were used in the older HVDC projects. Their measuring signals are transmitted to ground potential electrically. The modern HVDC schemes use either optical DCCTs, zero flux or precision resistors for DC current measurement, and their measuring signals are transmitted to ground potential via fibre optics. These devices themselves, whether older or newer, are relatively maintenance free.

#### 6.7.5.2 Life assessment

The older DCCTs lasted more than 30 years. The new DCCTs are very reliable. The lifetime of the new DCCTs will be determined by the availability of spare parts. The assessment of refurbishment requirement for DCCT electronics lifetime, is the same as that of the HVDC C&P module and accordingly a refurbishment plan needs to be evaluated.

#### 6.7.5.3 Refurbishment/Replacement

The new DCCTs can be kept in service as long as spare/replacement parts are available. However, the newer DCCTs can be considered for replacement sooner, when control and protection systems are replaced, due to interface challenges.

### 6.7.6 DC surge arresters

#### 6.7.6.1 General

DC surge arresters are similar to those for AC applications. They are gapped SiC surge arresters in older HVDC projects (i.e. installed prior to the late 1970s) and gapless ZnO/MOV surge arresters in modern projects. Surge arresters are essentially maintenance-free items. Their typical maintenance is visual inspection and cleaning as necessary.

#### 6.7.6.2 Life assessment

The average life of gapped DC surge arresters is expected to be around 35 years and can be much longer.

Silicone rubber sheds are used on some gapless DC surge arresters. Their lifetime is currently unknown because they have not been in service for very long. However, experience shows that RTV silicone can last over 25 years, and it is expected that silicone rubber sheds would likely last that long.

The life of old gapped surge arresters depends on their ageing characteristics and the number of operations. The sparkover voltage of a gapped arrester can decrease over time and eventually operate at a much lower transient voltage level, causing forced system outages. Ordinary field tests are not capable of revealing such an ageing characteristic. It is advisable to remove some of the gapped surge arresters from service and test them in an HV test facility after 30 years of operation or as needed.

The leakage current and discharge counter readings of a gapless arrester are indicators of its condition. The leakage current of the gapless arrester can be measured while in service except for those in the valve halls, as it is not easily accessible for measurement. If the leakage current is out of range or the counter readings are abnormally high, it can be considered to remove the arrester for further diagnostic tests.

#### 6.7.6.3 Refurbishment/Replacement

DC arresters are not normally refurbished. The surge arresters can fail catastrophically. They are generally replaced if they exhibit any signs of serious deterioration/ageing or other problems.

### 6.7.7 DC support insulators and bus work

#### 6.7.7.1 General

DC support insulators are also called post insulators and look very similar to those for AC applications. They support DC bus work and other equipment such as air-core smoothing reactors. They are relatively maintenance-free. Their typical maintenance is visual inspection and cleaning as necessary.

#### 6.7.7.2 Life assessment

The life of DC support insulators is expected to be around 35 years, but it can be as long as over 50 years.

Support insulators are usually inspected for cracks, breaks, damage or contamination during regular maintenance. It is advisable to remove a few representative ones and test them mechanically and electrically after about 20 to 25 years in service.

The porcelain support insulators in some HVDC projects can be coated with RTV silicone for flashover performance improvement. The RTV silicone coating is expected to last over 25 years. It is recommended to do an inspection after 20 years.

The life of bus work is expected to be around 50 years or longer. It can be visually inspected for corrosion, damage, etc. during maintenance outages and checked for loose connections using a thermal camera while in service. Repair of bus work is usually done during maintenance outages.

#### 6.7.7.3 Refurbishment/Replacement

A DC support insulator is replaced if it has failed or exhibited a sign of potential failure. The ageing RTV silicone coating of a DC support insulator needs to be removed and then replaced with a new coating.

### 6.7.8 DC switches

#### 6.7.8.1 General

DC switches are, for the most part, just AC switching equipment. They are used to isolate equipment from buses or other energized apparatus, but not for load break applications. DC switching equipment generally includes highspeed switches and disconnect switches. The highspeed switches are AC circuit breakers.

#### 6.7.8.2 Life assessment

The life of DC switches is expected to be around 35 to 40 years.

DC switches are generally assessed after about 30 years of operation or as needed to determine their remaining life. This involves the following activities:

- Review their repair/maintenance history.
- Assess their present conditions by following the maintenance instructions from the OEMs.
- Determine the availability of spare/replacement parts, and the ability and costs to procure new ones.

DC switches are, generally, the AC switching equipment along with commutating equipment (inductor, capacitor and nonlinear resistor) in parallel to the AC breaker to have the capability to commutate in parallel conducting path. All of the DC switches are opened under the condition of zero or small DC current (e.g. less than 50 A) except the by-pass switches (BPS) for the series-connected valve groups in some HVDC projects. To deblock a group valve, its BPS will be opened under current, and the resulting arc will not extinguish until the current is commuted from the BPS into the incoming valve group. For this reason, additional care can be required for the BPSs.

#### 6.7.8.3 Refurbishment/Replacement

The factors affecting the refurbishment or replacement decision include:

- Availability of spare/replacement parts and ability to procure them.
- Issues with previously refurbished DC switches (if any).
- Ageing/deteriorating conditions of DC switches as well as their foundations, steel structures and support insulators.
- Reliability, safety and maintenance costs.
- Plan for major system upgrades/improvements.

### 6.7.9 Station auxiliary supplies

The station auxiliary supplies consist of station service transformers, medium voltage switchgear, motor control centers (MCC), battery banks, first grade supplies, and uninterruptable power supplies (UPS). The first-grade supplies are fed from a separate set of battery banks and inverters (i.e. battery chargers) like those normally found in an AC substation. The auxiliary supplies are relatively easy to maintain.

The battery banks are usually replaced after approximately every 12 years. The battery chargers are installed with redundancy and usually allowed to fail.

Life extension is always necessary for the auxiliary supplies due to the shorter lifetimes of their components. The medium voltage switchgear and MCC breakers are usually refurbished after 25 to 30 years and in some cases replaced.

### 6.7.10 Earth electrodes and electrode lines

#### 6.7.10.1 General

Earth electrodes come in different types, sizes and shapes. A typical earth electrode would be circular in shape and consist of many sub-electrodes made of mild steel in a coke bed. In a bipolar HVDC system, the earth electrodes are normally designed to run at full load for 30 to 40 days in the event of a pole outage. A typical electrode line is similar to an overhead distribution line. It can also be DC cables.

#### 6.7.10.2 Life assessment

The life of earth electrodes is expected to be around 40 to 50 years or even longer.

Generally speaking, if there are no problems at the initial use of electrodes, they are relatively maintenance free for many years. However, if there are extended periods of monopolar operation or once they have aged after 25 to 30 years, they are checked, inspected and tested.

The life assessment of electrode lines or neutral return conductors would be similar to that of any AC distribution lines.

#### 6.7.10.3 Refurbishment/Replacement

Life extension can be achieved by replacing the electrode conductor or adding a new segment as necessary. Refurbishment can also be necessary if the DC current of the HVDC link itself is increased for any reason.

Refurbishment of electrode lines or neutral return conductors would be similar to that of any AC distribution lines.

### 6.8 Cyber security

During the design of a new control system or a control upgrade, the security architecture of the solution is generally designed based on a holistic approach according to internationally recognized standards, frameworks and norms such as IEC 62443, NIST Cybersecurity Framework and CIS Critical Security Controls. Some national authorities have additional requirements such as NERC CIP (North America) and BDEW whitepaper (Germany).

The requirements for a robust system can be well planned and thought out and clearly included within the requirements of the technical specification. Later modifications to the design, although possible, will be an expensive option and are not as effective as if they had been included in the original design.

According to the defense-in-depth principle, the expected security level is provided by a combination of different protection mechanisms and layers such that the failure of one mechanism or layer does not lead to a failure of the overall security architecture. The combination of individual protection mechanisms is generally chosen such that availability, integrity, and confidentiality of assets within the solution can be guaranteed at all times.

Typical protection mechanisms according to international norms include proper network segmentation, identity access management, system hardening, malware protection, security logging and monitoring, and security update management. Furthermore, security requirement tests, vulnerability tests, and optionally penetration tests, e.g., by a third-party vendor, are generally performed prior to delivery.

Especially for refurbishment projects, a threat and risk analysis (TRA) for new as well as legacy components is recommended. If protection mechanisms cannot be applied to legacy devices because they are technically or economically infeasible, proper mitigation measures are generally evaluated, e.g., placing legacy devices into dedicated isolated network segments.

Proper network segmentation requires the separation of different network zones by firewalls. It allows different network segments within the control system including critical components to be segmented from systems with less critical components.

Identity access management is ideally implemented by a centrally managed authentication server such as an active directory (AD) service. When only a limited number of devices are available, local user management might be considered.

State-of-the-art hardening is generally applied to all devices within the control system. All non-necessary services are disabled, all non-necessary ports are closed, and system configuration is done according to a well-known industry benchmark such as CIS (Center for Internet Security).

For malware protection on industry PCs, either a blacklisting or whitelisting solution is considered. If a blacklisting solution (standard virus scanner) has been chosen, virus patterns are updated frequently.

All devices within the control system are generally connected and log to a central logging system, for example a syslog-server. The centrally collected logs are reviewed periodically. Optionally, monitoring of devices is possible.

Software patches for known vulnerabilities are updated as frequently as possible. Often a risk assessment is required of how often an update is deployed versus shutting down the controls to perform this update and what the cost of such a shutdown would be. All devices within the control system including embedded devices can be considered for software or firmware updates.

Prior to testing, an asset inventory of hardware and software is generally acquired. Listing of firmware and software versions is crucial to future scanning. Vendors usually issue updates to their software or firmware when vulnerabilities are detected, and an up-to-date inventory will keep track of what software in the control system is subject to these identified vulnerabilities.

During the factory acceptance testing, cyber security testing is performed. This typically includes security requirement testing, i.e., checking that security-relevant configurations like hardening options have been applied correctly. The second test that is performed is a network vulnerability scan. This is a scan of all devices and networks which discovers known vulnerabilities such as open ports or misconfigured services. Finally, a penetration test performed by a third-party vendor is recommended to discover additional vulnerabilities which are not known or more complex.

## 6.9 AC filters

### 6.9.1 General

The replacement/refurbishment of AC filters is typically required for the following reasons:

- changes in system configuration,
- as a result of life assessment process.

Only replacement due to life assessment is discussed in this Clause 6. Refer to 6.9 for AC filter requirements due to system configurations. AC current harmonics are generated by a converter station as a result of the AC/DC conversion process. AC filters are installed in order to limit the level of AC voltage distortion and communication system interference caused by these harmonics. The conversion process also causes the converter to consume reactive power, which is compensated for by the AC filter banks.

The main components of AC filters are:

- Fixed capacitors,
- Reactors,
- Resistors,
- Current transformers,
- Surge arresters.

The AC filters can be configured as single tuned, double tuned or triple tuned.

The issues related to current transformers and surge arresters are discussed in other subclauses of this Clause 6.

#### 6.9.2 AC filter capacitors

##### 6.9.2.1 Life assessment

Individual capacitor units associated with AC filter capacitor banks are typically of all-film design as used in substation shunt capacitor banks. Many of the older HVDC facilities were built with capacitor units with polychlorinated biphenyl (PCB) dielectric fluids. However almost all of these units have been replaced to bring the facility into compliance with current PCB regulations independent of life expectancy as it was found to be more economical to be proactive and replace the units with units containing non-PCB dielectric fluids.

Capacitor units are replaced during the course of normal maintenance as a function of spare parts availability. Expected average service life of capacitor units is 30 years. It is recommended that filter banks be inspected on a regular basis and detailed records to be maintained. Leaks from capacitor units can be seen long before they become critical in most cases. In the event that the leak is from the bushing, a simple tightening is typically all that is required.

##### 6.9.2.2 Refurbishment/Replacement

Many older HVDC facilities had capacitor units manufactured with kraft paper/PCB (polychlorinated biphenyls) dielectric fluids or films/PCB dielectric fluids. Facilities with this style of capacitor units often replaced those capacitor units to bring the facility into compliance with current PCB regulations independent of life expectancy.

Failure of PCB contaminated capacitor units can result in expensive clean-ups. In rare cases if the old capacitors still contain PCB, applicable local regulations can apply for removal and disposal of these capacitors and site cleanup.

The capacitor banks making up typical filter banks have a standard rack configuration. This allows the capacitor banks to be easily replaced with new capacitor units. The owner reviews all weight ratings for the new devices to make sure they do not overload the existing racks and reviews the switching device's ratings and protection scheme if the electrical ratings of the bank are increased with the replacement.

#### 6.9.3 AC filter reactors

The air-core reactors are inspected on a regular basis and detailed records are maintained.

The air-core reactors are visually inspected for signs of:

- High heat,
- Corona discharge to the surface covering,
- Build up of surface contamination,
- Spacers falling on to ground,
- Surface covering damage.

The life assessment and refurbishment process for air-core reactors for the AC filters is the same as for air-core smoothing reactors (see 6.7.3).

#### 6.9.4 AC filter resistors

##### 6.9.4.1 Life assessment

Power resistors used in AC filters are typically the fixed resistance wire wound power or steel plate design type. The expected average service life of power resistors is 40 years. It is recommended that power resistors be inspected on a regular basis following the same guidelines as those of the air-core reactor.

##### 6.9.4.2 Refurbishment/Replacement

Power resistors do not lend themselves to refurbishment. If damaged, it is recommended that the units be replaced with new devices.

### 6.10 DC filters

The question of whether DC filters are required is of interest not only for new HVDC transmission projects, but also in the case of refurbishment of older projects, some of which have extensive DC filters. It is typically questioned whether those filters are still necessary, and if so in what form (wholly or partly), thereby reducing requirements for maintenance and spare parts, reducing losses, and possibly improving reliability. A similar question is raised when a refurbishment project includes an increase in DC line voltage, which would require substantial modification of DC filter HV capacitors if the DC filters were to continue in operation.

The considerations for the range of studies required are similar to those needed if elimination of DC filters is considered for a new project.

Similar to AC filters (6.9), the main components of DC filters are,

- Fixed capacitors,
- Reactors,
- Resistors,
- Current transformers,
- DC surge arresters.

The life assessment and refurbishment process for DC filters is the same as for AC filters (6.9).

## 7 Guideline for assessing techno-economic life of major equipment: Operational issues – Maintenance cost/management and availability of spares

### 7.1 Types of components used within HVDC systems

#### 7.1.1 General

HVDC installations use a wide variety of very different components supplied by a wide range of suppliers. These can be categorized into component types from the spares' replacement point of view.

### 7.1.2 Commercial off-the-shelf (COTS) components

These are available on the open market and delivered as a complete product. They are ordered against a manufacturer's catalogue number. These components include power supplies, processor modules, ethernet switches, relays, terminal blocks, fuses, current transformers (CTs), voltage transformers (VTs), miniature circuit breakers (MCBs), capacitors, reactors, AC switchyard components, and more.

Product design life, operational life, and reliability figures are defined by the component manufacturers as part of their standard literature.

### 7.1.3 Configured products

Some manufacturers offer a configuration service for their own or for a third-party manufacturer's COTS products. The configuration service specifies special adjustments or settings that require physical changes or modifications that make the product different from the standard product they are based on. These include power supplies, terminal blocks fitted with standard third-party components. These components will have an order number that is specific to their individual use.

### 7.1.4 Bespoke (customized) products

These products are designed to meet the functional specification provided to the supplier by the owner and are normally associated with the DC itself. Normally the specialist supplier is responsible for all the detailed design and contractually guarantees that the product meets all the criteria specified in the technical specification. These guarantees will include the performance criteria (sometimes risk mitigated by the supplier via acceptance testing), the design life, and reliability availability and maintainability guarantees.

Typical equipment of this type includes:

- Converter transformers,
- Converter valve assemblies,
- Thyristor valve cooling plants,
- DC capacitors,
- DC surge arrestors,
- Smoothing reactors,
- DC reactors,
- DCCTs/DCOCTs,
- VDR,
- DC switches, disconnectors and breakers,
- HVDC controls.

The purchase order for these items also includes a contractually binding spares replenishment time and specifies a minimum time over which spare parts will be available.

## 7.2 Management of obsolescence

### 7.2.1 General

Obsolescence of a component can be caused by a number of factors that are more or less likely for particular types of components.

