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Terry Krieg • John Finn
Editors

# Substations

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*Editors*
Terry Krieg
CIGRE Study Committee B3
Power Network Consulting Pty Ltd
Adelaide, Australia

John Finn
CIGRE UK
Newcastle upon Tyne, UK

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*This book is dedicated to the memory of*
*Dr. Adriaan Zomers*

# Message from the President

CIGRE is the global expert community for electric power systems. It is a nonprofit organization based in Paris. It consists of members from 90 countries representing 58 national committees. It functions as a virtual organization with members, who are experts in their technical field, forming working groups dealing with issues facing the power delivery industry. At present, there are around 230 working groups comprising 3000 experts working together to resolve the identified issues. The output of the working groups is technical brochures. These brochures, of which there are now over 700, comprise the combined knowledge and practice of engineering experts from all continents. The brochures are practical in nature enabling the engineer to plan, design, construct, operate, and maintain the power delivery solution required. CIGRE has over 10,000 reference papers and other documents supporting the brochures and dealing with other technical matters.

This book on substations, developed by Study Committee (SC) B3, represents the latest thinking in substation design, operation, technology selection, and asset management. It comprises input from published brochures as well as contributions from experts in the field. CIGRE is a source of unbiased technical information. Engineers can refer to this book without fear of favoring one supplier or country. It is a compilation of the combined expertise of many international experts providing an unbiased objective textbook in substation design.

This book is unique in that it consists of input from many experts, not only one or two. These experts are from all continents of the globe providing technical solutions no matter where the reader is residing. The views expressed and suggestions made are unbiased objective statements. These can be used as references for engineers to develop standards and guidelines within their organizations.

This book is a reference book for academia, substation design departments, and consultants. The sections on asset management provide vital information for asset managers involved in this technology.

I would like to congratulate those involved from SC B3 who have compiled this book. Many of them have had to work in their spare time for hours to complete this task, for which they worked as volunteers.

I would recommend this book in forming the basis for substation activities now and in the future.

February 2018 Dr. Rob Stephen

**Dr. Rob Stephen** was born in Johannesburg, South Africa. He graduated from the University of the Witwatersrand in 1979 with a B.Sc. Electrical Engineering degree. He joined the Eskom, electricity utility, in 1980. He holds M.Sc. and M.B.A. degrees as well as a Ph.D. in overhead line design. He is currently the Master Specialist in the Technology Group in Eskom and is responsible for distribution and transmission technologies of all voltages covering both AC and DC and was responsible for the smart grid strategy for Eskom. He is past chairman of CIGRE SC B2 on overhead lines and has held positions in CIGRE as special Reporter and Working Group Chairman and has authored over 100 technical papers. He was recently elected International President of CIGRE in 2016. He is also a Fellow of the South African Institute of Electrical Engineers (SAIEE) and was elected Honorary Vice President in 2005. He received the SAIEE President's Award in 2016.

# Message from the Chairman of the Technical Committee

Efficient use of electric energy is at the very heart of a sustainable future for all of us and for almost 100 years now, CIGRE has provided a worldwide platform for achieving such an ambitious target.

Initially, as integrated, high voltage, electric power networks were developed and became established in various parts of the world, CIGRE was very much focused on the technical aspects of transmission of electric energy. As the electric power industry evolved, it was vital that CIGRE also evolved. Over time, greater focus was placed on aspects such as markets, regulation, system planning, sustainability, and information systems, but this was certainly not at the expense of the more fundamental technical aspects.

Today, as the distinctions between transmission and distribution and between end user and electricity provider have eroded and as the entire electric power system has become more interactive and reliant upon intelligent systems, CIGRE's focus has, of course, widened to address the entire electric power system. Generation, transmission, distribution, and end use of electric energy are all addressed across the entire spectrum from 1200 kV transmission grids to local micro-grids, employing AC or DC.

The present-day activities of CIGRE can be divided into three key themes, namely, "developing the power system of the future," "making best use of existing power systems," and "environment and sustainability." Within this framework, CIGRE strives to bring together the widest possible range of experts from across the world to share and exchange knowledge and to use this combined knowledge and experience to develop and publish preeminent technical information and state-of-the-art guidance.

Our aim is to prepare documents and communications that are clear, readily accessible, unambiguous, and appropriate to the intended audience, and which also promote the value and importance of electrical engineering and the electric power industry within technical, political, business, and academic arenas. This has been achieved very successfully over many years and CIGRE's ever-growing library of technical brochures, conference papers, tutorials, and articles is a unique and unparalleled resource in the electric power industry. Nevertheless, recognizing that dissemination of high-quality, unbiased information is CIGRE's singular focus, finding new ways to make our work visible is always a priority, which brings us to the CIGRE Green Book initiative.

CIGRE Green Books are a way of consolidating, enhancing, and disseminating CIGRE's accumulated knowledge in specific fields. Addressing all aspects of CIGRE's key themes prepared and edited by world-recognized experts and building upon CIGRE's established library of world-class publications, the Green Books provide a single, invaluable reference source within their specific field of application. They also provide a unique resource for those wishing to develop themselves, for those wanting to make their contribution to the power system of the future, and to the vision of access to reliable, affordable, and sustainable electric energy.

The Technical Council is committed to the continuing development of CIGRE's technical leadership in the electric power industry, and the future expansion of the Green Book series is a key part of this commitment.

February 2018 Mark Waldron

**Mark Waldron** graduated in Electrical Engineering in 1988 and joined the Research Division of the Central Electricity Generating Board, and then, following privatization, National Grid in the UK by whom he is still employed. He has been involved in all aspects of lifetime management of switchgear and substation equipment, including research and development, specification, assessment, maintenance and monitoring, condition assessment, and end-of-life management. He presently holds the position of Switchgear Technical Leader in addition to his role as the Technical Council Chairman of CIGRE. His involvement in CIGRE spans over 20 years, during which he has been a participant in several working groups, working group convener, and Study Committee Chairman of Study Committee A3 and has led the Technical Committee project on Ultra High Voltage Transmission.

# Message from the Secretary General

Four years ago, I had the pleasure to comment on the launching of a new CIGRE publication collection in an introductory message about the first CIGRE Green Book, the one on Overhead Lines.

The idea to evaluate the collective work of the study committees accumulated over more than 20 years, by putting together all the technical brochures of a given field, in a single book, was first proposed by Dr. Konstantin Papailiou to the Technical Committee (now Council) in 2011.

One year later in 2015, the cooperation with Springer allowed CIGRE to publish it again as a "Major Reference Work" distributed through the vast network of this well-known international publisher.

Two years ago, in 2016, the collection was enriched with a new category of Green Books, the CIGRE "Compact Series," to satisfy the needs of the study committees when they want to publish shorter, concise volumes.

The first CIGRE Compact Book was prepared by Study Committee D2, under the title *Utility Communication Networks and Services*.

Since then, the concept of the CIGRE Green Books series has continued to evolve, and recently we introduced a third subcategory of the series, the "CIGRE Green Book Technical Brochures" (GBTB).

CIGRE has published more than 700 technical brochures since 1969, and it is interesting to note that in the first one, on Tele-protection, the first reference was a Springer publication of 1963.

A CIGRE Technical Brochure produced by a CIGRE working group, following specific Terms of Reference, is published by the CIGRE Central Office and is available from the CIGRE online library, e-cigre, one of the most comprehensive, accessible databases of relevant technical literature on power engineering.

Between 40 and 50 new technical brochures are published yearly, and these brochures are announced in *Electra*, CIGRE's bimonthly journal, and are available for downloading from e-cigre.

From now on, the Technical Council of CIGRE may decide to publish a technical brochure as a Green Book in addition to the traditional CIGRE Technical Brochure. The motivation of the Technical Council to make such a decision is to disseminate the related information beyond the CIGRE community, through the Springer network.

As the other publications of the CIGRE Green Books series, the GBTB will be available from e-cigre in electronic format free of charge for CIGRE members.

CIGRE plans to copublish new Green Books edited by the different study committees, and the series will grow progressively at a pace of about one or two volumes per year.

This new Green Book, a Major Reference Work prepared by Study Committee B3, is the third of this subcategory.

I want to congratulate all the authors, contributors, and reviewers of this book, which gives the reader a clear and comprehensive vision of the past, recent, and future developments of substations.

Philippe Adam
Secretary General

Graduate of the École Centrale de Paris, Philippe Adam began his career in EDF in 1980 as a research engineer in the field of HVDC and was involved in the studies and tests of outstanding projects like the Cross Channel 2000 MW link and the first multi terminal DC link between Sardinia, Corsica, and Italy. After this pioneering period, he managed the team of engineers in charge of HVDC and FACTS studies of the R&D division of EDF. In this period, his CIGRE membership as a working group expert and then as a working group convener in Study Committee 14 was a genuine support to his professional activities. Then he held several management positions in the EDF Generation and Transmission division in the fields of substation engineering, network planning, transmission asset management, and international consulting until 2000. When RTE, the French TSO, was created in 2000, he was appointed Manager of the Financial and Management Control Department, in order to install this corporate function and the necessary tools. In 2004, he contributed to the creation of RTE international activities as Project Director first and then Deputy Head of the International Relations Department. From 2011 to 2014, he has been the Strategy Director of Infrastructures and Technologies of the Medgrid industrial initiative. In the meantime, between 2002 and 2012 he has served CIGRE as the Technical Committee Secretary and as the Secretary and Treasurer of the French National Committee from 2009 till 2014. He was appointed Secretary General of CIGRE in March 2014.

# Preface

Looking back in history, we can see how substations have developed over time, and we can appreciate the work of pioneers such as Thomas Edison, Nikola Tesla, George Westinghouse, and many others from those early years.

The first three-phase AC line is believed to have been installed in 1891, a 40 Hz, 15 kV line running 175 km between Lauffen am Neckar and Frankfurt am Main. Presumably, the line was terminated at the first ever substations.

The very first substations were considered to be directly associated with single power stations, and so the name "*sub*stations" was used. Today, there are a range of types of substations used throughout the power system providing switching, voltage transformation, protection, and auxiliary functions within the global power grid, which is ever expanding and changing to meet the needs of the world community.

At this time in world history, we are seeing incredible changes in the way the grid is used, meeting the needs of rapidly developing nations, growth in population, and increased use of renewables throughout the power system. Access to electricity is now vital to the functioning of society, but still today more than one billion people do not have access to reliable sources of electricity around the globe. Many of those people live in sub-Saharan Africa. To achieve full potential, every community needs access to reliable electricity that can power economic growth.

The topic that we call "substations" covers a diverse scope. We deal not only with the design and construction of substations but also the management of substations as an asset throughout their lifetime, including technical, economic, environmental, and social aspects of substations. As a study committee covering this topic, we aim to provide information to support organizations in life-cycle management of substations, including the management of renovation, maintenance, monitoring, and reliability, all in a safe and sustainable manner. Our work aims to improve plant safety, reliability, and availability; optimize asset management; and minimize cost, risk, and environmental footprint, recognizing the diverse range of social needs and priorities of the broad range of substation stakeholders.

Historically, there are very few textbooks that cover the full topic of high voltage substations. This book aims to provide a reference book containing the collective knowledge of the members of CIGRE who are currently involved in the study of many aspects of substations, as an aid to those who want to know more about the topic. CIGRE Study Committee B3 includes more than 400 experts from almost 50 countries in 16 different working groups. Of course, the experts today follow in the steps of those who went before them. These experts have been willing to share their knowledge and experience to assist the world community manage the challenges associated with building and managing substations.

In 2012 when the idea of a reference book was first discussed in our study committee, there were some who were against it, arguing that the information was already available in the myriad of existing publications of CIGRE over the years since 1921. The intention with this book is to present that information in a summarized and readable manner, bringing information up to date where necessary. The book is the work of many authors who have freely given of their time and expertise.

This book, as with others in the Green Book series, will continue to grow and expand as we gather more knowledge in the field and as new experts join our global community.

Some people have described substations as merely shelters for their precious protection relays, but I think that you will appreciate the richness and depth of the topic of substations as you read this book and refer to it over the years. I hope that you enjoy it and the book becomes a valuable addition to your technical library for many years to come.

Chairman of Study Committee B3 – Substations Terry Krieg
Gawler, South Australia
February 2018

# Acknowledgments

A major reference book of this type is not the work of one person but is the collected knowledge of many individual authors contributing over a number of years. Some of these authors have passed away or have retired from the industry, but their work remains in the form of the many technical brochures and technical papers that have been published.

One special mention should be made here of Adriaan Zomers from the Netherlands. Adriaan passed away in January 2017 at the age of 78. He was extremely knowledgeable in the field of substations, passionate in the causes he believed in, and very active in the field of rural electrification and addressing problems in providing universal access to electricity. Adriaan produced the first plan for this book and was a keen supporter of the project from the outset. He is sadly missed by all of us. This book is dedicated to the memory of our friend and colleague, Adriaan.

This book was assembled by a team of dedicated individuals who were lead authors, reviewers, chapter authors, or contributors for the period from 2012 to 2016 predominantly. However, there is one person who all of us involved with this project, especially myself, are very grateful to, and that is the person who pulled it all together as convener, John Finn from the UK. John had a long career in the study committee and in industry and had the right mix of technical skills and, importantly, the ability to manage complex projects such as the Green Book, managing a team of busy professionals. When I asked him to take on the task of convener, he readily agreed, perhaps not knowing what lay in front of him. To John, I offer my sincerest thanks on behalf of the study committee and the global substation community. Without him, this book would not have become a reality.

Chairman of Study Committee B3 – Substations Terry Krieg
Gawler, South Australia
28 February 2018

**Adriaan Zomers** started his professional career in 1961 as construction and design engineer at Smit Slikkerveer and, in 1971, joined the Electricity Board of Friesland, responsible for the design, construction, operation, and maintenance of power stations and the high voltage network up to 220 kV.

In 1985, Adriaan joined CIGRE and became the Dutch representative of Study Committee 23 (now B3) "Substations." His membership of this SC continued until 1996. At the same time, he convened the Dutch mirror committee 23, encouraging a number of young engineers to become involved in CIGRE work. He successfully convened the working group on substation secondary equipment for more than 10 years.

In 2001, Adriaan was awarded a Doctoral degree by the University of Twente, Netherlands, on the basis of the dissertation "Rural electrification: utilities' chafe or challenge?" He was an energy adviser for the Dutch Government for two decades, and after the reorganization of CIGRE's technical activities in 2005, he was invited to also join the new SC C6 on Distribution and Dispersed Generation as an expert member to address the electrification of rural and remote areas. In SC C6, he has been secretary or member of specific working groups, member of panels, and keynote speaker as well as chairman of the International Advisory Group on Rural Electrification.

Adriaan remained active in the SC B3 Strategic and Tutorial Advisory Groups but sadly passed away on January 5, 2017, aged 78 years.