### 7.2.2 COTS, configured COTS components and bespoke components

For COTS components the marketability of a product is severely decreased if a better faster/smaller/more functional) replacement product becomes available. Alternatively changes to legislation that governs the processes or materials used to manufacture the components (lead-free solder, greener PCB cleaning technologies, etc.) can make a product very unattractive to manufacture.

Bespoke designs normally use third-party components that are subject to the same lifecycles as the COTS products.

Most mass market manufacturers therefore tend to renew their product offering over a period of about 3 to 10 years. The normal sequence is as follows:

a) Market a new product;

b) State that the old product is not to be used for new designs;

c) Increase the price of the old product;

d) Send an end of design life (EOL) statement to all customers, often accompanied with a "last time buy" opportunity;

e) Part only available on the "grey" market;

f) Part available from a "secondary" market (e.g. a supplier who used to work for the OEM);

g) Parts available directly from the sub-supplier of the OEM when the OEM no longer has a contract with the sub-supplier;

h) Part not available.

### 7.2.3 Components designed to meet a specific specification

In general, components of this nature do not become obsolete unless the manufacturer goes out of business.

Physically simple components such as capacitors and inductors and resistors normally use a standardized manufacturing process that is parameterized (via specifications and drawings) by the manufacturer’s in-house design team to provide a particular value or type of component. The lowest risk solution is normally to ask the original manufacturer to re-use the original design information to create an exact spare. While changes to legislation and materials used can still affect their ability to produce a spare, the manufacturer can normally be expected to provide a compatible spare, this is the next lowest risk solution. As components of this type are made to a functional specification it is also possible to request a different manufacturer to create a spare, though in this case the specification can be reviewed to ensure that the new component is fully compatible.

The above process and spares replacement service are subject to contractually binding spares replenishment times that permit the assumed site delivery spares replenishment times to be met. The price and service level for this spares service is agreed as part of an overall framework agreement with the supplier but will likely be challenging. These critical items such as HVDC control and protection are indented early and a plan is put in in place to supply such critical items, or an increased number of such spares is carried by the owner.

For more complex components such as thyristor valves, the manufacturer is contractually obliged to provide exact spares or compatible replacements within the spares replacement period for at least the longer of the contract warranty period or availability guarantee periods, and then for a specified time frame of 10 to 15 years.

# 8 Recommendation for specification of refurbishing HVDC system

## 8.1 General

It is not intended that this Clause 8 be of sufficient detail to specify either a brownfield or greenfield replacement but only to highlight the major areas within the scope.

Converter stations hold several types of AC equipment and DC equipment. Each of these elements has been specifically designed for the global product. The heterogeneity of these elements will lead to a difference of life duration for each one. Thus, the refurbishment can be done at different times, depending on the concerned element and on the lifetime of the converter station which is generally based on 35 to 40 years. Owing to the specific use and the uniqueness of each converter station, it appears that it is important to specify in as much detail as possible the specification of the piece of equipment that needs to be refurbished. It is important also to keep in mind what the vendors normally supply to keep the costs to a minimum.

The second important aspect that can be taken into account is interfaces. Some elements will have a limited interaction with the global converter station, like transformers. Other elements will have interaction with all the pieces of equipment, like control systems.

In any cases, specifying every single interaction is vital in order to have a functional final product.

The number of components and systems replaced for a brownfield project is less than that included for a greenfield project.

All the elements of the converter station are normally considered by a refurbishment:

– Thyristor valves,
– Associated cooling,
– Converter transformers,
– Smoothing reactor,
– DCCT/DCOCT and DCVD,
– HVDC protection and control system of the converter station,
– Possibly air conditioning/heating/ventilation of the valve halls (if present),
– DC switchyard area,
– AC switchyard area (outside the scope of this document),
– AC and DC filters (outside the scope of this document),
– Auxiliary systems.

The choice of refurbished elements is generally based on a technical and economic analysis as described in Clause 10.

The major difficulty for a contractor is the implementation of new equipment and a new logic in an existing installation and an existing logic.

### 8.2 Main components of a converter station: guideline for the specification

#### 8.2.1 Thyristor valves

The following list defines several aspects to identify in the specification and those which are the most important aspects.

Technical part:

- Compliance with existing components like transformers in terms of impedance between phases, taping range current and voltages;
- Existing valve hall and its constrictive capacity (dimensions, capability of the roof, of the floor, door access and interfaces);
- Fire and smoke clearing aspects;
- Fault aspects: to define the faults that can be withstood by the system if required;
- Insulation co-ordination: to define the requirements in terms of standards, studies, higher capability arrestor and results;
- Control angles (firing/extinction angles), and their maximum and minimum values during operation;
- As an input, the indoor ambient condition of the valve hall as maintained by the existing HVAC system can be provided by the employer.
- Required lifetime;
- Design part;
- Environmental issues – oil containment;
- Erection/Installation part;
- Mitigation of transport damage;
- Required data, drawings and documentation during the design phase and for each thyristor valve. This information depends on the level of detail required by the owner.

The following is an example of what could be required:

- Total number of thyristors, in all valves together;
- Installed number of thyristors per valve;
- Minimum number of non-faulty thyristors per valve for de-blocking;
- Minimum number of non-faulty thyristors per valve for safe operation;
- Number of non-faulty thyristors per valve at tripping;
- Losses for one thyristor level, at rated load, minimum load and blocked;
- Losses for one valve, at rated load, minimum load and blocked;
- Circuit diagram of converter bridge;
- Circuit diagram of a valve;
- Thyristor Qrr matching if required;
- Maximum DC voltage stress;
- Maximum thyristor junction temperature;
- Normal operating thyristor junction temperature.

Maintenance part:

(The aim is not to specify the time or the tools, or to say how many spare parts the owner requires, it is about asking the OEM to provide the necessary information and to highlight some required points.)

- The required time and tools to replace a faulty thyristor,
- Spare parts, including failure rates and optic fibers,
- Maintenance planning,
- Estimated time between maintenance periods.

Redundancy part:

- To be precise and prove that the number of redundant thyristors is compliant with the required availability.

Testing part:

- All the tests that the owner requires to be performed based on international standards or the owner's standards;
- Associated reports (level of design details required, type of test report);
- The witness of type tests by the owner, if required.

#### 8.2.2 Cooling of the valves

The following list defines the several aspects to identify in the specification and which are the most important aspects.

Technical part:

- Design requirements:
  - The cooling needs to be designed in the same project of valves refurbishment,
  - Type of cooling (water or air cooled),
  - Single or double loop,
  - Material used in the piping de-ionized water loop,
  - Operation temperature interval,
  - Types of additives in the water cooled, if required earthing of all these components,
  - Pumps and fans,
  - Physical interface flexibility,
- Erection/Installation part,
- Required alarms and trips,
- Mitigation of transport damage,
- Expected drawings and documentation.

Maintenance part:

(The aim is not to specify the time or the tools, or to say how many spare parts the owner requires, it is about asking the supplier to provide the necessary information and to highlight some required points.)

- Required spare parts,
- Needed tools,
- Maintenance planning
- Estimated time between maintenance periods.

Redundancy part:

- Parts which are important for the owner to be redundant if any? Alarms are sometimes not redundant but protections are, including the sensors.

Testing part:

- All the tests that the owner requires to be performed based on standards or the owner's standards,
- Associated reports (level of design details required, type of test report),
- The witness of type tests by the owner, if required.

### 8.2.3 Converter transformers

In the case of a refurbishment of single-phase transformer, it is advised to change all three single phase transformers at the same time in order to have a balanced technical solution. The risk of replacing only one single phase is the possibility of unbalanced voltage and current on the valves unless specified properly for less the 3 % to 5 % difference in impedance between phases.

The following list defines the several aspects to identify in the specification and those which are the most important aspects.

Technical part:

- Design requirements:
  - To stay close to the technical characteristics of the existing transformers as much as possible,
  - The easiest way to specify is to use the specification and tests reports of the original transformers,
  - The main technical characteristics to specify are:
    - Available space,
    - Current and voltages,
    - Impedance and reduced tolerance variance 3 % to 5 %,
    - Harmonic current requirements,
    - Tapping range,
    - DC barriers, DC bushings and DC insulation system design details,
    - Current switching,
    - Cooling systems.
- Erection/Installation part,
- Required alarms and trips (OTI and WTI),

- Expected drawings and documentation,
- Pressure relief device (PRD) and Buchholtz relay,
- Mitigation of transport damage transportation (IEEE C57.150 – IEEE Guide for the Transportation of Transformers and Reactors Rated 10 000 kVA or Higher),
- HVDC controls interface,
- Auxiliary power interface,
- Civil and foundations.

Maintenance part:

(The aim is not to specify the time or the tools, or to say how many spare parts the owner needs, it is about asking the supplier to provide the necessary information and to highlight some required points):

- Required tools,
- Maintenance planning,
- Estimated time between maintenance periods.

Redundancy part:

- In general, each converter station has one spare part transformer. It is up to the owner to decide if it is required. This part is not necessarily fulfilled in the specification.

Testing part:

- All the tests that the owner requires to be performed based on standards or the owner's standards;
- Associated reports (level of design details required, type of test report, etc.);
- The witness of type tests by the owner, if required.

#### 8.2.4 Smoothing reactor

Oil-filled smoothing reactors are similar to transformers. The main idea is to have as close as possible the same technical characteristics as the existing smoothing reactors but the new smoothing reactors will likely be air core reactors. However, with new thyristor valves, it is sometimes possible to reduce the inductance value of the smoothing reactors and this is investigated, prior to the bid specification being finalized.

In many cases the existing oil-filled reactors are being replaced with air core reactors to reduce the risk of fire, oil containment, reduce maintenance and reduce capital cost. This will require new foundations and a new DCCT/DCOCT as the existing DCCT is normally installed in a DC bushing turret in the oil-filled reactor. It is possible to require a new zinc oxide DC arrestor.

The following list defines several aspects to identify in the specification and which are the most important aspects.

Technical part:

- Design requirements,
- To stay close to the technical characteristics of the existing smoothing reactor as much as possible, unless a small one is feasible,
- The easier way to specify is to use the specification and tests reports of the original smoothing reactor.

- The main technical characteristics to specify are:
  - Available space,
  - DC current,
  - Harmonics,
  - Inductance,
  - Interfaces,
  - Existing foundations.
- Erection/Installation part,
- Required alarms and trips if oil filled,
- Expected drawings and documentation,
- Mitigation of transport damage.

Maintenance part:

(The aim is not to specify the time or the tools, or to say how many spare parts the owner requires, it is about asking the supplier to provide the necessary information and to highlight some required points.)

- Needed tools,
- Maintenance planning,
- Estimated time between maintenance periods.

Redundancy part:

- It is up to the owner to decide if redundancy is required. This part is not necessarily fulfilled in the specification.

Testing part:

- All the tests that the owner needs to be performed based on standards or the owner's standards,
- Associated reports (level of design details required, type of test report, etc.),
- The witness of type tests by the owner, if required.

### 8.2.5 Control system

The control system is the most difficult part to specify because of the required functionalities that can be different from the original ones and the interaction with all the components of the converter station such as the VBE and the communication with the owner's several entities. It is normal to interact and discuss with potential suppliers before coming up with a final specification.

The following list defines several aspects to identify in the specification and those which are the most important aspects:

Technical part:

- Design requirements:
  - Specification of the hardware.

The owner can define all the standards that they require and special components that they are used to if applicable (like specific LV cables).

– Specification of the software
  - Specification of the control principles,
  - Specification of the required functionalities to be maintained from the original station and the new ones,
  - Specification of the automatic mode and the manual mode. Specify all the communication system,
  - Provide the I/O of all the converter station components that interact with the control system,
  - Specify the minimum required protection,
  - Specify the alarms and trips: in this part the requirements are most turned on the important alarms that can be seen by the operators. The second aspect concerns the categories and the types of these alarms (definition of urgent, non-urgent, audible alarms, non-audible alarms, colour of the alarms on the HMI, etc.),
  - Specification of the HMI, web based or not. Some web-based specifications have a longer life.
  - Specification of the AC and DC measurement along with existing data, information and drawings.
– Auxiliary: description of the existing auxiliaries system.
– Earthing
– Erection/Installation part
– Expected drawings and documentation
– Mitigation of transport damage
– Available space

  It is very important that all data of retained equipment is provided which is connected to the C&P system. The layout of the existing control room and building can be provided by the owner such that an adequate (and fitting) layout of the new C&P system can be designed.

Maintenance part:

(The aim is not to specify the time or the tools, or to say how many spare parts the owner needs, it is about asking the OEM to provide the necessary information and to highlight the required points.) This is one area however where additional spare parts can extend the life of the controls:

– Needed spare parts,
– Needed tools,
– Fault analysis documentation,
– Maintenance planning,
– Estimated time between maintenance periods.

Redundancy part:

– To specify and prove that the designed redundancy is compliant with the required RAM.

Testing part:

- All the tests that the owner can perform based on international standards or the owner's standards,
- Associated reports (level of design details required, type of test report, etc.),
- The witness of type tests by the owner,
- Real time digital simulator (RTDS) testing.

## 8.3 Interfaces

### 8.3.1 General

The definition of the interfaces in the case of a brownfield project is critical and more complicated than in a greenfield project. The definition of the exact list of remaining and refurbished equipment is the first step. Then, for each component that will be refurbished, the interfaces with the existing and remaining equipment are described in a high level of detail. This description implies I/O, auxiliary, electrical interfaces, civil and foundations. Other interfaces concern the future replaced component which are its environment, space and mechanical interfaces.

### 8.3.2 Electrical interfaces

The owner can provide the electrical characteristics of the remaining components and specify those of the refurbished components if applicable or required.

### 8.3.3 Mechanical interfaces

In general, the mechanical interfaces of each system in the converter station, affected by the refurbishment activities, is relevant and will have an influence on the installation activities and also on the later operation of the complete system. This means that if the mechanical interface is not considered it is possible this will cause damages/faults for example due to critical vibrations or structural overloads etc.

The mechanical interfaces are mainly related to the support structures, foundations, the roof or any mechanical support to the refurbished or new components. For this purpose, the owner provides all relevant information on the existing environment. It is very important to know the footprints, the dimensions and loads of the new equipment. On that basis the contractor will design and adapt all new components to the existing system to allow an uncomplicated installation and safe operation after the refurbishment.

At least the following areas of the HVDC can be considered and specified in all cases:

- Valve hall and valves including valve cooling,
- Converter transformer and AC/DC HV equipment,
- Control and protection system,
- Auxiliary systems (HVAC, auxiliary power supply, etc.).

### 8.3.4 Environmental interfaces

The owner provides the environmental characteristics like fire protection, noise, temperature, oil containment, humidity, wind, snow or any other characteristics that have an impact on the operation or the ageing of the component that will be refurbished.

### 8.3.5 Space interface

The owner informs, via the specification, the supplier of the available space for the refurbished components. The supplier can take into account space constraints, existing foundations and provide solutions during the design phase.

### 8.3.6 Auxiliaries interface

The owner describes the auxiliaries related to the components and replacement of those can be carried out with more or less capacity, different voltages and asks the supplier to confirm if it is feasible to make the changes that are required.

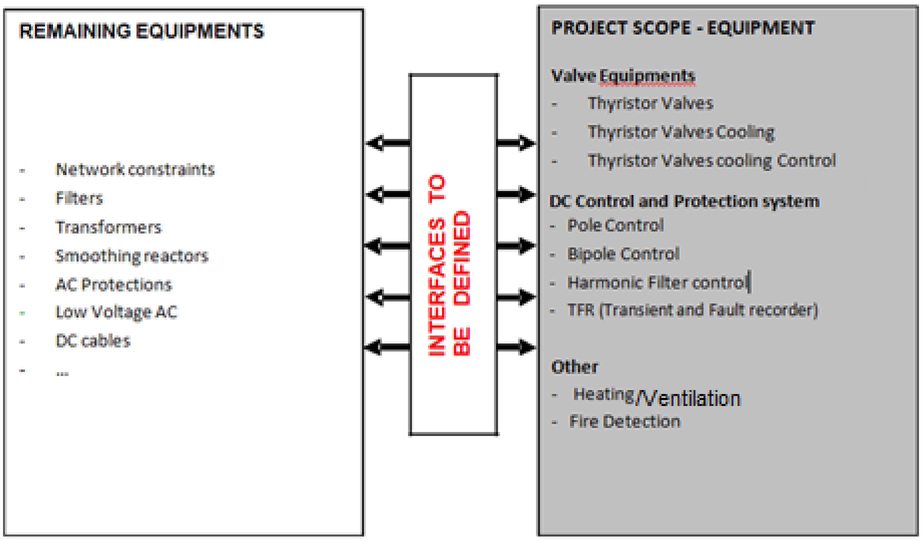
### 8.3.7 I/O interfaces

In the case of control system refurbishment, the I/O of the remaining components to be integrated are provided to the supplier.