# Contents

## Volume 1


**1 Introduction** . . . 1
John Finn and Adriaan Zomers
1.1 Purpose . . . 1
1.2 Substations . . . 2
1.3 Structure of the Book . . . 2
1.4 How to Use the Book . . . 4

**Part A Planning and Concepts** . . . **5**
John Finn

**2 Introduction to Substation Planning and Concepts** . . . 7
John Finn
2.1 Introduction . . . 7
2.2 System Requirements . . . 8
2.3 Site Location . . . 10

**3 Type of Switchgear to Be Used** . . . 11
Colm Twomey
3.1 Types of Switchgear Available . . . 11
3.1.1 Air-Insulated Switchgear (AIS) . . . 12
3.1.2 Gas-Insulated Switchgear (GIS) . . . 12
3.1.3 Mixed-Technology Switchgear (MTS) . . . 12
3.2 Choosing the Type to be Applied . . . 12
3.2.1 Reasons for Using AIS . . . 13
3.2.2 Reasons for Using GIS . . . 13
3.2.3 Reasons for Using MTS . . . 13
3.3 Conclusion . . . 13

**4 Selecting Circuit Arrangements: Requirements and Reliability** . . . 15
Gerd Lingner
4.1 Main Requirements . . . 16
4.1.1 Further Requirements and Implications . . . 17
4.2 Reliability . . . 18

4.3 Selecting Circuit Arrangements . . . . . 19
4.3.1 Description of Assessment Criteria . . . . . 20
4.3.2 Service Security . . . . . 20
4.3.3 Availability During Maintenance . . . . . 21
4.3.4 Operational Flexibility of a Substation . . . . . 23
4.4 Substation Configuration . . . . . 24
4.4.1 Substation Connecting to a Power Station . . . . . 25
4.5 Interconnection Substation . . . . . 25
4.6 Step-Up/Step-Down Substations . . . . . 26
4.7 Circuit Arrangements . . . . . 29
4.7.1 Single Busbar Arrangements . . . . . 29
4.7.2 Multiple Busbar Arrangements . . . . . 32
4.7.3 Ring Bus and Mesh Substation . . . . . 36
4.8 Selection Process . . . . . 37
References . . . . . 39

**5 Effect of Safety Regulations and Safe Working Practices on Substation Design** . . . . . 41
John Finn
5.1 Introduction . . . . . 42
5.2 Segregation of Live Conductors and Bare Live Equipment . . . . . 42
5.2.1 Techniques for Segregation . . . . . 43
5.2.2 Choice of Technique as a Function of the Voltage Level . . . . . 45
5.3 Clearances . . . . . 45
5.3.1 Definition . . . . . 47
5.3.2 Calculation of the Basic Value . . . . . 47
5.3.3 Determination of the Safety Zone . . . . . 47
5.3.4 Variations . . . . . 53
5.4 Earthing . . . . . 54
5.4.1 General Earth Mat or Grid . . . . . 55
5.4.2 Safety Earths . . . . . 56
5.5 Operation of High-Voltage Switchgear . . . . . 58
5.5.1 Types of Control . . . . . 58
5.5.2 Locking Off Switches . . . . . 60
5.5.3 Auxiliary Operating Supplies . . . . . 60
5.5.4 Current and Voltage Instrument Circuits . . . . . 61
5.6 Protection Against Fire . . . . . 61
5.6.1 Limitation of the Damage Zone . . . . . 61
5.6.2 Extinguishing of the Fire . . . . . 63
5.7 Fences . . . . . 64
5.7.1 External Fences . . . . . 64
5.7.2 Internal Fences . . . . . 65
References . . . . . 65

**6 Incorporating New Functionalities Into the Substation** . . . . . . . . . 67
John Finn
6.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 68
6.2 General Observations on Substation Design . . . . . . . . . . . . . 69
6.2.1 System Impact on Substation Design . . . . . . . . . . 69
6.2.2 The Impact on the Substation Single-Line Diagram . . . . . . . . . . . . . . . . . . . . . . 71
6.2.3 Impact on the Substation Bay . . . . . . . . . . . . . . . 72
6.3 Impact of Technology on Substation Design . . . . . . . . . . . . . 74
6.3.1 Mixed Technology Switchgear . . . . . . . . . . . . . . . 75
6.3.2 Compact and Integrated AIS Switchgear . . . . . . . 75
6.3.3 Dispersed Generation . . . . . . . . . . . . . . . . . . . . . . 76
6.3.4 Reactive Compensation . . . . . . . . . . . . . . . . . . . . 77
6.3.5 Nonconventional Instrument Transformers . . . . . . 78
6.3.6 Power Flow Control Devices . . . . . . . . . . . . . . . . 79
6.3.7 Custom Power Technology . . . . . . . . . . . . . . . . . 80
6.3.8 Fault Current Limiters . . . . . . . . . . . . . . . . . . . . . 80
6.3.9 HVDC . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 81
6.3.10 Protection . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 81
6.3.11 Gas-Insulated Lines, Transformers, and Superconducting Cables . . . . . . . . . . . . . . . . . . . . 82
6.3.12 Monitoring and Diagnostic Equipment . . . . . . . . . 83
6.4 Example of Detail for Line-Commutated Converter HVDC . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 83
6.5 Mobile Substations . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 91
6.5.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . 91
6.5.2 Standards . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 95
6.5.3 Typical Transport Restrictions Associated with Mobile Substations . . . . . . . . . . . . . . . . . . . . . . 96
6.5.4 Site Preparations . . . . . . . . . . . . . . . . . . . . . . . . 97
6.5.5 Design Guidelines for Mobile Substations . . . . . . 97

**7 Substation Specification and Evaluation** . . . . . . . . . . . . . . . . . . . 101
John Finn
7.1 General Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . 101
7.2 Conventional Specifications . . . . . . . . . . . . . . . . . . . . . . . . 102
7.2.1 Location and Spatial Constraints . . . . . . . . . . . . . 102
7.2.2 Effects of Environment on Substation . . . . . . . . . 102
7.2.3 Circuit Definitions, Terminal Points, and Physical Boundaries . . . . . . . . . . . . . . . . . . . . . . 103
7.2.4 Basic Information for Civil Works . . . . . . . . . . . . 103
7.2.5 Basic System Parameters (Repeat for Each Different Voltage in the Substation) . . . . . . . . . . . 104
7.2.6 The Required Switching Configuration . . . . . . . . 104
7.2.7 Secondary System Requirements . . . . . . . . . . . . . 104

7.2.8 Standards and Regulations . . . . . . . . . . . . . . . . . . 106
7.2.9 Health, Safety, and Environment . . . . . . . . . . . . . 106
7.3 Evaluation of Substation Concepts . . . . . . . . . . . . . . . . . . 107
7.3.1 The Life Cycle of a Substation . . . . . . . . . . . . . . 107
7.3.2 Method of Substation Evaluation . . . . . . . . . . . . . 107
7.4 Functional Specifications . . . . . . . . . . . . . . . . . . . . . . . . . 113

**8 Type of Contract for Substations (In House or Turnkey)** . . . . . . . . 115
John Finn
8.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 116
8.2 Advantages of Turnkey . . . . . . . . . . . . . . . . . . . . . . . . . . 116
8.2.1 Simplification . . . . . . . . . . . . . . . . . . . . . . . . . . 116
8.2.2 Variety of Options . . . . . . . . . . . . . . . . . . . . . . . . 116
8.2.3 Implementation of New Technologies . . . . . . . . . 117
8.2.4 Better Price Certainty . . . . . . . . . . . . . . . . . . . . . 117
8.2.5 Time Schedule Certainty . . . . . . . . . . . . . . . . . . . 117
8.2.6 Reduced Asset Owner's Resources . . . . . . . . . . . 117
8.3 Disadvantages of Turnkey . . . . . . . . . . . . . . . . . . . . . . . . . 118
8.3.1 Loss of Control . . . . . . . . . . . . . . . . . . . . . . . . . . 118
8.3.2 Requirement for Detailed Up-Front Documentation . . . . . . . . . . . . . . . . . . . . . . . . . . 118
8.3.3 More Complex Evaluation . . . . . . . . . . . . . . . . . . 118
8.3.4 Limited Number of Bids . . . . . . . . . . . . . . . . . . . 118
8.3.5 Risk of Poor Construction Quality . . . . . . . . . . . . 118
8.3.6 Risk of Solution Provider Insolvency . . . . . . . . . . 119
8.3.7 Risk of Inferior Quality Equipment . . . . . . . . . . . 119
8.3.8 Higher Cost . . . . . . . . . . . . . . . . . . . . . . . . . . . . 119
8.3.9 Loss of Engineering Expertise Within Asset Owner . . . . . . . . . . . . . . . . . . . . . . . . . . . 119
8.4 Transition from In-House Projects to Turnkey Projects . . . . . 119
8.4.1 The Summation of Two Experiences . . . . . . . . . . 120
8.4.2 Sharing for Success . . . . . . . . . . . . . . . . . . . . . . . 120
8.5 Key Actions to Minimize the Disadvantages of Turnkey Projects . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 121
8.5.1 Organizational Aspects . . . . . . . . . . . . . . . . . . . . 121
8.5.2 Establish a Basic Framework for the Execution of the Project . . . . . . . . . . . . . . . . . . . . . . . . . . . 121

**9 Innovation and Standardization of Substation Equipment** . . . . . . 123
Colm Twomey
9.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 123
9.2 Definitions . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 124
9.2.1 Standardization . . . . . . . . . . . . . . . . . . . . . . . . . 124
9.2.2 Innovation . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 125
9.3 Standardization Versus Innovation . . . . . . . . . . . . . . . . . . . 127

9.4 Guidelines for Controlled Introduction of Innovation . . . . . . 128
9.4.1 Future Development Structure . . . . . . . . . . . . . . . 129
9.4.2 Future Development Strategy . . . . . . . . . . . . . . . . 132
9.4.3 Future Development Road Maps (Implementation Plan) . . . . . . . . . . . . . . . . . . . . . 133
9.4.4 Future Development Projects (Execution Stage) . . . 135
9.5 Integrating Innovative Solutions into the New Generation of Standards . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 136
9.5.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . 136
9.5.2 Review of Initial Pilot Project . . . . . . . . . . . . . . . 137
9.5.3 Scoping . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 138
9.5.4 Implementation Process and Issues . . . . . . . . . . . 138
9.5.5 Rollout . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 139
9.5.6 Review Process . . . . . . . . . . . . . . . . . . . . . . . . . 139
9.6 Summary . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 140

**Part B Air-Insulated Substations . . . . . . . . . . . . . . . . . . . . . . . . . . 141**
Koji Kawakita

**10 Introduction to Air-Insulated Substations . . . . . . . . . . . . . . . . . . . 143**
Koji Kawakita
10.1 Site Location . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 145
10.2 Site Layout . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 145
10.3 Conceptual Design . . . . . . . . . . . . . . . . . . . . . . . . . . . . 146
10.4 Project Management Plan . . . . . . . . . . . . . . . . . . . . . . . 147

**11 Basic Design and Analysis of Air-Insulated Substations . . . . . . . . . 149**
Colm Twomey, Hugh Cunningham, Fabio Nepomuceno Fraga, Antonio Varejão de Godoy, and Koji Kawakita
11.1 General . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 151
11.2 Substation Layout . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 151
11.2.1 First Step: Busbar Phase Disposition . . . . . . . . . . 152
11.2.2 Second Step: Selection of Busbar Conductors . . . 154
11.2.3 Third Step: The Disposition of the High-Voltage Equipment in Each Standard Type of Circuit . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 156
11.2.4 Fourth Step: The Type of Connection Between the Busbar and the Individual Circuit . . . . . . . . . . 157
11.3 Electrical Clearances . . . . . . . . . . . . . . . . . . . . . . . . . . . 166
11.4 Insulation Coordination . . . . . . . . . . . . . . . . . . . . . . . . . 169
11.4.1 Protection of Substation Against Traveling Waves on Incoming Lines . . . . . . . . . . . . . . . . . . . . . . . . 171
11.4.2 Impact of Traveling Waves on a Substation . . . . . 172
11.4.3 Protection . . . . . . . . . . . . . . . . . . . . . . . . . . . . 173
11.5 Bus and Conductor . . . . . . . . . . . . . . . . . . . . . . . . . . . . 174
11.5.1 Current Ratings . . . . . . . . . . . . . . . . . . . . . . . . . 174

11.5.2 Electrical Clearances . . . 175
11.5.3 Mechanical Forces . . . 175
11.6 Structures . . . 180
11.6.1 Concrete . . . 181
11.6.2 Steel . . . 181
11.6.3 Aluminum . . . 182
11.6.4 Wood . . . 182
11.7 Earthing (Grounding) and Lightning Protection . . . 183
11.7.1 Functions of a Substation Earth Grid . . . 183
11.7.2 Earth Grid Resistance Value . . . 185
11.7.3 Soil Resistivity Measurements . . . 187
11.7.4 Design Touch and Step Voltage Limits . . . 187
11.7.5 Transferred Voltages and Hot Zones . . . 188
11.7.6 Earthing of GIS . . . 191
11.7.7 Control of Electromagnetic Interference . . . 192
11.7.8 Earth Grid . . . 192
11.7.9 Design Earth Fault Current . . . 194
11.7.10 Earth Grid Conductor . . . 195
11.7.11 Exceptional Cases . . . 196
11.7.12 Verification of Earthing System Model . . . 199
11.7.13 Protection Against Direct Lightning Strokes . . . 199
11.7.14 GIS . . . 200
11.8 Contamination (Salt and Dust Pollution, Creepage Distance) . . . 201
11.9 Audible Noise . . . 205
11.9.1 Introduction . . . 205
11.9.2 Characteristics of Transformer Noise . . . 205
11.9.3 Propagation of Sound . . . 206
11.9.4 Noise Level Limits . . . 206
11.9.5 Noise Level Measurement . . . 207
11.9.6 Calculation of Noise Levels . . . 208
11.9.7 Methods of Substation Noise Control . . . 208
11.9.8 Transformer Noise Control Measures . . . 210
11.9.9 Other Noise Sources and Control Measures . . . 212
11.10 Fire Protection . . . 213
11.10.1 Fire Protection Systems . . . 214
11.10.2 Transformers . . . 217
11.10.3 Cables . . . 219
11.10.4 Control, Relay, and Cable Rooms . . . 219
11.10.5 Other Measures in the Substations . . . 220
11.10.6 Conclusions . . . 221
11.11 Seismic (CIGRE 1992) . . . 221
11.11.1 Seismic Design Procedures . . . 222
11.11.2 Practical Means to Enhance the Seismic Performance . . . 224
11.11.3 Conclusion . . . 228

11.12 Foundations, Buildings, Cable Trenches, Oil Containments, Etc. . . . . . 229
11.12.1 Foundations . . . . . . 229
11.12.2 Buildings . . . . . . 231
11.12.3 Cable Trenches . . . . . . 233
11.12.4 Oil Containment . . . . . . 234
11.13 Fences, Gates, Security, and Animal Deterrents . . . . . . 238
11.13.1 Fencing . . . . . . 238
11.13.2 Gates . . . . . . 239
11.13.3 Substation Security . . . . . . 242
11.13.4 Animal Deterrents . . . . . . 242
References . . . . . . 244

**12 Specification and Selection of Main Components for Air-Insulated Substations** . . . . . . 247
John Nixon, Gerd Lingner, and Eugene Bergin
12.1 General . . . . . . 249
12.2 Circuit Breakers . . . . . . 259
12.3 Disconnectors, Earthing or Grounding Switches, and Earthing or Grounding Poles . . . . . . 264
12.4 Surge Arresters (or Lightning Arresters) . . . . . . 267
12.5 Instrument Transformers . . . . . . 279
12.6 High-Voltage Conductors and Connectors . . . . . . 285
12.6.1 Purpose . . . . . . 285
12.6.2 Conductor and Connector Material . . . . . . 286
12.6.3 Selection of Conductors, Singular or Bundled . . . 286
12.6.4 Variation Caused by Temperature and Ice . . . . . . 287
12.6.5 Movement Caused by Short-Circuit Forces and Wind . . . . . . 287
12.6.6 Vibration . . . . . . 287
12.6.7 Connector Types, E.g., Welded, Bolted, and Compression . . . . . . 289
12.6.8 Fixed and Thermal Expansion Connectors . . . . . . 289
12.6.9 Corona . . . . . . 289
12.6.10 Jointing Methodology . . . . . . 291
12.6.11 Joint Testing . . . . . . 291
12.7 Solid-Core and Hollow Insulators . . . . . . 292
12.7.1 Purpose of Insulators . . . . . . 292
12.7.2 Insulator Material and Types . . . . . . 295
12.7.3 Resistive Glaze . . . . . . 299
12.7.4 Strength Selection Due to Static and Dynamic Forces . . . . . . 299
12.7.5 Earthquake Ground Acceleration . . . . . . 301
12.7.6 Bushings . . . . . . 301
12.8 High-Voltage Cables . . . . . . 302
12.8.1 Single-Core or Three-Core . . . . . . 303

12.8.2 Cable Types . . . 303
12.8.3 Conductor . . . 303
12.8.4 Cable Insulation Materials . . . 304
12.8.5 Sheathing Material . . . 308
12.8.6 Outer Serving . . . 308
12.8.7 Bonding Design . . . 309
12.8.8 Current Ratings . . . 309
12.8.9 Cable Accessories . . . 310
12.8.10 Laying Arrangements . . . 310
12.8.11 Mechanical Considerations . . . 311
12.8.12 Jointing . . . 311
12.8.13 Testing . . . 312
12.8.14 Maintenance . . . 312
12.8.15 References . . . 312
12.9 Earthing or Grounding Grid . . . 313
12.9.1 General . . . 313
12.9.2 Materials Used in the Earthing or Grounding System . . . 313
12.9.3 Different Earth Rod Types . . . 313
12.9.4 Soil-Conditioning Agents . . . 314
12.10 Power Transformers and Compensation Equipment . . . 316
12.10.1 Impedance and Regulation . . . 316
12.10.2 Cooling Arrangements . . . 317
12.10.3 Winding Arrangements and Vector Groups . . . 317
12.10.4 Typical Transformer Arrangements . . . 318
12.10.5 Tertiary Winding Voltage and Rating . . . 318
12.10.6 Insulation Media . . . 320
12.10.7 Variation of Voltage . . . 321
12.10.8 Losses . . . 321
12.10.9 Noise . . . 322
12.10.10 Terminal Arrangements . . . 322
12.10.11 FACTS Devices . . . 322
12.10.12 Reactors . . . 323
12.10.13 Filters (Harmonic Filtering) . . . 324
12.10.14 Capacitors (Capacitor Banks) . . . 324
12.10.15 Static Var Compensator . . . 326
12.10.16 Voltage Source Converter Devices, E.g., STATCOMS . . . 326
12.11 Miscellaneous Equipment . . . 327
12.11.1 Purpose of Miscellaneous Equipment . . . 327
12.11.2 Line or Wave Traps . . . 327
12.11.3 Neutral Earthing or Grounding Resistors . . . 328
12.11.4 $SF_6$ Gas . . . 329
12.11.5 $SF_6$ Gas Analysis and Processing Equipment . . . 330
References . . . 332

**13 Construction of Air-Insulated Substations** . . . 333
Akira Okada
13.1 Construction Method . . . 334
13.2 Site Logistics and Transportation . . . 339
13.3 Construction Quality Control . . . 340
13.4 Outage Management . . . 341

**14 Instruction Manuals and Training for Air-Insulated Substations** . . . 343
Mark McVey
14.1 Instruction Manuals . . . 343
14.2 General Training . . . 345
14.3 Operations, Installation, and Maintenance Training . . . 346
14.3.1 Installation Training . . . 346
14.3.2 Maintenance Policy . . . 347
14.4 Safety Training . . . 348
14.5 Safety Procedure for On-Site Work . . . 350
14.5.1 Work Planning . . . 350
14.5.2 Awareness . . . 353
14.5.3 Verification . . . 353
14.6 Design for Safety and Human Protection . . . 355

**Part C Gas-Insulated Substations** . . . **359**
Peter Glaubitz

**15 Why Choose GIS?** . . . 361
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
15.1 Benefits of GIS . . . 361
15.2 Impact of Environmental Conditions on Switchgear . . . 363
15.3 Switchgear Impact on Environment . . . 365
15.4 Quality Assurance/Reliability . . . 365
15.5 Safety . . . 367
15.6 Life Cycle Costs . . . 368
15.7 Conclusion . . . 368

**16 GIS Configuration** . . . 369
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
16.1 Establishing a Preliminary Configuration for the GIS . . . 370
16.2 Further Studies . . . 370
16.3 Detailed Design and Design Approval . . . 370
16.4 Manufacturing Period . . . 371
16.5 Selection of GIS Type . . . 371
16.6 Type of Construction . . . 372
16.6.1 Extent of $SF_6$-Insulated Modules . . . 373
16.6.2 Hybrid Installation: Mixed Technology Systems . . . 373
16.6.3 Service Conditions . . . 374

16.7 Single-Line Diagram Design . . . 377
16.8 Layout Design . . . 379
16.9 Information to be Given by the User and the Manufacturer . . . 380
16.9.1 Basic User Input Data . . . 380
16.9.2 Basic Manufacturer Input Data . . . 381
16.9.3 Optimization . . . 381
References . . . 381

**17 Insulation Coordination . . . 383**
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
17.1 General . . . 383
17.2 $SF_6$ Breakdown Characteristic . . . 384
17.3 Insulation Coordination Procedure . . . 385
17.4 Determination of Withstand Voltages . . . 387
17.5 Actions Which May Be Taken to Achieve Insulation Coordination . . . 387
17.6 Information to Be Given by the User and the Manufacturer . . . 388

**18 GIS Primary Components . . . 389**
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
18.1 Conductors . . . 390
18.2 Enclosures . . . 390
18.2.1 Three-Phase or Single-Phase-Enclosed . . . 391
18.2.2 Segregation of Gas Zones . . . 393
18.2.3 Insulating Spacers/Parts: Bushings . . . 394
18.2.4 Pressure Relief Devices: Rupture Disks . . . 394
18.3 Switching Devices . . . 396
18.3.1 Circuit Breakers . . . 396
18.3.2 Other Switches . . . 397
18.4 Current Transformers (CTs)/ Core-in-Air CT . . . 398
18.5 Voltage Transformers (VTs) . . . 400
18.6 Nonconventional VTs and CTs . . . 400
18.7 Surge Arresters . . . 402
18.8 GIS Cable Connection . . . 403
18.9 Air Bushings . . . 405
18.10 Connection to Transformers and Reactors . . . 405
18.10.1 Direct Connection via $SF_6$-Insulated Bus Ducts . . . 405
18.10.2 Connection via Cable . . . 406
18.10.3 Connection with Short Overhead Lines . . . 406
18.11 Connection Elements Within GIS . . . 407
18.11.1 Compensators . . . 407
18.11.2 Coupling Element . . . 407
18.11.3 X-, T-, and Angle-Type Enclosures . . . 407

18.12 Nameplates/Labeling . . . 407
18.13 Online Monitoring and Diagnostics . . . 408
18.14 Integration of Protection and Control Devices into GIS . . . 409
18.15 Information to Be Given by the User and the Manufacturer . . . 409

**19 GIS Secondary Equipment** . . . 411
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
19.1 Interlocking . . . 412
19.2 Gas Monitoring . . . 412
19.3 GIS Condition Monitoring . . . 413
19.3.1 Partial Discharge (PD) Detection . . . 413
19.3.2 Fault Location . . . 414
19.4 Special GIS Demands on Protection System . . . 414
19.4.1 Protection System Timing . . . 414
19.4.2 Auto-Reclosing . . . 414
19.4.3 Busbar and Bay Protection . . . 415
19.4.4 Intertripping . . . 415
19.4.5 Earth Fault Protection . . . 415
19.5 Electromagnetic Compatibility . . . 415
19.6 Information to Be Given by the User and the Manufacturer . . . 416
19.6.1 Basic Users Input Data . . . 416
19.6.2 Basic Manufacturers Input Data . . . 417

**20 Interfaces: Civil Works, Building, Structures, Cables, OHL, Transformers, and Reactors** . . . 419
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
20.1 Training of Operation Personnel . . . 420
20.2 Building/Civil Works . . . 420
20.2.1 Construction . . . 420
20.2.2 Space Requirements . . . 421
20.2.3 Handling Equipment . . . 423
20.2.4 Load, Walls and Ceilings . . . 423
20.2.5 Windows/Doors . . . 424
20.2.6 GIS Mounting Points . . . 424
20.2.7 Cooling/Heating and Ventilation . . . 425
20.2.8 Fire Protection . . . 425
20.2.9 Noise Abatement . . . 425
20.2.10 Cables . . . 425
20.2.11 Lighting and Socket Outlets . . . 425
20.2.12 Earthing . . . 426
20.3 Support Structures and Accessibility . . . 426
20.4 Information to Be Given by the User and the Manufacturer . . . 426
20.4.1 Basic Users Input Data . . . 427
20.4.2 Basic Manufacturers Input Data . . . 427

**21 GIS Earthing** . . . . . 429
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
21.1 Effect of GIS on Design of Earthing Systems . . . . . 430
21.1.1 General . . . . . 430
21.1.2 Physical Size . . . . . 430
21.1.3 Transient Enclosure Voltage (TEV) . . . . . 430
21.1.4 Discontinuities . . . . . 431
21.1.5 Screening . . . . . 431
21.1.6 Effects on Personnel . . . . . 432
21.2 Design of GIS Earthing System . . . . . 432
21.2.1 Design of Earth Grid . . . . . 432
21.2.2 Connections to the Earth Grid . . . . . 433
21.2.3 Discontinuities . . . . . 434
21.2.4 Effects on Control Circuit . . . . . 437
21.2.5 Treatment of Sensitive Control Equipment . . . . . 438
21.2.6 Instrument Transformers . . . . . 438
21.3 Testing and Maintenance of Earthing Installations . . . . . 438
21.3.1 Power Frequency Compatibility . . . . . 438
21.3.2 High-Frequency Compatibility . . . . . 439

**22 GIS Testing** . . . . . 441
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
22.1 Type Tests . . . . . 442
22.2 Routine Tests . . . . . 442
22.3 Tests After Installation On-Site . . . . . 443
22.4 Installation, On-Site Test, Commissioning, and Formal Acceptance . . . . . 443
22.5 Site Preparation . . . . . 445
22.6 Work Crew Preparation . . . . . 445
22.7 Installation of New GIS . . . . . 446
22.8 Installation of GIS Extensions . . . . . 446
22.9 Service Continuity . . . . . 447
22.10 Commissioning . . . . . 447
22.10.1 Commissioning of Primary Equipment . . . . . 448
22.10.2 Commissioning of Secondary Equipment . . . . . 448
22.10.3 Commissioning of the $SF_6$ Insulation Medium . . . . . 448
22.11 Information to be Given by the Manufacturer and the User . . . . . 449
22.11.1 Basic Users Input Data . . . . . 449
22.11.2 Basic Manufacturers Input Data . . . . . 449

**23 $SF_6$, Its Handling Procedures and Regulations** . . . . . 451
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
23.1 The EU-F-Gas-Regulation (EU) 517/2014 . . . . . 453
23.1.1 Leakage Detection Systems . . . . . 454
23.1.2 Handling and Repair . . . . . 454

23.1.3 Training and Certification . . . . . . . . . . . . . . . . . . 455
23.1.4 Labeling . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 455
23.2 $SF_6$ Handling During Installation and Commissioning . . . . . . 455
23.3 Storage and Transportation of $SF_6$ Bottles . . . . . . . . . . . . . . . 456
23.4 Reuse of $SF_6$ . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 456
23.5 Handling of $SF_6$ Decomposition Products . . . . . . . . . . . . . . . 458
23.6 Information to Be Given by the Users and the Manufactures . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 459
23.6.1 Basic Users Input Data . . . . . . . . . . . . . . . . . . . . 459
23.6.2 Basic Manufacturers Input Data . . . . . . . . . . . . . . 459
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 460

**24 Training, Service, and Maintenance of Gas-Insulated Substations** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 461
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
24.1 Training of Operation Personnel . . . . . . . . . . . . . . . . . . . . . . 462
24.2 Operational Aspects and After Sales Support . . . . . . . . . . . . 462
24.3 Types of Maintenance . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 462
24.4 Maintenance Policy . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 463
24.5 Operation and Maintenance Provisions . . . . . . . . . . . . . . . . . 464
24.5.1 Operational and Maintenance Safety . . . . . . . . . . 464
24.5.2 Operational and Maintenance Opening Procedures . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 466
24.5.3 Substation Equipment . . . . . . . . . . . . . . . . . . . . . 469
24.6 Special Aspects of Repair Maintenance after Major Dielectric Failure . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 470
24.7 Basic Input Data and Additional Recommendations . . . . . . . 471
24.7.1 Information to Be Given by the User and the Manufacturer . . . . . . . . . . . . . . . . . . . . . . . . . . . 472
24.7.2 Additional Recommendations for the User and the Manufacturer . . . . . . . . . . . . . . . . . . . . . 472
24.8 General Training . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 474
24.9 Training for Installation . . . . . . . . . . . . . . . . . . . . . . . . . . . . 475
24.10 Training for Operating and Maintenance . . . . . . . . . . . . . . . 475
24.11 Specialized Training . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 476
24.12 Information to Be Given by the User and the Manufacturer . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 476
24.12.1 Basic Users Input Data . . . . . . . . . . . . . . . . . . . . 476
24.12.2 Basic Manufacturers Input Data . . . . . . . . . . . . . . 477