In the case of component refurbishment, the supplier can take into account the existing I/O of the refurbished component and provide the new one with the same I/O to fit the remaining control system.

### 8.3.8 Example: valve and control system refurbishment

Figure 3[2] is an example of a valve and control system refurbishment. It is a view of the scope of supplies with the equipment, which can be refurbished, and the remaining equipment that gives all the constraints for the new equipment.




SOURCE: CIGRE Technical Brochure No. 649.

**Figure 3 – Example of valve and control system refurbishment**

The interfaces are mainly made between:

– The physical control system and all the remaining low voltage equipment,

– The valves and the high voltage components (wall bushings, disconnects, and surge arresters of the smoothing reactors),

– The valves, other interfaces which include converter transformers, controls, AC filters and the buildings,

– The cooling system and the buildings of the converter station.

[2] Reproduced from CIGRE Technical Brochure No. 649 with the permission of CIGRE.

### 8.4 Maintainability including spares requirement

Maintainability of the converter stations implies different aspects; correct design of the new equipment, good quality of equipment, a routine preventive maintenance plan and adequate spare parts to meet the required availability of the station.

Any single component failure is not supposed to affect the power transfer capability of the HVDC system.

Preventive maintenance operations can be carried out with the hardware and software in operation, taking into account the redundancy required. If an operation cannot be carried out with the station in operation then the contractor can list the maintenance activities that are outage reliant along with details of resources required to complete the work (e.g. staff required, outage time, etc.). The contractor can state the maximum number of hours per pole required for maintenance per year.

The contractor is required to propose a spares structure that enables the owner's reliability and availability objectives to be met and provides corresponding deadlines for set-up and restocking and the costs involved.

Tested spare parts can be furnished as required for the safe and reliable operation of the plant to the target availability level. The required numbers of each spare for a life of 10 to 15 years can be detailed by the contractor.

All spare parts can be readily interchangeable with those that they are to replace. They can have the same physical, mechanical, material and electrical properties as the installed equipment (e.g. specified conditions in relation to tests, etc.). Instructions for loading specific application software on common spares, which can be used with proper software at multiple different locations, can be readily available.

All spares can be properly packed in such a manner as to allow prolonged storage at the site, taking into account the ambient conditions there.

It is very important that the spares in stores be updated as modifications occur to the in-service equipment so that they are viable spares.

During the warranty period the contractor provides a spares management service and ensures the quality and integrity of stored spares on an annual basis.

### 8.5 Cost minimization

All interconnections have commercial considerations, such as cost minimization. One of the key factors of cost minimization would be to reduce, as much as possible, the outage and site testing period.

The following is a list of proposals that could reduce cost:

- The spares are divided between the stations so as to optimize RAM.
- To determine and finalize the project details at the concept stage as much as possible and then freeze the design.
- Any design changes after that require management approval, supplier approval and detail the reason for the change, financial and technical justification and cost.
- To have a realistic but tight planning of the project.
- To have the same supplier for two or more sites.
- To have detailed specifications as much as possible while still giving the supplier the flexibility to design and reduce costs.

– To optimize the actions: to carry out as many as possible actions in parallel as feasible.
– To produce contingency plans for possible delays, i.e., transport damage.
– To perform all the required studies in depth (civil works, complete software FAT, complete equipment FAT).

### 8.6 Replacement time minimization

Replacement time minimization can be reached in multiple ways:

– Training program (training on mock-up for instance),
– Clear and simple O&M manual. The O&M manual contains replacement sheets. Each replacement sheet describes the actions to be taken, step by step, the required tools for each action and the level of security,
– Holdings and availability of spare parts,
– Considerations for replacement during design to ensure ease of access, removal, and replacement,
– Additional space might be foreseen to allow for shorter outage times.

In addition to spares, a full set of all special tools and test equipment to enable full operation, fault diagnostic and maintenance of plant to be included in the purchase and supply sufficient spares to provide adequate redundancy of the tools and equipment that will see the greatest levels of wear and tear. Special tools and test equipment are those which can be available from the OEM and those to be bought and maintained in good condition.

Furthermore, tools and test equipment are provided on the same basis as spares (e.g., management of obsolescence).

### 8.7 Operation outage minimization

#### 8.7.1 Outage due to refurbishment works: brownfield and greenfield

Greenfield projects need a longer outage time than brownfield projects as the perimeter of replaced components is bigger.

To minimize the outage of brownfield and greenfield sites, several steps and the following verifications are going to help:

– A complete factory testing in order to minimize as much as possible onsite testing,
– A well-defined and realistic schedule with sequencing and resource estimates,
– To promote the works in parallel if possible,
– Financial incentives if justified to speed up the process.

The main points related to brownfield are the following:

– An exact description of the implied interfaces, done by the owner,
– A detailed study of each one of the interfaces, done by the supplier,
– Supplier and owner can work jointly before and during the construction phase.

Shutdown planning can consider:

– Outage duration and scheduling difficulties, which are also influenced by C&P factory test and tests on replica, if available.
– Embed a technical owner representative at the vendor’s facility to continuously monitor C&P factory system testing.

– The avoidance of extended outage; the outage does not start until C&P testing is successfully completed.
– In addition to C&P testing, all spare parts can be on site and accounted for, all documentation is checked and on site and all necessary training is generally completed before the outage starts.

  Also refer to Clause 12 for outage planning.

#### 8.7.2 Outage due to a forced maintenance

Forced maintenance is unscheduled maintenance, which is carried out in the event of malfunction or damage to the stations' equipment.

The malfunction or failure of the equipment requires a pole or bipole to be disconnected immediately, or at a more convenient time if the operation of the converter is not challenged (e.g. where redundant equipment exists).

Two scenarios have thus been identified according to their impact on availability and it is recommended that an organization of corrective maintenance be provided by the supplier.

In the event of a requested site intervention, the following actions would save time:

– All the required spare parts located at one of the two sites or the required spares located at each site,
– Technical fluency by the intervention teams in the language of the country,
– A first quick action is to have an intervention over the telephone for a first analysis of the event,
– Authorization (depending on the country where the visit takes place) and skill of the intervention teams, effectiveness of the visit: resolution of the problem identified on site as quickly as possible,
– Compliance with "safety rules" and "environmental rules" of the owner, see Clause 10.

#### 8.7.3 Outage for scheduled maintenance

Programmed maintenance can be prepared with a planning, a work preparation, an inventory of the spare parts and tools and ensuring that all the required resources are available.

### 8.8 Guarantees, performance and warranties

The guaranteed losses for the entire HVDC scheme and/or individual equipment can be specified. The reliability performance can be specified, such as the failure rate per bipole forced outage (e.g. one every 10 years), pole forced outage rate (e.g. few per year) and valve group forced outage rate.

Also, the availability of forced outage equivalent (e.g., 1 %) and schedule outage rate (e.g. 1 %) as well as maintainability requirements are normally part of the guarantees. Guarantee of spare parts or functionally equivalent parts availability can also be included such as for 15 years. Warranties can include labour but normally only materials and can vary from 2 to 5 years or more.

This will largely depend on the scope of the refurbishment and on outages/failures for new equipment only.

## 9 Testing of refurbished/replacement equipment

The testing of the refurbished equipment can be carried out as per the relevant standards of the respective equipment. The pre-commissioning tests are done as per various applicable standards and as per manufacturer's guidelines as it has been carried out during the greenfield project. However, if any specific test is required by the owner as an integrated approach with existing equipment, the same can be mutually decided and agreed between owner and manufacturer.

## 10 Environmental issues

### 10.1 General

Environmental issues could be the driver behind a requirement to upgrade or replace a piece of equipment when it is necessary to comply with revised environmental legislation or to meet company policy or standards which are beyond the original capabilities of the installed equipment or systems.

Addressing environmental issues could also be a further benefit associated with a planned replacement of equipment or systems under consideration for life extension issues. Life extension projects could provide an opportunity to enhance environmental performance or accommodate revised or future anticipated environmental requirements and these opportunities are generally considered as part of any upgrade plans.

Environmental issues that place constraints on how work is completed are considered as part of a life extension project to ensure that unexpected demands to comply with environmental requirements do not add additional time and expense to a project. Also, environmental issues can be considered prior to a life extension project to avoid any inadvertent environmental damage. Items such as handling and disposal of contaminated soils or asbestos for example, can be considered when developing life extension plans.

All life extension work can consider present and future environmental issues to ensure a station designed and constructed under different environmental rules and conditions will continue to comply with new regulations.

Environmental requirements are very much driven by government regulations, specific interpretation of regulations and owner policy/standards. As such the region and business environment in which the owner operates dictates the specific actions and investment put forward to address environmental issues and manage environmental risks. Additionally, specific site conditions and parameters, such as proximity to environmentally sensitive areas, play a role in determining what and how certain environmental risks are managed.

Unrelated development within the vicinity of an HVDC converter station and evolving environmental legislation can subject the facility to unplanned environmental risk. It is possible that a site is affected by development in the immediate area, resulting in more stringent environmental constraints than considered in the original design. For example, residential development in the vicinity of a converter station that was considered an isolated site, could lead to more stringent regulations with respect to issues such as spill containment and audible noise.

This Clause 10 comprises the following subclauses which identify environmental issues to consider and potential opportunities to address those issues during life extension projects.

### 10.2 Insulating oil

Many pieces of equipment within an HVDC switchyard are filled with oil, which is necessary for cooling and providing electrical insulation for that device. The requirements around spill containment are generally covered in legislation and the degree of containment necessary can be dictated by interpretation of that legislation and in accordance with company standards. Site location and site conditions play an important role in evaluating appropriate containment to minimize risk and the consequences associated with any spill.

Oil filled equipment varies in size and associated volumes of oil; the volume of oil present typically defines the spill containment requirements and the type of containment.

Oil filled equipment within an HVDC station includes:

– Pad mounted transformers,
– Converter transformers,
– Smoothing reactors,
– DCCTs,
– Voltage dividers,
– Wall bushings,
– Transformer bushings.

As ageing equipment is replaced or upgraded, evaluation of oil containment requirements and opportunities to reduce oil on site are included in the development of life extension plans.

It is possible to take advantage of a life extension project to enhance oil containment or replace oil filled equipment with new technology which eliminates oil completely for that piece of equipment. For example, oil filled smoothing reactors could be replaced with air core smoothing reactors. The benefits of eliminating the oil include elimination of oil release risk, elimination of spill containment requirements, and elimination of oil fire hazard.

Oil spill containment involves the following:

Planning criteria for spill containment can be based on existing regulations, anticipated future regulations, site-specific hazards and company policy, and be developed considering the following.

– Size of equipment and oil volume requiring spill containment,
– Type of containment to be used for specific volumes of oil,
– Size of containment,
– Handling of oil beyond containment infrastructure,
– Evaluate central collection system requirements, compare localized holding vs. collection and centralized separation,
– Site discharge,
– Removal of oil from sensitive areas in the event of oil fire.

Note that there are numerous industry standards, guides and reports along with local legislation to consult when evaluating oil spill containment requirements and developing a strategy.

### 10.3 Polychlorinated biphenyl

Polychlorinated biphenyls (PCBs) were used as coolants and insulating fluids based on their chemical stability (low flammability) and electrical insulating properties. Although the manufacture of PCBs has been banned throughout the world since 1979, they are still present in equipment manufactured prior to the ban.

Environmental legislation is aimed at controlling and eliminating the release of PCBs into the environment. As a first step to comply with any regulation, an inventory of equipment containing PCBs, the concentration in parts-per-million (PPM) and the volume can be established.

Various world agreements, federal, provincial/state and municipal regulations will dictate (usually the most onerous will apply) the levels of concentration that are permitted and the time frame for removal. As part of any life extension planning the opportunity to eliminate PCB contaminated equipment is considered when considering replacement of equipment or evaluating life extension options.

Additionally, there is equipment that is sealed, where the ability to obtain oil samples for verification of PCB content is not possible. It is an option to verify the presence of PCBs by consulting equipment manuals or reviewing previous maintenance records. If the presence of PCBs cannot be reliably confirmed it can be necessary to remove pieces of equipment or take a sampling of pieces (where there are many) from service for destructive testing to verify PCB content. In this case procurement of replacement equipment is necessary.

Regulations can apply when dealing with any equipment identified as PCB contaminated to ensure the PCBs are disposed of in a compliant manner. This can require sampling of soil around the equipment and cleaning/disposal of any soil removed from contaminated areas. Disposal will be documented, and the shipment of PCBs will be tracked to a licensed facility for destruction and verifying that destruction has been completed.

From a life extension project perspective, the additional complication of handling PCBs and the disposal costs can be a major effort in terms of time and expense and could drive costs up significantly.

### 10.4 Sulphur hexafluoride gas

Sulphur hexafluoride gas (SF6) is an inert gas used extensively for dielectric insulation and current interruption in circuit breakers, switchgear, voltage dividers, bushings, bus work and other electrical equipment. Despite the many advantages associated with SF6 gas, including reduced size of equipment, its use is not without challenges.

SF6 is one of the strongest greenhouse gases mentioned by the Kyoto protocol. It has global warming potential about 23 900 times greater than carbon dioxide (CO2). It is also persistent in the atmosphere, having a lifetime of 3 200 years.

SF6 gas is heavier than air. In enclosed areas, it can displace breathable air, thus posing a safety hazard in confined locations. The toxic by-products released when SF6 gas interrupts an arc in a circuit breaker are also a concern. Decomposition products are toxic and adequate personal protective equipment and training are essential for personnel safety.

SF6 gas can be handled many times during product life: gas filling at the beginning of product life, during maintenance top up, sampling and gas recovery at the end of product life. Although regulations involving SF6 gas are not stringent at the time of publication of this document, there is generally a requirement to monitor and audit gas stocks and to manage the filling and recovery of gas.

From a life extension perspective, the requirements for handling SF6 gas in a compliant manner when removing existing equipment or installing new equipment, are considered during project planning and design. Recovered SF6 gas can be cleaned and recycled for reuse or destroyed in an approved manner.

Alternatively, when considering equipment options the presence of SF6 gas and plans for handling, monitoring and accounting of gas can be considered when making equipment decisions as well as preparing for equipment installation, commissioning and operations.

### 10.5 Halon gas

Halons are a class of halogenated chemicals containing bromine that have been and continue to be used as gaseous extinguishing agents in a wide range of fire and explosion protection applications. Halons are very potent stratospheric ozone depleting chemicals when released into the atmosphere. Halons were phased out of production under the Montreal Protocol in 1994 except in Article 5(1) countries where continued production of Halons was permitted through 2009. The phase-out of Halon production has had a dramatic impact on the fire and explosion protection industry.

Halons are a clean, non-conductive, and highly effective extinguishing agent. Halon is an extraordinarily effective fire extinguishing agent, even at low concentrations; it extinguishes a fire by interrupting the chemical chain reaction. It stops the fuel, the ignition and the oxygen from dancing together by chemically reacting with them. Halon 1301 in particular is safe for people when used at concentrations typically employed for "total flooding" fire extinguishing systems and explosion prevention (inert gas) applications. Halon 1211 was widely employed in portable fire extinguishing units for use in what are called "streaming agent" applications.

The primary benefit of Halon gas was its ability to quickly extinguish a fire without damaging items within the room. It is non-conductive, non-volatile, and leaves no residue once the fire has been suppressed. This makes Halon a popular choice for computer labs, museums, libraries and other locations where use of water-based suppressants could irreparably damage electronics or vital archival collections. Halon was also considered an effective choice for protecting electrical installations.

Halon gas has been identified as an environmental risk, along with many other types of refrigerants and chemicals (CFCs) linked to ozone depletion. The production of Halon has been banned in developed countries since 1994. In the USA existing Halon systems are still permitted to remain in service until end of life. However, in Canada, Provinces have started to mandate the removal of Halon systems (Manitoba December 31, 2009) except for military and aviation. Existing supplies are carefully monitored to provide reuse and recycling for maintenance and refills of critical systems as needed. All Halon must be recycled or disposed of in accordance with regulated guidelines to minimize adverse effects on the environment. Current supplies of Halon are expected to last at least through 2030.