**25 Execution of a GIS Substation Project** . . . . . . . . . . . . . . . . . . . . . 479
Peter Glaubitz, Carolin Siebert, and Klaus Zuber
25.1 Initiation of a Project . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 479
25.2 Engineering Planning . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 480
25.3 Planning the GIS Project Construction and Installation . . . . . 480
25.4 Site Preparation . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 482

25.5 Installation of the New GIS . . . . . . . . . . . . . . . . . . . . . . . . . 482
25.6 Installation of GIS Extensions . . . . . . . . . . . . . . . . . . . . . . 482
25.7 Equipment Access . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 482
25.8 Preparation of Inquiry for Tendering . . . . . . . . . . . . . . . . . . 483
25.9 Relevant Standards . . . . . . . . . . . . . . . . . . . . . . . . . . . . 483

**Part D Mixed Technology Switchgear Substations and Gas Insulated Lines . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 485**
Tokio Yamagiwa

**26 Mixed Technology Switchgear (MTS) Substations . . . . . . . . . . . . . 487**
Tokio Yamagiwa and Colm Twomey
26.1 Introduction to MTS . . . . . . . . . . . . . . . . . . . . . . . . . . . . 487
26.1.1 Why Use MTS? . . . . . . . . . . . . . . . . . . . . . . . . . . 490
26.2 AIS, GIS, and MTS . . . . . . . . . . . . . . . . . . . . . . . . . . . . 491
26.2.1 Insulation Technology Considerations . . . . . . . . . 491
26.2.2 AIS, GIS, and MTS Definitions . . . . . . . . . . . . . . 492
26.2.3 Evaluation of Applicability of AIS, GIS, and MTS . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 493
26.3 Conventional, Compact, and Combined Switchgear . . . . . . . 496
26.3.1 Installation and Functionality considerations . . . . 496
26.4 Conventional, Compact, and Combined Switchgear Definition . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 497
26.4.1 Examples of Compact and Combined Switchgear Assemblies . . . . . . . . . . . . . . . . . . . . . 501
26.5 Common Considerations of Insulation and Installation + Functionality . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 502
26.6 Application of Standards to MTS . . . . . . . . . . . . . . . . . . . . 504
26.7 Future Developments . . . . . . . . . . . . . . . . . . . . . . . . . . . 505
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 506

**27 Gas Insulated Lines (GIL) . . . . . . . . . . . . . . . . . . . . . . . . . . 507**
Hermann Koch
27.1 Basics . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 508
27.1.1 Basic Explanation . . . . . . . . . . . . . . . . . . . . . . . 508
27.1.2 Properties of the Insulating Gas . . . . . . . . . . . . . 509
27.1.3 Definition . . . . . . . . . . . . . . . . . . . . . . . . . . . . 509
27.1.4 Description . . . . . . . . . . . . . . . . . . . . . . . . . . . 510
27.2 Ratings . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 515
27.2.1 GIL Electrical Parameters . . . . . . . . . . . . . . . . . 515
27.2.2 Directly Buried GIL . . . . . . . . . . . . . . . . . . . . . . 516
27.2.3 Thermal Layout . . . . . . . . . . . . . . . . . . . . . . . . . 516
27.2.4 Short-Time Rating . . . . . . . . . . . . . . . . . . . . . . . 517
27.2.5 Insulation Coordination . . . . . . . . . . . . . . . . . . . 518
27.2.6 Standard Values . . . . . . . . . . . . . . . . . . . . . . . . 519
27.2.7 Capacity of GIL . . . . . . . . . . . . . . . . . . . . . . . . . 521

27.3 Installation Options . . . 523
27.3.1 Directly Buried GIL . . . 523
27.3.2 GIL in Structures . . . 528
27.3.3 Automated Laying Processes of GIL . . . 535
27.4 Environmental Impact . . . 537
27.4.1 Environmental Life Cycle Assessment . . . 537
27.4.2 General Environmental Aspects . . . 538
27.4.3 Magnetic Fields . . . 538
27.4.4 Environmental Aspects . . . 539
27.5 Long-Term Test . . . 539
27.5.1 Feasibility Study of 420 kV GIL . . . 539
27.6 Example Projects . . . 540
27.6.1 PP9 Saudi Arabia . . . 540
27.6.2 Limberg, Austria . . . 541
27.6.3 Kelsterbach GIL . . . 542
27.7 Future Applications . . . 544
27.7.1 General . . . 544
27.7.2 Possible Future Uses of GIL Associated with Substations . . . 544
27.8 Project Handling . . . 546
27.8.1 Site Assembly . . . 546
27.8.2 Factory Preassembly . . . 548
27.8.3 Gas Handling . . . 552
27.8.4 High-Voltage Test . . . 553
27.8.5 Pressure Test . . . 555
27.9 Operation, Maintenance, and Repair . . . 556
27.9.1 Online Insulation Monitoring . . . 556
27.9.2 Bonding and Grounding for Permanent and Transient Voltages . . . 556
27.9.3 Operation . . . 556
27.9.4 Maintenance . . . 557
27.9.5 Repair Process . . . 558
27.10 Safety . . . 559
27.10.1 Safety Analysis . . . 559
27.10.2 Fire . . . 559
27.11 Cost Analysis . . . 561
27.11.1 Overall Economic Aspects . . . 561
References . . . 562

## Volume 2

**Part E UHV and Offshore Substations . . . 565**
Kyoichi Uehara

**28 UHV Substations** . . . 567
Kyoichi Uehara
28.1 UHV Substations . . . 568

28.2 Technical Requirements for UHV Substation Equipment . . . . 572
28.3 Reliability Issues in Substation Equipment . . . . . . . . . . . . . 576
28.3.1 Data on Reliability Issues in Substation Equipment . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 576
28.4 Transportation and On-Site Tests of UHV Substation . . . . . . 579
28.4.1 General Consideration Concerning Transportation . . . . . . . . . . . . . . . . . . . . . . . . . . . . 579
28.4.2 Transportation Restriction for Transformers . . . . . 579
28.4.3 On-Site Tests . . . . . . . . . . . . . . . . . . . . . . . . . . . 582
28.5 Maintenance and Diagnostic Tests . . . . . . . . . . . . . . . . . . . . 582
28.6 Recommended Optimization of UHV Substation . . . . . . . . . 582
28.6.1 Insulation Coordination for UHV Substation . . . . 583
28.6.2 Layout for UHV Substation . . . . . . . . . . . . . . . . . 585
28.6.3 On-Site Acceptance Test and Commissioning Tests . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 587
28.6.4 Substation Comparison (GIS, Hybrid-IS, and AIS) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 588
28.7 Future UHV AC Transmission System Planning, Design, On-Site Assembly and Test, Maintenance, and Operation . . . 589
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 590

**29 AC Offshore Substations Associated with Wind Power Plants . . . 591**
John Finn and Peter Sandeberg
29.1 Introduction and Fundamental Considerations . . . . . . . . . . . 592
29.1.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . 592
29.1.2 Fundamental Considerations . . . . . . . . . . . . . . . . 594
29.2 System Considerations . . . . . . . . . . . . . . . . . . . . . . . . . . . . 599
29.2.1 Reliability and Availability . . . . . . . . . . . . . . . . . 599
29.2.2 Overloading Capability . . . . . . . . . . . . . . . . . . . . 602
29.2.3 Substation Size and Number Required . . . . . . . . . 602
29.2.4 Grid Code Compliance . . . . . . . . . . . . . . . . . . . . 603
29.2.5 Reactive Compensation and Voltage Control . . . . 606
29.2.6 Fault Level . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 608
29.2.7 General Substation Configuration . . . . . . . . . . . . 611
29.2.8 Neutral Earthing . . . . . . . . . . . . . . . . . . . . . . . . . 613
29.2.9 Insulation Coordination . . . . . . . . . . . . . . . . . . . . 613
29.2.10 Flicker and Voltage Fluctuations . . . . . . . . . . . . . 615
29.2.11 Systems Studies Required . . . . . . . . . . . . . . . . . . 617
29.3 Electrical Equipment Considerations . . . . . . . . . . . . . . . . . . 617
29.3.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . 617
29.3.2 MV Switchgear . . . . . . . . . . . . . . . . . . . . . . . . . . 618
29.3.3 Main Transformers and Reactors . . . . . . . . . . . . . 626
29.3.4 Earthing/Auxiliary Transformers . . . . . . . . . . . . . 640
29.3.5 HV Switchgear . . . . . . . . . . . . . . . . . . . . . . . . . . 644
29.3.6 Export and Inter-array Cables . . . . . . . . . . . . . . . 648
29.3.7 Site Tests and Commissioning . . . . . . . . . . . . . . . 651

29.4 Physical Considerations . . . 656
29.4.1 About Design Considerations . . . 657
29.4.2 Overall Health and Safety Aspects . . . 658
29.4.3 Fundamental Design Parameters . . . 659
29.4.4 Additional Design Inputs . . . 660
29.4.5 Development of Design . . . 665
29.4.6 Platform Concepts . . . 674
29.4.7 Substructure . . . 675
29.4.8 Fire and Explosion Design . . . 681
29.5 Substation Secondary Systems . . . 683
29.5.1 Power Supplies . . . 683
29.5.2 DC Supplies . . . 686
29.5.3 Protection . . . 690
29.5.4 Control and Supervisory Control and Data Acquisition (SCADA) System Requirements . . . 698
29.5.5 CCTV and Security Systems . . . 703
29.5.6 Navigation Aids . . . 704
29.5.7 Communications . . . 705
29.5.8 Equipment Accommodation and Environmental Management . . . 706
29.5.9 Maintenance Management . . . 707
29.5.10 Metering . . . 707
29.6 Special Considerations When Connected by HVDC Link . . . 708
29.6.1 System Design . . . 710
29.6.2 Grid Code Compliance . . . 720
29.6.3 Power Quality . . . 723
29.6.4 Technical Studies . . . 726
29.6.5 Protection, Control, and Communications . . . 726
References . . . 727

**Part F Secondary Systems . . . 729**
John Finn, Ray Zhang, and Yang Ruoling

**30 Secondary Systems: Introduction and Scope . . . 731**
John Finn and Adriaan Zomers
30.1 Auxiliary Systems . . . 732
30.2 Protection . . . 732
30.3 Control and Automatic Switching . . . 732
30.4 Metering and Monitoring . . . 732
30.5 Communications . . . 733
30.6 Digital Equipment . . . 733
30.7 Equipment Considerations and Interfaces . . . 733
30.8 Management of Secondary Systems . . . 734
30.9 General Considerations and Requirements . . . 734
30.9.1 Secondary System Functions . . . 734
30.9.2 Economic Aspects . . . 737

30.9.3 Operational and Maintenance Requirements . . . . . 738
30.9.4 Environmental Requirements . . . . . . . . . . . . . . . . 739
30.9.5 Use in Seismic Areas, Shocks, and Vibrations . . . 740
30.9.6 Electromagnetic Compatibility . . . . . . . . . . . . . . 741
30.9.7 Ergonomic Requirements . . . . . . . . . . . . . . . . . . 743

**31 Substation Auxiliary Systems** . . . . . . . . . . . . . . . . . . . . . . . . . . . 745
Mick Mackey
31.1 Low-Voltage AC System . . . . . . . . . . . . . . . . . . . . . . . . . . . 745
31.2 Secure AC Auxiliary Supply Systems and Emergency Generation . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 746
31.3 Batteries and DC Supply Systems . . . . . . . . . . . . . . . . . . . . 747
31.4 Power System Interruption and “Black Start” Requirements . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 752

**32 Substation Protection** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 753
Richard Adams
32.1 Principles and Philosophies . . . . . . . . . . . . . . . . . . . . . . . . 753
32.1.1 Current-Operated Protection . . . . . . . . . . . . . . . . . 754
32.1.2 Impedance Protection . . . . . . . . . . . . . . . . . . . . . 756
32.1.3 Differential (Unit) Protection . . . . . . . . . . . . . . . . 758
32.1.4 Tripping Philosophies . . . . . . . . . . . . . . . . . . . . . 761
32.1.5 Relay Settings . . . . . . . . . . . . . . . . . . . . . . . . . . 762
32.2 Protection: Commonly Used Schemes . . . . . . . . . . . . . . . . . 762
32.2.1 Feeders . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 762
32.2.2 Transformers . . . . . . . . . . . . . . . . . . . . . . . . . . . 765
32.2.3 Reactors . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 766
32.2.4 Busbars . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 767
32.3 Backup Protection Principles . . . . . . . . . . . . . . . . . . . . . . . 767
32.3.1 High-Set Overcurrent . . . . . . . . . . . . . . . . . . . . . . 768
32.3.2 Circuit Breaker Fail . . . . . . . . . . . . . . . . . . . . . . . 768
32.4 Protection: Safety Considerations . . . . . . . . . . . . . . . . . . . . 769
32.5 Fault Level Considerations . . . . . . . . . . . . . . . . . . . . . . . . . 769
32.6 Power System Faults, Types, Categories, Consequences, and Arc Energy . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 770
32.7 Fuses HV and LV . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 771
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 772

**33 Substation Control and Automatic Switching** . . . . . . . . . . . . . . . . 775
John Finn
33.1 Basic Control System . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 776
33.1.1 Details of Conventional HMI . . . . . . . . . . . . . . . . 776
33.1.2 Details of Computer-Based HMI . . . . . . . . . . . . . . 778
33.1.3 Computer Performance Criteria . . . . . . . . . . . . . . . 779
33.1.4 Control from the Substation . . . . . . . . . . . . . . . . . 779
33.1.5 Control from a Network Control Center . . . . . . . . 780

33.1.6 Architectures of Control Systems . . . . . . . . . . . . . 781
33.1.7 Extension and Modification Requirements . . . . . . 781
33.1.8 Avoiding Unwanted Operations Within the Control System . . . . . . . . . . . . . . . . . . . . . . . . . 782
33.2 Interlocking . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 782
33.3 Synchronizing . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 784
33.4 Voltage Control . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 786
33.4.1 Automatic Tap Change Control . . . . . . . . . . . . . . 786
33.4.2 Automatic Reactive Switching . . . . . . . . . . . . . . . 788
33.5 Controlled Switching: Point on Wave Control . . . . . . . . . . . . 790
33.6 Automatic Switching: Reclosing, Closing, and Operational Tripping . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 792
33.6.1 Automatic Reclosing . . . . . . . . . . . . . . . . . . . . . . 792
33.6.2 Automatic Closing . . . . . . . . . . . . . . . . . . . . . . . 794
33.6.3 Operational Tripping . . . . . . . . . . . . . . . . . . . . . . 794
33.7 Frequency Control and Consumer Load Control . . . . . . . . . . 795
33.7.1 Underfrequency Load Shedding . . . . . . . . . . . . . . 795
33.7.2 Consumer Load Control . . . . . . . . . . . . . . . . . . . 795