Life extension projects consider impending changes to regulations, the limited life cycle of Halon fire protection systems and evaluate the opportune time for replacement. While properly maintained systems could remain in use, both Halon supplies and system parts are becoming harder to acquire and there are fewer qualified people capable of servicing the older units.

Since Halon manufacturing was banned, fire extinguishing agent alternatives to Halons, in the form of non-ozone depleting gases, clean agent systems, gas-powder blends, powders and other not-in-kind technologies (e.g. non-gaseous agents) as well as water based misting and small droplet systems are now available for virtually every fire and explosion protection application once served by Halons.

(Gaseous extinguishing agents that are electrically non-conductive, and which leave no residue are referred to as "clean" agents.)

The selection of the best fire protection method in the absence of Halons is often a complex process. Either alternative gaseous fire extinguishing agents, so called in-kind alternatives, or not-in-kind alternatives can successfully replace Halon, but the decision is driven by the details of the hazard being protected against the characteristics of the gaseous agent or alternative method and the risk management philosophy of the user.

### 10.6 Refrigerants

Refrigerants are generally classified into one of three substances, CFC, HCFC or HFC.

CFC refrigerants are banned from use or production in most countries. CFC refrigerants have the highest ozone depleting rating and are also a greenhouse gas.

HCFC has been banned from production or new use since 2010 in most countries and a phase out is underway. HCFC refrigerants such as R22 have an ozone damaging potential and are also a greenhouse gas.

HFC refrigerants are used extensively. There is no current ban, but responsible use and equipment inspections are mandatory. The HFC refrigerants have no ozone depletion potential but do act as a greenhouse gas.

It is clear from a facilities life extension perspective that considerable management and control of refrigerants is necessary to comply with regulations and reporting requirements. Opportunities to move from banned substances to environmentally friendly alternatives are considered part of facility life extension plans.

### 10.7 Asbestos

Asbestos became increasingly popular among manufacturers and builders in the late 19th century because of its sound absorption, average tensile strength, its resistance to fire, heat, electrical, and chemical damage, and its affordability. It was used in such applications as electrical insulation building drains, floor tiles, ceiling tiles, fire stop material and in building insulation. When asbestos is used for its resistance to fire or heat, the fibers are often mixed with cement (resulting in fiber cement) or woven into fabric or mats.

Asbestos fibers are known to cause health hazards to humans. When asbestos-containing materials are damaged or disturbed by repair, remodeling or demolition activities, microscopic fibers become airborne and can be inhaled into the lungs, where they can cause significant health problems.

Regulations dictate appropriate handling procedures when asbestos is encountered on the work site. Life extension efforts consider the cost associated with handling asbestos and the extent that removal from the worksite is required. Where regulations are not dictating, industry best practices are implemented to handle and manage asbestos. Sampling for asbestos early in a project is recommended as discovery can result in health risks and budget over-expenditures.

### 10.8 Audible noise

Most equipment within an HVDC converter station will generate some audible noise, with transformers, filters banks, and forced air coolers being the largest contributors to noise. Normally an audible noise study will be required from the HVDC supplier. Factors that also can be considered are that the actual equipment noise levels exceed the levels used in the study and field mitigation can be required. In the case of field mitigation, exceeding the maximum operating temperature for acceptable life of the equipment is a significant concern. This problem is compounded by the fact that most equipment cannot be tested for audible noise in the factory with harmonics, only without the harmonics and estimating the audible noise impact of the harmonics. It will be necessary to ensure audible noise levels within the station fence remain at levels to ensure site safety for plant staff, when required. Additionally, audible noise outside the station fence must be controlled to meet any local standards or regulations. It is recommended to re-evaluate the acceptable level of audible noise if the existing stations have had development around them.

To complicate this issue many pieces of equipment cannot be tested adequately in the factory for noise resulting from the harmonics associated with HVDC systems.

If the converter station is located in a populated area, installing noise mitigation measures can be considered and included in the design of replacement equipment or added to the site design. Beyond replacing equipment, other mitigation measures could include physical barriers such as noise damping walls, barriers or earth works.

### 10.9 Electromagnetic effects

HVDC converters produce a variety of harmonic voltages and currents that are capable of being radiated from the converter station. Electromagnetic interference (EMI) has the potential for being coupled into various other communication systems.

Equipment replacement specifications generally consider acceptable maximum values for the following classes of EMI:

– Television interference (TVI),
– Telephone carrier interference (TCI),
– Railroad signal interference (RSI),
– Power line carrier interference (PLC),
– Radio interference (RI).

Additionally, as equipment is removed from service for replacement, the configuration of the remaining equipment can be evaluated to ensure that the EMI interference levels remain within compliance levels in the interim.

### 10.10 Mitigation of environmental issues

CIGRE technical brochure 508 provides the following simplified Table 2[3], which identifies the potential environmental issues and suggests methods of mitigating those issues based on specific equipment.

[3] Reproduced from CIGRE Technical Brochure No. 649 with the permission of CIGRE.

**Table 2 – Environmental issues associated with various HVDC equipment and mitigation techniques**

| Equipment | Environmental impact | Mitigation |
|---|---|---|
| Converter transformers | Visual<br>Audible noise<br>Oil | Enclosure / housing<br>Sound barriers, low noise design<br>Oil containment, plus oil separators |
| Thyristor valves[a] | Audible noise<br>Radio interference<br>Valve halls large/tall: visual impact<br><br>EMF | Building<br>Shielded building and RI filters<br>Distance to neighbours / hide halls in terrain<br>Distance from emission source<br>shielding |
| IGBT valves | Radio interference<br>Audible noise<br>EMF | Shielded building/container and RI filters<br>Distance from emission source<br>Shielding |
| Smoothing reactor (air core) | Audible noise<br>Visual | Sound barrier<br>Enclosure / housing |
| Smoothing reactor (Oil filled) | Audible noise<br>Visual<br>Oil | Sound barrier<br>Enclosure / housing<br>Oil containment, plus oil separators |
| DC and AC wall bushings if required | Oil if used<br>SF6 gas leakage if used | Oil containment, Use composite bushings<br>Potential gas leakage monitoring |
| DC isolating switches | Radio interference | Distance from sensitive area |
| DC ground switches | Audible noise<br>Radio interference | Distance from sensitive area |
| Thyristor valve cooling | Audible noise<br>Glycol leakage<br>Chemical cleaners | Sound barriers<br>Glycol containment or avoid glycol<br>Use dry air coolers |
| Auxiliary power and station service equipment | Audible noise<br>Oil<br>SF6 gas leakage | Housings<br>Oil containment<br>Leakage monitoring |
| Air handling systems, heating and air conditioning | Audible noise | Low noise equipment, Enclosures |
| DC bus and connectors | Radio Interference | Conservative design<br>Corona rings |

[a] During refurbishment of mercury arc valves, the mercury leftover in the facilities is considered when upgrades are done in these plants.

## 11 Interfaces and employer inputs

### 11.1 General – Interface issues

Having a clear boundary between owner and contractor scope is the most critical item and can be defined as part of the technical specification.

A complete and detailed interface specification can be defined upfront.

Owner engagement in the test laboratory setup is necessary as the interface to field devices will likely not conform to standard vendor laboratory setup.

Define the requirement for sharing intellectual property upfront during tendering process.

Ensure that the successful bidder will have access to all technical information that will be required to be successful.

This can be addressed during the specification stage to avoid costly delays after award. Ideally allow detailed site visits upfront and a refurbishment tender to allow potential contractors to familiarize themselves with the status of the system to avoid unnecessary risk positions in the bid.

Inaccurate models: relevant issue when dynamic performance studies are included as a part of C&P refurbishment.

Obtain models very early in the project and start integrating them into studies already available.

This will allow enough time to test the models and work with the vendor to refine them as the project moves into FAT and commissioning phases.

Depending on vendor design approach, C&P FAT using a real time simulator might be the most critical "study" and will likely be a critical path item.

## 11.2 System studies

### 11.2.1 General

For system studies the actual valid parameters of the AC grid can be known to adapt the design of the new components accordingly.

In general, the following information from the existing system is needed:

- AC network data,
- AC network harmonic impedance data (if harmonic performance is to be checked or new filters are planned for refurbishment),
- Short circuit level (minimum, nominal and maximum),
- Fault clearing time,
- Performance criteria,
- Grid code requirements.

Depending upon the scope of refurbishment, the studies recommended for the owner to specify for the bidder/contractor of the HVDC system during tender/execution phase of the HVDC refurbishment project are summarized in the Table 3, mainly HVDC C&P refurbishment or HVDC C&P, valve, valve cooling as a package through multi-vender procurement.

**Table 3 – List of possible system studies to be conducted in case of HVDC refurbishment**

| HVDC refurbishment scope | Tender phase | Execution phase |
|---|---|---|
| 1) C&P | – Preliminary dynamic performance study<br>– Preliminary EMC study | – Detailed dynamic performance study<br>– Detailed EMC study<br>– Dynamic performance tests<br>– Fundamental frequency overvoltage.<br>– Multi-infeed (If applicable, since new HVDC/STATCOM have been added in vicinity)<br>– Sub-synchronous oscillations (If applicable)<br>– Filter circuit breaker verification study<br>– Stability, modulations and runback controls |
| 2) C&P and Valves | 1) above and in addition<br>– Preliminary insulation coordination and overvoltage protection<br>– Transient currents<br>– Preliminary HVDC losses | 1) above and in addition<br>– Insulation coordination and overvoltage protection<br>– Transient currents<br>– AC filter performance and rating verification (if operating points have been changed)<br>– Electrical interference study<br>– HVDC losses<br>– Main circuit parameters<br>– Reactive power<br>– Filter circuit breaker verification study<br>– DC current in transformer |
| 3) AC filters | 1) and 2) above and also<br>– AC filter performance and rating<br>– Filter circuit breaker verification study<br>– Preliminary filter transient studies | 1) and 2) above and<br>– AC filter performance and rating<br>– Filter circuit breaker verification study<br>– Preliminary filter transient studies |

These above-mentioned studies in Table 3, as applicable, are preferred to be carried out in a refurbishment project before the functional performance test (FPT) and dynamic performance test (DPT).

Further details of typical studies and the reasons for carrying out the same are given in Table 4.

### 11.2.2 Refurbishment of HVDC projects

HVDC technology undergoes drastic changes making some components/systems obsolete at the OEM end. So, when the HVDC link has reached the mid-life of operation, generally issues arise during operation such as

- Non-availability of spare parts,
- Increased equipment ageing,
- Detuning of components,
- Higher maintenance requirement,
- Lack of OEM support due to obsolete technology especially in thyristors and associated electronics and Control & Protection systems.

It is envisaged that refurbishment work will extend life, increase efficiency and improve reliability and performance of the HVDC system. Further timely refurbishment will help to avoid any long outage owing to failure of minor equipment or cascading thereof.

Also, AC networks connected to HVDC on either side undergo change over decades. So the short circuit level (SCL) can generally change considering decommissioning of old thermal generation and the addition of a large number of renewable generations during life of the HVDC project and addition of transmission lines or generators. If the original network was weak (low SCL) or had operating restrictions, its performance can be improved by refurbishment (control system tuning) based on the present scenario of SCL.

However, it must be ensured in refurbishment that new equipment/systems such as Control & Protection, takes into account existing equipment and its capabilities. Coordination or assessment study can be required based on the scope of refurbishment. Hence during refurbishment of HVDC project, it is essential to ensure smooth integration of new refurbished equipment with existing old ones. The coordination of newer contractor equipment with older OEM equipment is critical, especially at interface points of key equipment such as transformer and filters, smoothing reactor, etc.

To safeguard rating and performance requirements of retained equipment and overall HVDC system, typical studies also are generally included in refurbishment work. Further, these studies help to extract the best performance considering system requirements within the capability of existing equipment.

The following studies as summarized in Table 4 can be required to be carried out for refurbishing HVDC links depending upon the scope.

**Table 4 – List of various typical studies/design carried out for refurbishment of HVDC**

| Sr. No. | Name of the study/design | General reasons / Outcomes |
|---|---|---|
| 1 | Main circuit parameters (MCP) | The main scheme parameters study covers the main station components such as the converter valves, the converter transformers and the reactive power elements in greenfield project.<br>In refurbishment (brownfield projects) based on scope of refurbishment (e.g. whether valves or transformer or filter are included or not) main circuit parameters must be checked for compatibility and to finalize design of new equipment or control settings such as firing angle range for valves.<br>If only control and protection is being refurbished, old (the original) such MCP studies are taken as input for new refurbished HVDC C&P system. |
| 2 | General control and protection | Laying of control and protection philosophies can be carried out especially if refurbishment is being carried out by other than OEM of HVDC link. Improvements carried out in C&P philosophy during the passage of time by a vendor in C&P system can be incorporated during refurbishment for superior performance. |
| 3 | Reactive power | In greenfield projects, this study is done to assess reactive power support (import/export) requirement to maintain AC bus voltage within specified band. In refurbishment projects, if filters are not being replaced, it is recommended to carry out this study to change reactive power exchange limits with grid considering network improvement near HVDC link. Further checking of converter reactive power consumption, filter switching strategy change, firing angle range improvement can be assessed with modified reactive power element switching strategy of existing reactive power element. |
| 4 | DC protection | In greenfield projects, DC protection ensures the avoidance of damage to equipment where a fault has occurred, also quickly isolates such equipment to allow remaining system operation and minimize cascading of events or avoid damage to equipment and maintain personnel safety. If refurbishment is being carried out by an HVDC contractor other than OEM, it can be possible to reassess and finalize DC protection principles, measurement locations, co-ordination priority. |
| 5 | DC station control<br><br><br><br><br><br><br><br>Pole control | In greenfield projects, station control is designed to provide station level co-ordination and functions for smooth operation of multiple poles in a station. If refurbishment is being carried out by an HVDC contractor other than OEM, station control will be replaced if any station level feature is envisaged the same can be incorporated based on operation requirement/experience or grid elements connected on either side of HVDC.<br>Similarly, for pole control, HVDC contractor other than OEM, can have different control philosophies or additional controls can be implemented as part of refurbishment. |
| 6 | Insulation coordination | In greenfield projects, the insulation coordination of the HVDC link protective and withstand levels are initially decided based on empirical rules/experience and the ascertained by detailed AC and DC transient overvoltage studies.<br>During refurbishment, based on the scope of this study is determined by the scope of work. |
| 7 | Sub-synchronous torsional interaction (SSTI) screening study<br>Sub-synchronous torsional interaction (SSTI) Part 2 – Time domain studies | If refurbishment is being carried out by an HVDC contractor other than OEM, SSTI control method (DC current-Idc or firing angle based), measurement location can be different hence during refurbishment these assessments can be carried out. Also network change around HVDC (new or refurbished generators) can also be assessed and safe operation can be improved further by tuning damping controller. |

| Sr. No. | Name of the study/design | General reasons / Outcomes |
|---|---|---|
| 8 | Multi-infeed and interaction study (RMS) | If refurbishment is being carried out by HVDC contractor other than OEM or control philosophies are changed by OEM, or new HVDC have come up nearby, then assessment of possible interaction with nearby grid elements are carried out to ensure safe operation. |
| 9 | AC protection | In greenfield projects, AC protection ensures similar functionalities as DC protection regarding equipment safety and minimizes impact on system operation. If refurbishment is being carried out by HVDC contractor other than OEM with different protection principles, or refurbishment scope can impact AC protection settings, measurement locations, co-ordination (considering new AC lines or other element added on either side of HVDC or change of converter transformer, AC filters) can be reassessed and finalized. |
| 10 | HVDC valve design | Replacement of valve, valve base electronics and valve cooling can be carried out as a package from vendor other than OEM along with HVDC C&P to make larger scope. The design of those is carried out based on existing equipment capability and operational input of connecting grid. |
| 11 | AC overvoltage / fundamental frequency overvoltages (FFOV) | If refurbishment is being carried out by HVDC contractor other than OEM or considering network change around HVDC link, reactive power control or filter switching strategy change, this study is required. |
| 12 | AC system equivalent | This study is required to adequately represent AC network and key HVDC/STATCOM in real time simulators (considering simulation capability limitation to meet required accuracy) or offline simulation such as PSCAD during dynamic performance studies for refurbishment. |
| 13 | General interlocking | If refurbishment is being carried out by HVDC contractor other than OEM and select section of HVDC is being replaced assessment interlocking requirements especially interface points is necessary. |
| 14 | AC filter rating verification study | If refurbishment is being carried out by an HVDC contractor other than OEM AC filter rating verification study is required to ensure that harmonics from new converter/control strategies do not pose risk to existing AC filters. Performance validation is required to be at least the pre-refurbishment status. |
| 15 | Transformer winding DC current | Generally, the number of thyristors level in back-to-back HVDC system is much lower than in bipolar HVDC systems. With improvement in semiconductor technology (more than 25 years) it can happen that the number of thyristor levels has reduced in a back-to-back scheme per valve. Verification of studies to be done that few of protective firing of refurbished (new) valve in back-to-back scheme can lead to high DC current in existing converter transformers. Accordingly necessary measures in C&P system can be considered. |
| 16 | Stability, modulation and frequency control | In refurbishment projects, this study covers stability assessment with new AC network, assessment of runback requirement or earlier runback/emergency actions can be modified based on these studies. Further frequency control or POD control requirement can be assessed with new network or tuned to new network. |
| 17 | Functional performance test/dynamic performance test | In refurbishment projects, with revised control and protection, these tests are carried out to ensure effectiveness of designed control and protection strategies /settings and any corrective measures can be taken before implementation in the field. A wide range of test cases that cannot be easily tested in field, can be designed and tested. |
| 18 | Thermal rating study for key equipment overload study | In refurbishment projects, this study is performed to safeguard existing equipment rating and prove that the proposed solution for refurbishment is adequate. For further improvement, specific control and protection are validated and co-ordinated with old/original MCP report. |

| Sr. No. | Name of the study/design | General reasons / Outcomes |
|---|---|---|
| 19 | Dynamic performance | In refurbishment projects, considering network changes around HVDC links, dynamic performance such as recovery times, power compensation times can be improved. Also, to ensure HVDC performance for AC faults, DC line faults, AC side auto re-closure dynamic performance study can be carried out if control & protection or valves are being replaced to provide improved performance or keeping the existing performance benchmark. |
| 20 | EMC PLC and RI emission | In refurbishment projects, considering EMC PLC and RI emission study is carried out to ensure new control & protection scheme or valve change complies with the limits stipulated in standards. |

Retaining existing features of the HVDC system and improving system performance with ease of operation, and reduced maintenance are the general focus during refurbishment.

Data requirement for refurbishment of HVDC link can vary based on scope. Typically, in HVDC refurbishment with control and protection such requirement includes:

– AC network data,
– Existing main circuit design data (existing valve data, transformer MVA, impedance tap data, firing angle ranges, power compensation),
– Transmission line details (tower data, impedance, length of line, electrode line, ground resistivity, etc.),
– Transformer saturation curve, harmonic spectrum,
– Nearby generators' multi-mass torsional data,
– AC filter/PLC filter/converter circuit breaker details,
– DC yard single line diagram with DC measuring element (DC current transducer, DC voltage divider),
– AC yard single line diagram, AC switchyard CT details, CVT details,
– Control room cubicle layout, service building: dimensions of all rooms,
– Information of cubicles with signals from switchyard,
– Auxiliary power for fetching refurbished HVDC C&P panels.

If along with control and protection, valves are being replaced then following additional data is necessary:

– Transformer DC current limits, high frequency model of transformer,
– Existing valve capabilities, valve hall arrangement,
– Valve hall health assessment,
– Valve cooling room dimensions,
– Water quality report.

### 11.3 Control and protection

#### 11.3.1 General

In general, "Interface" means all necessary data which can be known to design a new control and protection system. For control and protection systems the software interface and the hardware interface can be considered.

The following list shows the different type of interfaces:

– Mechanical interface (dimensions, weight, cable entry),
– Electrical interface (cubicle load, power supply),
– Cable entry, cable trenches, cable schedules,
– Binary signalling interface (single signal definitions to existing equipment),
– Analog signalling interface (measuring values),
– Data protocols (serial data protocol definitions to existing equipment).

During refurbishment of control and protection (C&P), it is prudent to keep a provision in the technical specification for the HVDC contractor to keep a replica of C&P so as to speed up the refurbishment work considering testing and site commissioning schedules.

Replica of C&P: At least HVDC C&P without redundancy, both stations using inbuilt feature of simulator for one station and another one is the actual HVDC C&P. However, the actual configuration is mutually discussed between owner and vendor.

If redundancy for a few control (HVDC C&P) sections is not present in the old HVDC project, the same can be included in the refurbishment. However, the redundancy concept is generally mutually discussed between owner and vendor and decided accordingly.

### 11.3.2 Mechanical interface control and protection system

The mechanical interfaces of the control and protection system can be known in great detail to ensure an installation in the existing control building with as few problems as possible. This means the footprints, the mechanical loads (weights), the dimensions, the cable entry (top/bottom), the needed space for door opening, the door hinges (left/right) and the emergency exit ways can be considered in depth in the detailed planning phase. The adaptation of existing foundations can be coordinated with civil work activities.

## 11.4 Thyristor / Valves

Figure 4 shows the interfaces between the control and protection system, valve base electronic and thyristor valves:

1) Interface between control and protection system and VBE,
2) Interface between VBE and gate unit (GU) / thyristor electronic (TE) of the thyristors/valves,
3) Interface between gate unit and thyristors.

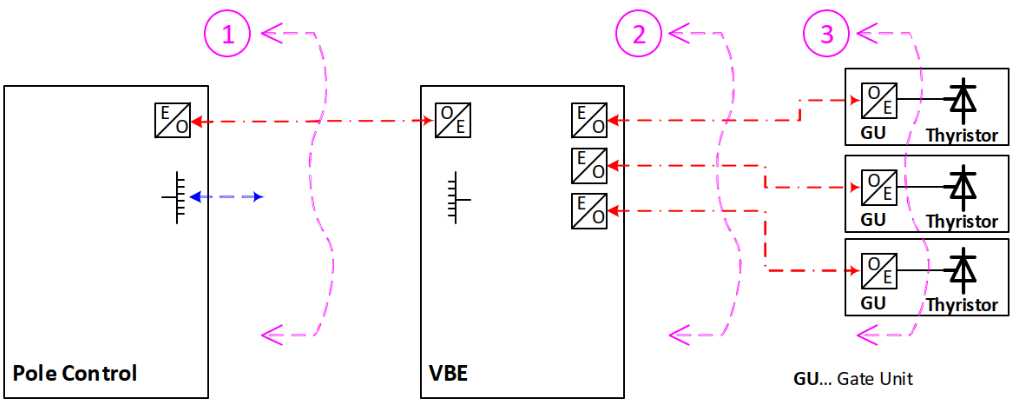



**Figure 4 – Interfaces between HVDC C&P, VBE and thyristor valves**

Detailed information about all these interfaces is unknown other than by the OEM. This means that without a detailed knowledge, a third party is not able to build a correct communication to an existing interface. At least the following information of the HVDC system is necessary to enable a third party to interface with an existing system:

a) block diagrams (VBE, GU/thyristor electronic (TE), thyristors and associated equipment),
b) functional descriptions including operating modes and protection functions (VBE, GU, thyristors),
c) descriptions for all interfaces (VBE, GU/TE, thyristors),
d) circuit diagrams (GU/TE, VBE driver circuit),
e) data protocols including protocol structure and timing diagrams (VBE, GU/TE, thyristors),
f) Equipment data (thyristors),
g) Transformer bushings stray capacitances,
h) Installation drawings, anchoring details from VH roof, etc.,
i) Clearances within valve hall.

### 11.5 Transformer

The interface for the transformer can be divided into primary and secondary interfaces. According to the scope of a refurbishment project this interface can be considered, and all related necessary information can be available.

The typical primary interfaces are:

– Transformer ratings,
– Short circuit impedance,
– Tapchanger range,
– Dimensions, loads and footprint,
– The connection for high voltage sealing (bushings),
– Measuring devices (i.e., CT/VT in the bushing),
– Type of cooling arrangement (ONAN, OFAF, ODAF),
– Type of converter breaker switching (POW, PIR),
– Transformer arrester data.

The typical secondary interfaces are:

– Control cable interface (hardwired) for command, monitoring and protection signals,
– Transformer control units,
– Interface to tapchanger,
– Interface to measuring devices (CT/VT),
– Interface to fan group control,
– Serial signal connection interface.

Description for mechanical/civil interface to be added:

– Outline drawings,
– Foundation details,
– Oil sump,
– Transformer movement at site (details of rail tracks, etc.),

- Transport limits,
- Fire fighting system, if applicable.

## 11.6 Equipment AC/DC yard

### 11.6.1 General

The equipment for the AC yard and DC yard consists of switching devices like circuit breakers, isolators, earthing switches and also of non-switching devices like filters, measuring devices and busbars. Similar to the transformer interface, the switching devices interface can be divided into a primary and a secondary part.

The single line diagram from the existing system is required to show the actual valid configuration.

AC harmonic filters to be added:

- Filter performance and ratings report,
- SLD,
- Measuring CT/CVTS and filter component protections,
- Arrester details.

The typical primary interfaces for switching devices are:

- Equipment rating,
- Dimensions, loads and footprint,
- The connection for high voltage sealing or busbar.

The typical secondary interfaces for switching devices are:

- Control cable interface (hardwired) for command, monitoring and protection signals,
- control units (integrated electronic devices),
- Serial signal connection interface (copper or fiber optic).

For the non-switching devices, the primary interface only can be considered. Except for the measuring devices the primary and secondary part of the interface can be considered.

The typical primary interfaces for non-switching devices are:

- Equipment rating,
- Dimensions, loads and footprint,
- The connection for high voltage sealing or busbar.

The typical secondary interface for measuring devices is:

- Signal cable interface (copper or fiberoptic) for measuring signals.

### 11.6.2 Measuring devices

The measuring devices inside the DC side can be investigated very carefully. If the measuring interfaces of the new control and protection system are not compatible with the existing measuring devices, new measuring devices will be required.

The following two scenarios are possible:

1) existing primary measuring heads in the DC side are in good condition and can be used further because the new control and protection system can be adapted or the related secondary measuring electronic is still available in the market.
2) existing primary measuring heads cannot be used due to incompatible interface with the new control and protection system. In that case the complete measuring components in the DC side can be exchanged.

### 11.7 Auxiliaries

During refurbishment, the owner can make an assessment as to whether any of the auxiliary equipment/devices such as auxiliary transformer, feeder, battery, etc. need uprating due to complete or partial refurbishment of the HVDC station. However, if there is no impact on the rating of these pieces of equipment because of refurbishment and if these pieces of equipment are serving quite well without requiring any replacement, then there is no requirement for immediate refurbishment/replacement of the same.

If any of the auxiliary equipment/devices can be refurbished/replaced/uprated, this can be assessed and integrated with that of the station equipment so as to minimize the overall shutdown time.

Hence, the following can be assessed by the owner while planning a complete or partial refurbishment:

- Transformer ratings,
- Feeder ratings,
- Battery capacity,
- SLD for auxiliary power.

## 12 Outage planning

### 12.1 General

Independent from the scope of a refurbishment project, outage planning can be divided into three different stages:

– Stage 1. Activities before outage,
– Stage 2: Outage,
– Stage 3. System test / trial operation.

For bipole HVDC systems the refurbishment can be planned with pole by pole outage or bipole outage. The benefit of a pole by pole outage is a higher transmission capability because one pole is always in operation. The disadvantage is a longer project running time and a higher risk of a trip for the other pole as works are performed next to an active system. The refurbishment of an HVDC with one bipole outage can be carried out in a shorter time but the transmission capability is zero for a longer time. This means the system owner must decide according to economic aspects which form of outage is preferred.

An overview of a typical refurbishment sequence with power capability and outage time is indicated in Figure 5.

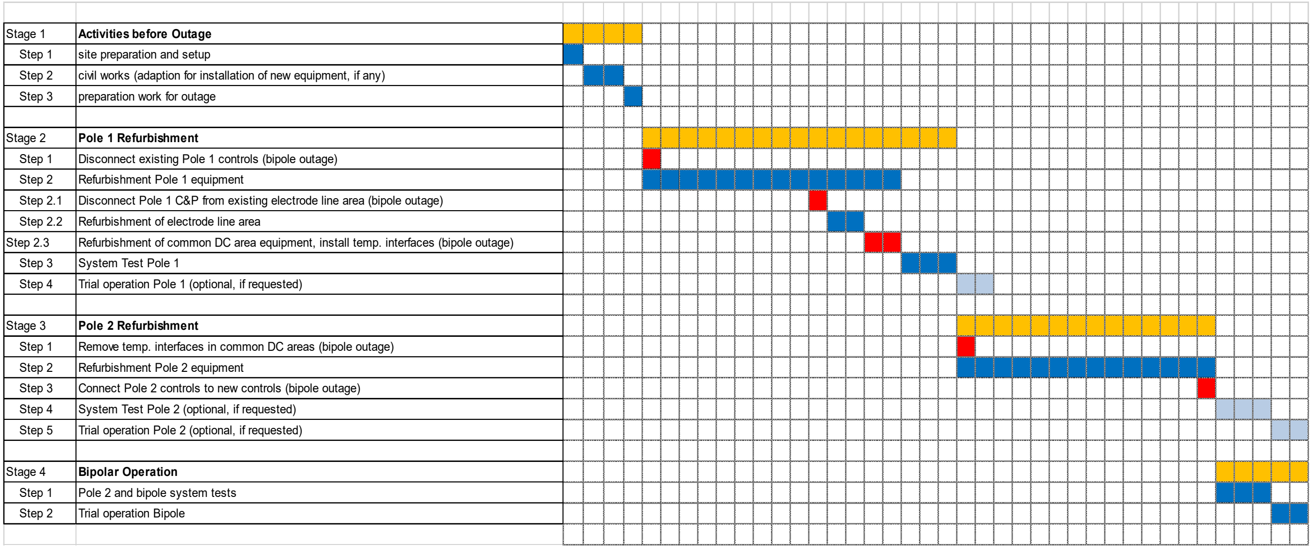



**Figure 5 – Typical refurbishment sequence and outage time**

It is understood that the outage time required for pole outage and bipole outage will be project specific and depends on several factors such as scope of refurbishment, access at sites, availability of manpower and number of shifts employed for dismantling/installation. As general guideline, projects involving complete C&P refurbishment in the scope of supply would require typically pole outage one at a time for a duration of one to three months based on the scope of the refurbishment work and shutdown of the link (back-to-back or bipole) that the utility can afford. The bipole outage can be split into smaller duration outages as indicated in the above sequence in Figure 5.

Furthermore, some pre-conditions can be fulfilled to allow the outage planning in a good manner. These pre-conditions are shown in the following list:

– complete as-built documentation being available, which represents the actual status of the station,
– full access to all areas inside the converter station,
– possibility for investigation of the existing system,
– owner contact person with good knowledge of the HVDC station equipment,
– enough space for site setup.

## 12.2 Stage 1: Activities before outage

The activities before the outage phase can be divided into different steps:

– Step 1: Site preparation and setup,
– Step 2: Civil works,
– Step 3: Preparation work for outage (all work packages for isolation, installation, commissioning and final integration, are complete).

### 12.3 Stage 2: Outage

The majority of all the activities in the different locations of a HVDC can be carried out in parallel to ensure an as short as possible outage time. For this purpose, the activities can be planned in great detail to ensure an optimized sequence of work.

The activities for the outage are shown by the following list in general:

- Dismantling of the old equipment,
- Adaptation of the exiting environment for the new equipment,
- Installation of the new equipment,
- Subsystem test.

### 12.4 Stage 3: System test, performance and trial operation

#### 12.4.1 General

After completion of the installation and after successful subsystem tests the new system is ready to start with the first energization after the refurbishment. Depending upon the scope of refurbishment some or all system tests will be carried out at this stage to ensure the correct behaviour of the newly installed components along with the retained equipment.

#### 12.4.2 System tests

The system tests depend upon the scope, and include at least the following:

– AC and DC switching sequences,
– Trip test,
– Energization of AC reactive power elements,
– Energization of blocked valve group,
– Operator control modes, setpoints and limits,
– Converter block / deblock performance,
– Steady state performance,
– DC power / current ramp,
– Power step response,
– Power reversal (if applicable),
– DC voltage step response,
– Control mode transfer (Ud/Id/Gamma),
– Commutation failure / misfire,
– Stability functions,
– Loss of auxiliary power,
– Loss of redundant equipment,
– Heat run, overload, temperature rise,
– Reactive power control.