**34 Metering and Monitoring** . . . . . . . . . . . . . . . . . . . . . . . . . . 797
John Finn
34.1 Metering . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 797
34.1.1 Accuracy Class . . . . . . . . . . . . . . . . . . . . . . . . . 798
34.1.2 Digital Measuring Equipment . . . . . . . . . . . . . . . 799
34.1.3 Transducers . . . . . . . . . . . . . . . . . . . . . . . . . . . . 799
34.1.4 Digital Transducers . . . . . . . . . . . . . . . . . . . . . . . 799
34.2 Fault Locating . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 799
34.3 Fault Recording and Event Recording . . . . . . . . . . . . . . . . . 800
34.4 Supervision and Alarms . . . . . . . . . . . . . . . . . . . . . . . . . 801
34.5 Monitoring . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 802

**35 Substation Communications** . . . . . . . . . . . . . . . . . . . . . . . . . 803
John Finn
35.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 804
35.2 Communications Within the Substation . . . . . . . . . . . . . . . . 805
35.2.1 Substation Automation with Electromechanical Relays . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 806
35.2.2 Substation Automation with Numerical Relays . . . 806
35.3 Communications Outside of the Substation . . . . . . . . . . . . . 808
35.3.1 Information to Be Communicated . . . . . . . . . . . . 809
35.3.2 Multiplexing . . . . . . . . . . . . . . . . . . . . . . . . . . . . 810
35.3.3 Digital Hierarchies . . . . . . . . . . . . . . . . . . . . . . . 810
35.3.4 PDH, SDH, and SONET . . . . . . . . . . . . . . . . . . . 810
35.4 Media . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 814
35.4.1 Pilot Wires . . . . . . . . . . . . . . . . . . . . . . . . . . . . 815
35.4.2 Power Line Carrier Communication (PLCC) . . . . 815

35.4.3 Microwave . . . . . . . . . . . . . . . . . . . . . . . . . . . . 816
35.4.4 Basic Communication Requirements for Protections . . . . . . . . . . . . . . . . . . . . . . . . . . . . 817
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 818

**36 Substation Digital Equipment** . . . . . . . . . . . . . . . . . . . . . . . . . . . . 819
Richard Adams
36.1 Digital Systems Within Substations and IEC 61850 Impacts . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 820
36.2 Software and Firmware . . . . . . . . . . . . . . . . . . . . . . . . . . . 824
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 825

**37 Equipment Considerations and Interfaces for Substations** . . . . . . 827
John Finn
37.1 Equipment . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 828
37.1.1 Circuit Breakers . . . . . . . . . . . . . . . . . . . . . . . . . 828
37.1.2 Current Transformers . . . . . . . . . . . . . . . . . . . . . 828
37.1.3 Voltage Transformers . . . . . . . . . . . . . . . . . . . . . 831
37.1.4 Other Plant . . . . . . . . . . . . . . . . . . . . . . . . . . . . 833
37.2 Testing Associated with Primary Plant . . . . . . . . . . . . . . . . . 834
37.2.1 Circuit Breaker Interface Testing . . . . . . . . . . . . . 834
37.2.2 Primary Injection of Current Transformers . . . . . . 834
37.3 Secondary System Isolation . . . . . . . . . . . . . . . . . . . . . . . . 835
37.3.1 DC Voltage Isolation . . . . . . . . . . . . . . . . . . . . . 835
37.3.2 Trip Isolation . . . . . . . . . . . . . . . . . . . . . . . . . . 836
37.3.3 Current Transformer Isolation . . . . . . . . . . . . . . . 836
37.3.4 Voltage Transformer Isolation . . . . . . . . . . . . . . . 836
37.4 Secondary Equipment Considerations . . . . . . . . . . . . . . . . . . 836
37.4.1 Separation of Cubicles/Rooms . . . . . . . . . . . . . . . 837
37.4.2 DC Distribution . . . . . . . . . . . . . . . . . . . . . . . . . 837
37.4.3 Relay Rooms . . . . . . . . . . . . . . . . . . . . . . . . . . . 837
37.4.4 Cabling and Wiring . . . . . . . . . . . . . . . . . . . . . . 838
37.4.5 Accommodation of Equipment and Ventilation . . . 838
37.4.6 Fire Detection and Extinguishing . . . . . . . . . . . . . 839
37.5 Earthing Practice . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 841
37.5.1 Measures to Be Taken on Secondary Equipment . . . . . . . . . . . . . . . . . . . . . . . . . . . . 842
37.5.2 Measures to Be Taken in the Installation . . . . . . . 842
37.5.3 Screening of Relay Rooms and Control Rooms . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 843
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 843

**38 Asset Management of Secondary Systems of Substations** . . . . . . . 845
Mick Mackey
38.1 Design, Installation, and Building Requirements . . . . . . . . . . 847

38.2 Reliability Impacts . . . 847
38.2.1 Reliability and Availability of Systems/ Components . . . 847
38.2.2 Redundancy . . . 848
38.3 Plant Labelling . . . 851
38.3.1 Panel/Kiosk Labelling . . . 851
38.3.2 Wire and Fiber Identification . . . 851
38.4 Quality Assurance Requirements and Testing . . . 852
38.4.1 Quality Assurance: Introduction . . . 852
38.4.2 Quality Assurance: Manufacturer's Perspective . . . 855
38.4.3 Quality Assurance: Utility's Perspective . . . 857
38.4.4 Laboratory, Factory, and On-Site Tests . . . 859
38.4.5 Test of Software . . . 861
38.4.6 Test of Printed Circuit Boards . . . 863
38.4.7 Cost-Benefit . . . 865
38.5 Maintenance . . . 865
38.5.1 General . . . 865
38.5.2 Cause and Effects of Deterioration and Aging Factors . . . 866
38.5.3 Maintenance of Secondary Equipment . . . 867
38.5.4 Fault-Finding and Recovery: Influence on Design . . . 868
38.5.5 Conventional Equipment . . . 869
38.5.6 Microcomputer-Based Equipment . . . 869
38.5.7 Spare Parts . . . 874
38.5.8 Training of Staff . . . 874
38.6 Asset Lifetime Expectancy and Replacement . . . 875
38.6.1 General Considerations . . . 876
38.6.2 Updating of Secondary Systems with Computer-Based Systems . . . 879
38.7 Security of Electronic Systems . . . 880
38.7.1 Cyber-Induced Attacks . . . 881
38.7.2 Intentional Electromagnetic Interference . . . 889
38.8 Physical Security Requirements . . . 895
38.8.1 Site Access . . . 896
38.8.2 Alarm System . . . 896
38.8.3 CCTV and Intruder Alarm Systems . . . 896
References . . . 897

**Part G Environmental Impact of and on Substations . . . 899**
Jarmo Elovaara

**39 Introduction to the Environmental Impact of and on Substations** . . . 901
Jarmo Elovaara

**40 Impact of Ambient Conditions on Substations** . . . . . . . . . . . . . . . . 903
Jarmo Elovaara and Angela Klepac
40.1 Normal Ambient Conditions . . . . . . . . . . . . . . . . . . . . . . . . 904
40.2 Polluted Conditions . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 906
40.3 Abnormal Ambient Conditions . . . . . . . . . . . . . . . . . . . . . . 907
40.3.1 Heavy Wind and Storms . . . . . . . . . . . . . . . . . . . 907
40.3.2 Winter Conditions . . . . . . . . . . . . . . . . . . . . . . . 909
40.3.3 Substations in Very Hot and Dry Conditions . . . . 910
40.3.4 Earthquakes . . . . . . . . . . . . . . . . . . . . . . . . . . . . 912
40.4 Substations under Special Conditions . . . . . . . . . . . . . . . . . 913
40.5 Effects of Wild Life . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 913

**41 Electromagnetic Interference (EMI) in Substations** . . . . . . . . . . . 917
Jarmo Elovaara

**42 Impact of the Substation on the Environment** . . . . . . . . . . . . . . . . 919
Jarmo Elovaara
42.1 Site Selection and Impact of the Substation on Environment in Construction Phase . . . . . . . . . . . . . . . . . . . . . . . . . . . . 920
42.2 Impact of the Substation during Operation . . . . . . . . . . . . . 921
42.2.1 Visual Impact . . . . . . . . . . . . . . . . . . . . . . . . . . 921
42.2.2 Noise . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 923
42.2.3 Electromagnetic Fields . . . . . . . . . . . . . . . . . . . 925
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 928

**43 Special Risks Related to Substation Equipment (Transformers, Reactors, and Capacitor Banks)** . . . . . . . . . . . . . . . . . . . . . . . . . . 929
Jarmo Elovaara

**44 Use of $SF_6$ and $CF_4$** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 933
Jarmo Elovaara
44.1 Properties and Electrotechnical Use of $SF_6$ Gas and $SF_6$-Based Gas Mixtures . . . . . . . . . . . . . . . . . . . . . . . . . . . . 933
44.2 Obligations to the User of $SF_6$ and $SF_6$ Gas Mixtures . . . . . . 935
44.3 Possibilities to Replace $SF_6$ with Some Other Insulating Gas . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 936
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 937

**45 Handling, Recycling, Disposal, and Reuse of Substations** . . . . . . . 939
Jarmo Elovaara

**Part H Substation Management Issues** . . . . . . . . . . . . . . . . . . . . . . **941**
Johan Smit

**46 Asset Management in an Electric Infrastructure** . . . . . . . . . . . . . . 943
Alan Wilson, Mark Osborne, and Johan Smit
46.1 Managing the Asset Base . . . . . . . . . . . . . . . . . . . . . . . . . . . 944
46.2 Driving Performance . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 945

46.3 The Asset Manager Role . . . . . . . . . . . . . . . . . . . . . . . . . . 946
46.4 Utility Organization to Achieve Business Goals . . . . . . . . . . 947
46.5 The Historical Context . . . . . . . . . . . . . . . . . . . . . . . . . . . . 947
46.6 Legislation and Standards . . . . . . . . . . . . . . . . . . . . . . . . . 949
46.7 Asset Management Tools . . . . . . . . . . . . . . . . . . . . . . . . . 950

**47 Developing Strategic Policies** . . . . . . . . . . . . . . . . . . . . . . . . . . 953
Paul Leemans, Mark Osborne, and Johan Smit
47.1 Asset Management Roles . . . . . . . . . . . . . . . . . . . . . . . . . 955
47.2 Setting Corporate Strategy . . . . . . . . . . . . . . . . . . . . . . . . 957
47.3 Asset Intervention Planning . . . . . . . . . . . . . . . . . . . . . . . 959
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 960

**48 Whole Life Management of Substations** . . . . . . . . . . . . . . . . . . . 961
Nhora Barrera, Mark Osborne, and Johan Smit
48.1 Life-Cycle Factors . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 962
48.2 Life-Cycle Phases . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 962
48.3 Life-Cycle Cost Analysis . . . . . . . . . . . . . . . . . . . . . . . . . 963
48.4 Application of Whole-Life Costing . . . . . . . . . . . . . . . . . . . 965
48.4.1 Design Process . . . . . . . . . . . . . . . . . . . . . . . . . . 966
48.4.2 Procurement Process . . . . . . . . . . . . . . . . . . . . . . 966
48.4.3 Construction Process . . . . . . . . . . . . . . . . . . . . . . 967
48.4.4 Testing and Commissioning Process . . . . . . . . . . 967
48.4.5 Maintenance Regimes and Condition Assessment Techniques . . . . . . . . . . . . . . . . . . . . . . . . . . . . 967
48.4.6 End of Life Options . . . . . . . . . . . . . . . . . . . . . . . 968
48.5 Evaluation of Substation Life-Cycle Costs . . . . . . . . . . . . . . 968
48.6 Optimizing Asset Management . . . . . . . . . . . . . . . . . . . . . 969
48.6.1 Reliability Centered Asset Management . . . . . . . . 969
48.6.2 Stochastic Optimization Algorithm . . . . . . . . . . . 970
48.6.3 Standard Substation Bays . . . . . . . . . . . . . . . . . . 970
48.7 Managing the Design for the Future . . . . . . . . . . . . . . . . . . 971

**49 Commissioning** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 973
John Finn, Mark Osborne, and Johan Smit
49.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 974
49.2 Workflow . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 974
49.3 Stage 1 Pre-commissioning . . . . . . . . . . . . . . . . . . . . . . . . 977
49.3.1 Purpose and General Principles . . . . . . . . . . . . . . 977
49.3.2 Order for Inspection and Testing . . . . . . . . . . . . . 978
49.3.3 LVAC Supplies . . . . . . . . . . . . . . . . . . . . . . . . . . 979
49.3.4 Building Services . . . . . . . . . . . . . . . . . . . . . . . . 979
49.3.5 Batteries and Chargers . . . . . . . . . . . . . . . . . . . . 979
49.3.6 Switchgear . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 980
49.3.7 Transformers . . . . . . . . . . . . . . . . . . . . . . . . . . . 981
49.3.8 Power Cables . . . . . . . . . . . . . . . . . . . . . . . . . . . 983

49.3.9 Earthing System . . . . . . . . . . . . . . . . . . . . . . . . . 986
49.3.10 Instrument Transformers . . . . . . . . . . . . . . . . . . . 988
49.3.11 Protection Equipment . . . . . . . . . . . . . . . . . . . . . 989
49.3.12 Control, Indications, and Alarms . . . . . . . . . . . . . 990
49.3.13 Other Equipment . . . . . . . . . . . . . . . . . . . . . . . . 991
49.3.14 Overall Checks, Interlocking, Synchronizing, etc. . . . 991
49.3.15 Final Pre-energisation Checks . . . . . . . . . . . . . . . 992
49.4 Stage 2 Energization and Final Commissioning . . . . . . . . . . . 992
49.4.1 Preparation of Switching Program . . . . . . . . . . . . 993
49.4.2 Authorization to Proceed to Stage 2 . . . . . . . . . . . 993
49.4.3 General Principle . . . . . . . . . . . . . . . . . . . . . . . . 994
49.4.4 Soak Testing . . . . . . . . . . . . . . . . . . . . . . . . . . . 994
49.4.5 Load Testing . . . . . . . . . . . . . . . . . . . . . . . . . . . 994
49.4.6 Handover for Operation . . . . . . . . . . . . . . . . . . . 995
49.5 Documentation . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 995
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 996