After a successful system test, performance tests and thereafter the trial operation can start.

#### 12.4.3 Performance tests

##### 12.4.3.1 General

It is often required by the employer to demonstrate EMC compliance of the refurbished equipment. The following tests can be required to be done on site to compare the performance pre-refurbishment and post-refurbishment.

##### 12.4.3.2 Radio interference tests

The object of this test is to measure the radiated noise in the frequency range from 150 kHz to 300 MHz. The radiated emission of the converter after the refurbishment can meet the specified requirements. The specified requirement can be pre-refurbishment and post-refurbishment measurement, defined values, CIGRE/IEC standard values, etc. as per utility requirements. For this test, test methods for radiated noise with a measurement (as per specification) point close to the energized parts can be used for verification.

##### 12.4.3.3 Harmonics

The object of the test is to measure the harmonic emission up to the 50th or 60th harmonic (3 kHz). The harmonic emission of the converter after the refurbishment is required to meet the specified requirements. The specified requirement can be pre-refurbishment and post-refurbishment measurement, defined values, CIGRE/IEC standard values, etc. as per utility requirements.

##### 12.4.3.4 Power line communication

The object of this test is to measure the conducted noise in the applicable frequency range in the band of 40 kHz to 500 kHz. The conducted emission of the converter after the refurbishment is required to meet the specified requirements as applicable. The specified requirement can be pre-refurbishment and post-refurbishment measurement, defined values, CIGRE/IEC standard values, etc. as per utility requirements. However, since previous PLC communications are getting retired in phased manner, applicability of this previous requirement can be checked and decided during refurbishment.

## 13 Regulatory issues

### 13.1 General

With large expansions and development of power grids all over the world, the role of electricity regulators is becoming more and more important, particularly to ensure a tariff structure which is fair and acceptable to both the transmission utility and the consumer. The tariff is generally structured in such a manner so that it does not result in excessively high rates to the consumer, nor does it place any burden of unprofitable operation and subsequent reliability of supply on the transmission utility. At this stage a transmission system operator (TSO), in the interest of reliability and security of operation, is required to replace certain items of equipment or carry out some renovation and modernization (R&M). This would therefore cause additional capital expenditure which in all probability would not be covered in the existing tariff structure. Therefore, a mechanism can be developed to ensure that the TSO or asset owner is suitably compensated to take up this additional capital expenditure in the interest of grid security.

These issues can be even more aggravated when the regulatory framework of a particular country determines the "end of concession term" for an owner, say, after 30 or 35 years of exploitation of the service granted. The last years of concession, for such cases, can be very critical in terms of investments for keeping high reliability and availability indices against a pragmatic approach of optimizing assets costs if the concession period (term) is foreseen to be soon terminated.

The main reasons for this additional expenditure are:

1) A large number of HVDC stations and AC sub-stations in the world are going to complete their useful life in the near future and also some HVDC stations are relatively old. An unreliable element in the transmission system is a potential danger to the EHV grid system and the same can lead to outages and consequent huge losses. It is therefore essential to keep all elements of transmission assets in reliable operating condition to meet any contingency.
2) Transmission system elements such as transmission lines, transformers, switchgear, and HVDC systems are expected to serve for a predetermined life span which is the "useful life" of the equipment and transmission usually from the commercial operation date of the system. It is noted that some HVDC projects' equipment might have been manufactured several years prior to such date.
3) Based on the feedback from users on problems and failures of equipment and also due to technological advancement, manufacturers are often incorporating major changes in equipment to rectify design and performance deficiencies. Such new and improved and modified features can be incorporated in the existing and operating assets also to increase the performance and life and to prevent failures. Replacement of certain equipment can also be required due to damage by natural calamity, accident, breakdown, malfunctioning and maloperation.
4) Existing transmission systems are continuously augmented with various new system strengthening schemes and the addition of generating stations, etc. This leads to changes in the fault level of the transmission network and the existing installed equipment are subjected to the changed fault levels and changed load conditions. Hence it is necessary to review the existing equipment with reference to these parameters and the changed conditions can require the replacement of the equipment itself. Another aspect of concern would be the incremental increase on system (background) harmonics due to large loads that can "pollute" the system and by this, stress HVDC filter ratings previously designed. This situation occurred in the FURNAS – Itapúa 600 kV HVDC system, which ended up leading to extra 3rd/5th AC harmonic filter branches installation to cope with the current background harmonics level coming from the network level which increased after the initiation of the scheme's design. There are a number of HVDC schemes where 5th and 7th harmonic filters are required even though it is a 12 pulse system and sometimes even these have been forced to be off-tuned due to the presence of excessive background ambient harmonics.

In order to carry out improvements and changes necessitated for the above-mentioned reasons, substantial expenditures are incurred by the utilities. Normally the cost of regular maintenance, condition monitoring and overhauls are covered in the O&M tariff of the utility. However, the problem really arises when the equipment and systems will be replaced for reasons attributable to changed system parameters or failures and deterioration of performance caused by external factors like natural disasters. Therefore, in order to ensure that utilities do not defer costs on this unforeseen expenditure, the regulators deciding tariffs generally clearly specify the guidelines and tariff mechanism under which the transmission utility can carry out the required equipment replacements and modifications during operation stage. The additional tariffs can broadly be divided into two heads:

– Additional capitalization,
– Renovation and modernization.

An important aspect to be considered too is the regulator's policy for the periodic tariff revision application, which directly affects the remuneration of the owner, and therefore, can affect their policy for O&M investments. Tariff revision, by itself is a very complex subject, but in principle calibrates the transmission tariff (a fair tariff for consumers), with utility/TSO's assets capital return, cash-flow and O&M expenditures coverage enough to ensure a stimulated service of good quality.

The useful life of the transmission system as given above can be considered for the purposes of renovation and modernization (R&M). However, given practical realities, some of the equipment can require replacement or major repair for reliable and efficient operation of the transmission system before completion of its useful life. The replacement of some of the equipment can also be necessary in transmission lines like insulators due to pollution. For replacing this equipment and systems, regulators make provision for this capital expenditure under additional capitalization and adjust the tariff accordingly – tariff revision. The objective here is to enable owners to overcome operating problems, equipment failures and equipment obsolescence so as to sustain higher availability and reliability of the transmission system.

### 13.2 Renovation and modernization

The expenditure incurred for extending the life beyond the useful life of the transmission system can be taken under the heading of renovation and modernization (R&M).

The transmission utility responsible for meeting the expenditure on renovation and modernization (R&M) for the purpose of extension of life beyond useful life generally prepares a detailed cost-benefit analysis along with estimated life extension.

The expenditure incurred or projected to be incurred after a prudent check based on the estimates of renovation and modernization expenditure and life extension, can form the basis for determination of the tariff after deducting the accumulated depreciation already recovered from the original project cost.

### 13.3 Recommendation

The above proposals will result in improvement of the performance of the HVDC system and increase efficiency and reliability. The revenue for the expenditure incurred for the same can be realized through the tariff. This expense is not linked to the regular operation and maintenance tariff as activities on this account which are generally carried out as per norms within the existing O&M tariff mechanism.

## 14 Techno-economics – Financial analysis of refurbishment options

### 14.1 Objective of financial analysis

When embarking on a refurbishment project, there will generally be a host of possible approaches and scopes under consideration. The objective of the financial analysis is to compare the financial costs and benefits of the options under consideration, and then to select the option that aligns best with the financial objectives and constraints of the organization. In certain circumstances, especially when the utility has public responsibilities, this is broadened to economic analysis of the costs and benefits to all economic stakeholders.

There is no general rule as to which option is best. For example, if an organization has high levels of retained earnings, an option which has a higher initial cost or higher operating cost, but substantially longer life can be preferred based on the NPV over say 35 years. By contrast, a cash-strapped organization can prefer an option with a low operating cost and shorter lifetime because of the improved cash flow. Therefore, at the outset, it is important that the organization vigorously debates the broad financial environment in which it is operating and achieves a degree of consensus on the financial objectives of the refurbishment. Where the scope of the analysis includes all economic participants, this is even more important.

### 14.2 Preliminary designs

For each of the options under consideration, a financial model is required. Technical issues have a major impact on the financial model though. Therefore, one of the first activities to be undertaken is preparation of preliminary or sketch designs for each option. The initial design concepts can be engineered to the level that reasonably accurate capital cost and ongoing maintenance expenditure can be made. The methodology for implementing the option can also be considered carefully, so that any temporary facilities are provided for. If possible, first order optimizations are done at this stage, to reduce the number of options as far as possible. At the end of the preliminary or sketch design phase, ideally there will only be a handful of options. A report documenting the options clearly is generally prepared and accepted by the critical stakeholders.

### 14.3 Reliability and availability models

Having completed the preliminary designs, a reliability and availability model for each of the designs is prepared. Using IEC TR 62672, the impact of each option on the key reliability and availability parameters is quantitatively estimated. The most difficult option to assess is generally the "do nothing yet" option. It will probably be accepted that the ongoing repair and maintenance cost is increasing, and the availability (and hence revenues) are decreasing, but a quantitative prediction will almost certainly be contentious. Although it dramatically increases the analysis effort required, it can be required that a "best case", "likely case", and "worst case" scenario is prepared for this option.

Since the CIGRE reports generate availability parameters that are averaged and annualized, it is normally most practical to model the system on a year-by-year basis. Trying to model the system in shorter intervals is normally counter-productive. In fact, given the high reliability of HVDC links, there can be some justification for modelling the system over longer intervals.

- Considering the range of options, the sub-systems whose reliability and availability will be affected are listed.
- Based on the available data, the mean time between failures (MTBF) and mean time to repair (MTTR) of each of these sub-systems is estimated, as well as the MTBF and MTTR of the systems that will not be refurbished.
- Calculated reliability and availability of the whole system based on the MTBF and MTTR of the individual sub-systems are checked against the input data, to verify the base model.
- For each of the options under consideration, the impact of changes to the MTBF and MTTR of the refurbished sub-systems on the reliability and availability of the entire system is modelled.

Extrapolating reliability data for sub-systems that are close to the end of life or end of their useful life is difficult, because failure rates increase almost exponentially for such sub-systems. Failure rates can increase so rapidly that an entire population of components can fail within a very short space of time, resulting in a sub-system which moves from a high availability to extremely low availability in the same space of time. This can be as short as six months to a year. Nevertheless, parametric investigations of the onset of rapidly increasing failure are possible in these circumstances, and will indicate which sub-systems have the biggest impact.

Reliability models will generally be prepared by a team that includes the operations and maintenance staff as well as specialist reliability engineers.

### 14.4 Financial models

Having completed the reliability and availability models, a financial model is prepared for each option.

These models will:

- Identify the overall lifecycle cost of the refurbishment, including capital cost and the effect on operation and maintenance costs and losses,
- Show the financial impact of the improved reliability and availability, in terms of increased revenues and reduced operating and maintenance costs,
- Show the financial impact of the implementation methodology in terms of the cost of temporary facilities, outages, and constraint charges,
- Show the financial impact of the extended life.

The financial model is generally built on the same basis as the reliability and availability models. It will be prepared by a team that includes both engineers and power system economists.

### 14.5 Impact of discrete events on financial models

In many situations, the timing of discrete events can have a massive impact on the financial model. For example, in a deregulated market the energy charges can be strongly dependent on the status of other links, so a failure in another portion of the network can increase the potential revenues hugely. If the HVDC link is out of service for rehabilitation at this time, the potential lost revenue could be very large. Accurate treatment of these is almost impossible in the financial model. Statistical methods can be applicable to some extent, but even these are generally of limited benefit. Therefore, such events during the implementation of refurbishment are normally ignored, unless they have a very high likelihood of occurring. If they are likely, then the implementation methodology generally makes provision for temporary facilities or for ways of temporarily returning equipment that is not yet refurbished equipment to service quickly if something happens.

### 14.6 Cost-benefit analysis

#### 14.6.1 General

Using the financial models, the financial internal rate of return (FIRR) for each option is determined. The discount rate used in this analysis will generally be uncertain to some degree, so the analysis will be done for a range of values. Typically, a best-case, worst-case and expected case will be investigated.

Where full economic analysis is required, this will be expanded into an economic internal rate of return (EIRR) analysis. This analysis is generally performed by qualified power economists together with engineers.

Depending on the criteria to be used in comparing the options, the net present value (NPV) over a defined life, for a range of discount rates, can also be calculated. This has traditionally been one of the most widely used indicators, but it is open to abuse because it is very sensitive to both the life and the discount rate, and the NPV can easily be manipulated to give a result that was selected a priority. FIRR and EIRR are not as easily manipulated.

The following is a simple example of a cost benefit analysis used by one company called the Capital Project Justification (CPJ) Process.

#### 14.6.2 Background

It was identified through root cause analysis that the nylon tubing and associated manifolds, connectors had reached the end of their life and was causing forced outages of 0,33 % per year on a bipole basis. It was expected that without intervention the number of forced outages would increase. Almost all of the forced outages occurred during the day when loading was much higher than at night. The company involved has a program to perform the NPV tasks so to illustrate here the example will be greatly simplified. The real discount rate used was 6 %. The real discount rate is the difference between the cost to borrow the money at 8 % and the real of inflation at 2 %. The period of 15 years was used as a life extension, as the thyristor valves would only have that much additional life. The cost to replace the tubing including material, labour and scheduled outage costs was $ 6,0 million.

#### 14.6.3 Alternatives

1) Do nothing: The FOA of 0,003 3 times 8 760 hour per year times 4 valve groups = 115,6 h or divided by 8 = 14,5 days. The average cost of a daily outage was $ 60 000 USD. Thus, the outages were costing 14,5 times $ 60 000 = $ 870 000 per year.

   For simplicity 15 years times $ 870 000 = $ 13,05 million USD. This is reasonable as the discounted rate would show a lower number but as the outages will increase the dollar value of the outage costs will be higher in the future.

   Thus, the NPV = $ 6,0 million – $ 13,5 million = −$ 7,5 million.

2) Replace the thyristor valves: The cost to replace the thyristor valves was $ 200 million USD. Using the real discount rate of 6 % times $ 200 million = $ 12 million per year. Plus one can recover the costs of the $ 200 million over 15 years which is another $ 13,3 million. Thus the cost of this option is $ 25,3 million per year. Again, for simplicity 15 years times $ 25,3 million = $ 379,5 million USD. One could argue that the $ 200 million is amortized over 40 years instead of over 15 years but that will still not change the result.

   Thus, the NPV = $ 6,0 million – $ 379,5 million = −$ 373,5 million.

3) Replace the tubing: In this case the savings are $ 13,5 million over 15 years and the cost is $ 6,0 million. Normally the savings would not start totally in the first year as this project would take 2 to 3 years to implement, but for simplicity we will assume so.

   Thus, the NPV = $ 13,5 million – $ 6,0 million = +$ 7,5 million.

It can be seen from this simple example that the best option is life extension for the thyristor valves by replacing the tubing instead of the thyristor valves themselves.

# Annex A
(informative)

# Refurbishment experience

## A.1 Long distance HVDC

### A.1.1 Pacific Intertie

The Pacific Intertie DC link is an example of a very significant HVDC link that has seen many different additions and replacements to extend its life, but also to increase the power capabilities, over its almost 50 years operational life.

The original Pacific Intertie was built by ASEA in 1970 and rated at 400 kV, 1 800 A, 1 440 MW. After 10 years in operation the mercury arc valves had proven to be so stable that the current could be raised to 2 000 A (1 600 MW) without any significant changes to the equipment.

The Pacific Intertie originally consisted of 3 series connected valve groups of 133 kV each (400 kV pole voltage). In 1984 a fourth valve group with 100 kV was added by ASEA raising the voltage to 500 kV and the power to 2 000 MW.

In the period 1940 to 1972 the converter firing was handled by so called delay angle determinators (DAD) of an electromagnetic type. These were well suited for series connections, but also quite difficult to adjust. When the Pacific Intertie voltage was raised, the 4th valve groups were controlled by an electronic version of the DADs to allow the unsymmetrical series connection. This design proved so successful that new electronic DADs were ordered to replace all old DADs in PI during 1985 to 1986, a form of partial control upgrade.

In 1989 the power of PI was raised once more by adding parallel converters (500 kV, 1 100 A) to each pole raising the total power to 3 100 MW. This project was called the Pacific Intertie Expansion (PIE) and was supplied by ABB.

In the mid-1990s the original southern station, Sylmar West, was damaged by an earthquake and was repaired using up most of the combined spares of both Sylmar and Celilo stations.

In 2004 the parallel (PIE) converters in the Sylmar stations were replaced by new valves delivered by ABB in the same valve halls raising the power from 1 100 MW to 3 100 MW, thus eliminating the need for the mercury arc valves. This also meant new transformers and new control and protection systems.

In the same year Siemens replaced the mercury arc valves in the Celilo station with thyristor valves on a one-to-one basis maintaining the series and parallel structure as well as the original control systems.

In 2016 the Celilo station was rebuilt in the same way as the Sylmar station ten years earlier replacing all previous generations of thyristor valves (from 1984, 1988 and 2004) with new valves in the PIE valve halls. This also meant new transformers, control and protection systems and additional AC and DC filters. At the same time the rating of the Celilo station was raised so it is currently prepared to handle 560 kV, 3 410 A (3 800 MW).

In 2019 the Sylmar station was refurbished with new filters and control and protection systems prepared to handle the higher power rating. To be able to use the increased power rating in Celilo will however require increased insulation of the California and Nevada sections of the HVDC line.

### A.1.2 New Zealand 1&2

The original New Zealand HVDC link was built by ASEA in 1965 as a bipole with two mercury arc valve groups per pole.

In 1991 a new pole was built by ABB, and the two original valve groups were arranged for parallel operation in the other pole. As this was not at all anticipated when building the original bipole, the control and protection system was replaced, providing the capability for parallel operation and extended life for the original valve groups. This upgrade meant that the original valves were able to be operated for 42 years before finally being retired in 2012 and being replaced with a completely new thyristor pole (pole 3) supplied by Siemens. In conjunction with pole 3 Siemens also replaced the control system for pole 2.

In 2020 ABB replaced the valve control units (VCUs) and the capacitors and light guides for the valves in pole 2.

### A.1.3 CU

The CU project in midwestern U.S., was built by ASEA in 1978.

In 2004 the control and protection system was upgraded by ABB to the latest technology with the target to continue operation until at least 2027 (approximately 50 years).

The CU project is fed from a generator station with two units owned by the same utility, Great River Energy (GRE) and every 6 to 7 years there is a major overhaul of one generator and its turbine. This creates a situation when only half the rated power of the HVDC link is available for one month and this provides a window of opportunity for maintenance and upgrade work on one pole without any economic impact. Therefore, one pole could be taken out of operation for 14 days while the remaining pole was operated in metallic return. During these 14 days the control and protection system was replaced and tested and started up to carry the available power, so the other pole could be taken out of operation and have its control and protection system replaced. The sequence ended with a 1½ days bipole outage and testing over a weekend before commercial operation with full power was restored.

In 2015 GRE decided to also replace their air-cooled valves with modern water-cooled valves to reduce losses and maintenance efforts. In 2019 the valves, valve cooling system, smoothing reactors, valve hall arresters and wall bushings were replaced by ABB together with the control and protection system and this whole operation could also be performed in one pole at a time with the other in operation in around 35 days per pole.

### A.1.4 Square Butte

The Square Butte HVDC link, between Center in North Dakota and Duluth in Minnesota, was built by US General Electric (GE) in 1976 using air-cooled valves.

In early 2000 the original analog control and protection system started to approach its design life of 30 years and a decision was made to upgrade to a modern digital and redundant control system.

This upgrade was carried out in 2004 by ABB during a 6 week generator maintenance period when the need for power transfer was minimal.

### A.1.5 Skagerrak1&2

The Skagerrak HVDC link using submarine cable between Norway and Denmark was built by ASEA in 1976. In preparation for continued operation until 2027 (51 years) the owners Statnett and Energinet.dk decided to upgrade the original analog control and protection system to a redundant digital system.

ABB got the order for an upgrade and in the summer of 2007, there was an activity for maintenance on the overhead line section in Denmark that required a bipole outage. This created a great opportunity and the complete control and protection system for the bipole could be replaced and tested in just 15 days.

### A.1.6 Cahora Bassa

Cahora Bassa is an HVDC link from Songo on the Zambezi River in northern Mozambique to Apollo in South Africa (RSA). It was built in the late 1970s, but operation was disrupted around 1985 due to civil war activities in Mozambique.

The HVDC link was built by the ZAMCO consortia and the HGÜ group (AEG Telefunken, BBC, Siemens) and employed a unique design using four series connected outdoor oil-cooled and oil-insulated thyristor valves in each pole of the bipole.

After an extensive repair and refurbishment program of the damaged overhead line and of the two converter stations the link could restart operation in 1997.

Siemens replaced at the Songo station during this period of time the control and protection system.

In 2007 ABB was awarded a contract to replace the control and protection system and upgrade the outdoor oil cooled thyristor valves to air insulated water-cooled thyristor valves in the Apollo station. The refurbishment was done in two converter groups at a time keeping transfer capability at 75 % during most of the refurbishment period. The refurbishment was finished in 2008.

In the Songo station the valves and control system remain, but several other refurbishment activities have been implemented. A transformer refurbishment program was carried out and some new transformers have been procured. New air insulated smoothing reactors have replaced the original oil filled reactors, new arrestors and direct current measuring equipment has been installed and new filter banks has been built.

### A.1.7 Intermountain Power Project

Intermountain Power Project (IPP) is transferring power from Delta in Utah to Adelanto outside Los Angeles in the United States. It was built by ASEA in 1986 and had the capacity of 1 600 MW with a unique feature of 100 % short time overload and 50 % continuous overload of one pole at a time with all redundancies available. The rated power was raised to 1 920 MW in 1989.

In 2007 a plan was developed to add 480 MW wind power in the Delta region and transfer this additional power to the Los Angeles region to help the state to reach its renewable power generation targets before the end of 2010.

An opportunity was then to use the continuous pole overload in both poles at the same time. However, this required improved valve cooling capacity (additional cooling towers and new heat exchangers), improved transformer cooling, additional filter banks. Because of the many changes that would involve control system changes it was decided to upgrade the complete control and protection system at the same time.

This upgrade project was awarded to ABB and was carried out in the fall of 2010. The replacement of the control and protection system and upgrading of the cooling system was performed in a three-week outage per pole with the other pole running and was finished in December 2010.

### A.1.8 Cross Channel

The Cross-Channel link is a double bipole (2 × 1 000 MW) connecting France and the UK. It was built by GEC (Sellindge) and Alsthom (Les Mandarins) in 1986.

Both stations used air-cooled thyristor valves and analog control and protection systems and were upgraded by Alstom to water-cooled valves and digital control and protection systems in 2011 and 2012.

### A.1.9 FennoSkan1

FennoSkan1 (FS1) is a submarine cable connecting Finland and Sweden across the Baltic Sea. It was built by ABB in 1989.

In 2011 another pole, FennoSkan2 (FS2), was built by ABB and there was a desire to operate FS1 and FS2 as a bipole with current balancing and power compensation, so it was decided to upgrade the control and protection system of FennoSkan 1 and introduce bipole functionality.

ABB was awarded the control and protection upgrade and FS1 was upgraded in 2013.

### A.1.10 Inga Kolwezi

Inga Kolwezi is an HVDC link in the Democratic Republic of Congo (DRC). It was built by ASEA and started operation in 1982 but the design was from the mid-1970s using air-cooled thyristor valves and analog control systems.

In 2014 the link was upgraded by ABB with new water-cooled valves and a new digital redundant control and protection system.

### A.1.11 Kontek

Kontek is a submarine HVC link connecting Germany and the island of Sjaelland in Denmark. It was built by ABB in 1995.

In 2016 the control and protection system was upgraded by ABB.

### A.1.12 Gotland 2&3

The island of Gotland has been supplied by HVDC power since 1954. In 1983 an additional pole (Gotland 2) was built by ASEA and in 1987 an additional pole was built, which allowed the original pole from 1954 to be retired after 33 years of successful operation.

In 2018 the control and protection systems of Gotland 2 and 3 were refurbished by ABB after 35 years of successful operation. The thyristor valves continue to operate but to improve the spare part situation for the coming years one single valve in one pole had new thyristors fitted. This freed up some 60 thyristors that can serve as spares in any of the remaining 47 valves.

### A.1.13 KontiSkan 2

KontiSkan 2 is a submarine cable connection between Sweden and Denmark. It was built in 1988 by ABB to complement the mercury-arc based KontiSkan 1 from 1965.

In 2019 the control and protection system upgrade was granted to ABB.

### A.1.14 KontiSkan 1

The original mercury-arc based KontiSkan 1 was retired in 2006 after 41 years in operation.

An entirely new KontSkan 1 pole was built by Areva in 2007 to 2010 using the same cable. On the Swedish side the converter station was placed in a new location in Lindome.

In 2019 ABB replaced the control and protection system also for KontiSkan 1 thus providing bipole control and emergency power control that has been lacking from KontiSkan 1.

#### A.1.15 Baltic Cable

Baltic Cable is a submarine cable between Sweden and Germany that was built by ABB in 1994.

In 2019 ABB upgraded the control and protection system.

#### A.1.16 Directlink 1, 2 & 3

Directlink (also called Terranora interconnector) is the world's second commercial VSC based HVDC link built in 2000 by ABB. It connects the New South Wales and Queensland electrical grids in Australia.

It consists of 3 independent connections each rated 60 MW.

In 2019 the control and protection systems of all links were upgraded by ABB.

#### A.1.17 Murraylink

Murraylink is an HVDC VSC link built by ABB that connects the converter stations Red Cliffs in Victoria and Berri in South Australia. It is a 220 MW link and went into operation 2002.

In 2020 the control and protection system was upgraded by ABB.

#### A.1.18 Nelson River Bipole 1 – Pole 1 Valves, valve cooling and valve controls

Nelson River Bipole 1 is an HVDC system with 896 km overhead transmission line (OHL) between Radisson (in the north)and Dorsey (near Winnipeg) in Canada. Bipole 1 consists of 6 × 6 pulse converter groups at both converter stations (three in series per pole). It went into service in 1974 to 1977 and its transfer capability is 1 854 MW. It was built for Manitoba Hydro as a mercury arc valve system by G.E. Alstom (originally English Electric).

In 1992 to 1993 Alstom replaced the Mercury arc valves and analog valve group controls for three converters in Pole 1, with thyristor valves and new version of analog controls and added valve cooling system for the thyristor valves. The Pole 1 controls and Bipole Master controls were not replaced. The replacement was done in three separate outages of three months each. During each outage the other two converters in Pole 1 remained in service.

#### A.1.19 Nelson River Bipole 1 – Pole 2 Valves and valve cooling

In 2003 Siemens replaced the Mercury arc valves for three converters in Pole 2, with light triggered thyristor valves and added a new valve cooling system for the thyristor valves. The original analog controls for the converters were not replaced as the performance was very good and in-house knowledge of the controls was excellent. The converter controls were modified by Manitoba Hydro staff to interface with Siemens thyristor valves. The interface circuit built by Manitoba Hydro was tested in the Siemens plant for verification before the outages started. The Pole 2 controls and Bipole Master controls were not replaced. The cooling system was installed in available spare space before the actual outage was taken. As the controls were not replaced, it was possible to complete the replacement in three separate outages of only four weeks each. During each outage, the other two converters in Pole 2 remained in service.

It is noted that Nelson River Bipole 1 is still operating with analog controls that were installed in 1974 to 1977 with very good performance.

### A.1.20 Nelson River Bipole 1 and 2 – Smoothing reactors

In addition to Bipole 1, the Nelson River also has Bipole 2. The Bipole 2 has 937 km overhead transmission line (OHL) between Henday and Dorsey (near Winnipeg) in Canada. Bipole 2 consists of 4 × 12- pulse converter groups at both converter stations (two in series per pole). It went into service in 1979 and its transfer capability is 2 000 MW. It was built for Manitoba Hydro by a consortium of Siemens, AEG and Brown Boveri.

Originally both bipoles were built with oil filled smoothing reactors. Over the years these reactors required lots of maintenance and there were issues with loose windings, bushings and oil leakage. It was decided to replace these reactors with air core reactors to eliminate maintenance and environmental issues.

It is noted that Nelson River Bipole 2 is also still operating with original analog controls that were installed in 1979 with very good performance.

### A.1.21 Basslink

Basslink is an HVDC OHL/cable interconnector between the electricity grids of the states of Victoria and Tasmania in Australia.

The cable crossing the Bass Strait and connecting the Loy Yang Power Station Victoria on the Australian mainland to the George Town substation in northern Tasmania. The interconnection is 370 km long.

Basslink went into service in 2005 and its transfer capability is 500 MW. It was built for Keppel Infrastructure Trust by Siemens.

In 2012 Siemens replaced the old HMI inclusive all related hardware.

### A.1.22 Trans Bay Cable

Trans Bay Cable is an HVDC underwater cable interconnection between San Francisco and Pittsburg in California U.S. It went into service in 2010 and its transfer capability is 400 MW. It was built for Steel River Transmission Company by Siemens. Trans Bay Cable is the first VSC in commercial operation using Modular Multilevel Converter (MMC) technology.

It was upgraded by Siemens in 2016. The scope of the upgrade was the implementation of Blackstart functionality, new control and protection software and new control and protection hardware components.

### A.1.23 East South Interconnector II (Upgrade – Power capability enhancement 2 000 MW to 2 500 MW) – in 2006

East South interconnector owned by Powergrid Corporation of India Ltd. is a 2 000 MW HVDC bipole system with its two stations located at Talcher and Kolar in India. The station was upgraded in 2006 from 2 000 MW to 2 500 MW by increasing cooling of transformers, forced air cooling of smoothing reactors and additional AC filter banks.

### A.1.24 Rihand Dadri HVDC refurbishment

Rihand Dadri owned by Powergrid Corporation of India Ltd. is a 1 500 MW HVDC bipole system with its two stations located at Rihand and Dadri in India. It was commissioned in the 1990s and is the first HVDC point to point system in India. The station has already completed more than 25 years of service.

Replacement of the majority of the equipment has already been carried out with converter transformers and bushing being separately procured whereas TCU, valve cooling and control protection have been replaced together by Hitachi Energy in 2021 and the system is under operation after refurbishment.

### A.1.25 Gezhouba-Shanghai ±500 kV HVDC project

It is the first HVDC power transmission in China and was built to connect the 2 715 MW Gezhouba hydropower generating plant near Yichang city on the Changjiang River with the city of Shanghai.

In 1985, ABB – in a consortium with Siemens – received the contract to build an HVDC transmission system between Gezhouba and Nanqiao District, near Shanghai from The State Power Corporation, China. Commissioned in 1989, the bipolar 1,046-km Gezhouba – Shanghai HVDC transmission link is rated at ±500 kV, with maximum power capacity of 1 200 MW.

In 2004, because of the following problems: high hardware and software fault rate, low availability capacity lead to diseconomy, more and more electronic boards were broken, in danger of exhausting spare parts, and drawbacks of HVDC control and protection system, the control and protection system was replaced by NR Electric. Since the retrofit was performed during the dry season of the Changjiang River, no power transmission was necessary, both poles were shut down altogether at the end of 2004, and the project was put in operation in May 2005.

### A.1.26 Tian-Guang ±500 kV HVDC project

The Tian-Guang HVDC project is a bipolar 960 km 500 kV HVDC system used for transmitting power generated at Tianshengqiao Hydroelectric Plant to Guangzhou. HVDC Tian–Guang, which was built by Siemens and inaugurated in 2001, is capable of transmitting a maximum power of 1 800 MW.

In 2009, because of the low availability ratio caused by high fault rate, a retrofit including the control and protection system and CT&PT of DC yard was performed by NR Electric at the end of 2009. During the commission work both poles were shut down since it was dry season for the Tianshengqiao Hydroelectric Plant at the rectifier end. Both poles were put into operation in May 2010.

### A.1.27 Ormoc-Naga 344 kV HVDC project

The HVDC Leyte–Luzon is a one pole HVDC transmission link in the Philippines between geothermal power plants on the island of Leyte and the southern part of island of Luzon. The HVDC Leyte – Luzon went into service in August 1998.The HVDC Leyte – Luzon begins at Ormoc converter station (Leyte Province) and ends at Naga converter station (Province of Camarines Sur).

In 2013, NGCP decided to carry out a retrofit to improve the operation of this HVDC project. The scope of retrofit included the control and protection system of the DC and AC system, DC measuring system (only the secondary parts), VCU (valve control unit) and the valve cooling system.