**50 Substation Maintenance Strategies** . . . . . . . . . . . . . . . . . . . . . . . . 997
Ravish Mehairjan, Mark Osborne, and Johan Smit
50.1 Definitions . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 997
50.2 Maintenance Strategies . . . . . . . . . . . . . . . . . . . . . . . . . . 998
50.2.1 Failure-Based Maintenance (FBM) . . . . . . . . . . . 999
50.2.2 Time-Based Maintenance (TBM) . . . . . . . . . . . . . 999
50.2.3 Condition-Based Maintenance (CBM) . . . . . . . . . 1000
50.2.4 Reliability Centered Maintenance (RCM) . . . . . . . 1001
50.2.5 Risk-Based Maintenance (RBM) . . . . . . . . . . . . . 1003
50.3 CIGRE Survey of Maintenance Strategies . . . . . . . . . . . . . . 1004
50.4 Maintenance Management Strategies . . . . . . . . . . . . . . . . . 1004
50.5 Developments in Maintenance Management . . . . . . . . . . . . 1006
50.6 Key Elements of Maintenance Management . . . . . . . . . . . . 1008
50.7 Developing Future Strategies . . . . . . . . . . . . . . . . . . . . . . 1009

**51 Substation Condition Monitoring** . . . . . . . . . . . . . . . . . . . . . . . . . 1011
Nicolaie Fantana, Mark Osborne, and Johan Smit
51.1 Definitions and Terminology . . . . . . . . . . . . . . . . . . . . . . 1012
51.2 Incentives for Condition Monitoring . . . . . . . . . . . . . . . . . 1014
51.3 Condition Monitoring Principles . . . . . . . . . . . . . . . . . . . . 1016
51.4 Condition Monitoring Strategies . . . . . . . . . . . . . . . . . . . . 1018
51.4.1 CIGRE Survey of Common Preventive Maintenance Methods . . . . . . . . . . . . . . . . . . . . 1019
51.4.2 In-Service Monitoring . . . . . . . . . . . . . . . . . . . . 1019
51.5 Permanent Monitoring . . . . . . . . . . . . . . . . . . . . . . . . . . . 1025
51.6 Analysis and Diagnostics . . . . . . . . . . . . . . . . . . . . . . . . . 1026
51.6.1 Traditional Condition Monitoring . . . . . . . . . . . . 1027
51.6.2 On-line Condition Monitoring (OLCM) . . . . . . . . 1027

51.7 Evolving Condition Monitoring Strategies . . . . . . . . . . . . . . 1029
51.7.1 Hybrid Condition Monitoring . . . . . . . . . . . . . . . 1029
51.7.2 Holistic Condition Monitoring . . . . . . . . . . . . . . . 1029
51.8 Data Collection and Management for Condition Monitoring . 1031
51.8.1 Data Collection . . . . . . . . . . . . . . . . . . . . . . . . . 1031
51.8.2 Data Management Over Equipment Lifetime . . . . 1033
51.9 Condition Data Analytics . . . . . . . . . . . . . . . . . . . . . . . . . 1036
51.10 Value from Condition Monitoring . . . . . . . . . . . . . . . . . . . . 1037
51.11 Outlook for Condition Monitoring . . . . . . . . . . . . . . . . . . . 1042
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1042

**52 Managing Asset Risk and Reliability of Substations . . . . . . . . . . . 1043**
Gerd Balzer, Mark Osborne, and Johan Smit
52.1 Risk Basics . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1044
52.2 Risk Assessment Process . . . . . . . . . . . . . . . . . . . . . . . . . 1045
52.3 Applying Risk Analysis . . . . . . . . . . . . . . . . . . . . . . . . . . 1047
52.3.1 Failure Mode and Effect Analysis . . . . . . . . . . . . 1048
52.3.2 Examples . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1051
52.4 Residual Life Concepts Applied to HV GIS . . . . . . . . . . . . . 1053
52.4.1 Asset Life . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1054
52.4.2 Obsolescence Management . . . . . . . . . . . . . . . . . 1055
52.4.3 Life Extension Functional Requirements . . . . . . . 1055
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1056

**53 Managing Obsolete and New Technologies in Substations Together . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1057**
Jan Bednarik, Mark Osborne, and Johan Smit
53.1 Introduction . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1058
53.2 HV Equipment Replacement . . . . . . . . . . . . . . . . . . . . . . . 1058
53.3 Protection Upgrades . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1058
53.4 Control System Upgrade . . . . . . . . . . . . . . . . . . . . . . . . . 1059
53.4.1 Existing Hardwired Control Systems May Need to be Modified/Expanded to Contain New Bays . . . . 1060
53.4.2 A New Numerical Control System May Replace an Existing Hardwired or Numerical Scheme . . . . 1060
53.4.3 Hybrid: A New Numerical Control System May be Used for New Bays While Keeping the Existing System for Existing Bays . . . . . . . . . . . . . . . . . . 1060
53.5 New Bay Installation . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1061
53.5.1 New Capacity . . . . . . . . . . . . . . . . . . . . . . . . . . 1061
53.5.2 Increase the Load Capacity . . . . . . . . . . . . . . . . . 1061
53.5.3 Change in Busbar Configuration . . . . . . . . . . . . . 1061
53.6 Managing the Design for the Future . . . . . . . . . . . . . . . . . . 1061
53.7 Concluding Remarks . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1061
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1062

**Part I Future Developments** . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . **1065**
Mark Osborne

**54 Future Developments in Substation Design** . . . . . . . . . . . . . . . . . . 1067
Mark Osborne
54.1 Evolution of Substations to Date . . . . . . . . . . . . . . . . . . . . . . 1068
54.1.1 Background . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1068
54.1.2 Looking Ahead . . . . . . . . . . . . . . . . . . . . . . . . . . . 1068
54.2 Digital Substations . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1070
54.2.1 Automated System Operation . . . . . . . . . . . . . . . . 1071
54.2.2 Asset Awareness . . . . . . . . . . . . . . . . . . . . . . . . . 1071
54.2.3 Commissioning and Testing . . . . . . . . . . . . . . . . . 1071
54.3 Novel Materials and Technologies . . . . . . . . . . . . . . . . . . . 1073
54.3.1 Drivers for New Materials . . . . . . . . . . . . . . . . . . 1073
54.3.2 Generic Issues to Consider . . . . . . . . . . . . . . . . . . 1073
54.3.3 Commissioning and Testing . . . . . . . . . . . . . . . . . 1074
54.3.4 Roles for New Technology . . . . . . . . . . . . . . . . . 1074
54.4 Designing for Modularity and Flexibility . . . . . . . . . . . . . . . 1075
54.4.1 New Installation Techniques . . . . . . . . . . . . . . . . 1076
54.4.2 Changing Attitudes to Maintenance . . . . . . . . . . . 1077
54.5 DC Substations . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1077
54.5.1 Design Issues . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1078
54.5.2 Standards . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1078
54.6 Chapter Summary . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1078
References . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . 1079

# About the Editors

**Terry Krieg** was born in Gawler, South Australia, where he currently resides. He studied electrical engineering at the University of South Australia following a Certificate of Electrical Engineering and an apprenticeship as an Electrical Instrument Maker. He was appointed Chairman of the CIGRE Substation Study Committee B3 (Substations) in 2012.

In a career that spans more than 40 years in the power sector, he has held senior management and technical positions at a number of Australian power utilities in generation, transmission, and distribution, where he led the introduction of new approaches to maintenance, substation design standardization, online condition monitoring, asset management, and risk management. He has held senior technical roles including major substation design, test and commissioning, condition monitoring, high voltage, and diagnostic testing of high voltage network plant.

An honors (first class) graduate of the University of South Australia (Bachelor of Engineering – Electrical), he is also a Fellow of the Institute of Engineers Australia (FIEAust) and a Registered Professional Engineer Queensland (RPEQ). He is an endorsed assessor for the asset management specification BSi PAS-55:2008 and, as a consultant, assists companies to develop asset management practices aligned to ISO 55000. In addition, Terry is a graduate of the Australian Institute of Company Directors.

He has presented more than 45 engineering and management papers and keynote addresses on aspects of substations, strategic asset management, diagnostics and monitoring, and the management of power networks to a number of international industry conferences and events.

**John Finn** worked initially in the electricity supply industry in the UK in protection, operation and maintenance, and system studies. He then joined private industry working with contractors on power station and substation projects in the UK and overseas at voltages up to 500 kV and as diverse as the initial 400 kV supergrid for China Light and Power to project-managing the power supplies for the Channel Tunnel between England and France. In his role as an in-house engineering consultant with Siemens in the UK, he was involved in developing the onshore and offshore substation designs associated with offshore wind farms. He has been involved in CIGRE as Area Advisor on Substation Concepts from 2002 to 2006 and convenor of working groups on “standardization and innovation” and “guidelines for offshore substations.” He received the Technical Committee Award for contributions to Study Committee B3 in 2006 and the Distinguished Member Award in 2008. He is currently Secretary for the UK National Committee of CIGRE.

# Contributors

**Richard Adams** Power Systems, Ramboll, Newcastle upon Tyne, UK

**Gerd Balzer** Institute of Electrical Power Systems, Darmstadt University of Technology, Darmstadt, Germany

**Nhora Barrera** HV Substations, Axpo Power AG, Baden, Switzerland

**Jan Bednarik** Networks Engineering, ESBI, Dublin, Ireland

**Eugene Bergin** Mott MacDonald, Dublin, Ireland

**Hugh Cunningham** Substation Design, ESB International, Dublin, Ireland

**Antonio Varejão de Godoy** Generation Director of Eletrobrás, Casa Forte, Recife, Brazil

**Jarmo Elovaara** Grid Investments, Fingrid Oyj, Helsinki, Finland

**Nicolaie Fantana** Consultant, ex. ABB Research, Agileblue consulting, Heidelberg, Germany

**John Finn** CIGRE UK, Newcastle upon Tyne, UK

**Fabio Nepomuceno Fraga** DETS, Chesf, Departemento de Engenharia, Recife, Brazil

**Peter Glaubitz** GIS Technology, Energy Management Division, Siemens, Erlangen, Germany

**Koji Kawakita** Engineering Strategy and Development, Chubu Electric Power Co., Inc., Nagoya, Japan

**Angela Klepac** Zinfra, Sydney, Australia

**Hermann Koch** Gas Insulated Technology, Power Transmission, Siemens, Erlangen, Germany

**Paul Leemans** Asset Management Substations, ELIA, Brussels, Belgium

**Gerd Lingner** DK CIGRE, Adelsdorf, Germany

**Mick Mackey** Power System Consultant Section, Dublin, Ireland

**Mark McVey** Operations Engineering, Dominion Energy, Richmond, Virginia, USA

**Ravish Mehairjan** Corporate Risk Management, Stedin Group, Rotterdam, The Netherlands

**John Nixon** Global Project Engineering, GE Grid Solutions, Stafford, UK

**Akira Okada** Global Business Division, Hitachi, Tokyo, Japan

**Mark Osborne** Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK

**Peter Sandeberg** HVDC, ABB, Vasteras, Sweden

**Carolin Siebert** Energy Management, Siemens AG, Berlin, Germany

**Johan Smit** High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands

**Colm Twomey** Substation Design, ESB International, Dublin, Ireland

**Kyoichi Uehara** Transmission and Distribution Systems Division, Toshiba Energy Systems and Solution Corporation, Kawasaki, Japan

**Alan Wilson** Doble Engineering, Guildford, UK

**Tokio Yamagiwa** Power Business Unit, Hitachi Ltd, Hitachi-shi, Ibaraki-ken, Japan

**Adriaan Zomers**

**Klaus Zuber** Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany

Adriaan Zomers: deceased.

# Introduction

# 1

John Finn and Adriaan Zomers

## Contents

1.1 Purpose .......... 1
1.2 Substations .......... 2
1.3 Structure of the Book .......... 2
1.4 How to Use the Book .......... 4

## 1.1 Purpose

CIGRE is the only organization worldwide which for almost 100 years, since 1921, has dedicated its activities to the work of the electricity supply industry. During this time the Substations Study Committee has addressed many and varied topics associated with all aspects of high voltage substations, and this work has been published in the form of Technical Brochures, Electra Papers, Session Papers, and Symposium and Colloquium Papers, and the majority of these are available freely to CIGRE members through the e-CIGRE website. However, these papers usually address specific topics which were particularly relevant or "hot topics" at the time they were written. This means that if one wishes to consider all aspects of high voltage substations, it is not easy to find your way around this mass of information. The purpose of this book is to draw on this wealth of information and to present it in a more accessible and comprehensive way in order to provide a reference book on all aspects of high voltage substations which would be of value to all decision-makers

Adriaan Zomers: deceased.

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

A. Zomers

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working in this field of expertise. It is hoped that this book will become a standard reference work, present on the bookshelves of all such colleagues.

## 1.2 Substations

Substations are vital parts of the overall global power system that includes generation of energy, transmission, and finally, distribution to end consumers. Since the first power networks, the energy mix and the sources of generation have changed, the functionality and performance demands of the system have evolved, but the role of substations within the overall power system remains as important as always.

When substations were first installed, they were considered to be associated with a single generating station; hence the name “substations” was first used. In the modern network, substations play a key role in assuring network stability and safety by providing sensing and switching functions to detect line faults and rapidly isolate these faults to maintain overall grid stability.

The overall function of a substation within the network is to transform voltages from one level to another and also to provide switching functions to provide a connection between the sources of energy and the ultimate consumer providing protection for the grid and its components.

In a power network, substations can be considered to be “nodes,” enabling connection between transmission and distribution lines and the safe connection and disconnection of one line to another.

This book is intended to provide an overview of the topic of high voltage “substations” and a reference book for those interested in the topic.

## 1.3 Structure of the Book

When preparing a reference book on the topic of substations, there are many different ways in which the book could be structured. Each way, undoubtedly, would have some merits and some disadvantages. The editorial committee for the preparation of this book has decided on a structure which basically mirrors the work of the study committee during the many decades since it was established. On the other hand, the structure needs to be such that the book is self-contained.

To that end the book tries to place information in a logical order so Part A starts with the planning or need for a substation or extension including the system requirements and location. Then the relevant concepts to be employed are considered. These concepts include such aspects as the type of switchgear, switching configurations, how to incorporate new technologies into substations, and how to introduce innovation. The effect that safety regulations and safe working practices have on the design of the substation is considered, and then some practical items such as the specification and contracting method are covered.

Throughout the world the majority of high voltage transmission substations are air insulated, and Part B deals with the design, selection of main components, and construction of such substations. The design aspects cover such items as short circuit forces on conductors, damping of aeolian vibrations, the earthing (grounding) system, insulation coordination, and the selection of insulators in polluted areas. Furthermore, structures, foundations, buildings, fences, impact of audible noise, and fire protection requirements are considered. The basic construction methods, logistics, and quality control are discussed in conjunction with outage management.

Certain locations demand the use of gas insulated switchgear (GIS) which are covered in Part C. This part starts by asking "why choose GIS?" It then looks at the configuration, insulation coordination, the primary components, special secondary system requirements, special earthing requirements, and interfaces with buildings and other equipment. The construction side is also covered, looking at transport, erection, testing, gas handling, and then the ongoing lifetime requirements of GIS.

With the growing use of gas insulated equipment, special considerations have arisen in air insulated substations such as the use of "hybrid" or "mixed technology switchgear" and gas insulated lines instead of cables. Part D deals with the application of these items in substations.

In recent years there has arisen a need for some special types of substation. Examples of these are substations operating at ultrahigh voltage of 800 kV or above and substations built offshore for use with wind power plants. The special requirements associated with these special substations are detailed in Part E.

For any substation to operate satisfactorily, there are a number of secondary systems which are vital. Such systems are the auxiliary supplies, protection, control, metering, and communications. These are discussed in Part F along with the issues associated with digital equipment and the special management techniques required for this type of equipment.

In the modern world, we are all aware of the environment and "global warming" and "climate change." Clearly the substations which we construct must be capable of operating effectively in the environment at their specific location, and so we have to be aware of the impact of the environment on the substation. However, what is becoming equally, or possibly even more, important is the effect that the substation has on the environment. Both of these aspects are dealt with in Part G.

Once we have planned, designed, and constructed our substation, it is very important to effectively manage this important asset throughout its lifetime. Part H looks at the strategic policies, maintenance strategies, and tools for managing the substation as an asset starting with commissioning through to disposal. The editorial committee had considerable debate on whether commissioning was the last act of construction or the first act of management but eventually decided to include it in management.

Finally Part I tries to take a look at how substations will change over the next few years. It starts by tracking the evolution of substations up to the present time and then considers the possible changes which new technologies, digital equipment, smart devices, and high voltage DC may make to the substation of the future.

## 1.4 How to Use the Book

The authors of the various chapters would like to think that the book is interesting enough to read from cover to cover like a novel. Naturally, this is not the way that most people will use a reference book.

In order to find the subject you wish to refer to, firstly decide which of the parts is likely to be most relevant. For example if the subject is to do mainly with air insulated substations, then refer to the index for Part C. The index for each part is divided into subsections, and you should find a subsection which relates to your subject, and the index will indicate the relevant page to refer to. The content contained within the book covers the main aspects of the subject; however, as the content of the book is largely drawn from the existing work of CIGRE, then the original brochure or Electra Paper will probably cover the subject in greater depth. The CIGRE documents which have been referred to in the preparation of each part are listed in the "References" section at the end of the book. The references are divided by part so the same reference may occur a number of times if that document has been used in more than one part. However, by having the references organized by part, it is hoped that this will make it easier for readers who wish to pursue the subject in more detail to be able to find the relevant documents.

To ensure that the book is comprehensive and coherent, some subjects have drawn on work not previously covered by a CIGRE document, and references to these other documents are also included within the references for each part.

Some subjects are relevant to more than one of the parts. To avoid duplicating the content in a number of parts, the major content on a subject will be included in one of the parts and reference back to this main content included in the other parts. For example, let us consider that you wish to refer to earthing (grounding) in gas insulated substations. Then in the index, this subject is considered in ▶ Chap. 21. However many aspects of gas insulated substation earthing are the same as for air insulated substations. The main topic of substation earthing is covered under air insulated substations; however in ▶ Chap. 21 those aspects specific to gas insulated substations are covered, and the chapter refers the reader to ▶ Sect. 11.7 for the main considerations of substation earthing.

It is hoped that the book covers each subject to a meaningful level of detail for the majority of readers so that further reference is not necessary, but for those who wish to delve into the subject in greater detail, the part reference sections will provide an easy route to find the additional material.

The editorial committee and the authors sincerely hope that this book provides a really useful reference for you in your day-to-day work associated with high voltage substations.

# Part A

# Planning and Concepts

*John Finn*

# Introduction to Substation Planning and Concepts

# 2

John Finn

## Contents

2.1 Introduction .......... 7
2.2 System Requirements .......... 8
2.3 Site Location .......... 10

## 2.1 Introduction

The transmission and distribution network performs three main functions:

a) The transmission of electric power from generating stations (or other networks) to load centers
b) The interconnection function, which improves security of supply and allows a reduction in generation costs
c) The supply function, which consists of supplying the electric power to sub-transmission or distribution transformers and in some cases to customers directly, connected to the transmission and distribution network

These network functions are fulfilled through different types of substations as follows:

a) Substations attached to power stations
b) Interconnection substations
c) Step-down (EHV/HV, EHV/MV, HV/MV) substations
d) Converter substations (AC/DC)

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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A single substation may perform more than one of these functions.

System studies are carried out regularly by utilities to ensure that the network is capable of satisfactorily fulfilling the above functions. These studies will indicate when the network needs to be augmented and if this augmentation requires the construction of new substations or the extension of existing ones. Once the need for a new substation or extension of an existing one has been established and the range of duties, loading, and general location determined, then the detailed planning of the substation can commence.

## 2.2 System Requirements

The utility's planning department will define the key parameters for the new substation or substation extension. System planners seek to optimize the parameters that apply to the complete transmission system. This is normally done by carrying out network studies mainly covering insulation coordination, transient stability, short circuit level, and load flow.

Examples of these parameters that will normally be common to the whole network or parts of a network are:

i) Insulation impulse levels – the lightning impulse withstand level and the switching impulse withstand level to be applied. The relevant IEC standard offers a range of values for each normal operating voltage, and the utility needs to clarify which values will be applicable to their network.
ii) Fault clearance time required ensuring system stability – transient stability characterizes the dynamic behavior of a generator in the case of large oscillations following a major disturbance. In order to comply with the requirements of the network (system stability) or the specifications of particular utilities, specified fault clearance times must not be exceeded. Fault clearance time limits and the reclosing conditions may influence the choice of circuit breaker and other switchgear.
iii) Fault current levels – the short circuit current rating of the substation equipment (busbars, circuit breakers, current transformers, etc.) and support structures. These short-time current ratings are usually also linked to a time duration for design purposes, typically 1 s for voltages in excess of 170 kV and 3 s for lower voltages.
iv) Current rating – the maximum load current passing through the components in the substation (which is normally related to the maximum current capacity of the lines and underground cables).
v) Neutral point earthing – the electrical networks may be effectively or solidly earthed (earth fault factor up to 1.4), noneffectively earthed, for example, resistance earthed, or resonant earthed (earth fault factor 1.7) or isolated.
vi) General control requirements – such as the methodology of control which may be dependent on:

- Whether disconnectors are operated manually or by motor
- Presence of earthing switches
- Degree of substation automation and sequence control
- Remote control from grid control center
- Regulations

The need for telecontrol and telecommunication links depends on the needs of the automation, remote control, data transmission, and operation of the network. Substations are frequently also the nodal point of a data transmission network.

The requirement for load shedding, network sectioning, voltage regulation, and load distribution regulation devices may be placed in substations.

vii) General protection requirements – the substation has to be constructed so that all possible faults can be cleared:
- Selectively
- Without exceeding the current rating of the lines and equipment
- Without causing danger to personnel and ensuring that the requirements of the safety codes are fulfilled
- Sufficiently quickly to ensure that the stability of the network is maintained (i.e., within the required fault clearance times)
- In such a way that the load/generation balance is preserved

Requirements for main protection redundancy and provision of backup protection should be defined.

Examples of other parameters that are specific to the particular substation are:

a) General site location – see Sect. 2.3.
b) Extent of the substation – this will be dependent upon the area available for the substation, the number of outgoing feeders of different voltage levels, the number of main transformers, the busbar schemes, and the possibility of extension as well as options for compensating equipment which should be selected for the needs of the future. It should be noted that the lifetime of the substation might be between 30 and 50 years.
c) Required availability of the circuits and busbar schemes – see ► Chap. 4.
d) Future extensions – it is very important to allow sufficient space for extension. This is often determined as the “ultimate layout” of the substation. Sophisticated network planning is needed to estimate the necessary reserve space. Depending on the type and function of the substation, this reserve space may be 100% reserve for outgoing feeders. Extension work such as building of new bays, reconstruction of existing bays, and extension of the busbars can be difficult and expensive if there has been no previous planning for them. In case of GIS, it is usual to reserve space for a number of spare bays and also to make allowance for the future extension of the control building. The outgoing line corridors should be planned in coordination with the substation and designed to minimize the number of crossings between different circuits.

## 2.3 Site Location

Several alternatives often exist for the location of a new substation in the network. The total costs of each option should be calculated. The cost of building new transmission lines and the reinforcement of existing circuits are often of the same order as that of the substation. Consequently, the system planners should consider various alternatives to limit the overall transmission costs. The following should be considered when assessing the overall costs:

- Site suitability and cost
- The losses in power transmission and transformation
- Telecontrol and communications
- Reliability and busbar schemes
- Fault current and load flow calculations

Obtaining new line corridors is becoming increasingly difficult to achieve, and their availability alone may determine the location of the substation.

# Type of Switchgear to Be Used

# 3

Colm Twomey

## Contents

3.1 Types of Switchgear Available .......... 11
3.1.1 Air-Insulated Switchgear (AIS) .......... 12
3.1.2 Gas-Insulated Switchgear (GIS) .......... 12
3.1.3 Mixed-Technology Switchgear (MTS) .......... 12
3.2 Choosing the Type to be Applied .......... 12
3.2.1 Reasons for Using AIS .......... 13
3.2.2 Reasons for Using GIS .......... 13
3.2.3 Reasons for Using MTS .......... 13
3.3 Conclusion .......... 13

## 3.1 Types of Switchgear Available

Another important decision made at the planning/concept stage is the type of equipment that will be used for the substation. Three types of equipment are available for selection by a substation designer in order to implement the most appropriate solution for a particular substation, i.e.:

- Air-insulated switchgear (AIS)
- Gas-insulated switchgear (GIS)
- Mixed-technology switchgear (MTS)

C. Twomey (✉)
Substation Design, ESB International, Dublin, Ireland
e-mail: Colm.Twomey@esbi.ie

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These solutions can be defined as follows:

### 3.1.1 Air-Insulated Switchgear (AIS)

Switchgear and other high-voltage equipment where the insulation to earth and between phase conductors is mainly provided by air at atmospheric pressure and where some live parts are not enclosed (from IEC 6050-605-02-13).

### 3.1.2 Gas-Insulated Switchgear (GIS)

Metal-enclosed switchgear and other high-voltage equipment where the insulation is obtained, at least partly, by an insulating gas other than air at atmospheric pressure (from IEC 62271-203, 3.102). This gas is usually $SF_6$ or an $SF_6$ mixture with other gases, e.g., nitrogen although other gas types are being evaluated.

### 3.1.3 Mixed-Technology Switchgear (MTS)

Equipment that has been developed from AIS or GIS into one of the following combinations:

- AIS in compact and/or combined design
- GIS in combined design
- Hybrid-insulated switchgear where bays are made from a mix of AIS and GIS technology components.

## 3.2 Choosing the Type to be Applied

A large number of factors must be considered in making the decision as to which is the most appropriate technology to be used in a particular installation. This topic was investigated in generic terms by Working Group B3.20 whose conclusions are included in Technical Brochure 390 "Evaluation of different switchgear technologies (AIS, MTS, GIS) for rated voltages of 52 kV and above."

The detail of this analysis is reported in ► Sect. 26.2.3 that concludes that often the preferred order is MTS, followed by GIS and finally AIS. This analysis clearly does not address all of the relevant factors which have to be considered, or we would find that all substations should be built using MTS technology, whereas in practice the most common is AIS followed by GIS with MTS being the least common.

### 3.2.1 Reasons for Using AIS

AIS has the significant advantage that the equipment is generally the cheapest to purchase. Unfortunately, it has disadvantages that it takes up more space because of the clearances required in air and that the equipment is exposed to the environment. However, if there is space available for the substation, the land cost is not significantly high, and the area is not susceptible to significant salt or industrial pollution; then AIS will still probably be the most suitable solution for a HV or EHV substation. It also has the advantage that it is relatively easy to extend and modify as the needs of the substation develop.

### 3.2.2 Reasons for Using GIS

GIS equipment is usually the most expensive option. However, it has the major advantage that it is very compact. This means that the amount of land required for the substation will be many times smaller than for an AIS substation. This is a very important factor when considering building a HV or EHV substations in cities where the cost of the land can be extremely high. In addition, because of its compactness, it can easily be housed within a building, and consequently the aesthetic aspects can be tailored to suit the surrounding environment. Another major advantage of GIS is that all of the electrical components are housed within an enclosure filled with gas and so not exposed to the environmental pollution at the site. Where a substation is close to the sea and salt pollution is a major issue or close to industry where industrial pollution may be severe, then GIS may well prove to be the best if not the only satisfactory solution. GIS may also be advantageous from a safety perspective with less exposed high-voltage components.

### 3.2.3 Reasons for Using MTS

MTS has the advantage of being compact and also combining multiple functions together. This can enable a solution that is small in size while still being significantly cheaper than GIS. This can be used where the land costs are moderate and pollution is not a major issue to provide a compact and cost-effective solution for new substations. However, it also has been used very effectively for the extension of existing AIS substations where the space is very limited, without the need for procuring more land.

## 3.3 Conclusion

Whereas one should be aware of the considerations in CIGRE Brochure 390 and the advantages and disadvantages mentioned above, there is no single solution that is always correct for a particular type of substation. The choice will be influenced not only by geographical considerations but also by the specific factors that a particular utility may consider important, particularly maintenance strategy.

# Selecting Circuit Arrangements: Requirements and Reliability

# 4

Gerd Lingner

## Contents


4.1 Main Requirements ........ 16
4.1.1 Further Requirements and Implications ........ 17
4.2 Reliability ........ 18
4.3 Selecting Circuit Arrangements ........ 19
4.3.1 Description of Assessment Criteria ........ 20
4.3.2 Service Security ........ 20
4.3.3 Availability During Maintenance ........ 21
4.3.4 Operational Flexibility of a Substation ........ 23
4.4 Substation Configuration ........ 24
4.4.1 Substation Connecting to a Power Station ........ 25
4.5 Interconnection Substation ........ 25
4.6 Step-Up/Step-Down Substations ........ 26
4.7 Circuit Arrangements ........ 29
4.7.1 Single Busbar Arrangements ........ 29
4.7.2 Multiple Busbar Arrangements ........ 32
4.7.3 Ring Bus and Mesh Substation ........ 36
4.8 Selection Process ........ 37
References ........ 39


The basic function of circuit arrangements is to facilitate the operational functions of substations inside electrical networks. In the past, maintainability and accessibility of high voltage equipment were very important due to the requirements for frequent maintenance. Different kinds of circuit breaker designs such as oil-filled breakers and air-blast breakers and also the different types of operating mechanisms required regular maintenance in short intervals. These requirements meant that various configurations and arrangements of substations were developed to isolate the circuit

G. Lingner (✉)
DK CIGRE, Adelsdorf, Germany
e-mail: gerd.lingner@gmx.net

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breaker and current transformer in a bay for maintenance while ensuring availability of supply on adjacent equipment. Disconnectors are required to deal with safety requirements and provide physical isolation during maintenance activities.