NR Electric performed the retrofit.

The whole retrofit lasted 18 months, from April 2013 to October 2014. The shutdown time was only 5 weeks and most of the time was used for AC grid related system tests. The retrofit finished successfully 15 days ahead of schedule.

### A.1.28 Luchaogang-Shengsi ±50 kV HVDC project

The Lu–Sheng HVDC project is a bipolar 60 km 50 kV HVDC system used for supply power to Sijiao Island. The HVDC Lu–Sheng, which was built by Xuji and inaugurated in 2002, is capable of transmitting a maximum power of 60 MW.

In 2012, because of the low HVDC utilization ratio caused by high fault rate, a retrofit including the control and protection system and CT&PT of DC yard was performed by NR Electric at the end of 2012. During the commissioning work both poles were shut down since it has another AC line to transmit power to the Sijiao Island. Both poles were put into operation in May 2013.

## A.2 Back-to-back HVDC

### A.2.1 Blackwater

Blackwater is a back-to-back (BtB) HVDC link between the New Mexico and Texas AC networks. It was built by BBC and finished in 1985.The area has a lack of water supply so over the years the wet and water consuming cooling towers became a maintenance burden, with the necessity to bring in water by truck during some periods of the year. It was also an issue to obtain spare parts for the control and protection system.

ABB got a refurbishment order and in 2008 the valve cooling system was replaced by a dry type cooling system. In 2009 the control and protection system was replaced.

### A.2.2 Châteauguay

Châteauguay is a BtB close to Montreal (Canada) that connects the Quebec AC network to a dedicated AC line to New York (NYPA). It consists of two blocks of 500 MW and was built in 1984 by Siemens and BBC.

It was upgraded by ABB in 2009 replacing the analog control and protection system with a digital and redundant system. Also, the installed VBE that was located at the bottom of the valve stacks inside the valve hall was replaced by new valve control units outside the valve hall. To achieve this also all light guides in the valves had to be replaced.

### A.2.3 Highgate

Highgate is a BtB in Vermont US that connects the Quebec AC network to the US AC network. It was built in record time in 1985 by ASEA to replace the power from a nuclear plant that was being taken out for a rebuild.

In 2012 ABB supplied an upgrade with a new and higher capacity valve cooling system, some new valve components and a new control and protection system.

### A.2.4 Eel river

Eel River is a BtB between the Quebec and New Brunswick AC networks in Canada and consists of two blocks of 350 MW each. It also employs three synchronous compensators connected to converter transformer tertiary windings. Also the AC filters are connected to transformer tertiary windings.

Eel River was built in 1972 by Canadian General Electric (GE) and is recognised as the first commercial HVDC installation using only thyristors. The Gotland voltage upgrade in 1970 was earlier but added thyristor valve groups in series to existing mercury-arc valve groups.

In 2014 ABB replaced the air-cooled valves with modern water-cooled valves and new valve cooling systems. Also, the analog control and protection system was replaced with state-of-the-art digital redundant control and protection systems.

### A.2.5 Madawaska

Madawaska is a 350 MW BtB connecting the AC grids of Quebec and New Brunswick in Canada. It was built by GE in 1985 using air-cooled thyristor valves and an analog control and protection system.

The station was upgraded to water-cooled thyristor valves and digital control and protection by ABB in 2016.

### A.2.6 Rapid city

Rapid City is a BtB connecting the eastern and western AC grids in the US. Because of the very low short circuit power, CCC technology (capacitor communicated converters) is used. It was built by ABB in 2003 and consists of two 100 MW blocks.

ABB upgraded the control and protection systems in 2020.

### A.2.7 Vindhyachal HVDC refurbishment

Vindhyachal back-to-back HVDC system owned by Powergrid Corporation of India Ltd. is a 500 MW (2 × 250 MW) HVDC Station located at Vindhyachal, India commissioned in 1989 and was the first back-to-back HVDC station commissioned in India. The back-to-back station has acted as an asynchronous link between the northern region and western region of India. Though currently these regions have been synchronised the Vindhyachal back-to-back project is still used for power exchange and grid stability. The system has completed 30 years of its useful life and was badly needing refurbishment of the majority of the equipment.

Replacement of majority of equipment has already been carried out by Siemens with converter transformers and bushing being separately procured and valves valve cooling and control protection and DC equipment in valve hall (arrester, DCCT, DCVD) being replaced together. After refurbishment, the system has been in operation since 2021.

### A.2.8 Welsh HVDC converter station

Welsh is a BtB connected between the Robert Welsh Power Plant and the Oncor Electric Substation at the Monticello Power Plant in Titus County north-eastern Texas in the U.S. It went into service in 1995 and its transfer capability is 600 MW. It was built for AEP Southwestern Electric Power Company (SWEPCO) by Siemens.

It was upgraded by Siemens in 2017. The scope of the upgrade was the complete control and protection system, valve cooling system and HVAC. Furthermore, Siemens delivered low order filters (LOF) and shunt reactors with the related control and protection system for compensation of low order harmonics in the AC grid on both network sides.

## A.3 Multiterminal – Quebec New England multiterminal DC (MTDC)

The Quebec New England multiterminal HVDC system was originally designed as a five terminal system incorporating the already existing stations in the point to point transmission across the U.S. Canada border, Comerford Des Canton supplied by GE, and adding the new stations Radisson, Nicolet in Canada and Sandy Pond in the U.S. supplied by ABB.

The design and factory system testing were thus carried out with five terminals anticipating replacing the existing control and protection systems in Comerford and Des Canton. In subsequent system studies it was found that the smaller existing stations would limit the performance of the larger newer stations, so a decision was taken to abstain from putting those stations back in service after the control replacement.

The multiterminal project went into operation as a two-terminal link in 1990 and adding Nicolet to become a three-terminal link in 1992.

The control and protection system was upgraded by ABB starting with Nicolet in 2015 and continuing with Radisson and Sandy Pond in 2016.

# Annex B
(informative)

# Replacement of LCC station with VSC station

## B.1 General

### B.1.1 Overview

For the HVDC converters the following two technologies are most used:

– Line commutated converter LCC,

– Voltage sourced converter VSC.

### B.1.2 Line commutated converter

The design of the first line commuted converters (LCC) used mercury arc rectifiers in the HVDC conversion process. Thyristor valves replaced the mercury arc technology in the early 1970s. Innovations with higher current and voltage rated thyristors, water cooled and air insulated valves utilizing both electrically triggered and light triggered thyristors contributed to the reduction of the components.

Between 1970 and 2000 more than 70 LCC based systems of various ratings were commissioned. Some of these systems have already been refurbished while others are going to be refurbished in the next 10 years.

### B.1.3 Voltage sourced converters

The voltage sourced converter technology (VSC) was introduced in 1997 at the rating of 3 MW and 10 kV. Within 20 years VSC technology reached the rating of 1 000 MW in the symmetrical monopole and 3 000 MW in a bipolar system. Presently the multi-module converter (MMC) in both half and full bridge are the VSC technology of choice. VSC technology provides many distinct advantages over the LCC. It is expected that in 10 years the VSC will be the technology of choice for ratings up to 5 000 MW. The LCC will certainly have its place for the very high ratings, in both voltage and power. Therefore, the VSC option can be considered for the replacement of existing LCC facilities. Obviously, economics will play a major role in the decision-making process, however, the VSC advantages are generally considered in the evaluation of the options.

### B.1.4 Comparison between LCC and VSC HVDC converters

Table B.1 summarizes the comparison between LCC and VSC HVDC systems.

**Table B.1 – Comparison between LCC and VSC converters**

| LCC HVDC system | VSC HVDC system |
|---|---|
| In service since 1954 | In service since 1997 |
| Maximum installed bipole rating 12 000 MW | Maximum installed and in service rating: 2 000 MW |
| Highest DC voltage: 1 100 kV | Highest DC voltage: 525 kV |
| Thyristor rating: 6 kA, 8 kV | IGBT, available up to 2,5 kA, 4,5 kV (3 KA is being quoted) |
| Requires AC filters | Minimum filter requirement or none |
| Consumes reactive power | Can absorb or supply reactive power independent of the active power |
| Difficult and not practical since requiring large scale synchronous condensers and small local power support. | Can be used in black start |

| LCC HVDC system | VSC HVDC system |
|---|---|
| Requires certain AC system strength SCR | Lower SCR requirement |
| Losses (0,6 to 0,7 % per station) | Losses (0,8 to 0,9 %) per station) |
| Within the limited operational condition | Very limited overload capability |
| Most applications are with MIND cables because of power direction reversal requirements | Can use extruded/XLPE cables |
| AC faults cause commutation failures | No commutation failures |
| Large overvoltage at load rejection | Overvoltage at load rejection can be controlled by converter controls. |
| DC line faults cleared, and transmission restored in short time through HVDC controls | DC line faults take longer to clear (approximately 1 s) with half bridge, but can be reduced to few hundred milliseconds using full bridge |
| Very suitable for overhead line applications | Requires DC breaker or full bridge if connected to overhead line |
| Large footprint | Approximately 40 % footprint reduction |
| The DC voltage polarity must be reversed to reverse power. | No polarity reversal is required to reverse power. |

### B.1.5 Replacement of LCC station with VSC station

#### B.1.5.1 General

A recent report by EPRI [1][4], analysed the issues related to the conversion of an LCC station to a VSC station.

For conversion of an LCC station to a VSC station, the following aspects can be considered, before making the final decision:

#### B.1.5.2 System strength changes

The changes in the system configuration can play an important part in the decision. LCC systems require a minimum short circuit ratio (SCR) of 2,5 for satisfactory operation, whereas a VSC system can operate with much lower SCR. With the introduction of renewable generation, the old fossil fuel-based plants are being retired. If the changes in the system (e.g., a thermal generator nearby retired) have resulted in reduced SCR, then VSC can be a better option.

#### B.1.5.3 Valve hall dimensions

The LCC thyristor valves are typically stacked vertically whereas the VSC valve sections are mostly installed more in a horizontal configuration, as a result the VSC valve halls require more land area than an LCC valve of the same rating.

If the new station will be located on the existing land area, the existing LCC valve halls would be demolished and a new VSC valve hall built in that space.

#### B.1.5.4 Phase reactors

A VSC valve requires reactors in each phase in series with valve. These reactors can be located on the AC side of the valve or the DC side of the valve depending on the system. Further, in some designs it is included in the transformer leakage reactance. In both designs additional space will be required for these reactors which will likely not be available in the existing LCC station.

[4] Numbers in square brackets refer to the Bibliography.

#### B.1.5.5 DC line faults

If the existing LCC link contains overhead transmission line, system studies can be performed to determine if switching of AC breakers is enough or not. DC breakers or full bridge converters might be required to meet system requirements. Either option will add to the cost of the system.

#### B.1.5.6 Losses

The VSC converter has slightly higher losses even with half bridge configuration. The losses will be even higher if full bridge configuration will be used. The cost of higher losses is taken into account in economic analysis for the upgrade.

#### B.1.5.7 Common equipment

When replacement of an LCC station with a VSC station is considered, a question will always be asked, "Can any of the LCC station equipment be used for VSC station?"

Equipment common to LCC and VSC systems are:

- Converter transformers,
- Smoothing reactors,
- DC switchgear,
- Control and protection,
- AC filters,
- DC filters,
- DC measuring equipment,
- Auxiliary supplies,
- Valve cooling.

The feasibility of reusing any of the above equipment is discussed in the following subclauses.

For discussion and comparison purposes, it is assumed that the LCC HVDC scheme is a bipolar system and the VSC HVSC scheme will also be a bipolar system and not a symmetrical monopole.

### B.1.6 Converter transformers

All modern LCC converters are built as 12 pulse converters. The LCC converter transformers have a star and a delta winding on the valve side, each rated to half the required MVA.

A VSC converter is connected to a transformer with only one winding on the valve side. Usually transformers for a VSC are connected in a wye delta configuration however in some instances a wye to wye transformer configuration has been utilized. From an electrical point of view, the peak of the phase to ground valve winding voltage of the VSC must be at lower value than the DC voltage.

Consider a single 12-pulse converter per pole is the original configuration of the LCC. Depending on the rating of the converter, the converter transformers are likely to be one of the following configurations:

- Singe phase two winding,
- Single phase three winding.

Single phase two winding transformers are used for higher rating converters (e.g., > 750 MW). The star and delta bridges would likely be physically separated as double valves. Each 12-pulse converter would be replaced by two series connected VSC converters. It is even more complicated because of the location of the phase reactors, which can be placed either between the converter transformer and each converter arm or between each arm and the DC busbars of each converter. The phase reactors can be placed inside or outside the valve hall. Owing to limited space available inside LCC valve halls the phase reactor would be located outside the valve hall. However, placing them outside the valve hall will increase the number of wall bushings. Space is also needed for the charging resistors and their bypass breakers either on the system side or the converter side of each transformer. So, the limitation here, is not the transformer electrical rating but the physical configuration.

The problem is more pronounced for converters of smaller rating in a LCC bipolar scheme or in a BtB arrangement. In these systems the LCC valves would likely be quadrivalves. This will make installation of two VSC converters almost impossible in the existing LCC valve hall.

In some schemes the transformers star and delta bushings are protruding into the valve hall. In this arrangement the phase reactors would be installed on the DC side and outside the valve hall. Connecting the valve winding bushings to two series connected independent VSCs is not possible because the two VSC converters are in separate valve halls with their respective phase reactors. Similar to the previous scenario, extra space is needed for the phase reactors and the charging resistors.

Although from a rating perspective the LCC converter transformers can be used for a VSC converter, physical restrictions will make it impossible to use the LCC converter transformers.

### B.1.7 Smoothing reactors

The size of the smoothing reactor used for LCC transmission is generally much larger than one used in a VSC HVDC scheme of the same power rating. Therefore, using the existing smoothing reactors is possible (although it is not optimal) as long as studies are performed to ensure there are no resonance conditions. If the LCC reactor is composed of smaller sized units, the smaller reactors can be used. Otherwise the available area from an LCC smoothing reactor would provide sufficient space for a VSC smoothing reactor replacement in the DC area. The smoothing reactor for the back-to-back LCC systems is small. Back-to-back VSC systems can be realized without a smoothing reactor.

### B.1.8 DC switchgear

Some of the LCC DC switchgear can be redeployed for a VSC application. For instance, the DC switchgear used for connecting the LCC converter to the high voltage side and the neutral side and all the switchgear used for metallic return operation can be used.

In terms of the lightning and switching impulse levels, the existing DC switchgear insulation levels would remain the same. However, a new insulation coordination study can be performed to determine the protection levels and what existing equipment is suitable. The ratings of the various surge arresters can also be verified.

### B.1.9 Control and protection

The control strategy of the VSC is totally different from that of the LCC even if the LCC system currently operates using the latest digital based control system. The function in a VSC module management system or VBE is different from that of the LCC. The overall space requirements for the cubicles would be much the same as for an LCC converter. The control and protection system of an LCC is not suitable to be used in a VSC.

### B.1.10 AC filters

LCC converter technology requires the extensive use of harmonic filters to comply with utility emission standards as well as for reactive compensation. However, the VSC systems require a very small number of AC filters of only higher harmonics. It can be possible to modify high pass filter arrangements to be redeployed for the VSC converter however the AC filter requirement would be specified on a case by case basis.

### B.1.11 DC filters

Since VSC converters do not require DC filters, the DC filter area from an LCC system could be used if more space is required in the DC yard for other related VSC equipment.

NOTE BtB systems do not have DC filter requirements.

### B.1.12 DC measuring equipment

The DC measuring equipment for an LCC converter would be basically the same for a comparable VSC converter.

However, the lifetime of the existing equipment can be factored in as well as finding spare parts and matching the response time and interfacing issues.

### B.1.13 Auxiliary supplies

The auxiliary supply requirements for a VSC converter would be almost the same as those of an LCC converter so the existing chargers and batteries could be used. The lifetime of the existing battery systems is considered for reuse in a VSC system since the typical lifespan of lead acid batteries is 15 to 20 years.

### B.1.14 Valve cooling

The losses for an LCC station are in the order of 0,6 % to 0,7 %. For a comparable rated VSC station the losses are in the order of 0,8 % to 0,9 %. The additional losses are mostly in the VSC valve itself. Therefore, a valve cooling system of higher capacity (compared to LCC valve) is required.

Existing LCC cooling systems which have been upgraded with improved redundancy can be reviewed on a case by case basis.

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