The developments in the design of high voltage devices and new switchgear components using different design principles with higher reliability or integrated functions mean that the reliable and efficient circuit arrangements of the past may not be necessary and result in onerous life-cycle-cost requirements for utilities.

The circuit configuration alone will not be sufficient in determining an adequate configuration for a substation. The location of the substation in a network, its purpose, and requirements will also need to be taken into account.

Substations are nodes or hubs for interconnections between regions, countries, etc. in the network and also transform power between networks of different voltages and at infeed (generation) and load points of the network. The network characteristics together with a particular substation type lead to the proposals for different circuit arrangements.

Circuit arrangements are also called switching arrangements, circuit configurations, busbar schemes, busbar switching arrangements, busbar configurations, etc. The single-line diagram (SLD) gives an overview of each circuit arrangement with all switching and non-switching high voltage equipment. It is the basic document required to plan a high voltage substation.

A guiding definition from IEC 61936-1 is as follows:

> 7.1.1 Circuit arrangement
>
> 7.1.1.1. The circuit arrangement shall be chosen to meet operating requirements and to enable implementation of the safety requirements in accordance with 8.3. The continuity of service under fault and maintenance conditions, taking into account the network configuration, shall also be considered. The circuits shall be arranged so that switching operations can be carried out safely and quickly.

Circuit arrangements determine the functionality by the number and arrangement of required bays, busbars, and busbar sections. Each circuit with all high voltage switching devices (circuit breakers, disconnector/earthing switches) and non-switching devices (instruments transformers, surge arresters) influences the arrangements with their properties (failure and maintenance rate and frequency, reliability, availability) control and protection systems as well as the life-cycle costs.

## 4.1 Main Requirements

Modern society increasingly depends on a continuous power supply. To achieve better reliability of transmission and distribution systems and to avoid interruption of power supply, reliability analysis and planning are therefore becoming increasingly important. Substation designers have always to consider the optimum solution from the technical and economical point of view of the substation configuration regardless of the voltage level or whether the scope of works involves a new substation or an extension or a refurbishment. The selection of reliable circuit arrangements and its possible extension for a particular substation is an important initial step of the design of a substation. The substation has to fulfill a specific function in the network under consideration of parameters defined by system studies and economic aspects. There are three main requirements that have to be analyzed and evaluated during the selection process:

1. Service security
2. Availability during maintenance
3. Operational flexibility

To find and select the optimized circuit arrangement for a specific requirement, further necessary topics need to be analyzed, assessed, defined, and determined individually, such as:

- Influence of credible and permissible situations (e.g., loss of the whole substation)
- Application of different utilities' performance standards
- Operational issues and maintenance procedures
- Control and protection philosophies
- Cost-benefit analysis

There is no common basis for evaluation since each country and customer has their own standards and requirements.

### 4.1.1 Further Requirements and Implications

The technology choice of the type of switchgear is often made at the start of the planning cycle, and the circuit arrangement can be influenced by:

- Extension of an existing substation
- Familiarity and good experience with particular equipment
- Long-term procurement contracts
- Environmental protection issues such as gas and oil leakage, material recycling, physical esthetic, etc.
- Use of a particular technology due to environmental reasons, e.g., proximity to salt water, lightning-prone area, space limitations, etc.

If the choice of technology is driven by one of the above reasons, prior to deciding on the substation configuration, then the following issues may play an important part in deciding the configuration:

- Maintainability, maintenance frequency and duration
- Repair time, outage time
- Access

- Life-cycle cost (capital)
- AIS – independence between HV devices since the insulation is ambient atmosphere
- GIS – dependencies may exist between HV devices depending on the arrangement of the gas compartments
- MTS – sometimes more than one HV device in the same gas compartment, which leads to reduced functionality for maintenance and repair activities.

If however, the configuration is selected before the technology is chosen, then other factors may play a larger part in the technology selection. These may include but are not limited to:

- Flexibility/extendibility
- Arrangement of feeders (possibility to split up for load distribution or fault level control)
- Number of busbars and/or busbar sections
- Physical location of busbars (e.g., avoid risk of having one fault in the substation affecting both busbars (2 CB configuration))
- Testing
- Civil works
- Engineering complexity
- Esthetics/visual impact
- Construction complexity
- Safety
- Physical security (e.g., reduce number of switching operations of circuit breakers (shunt reactor switching in 2 CB configuration))

## 4.2 Reliability

Service reliability is described as:

- *The ability of a power system to meet its supply function under stated conditions for a specified period of time. [IEV 603-05-02]*

Reliability (of an electric power system) is described as:

- *The probability that an electric power system can perform a required function under given conditions for a given time interval.*
- *Note 1 – Reliability quantifies the ability of an electric power system to supply adequate electric service on a nearly continuous basis with few interruptions over an extended period of time.*
- *Note 2 – Reliability is the overall objective in electric power system design and operation. [IEV 617-01-01]*

High voltage substations connect transmission and distribution systems with consumers of electric energy. The reliability as a criterion of electricity supply depends on the availability of their system components, like transmission lines and cables and high voltage substations.

However, the functions of their system components depend on the availability of their individual components and their interdependencies. The substation function is given by the circuit arrangement.

The components of the high voltage substations are the circuit breakers, the disconnectors, the busbars, the transformers, and also the necessary equipment in the related control and protection systems. Criteria include the failure rate and repair rate of the individual devices described in the parameter “Meantime between Failure” (MTBF) as an outage time per year. This is a statistical value needed for probabilistic calculations.

Normally the reliability analysis (system studies) will be executed by computerized “Failure Mode and Effect Analysis” (FMEA) by development of physical reliability models and determination of the failure and repair rates.

Paper 23-05 (1974) gives an idea of failure rates of different circuit arrangements and voltage levels. For applying the results, all the developments in the design of high voltage devices and new switchgear components using different design principles with higher reliability or integrated functions have to be considered. In addition, the change in maintenance strategies and philosophies influences the MTBF value and the reliability of the substation.

Paper B3-216 (2014) investigated the reliability of HV/MV substations by using a “selective search method” for H-arrangements and double busbar arrangement.

However, practical design engineers tend to prefer a simple method, at least for the first selection of a circuit arrangement. The FMEA is the step undertaken after determination and selection of the appropriate high voltage devices.

## 4.3 Selecting Circuit Arrangements

The selection of the most appropriate substation configuration for the utility or asset owner can be assisted by defining criteria based on areas of specific importance to utilities and other substation owners. These criteria should be based on network performance and can therefore be used to compare substation configurations regardless of which technology is being used. However, the choice of technology cannot be totally ignored, as it could influence the configuration type or even result in new types of configuration.

The evaluation criteria defined in this section enables the reader to assess various types of arrangements in a simple and objective manner. The method described uses the main requirements to compare various substation configurations, thereby resulting in a comparison baseline.

- Service security
- Availability during maintenance
- Operational flexibility

To provide objectivity and a degree of customization for the user, weighting factors, based on importance, are allocated to each assessment criterion. These allow the user to assign the degree of significance to a particular element if it is more critical than other features.

### 4.3.1 Description of Assessment Criteria

The criteria against which each of the various substation configurations is to be assessed are described and defined in the paragraphs below. The definitions of the criteria are based on IEC definitions, where applicable. All others are described for the purpose of the assessment.

### 4.3.2 Service Security

IEC definitions:

**Service Security**
*The capability of a power system at a given moment in time to perform its supply function in the case of a fault [IEV 603-05-03]*

Some contingencies considered in the system security analysis of the network are based on N-1 criteria and N-2 criteria

- N-1: single failure in any system element (line, transformer, generator, or reactor)
- N-2: simultaneous double failure in any system element (line, transformer, generator, or reactor)

As a general rule, acceptable network conditions may be as follows:

- N-1: A system has to be able to support a single contingency without exceeding dynamic and static limits such as:
  - Allowable thermal limit in lines due to permanent over currents
  - Allowable permanent over current in transformers in relation to the nominal power
- N-2: A system has in addition to be able to support some specific simultaneous or sequential contingencies such as the following:
  - Simultaneous loss of some double lines
  - Simultaneous or subsequent loss of the higher-generation group in an area and an interconnection line of this area with another area

These definitions are related to the network and cannot be considered in a direct way in the configuration security study. It has to be noted that the loss of one high voltage substation element can mean the loss of one (N-1) or more elements (N-2, N-x) in the network.

This document focuses on the consequences to the network of the behavior of the substation under contingency situations. If the configuration is able to support a contingency with no effect on the system, the substation will provide the highest level of service security for this situation.

Considering the circuit breaker as the dividing element, two main contingency groups will be evaluated based on the location of the fault:

- External faults on the outside (object side) of the circuit breaker (e.g., transmission line, transformer, etc.)
- Internal faults on the inside (busbar side) of the circuit breaker

Service security is the analysis of the substation's configuration in terms of availability of supply to the network after internal (busbar side of circuit breaker) and external faults (object side of circuit breaker), prior to any switching operations.

An internal or external primary fault leads to a trip signal to the appropriate circuit breaker. This means that the condition N-1 is considered. If there is a circuit breaker failure after a single primary fault, i.e., the appropriate circuit breaker fails to trip, breaker failure protection acts by opening all the circuit breakers around the breaker that failed to open and an N-2 condition is considered.

**Assumptions**
To be able to compare different configurations using the same rules, some protection operation consequences related to the number or location of current transformers such as the cases listed below will not be considered.

- One or two current transformer per bay
- Relative position of current transformer and circuit breaker
- Behavior with a fault located between current transformer and circuit breaker

This means that protection zones are considered perfect, i.e., for object side faults trip signals will be given only to the circuit breaker(s) feeding the object.

Accordingly for faults on busbar side trip signals will be given to the object breaker(s) together with all other circuit breakers connected to this busbar.

Both object side and busbar side type primary faults will be studied with and without breaker failure when a trip signal is sent to the appropriate circuit breaker(s).

The scores in the table are 1 the worst, i.e., the highest impact; 6 best, i.e., the lowest impact.

### 4.3.3 Availability During Maintenance

IEC definitions:

**Availability**
*The ability of an item to be in a state to perform a required function under given conditions at a given instant of time or over a given time interval, assuming that the required external resources are provided. [IEV 191-02-05].*

*The state of an item of being able to perform its required function [IEV 603-05-04]*

**Maintainability**
*The ability of an item under given conditions of use, to be retained in, or restored to, a state in which it can perform a required function, when maintenance is performed under given conditions and using stated procedures and resources [IEV 191-02-07].*

**Dependability**
*The collective term used to describe the availability performance and its influencing factors: reliability performance, maintainability performance and maintenance support performance [IEV 191-02-03]*

Maintainability is defined as a calculation of the statistics of disconnection of a feeder connected to a substation when high voltage components must be maintained. This is normally used to calculate the unavailability of feeders based on failure.

The availability depends on the reliability of the individual equipment. It will be calculated (using probabilistic calculation) as the outage time required in hours per 1000 years.

Because of the variety of circuit breaker and disconnector types and the variety of availability and maintenance data, the study will consider the availability during maintenance. This will define the consequences for the network due to maintenance of disconnectors and circuit breakers in the substation. The result of this calculation will vary, based on the substation's configuration and weighting factors applied (Table 4.1).

Availability during maintenance is a function of the substation configuration's ability to maintain feeders energized while maintaining disconnectors and circuit breakers.

**Assumptions**
No switching risks and no primary faults during maintenance operations have been considered. It should be noted that, however, during construction or maintenance is a

**Table 4.1** Evaluation criteria with matching score for service security

| Score | Possible consequences to the network because of a primary fault | Possible consequences to the network because of a primary fault when breaker fails to open |
|---|---|---|
| 1 | Possible loss of the whole substation | Loss of the whole substation |
| 2 | Loss of one or more feeders but not the whole substation | Loss of more than one feeder or the whole substation |
| 3 | Loss of one or more feeders but not the whole substation | Loss of more than one feeder but not the whole substation |
| 4 | Loss of one feeder | Loss of one feeder and always one feeder more but not the whole substation |
| 5 | Loss of none or one feeder | Loss of one feeder and possibly one feeder more but not the whole substation |
| 6 | Loss of none or one feeder | Loss of one feeder |

**Table 4.2** Evaluation criteria with matching score for availability during maintenance of circuit breakers and disconnectors

| Score | Maintenance of | Consequence |
|---|---|---|
| 1 | Any busbar disconnector | Outage of whole substation |
| 2 | Sectionalizer disconnector | Outage of whole substation |
| 3 | Any busbar or sectionalizer disconnector | Outage of half the substation |
| 4 | Any busbar disconnector | Outage of one busbar, remaining objects in service on the same busbar |
| 5 | Any busbar disconnector | Outage of one busbar, remaining objects in double busbar configuration |
| 6 | Any busbar disconnector | Remaining circuits in service |
| | | Open ring |
| | | Split-up of the substation |
| | Circuit breaker | Split-up of the substation and all circuits in service |
| 7 | Any busbar disconnector | Outage of one busbar, all objects in service on the same busbar |
| | Circuit breaker | All circuits remain in service |

time when the likelihood of substation faults could increase. The switching can be done with circuit breaker or disconnector depending on the particular configuration.

Maintenance on circuit disconnector (object side of circuit breaker) always leads to outage of the circuit. This is common for all circuit configurations and is therefore not mentioned in the table below. This element will impact on the ability to provide supply security for switching time.

The scores are listed in the table below and have the following values:

- 1 – the worst consequences in the network: outage of whole substation.
- 7 – the least consequences in the network: no network element is disconnected and the network topology is not weakened (Table 4.2).

### 4.3.4 Operational Flexibility of a Substation

There is no IEC definition for this terminology.

The proposed definition of operational flexibility from a planning and operation point of view is as follows:

- The ability to split the substation, for the following reasons:
- To limit the consequences in case of a primary fault in the substation such as not losing both circuits feeding a supply point, e.g., two power transformers or a double overhead line, etc. can be connected to different busbars so that for a busbar fault or a feeder fault with following breaker failure, only one of the feeders is lost. In these cases the two parts of the substation are usually electrically

**Table 4.3** Evaluation criteria with matching score for flexibility

| Scores | Definition |
|---|---|
| 1 | Not possible to split |
| 2 | Non-energized split (disconnector only), no flexibility |
| 3 | Energized split (with circuit breaker), no flexibility |
| 4 | Energized split (with circuit breaker), low flexibility |
| 5 | Energized split (with circuit breaker), high flexibility, switching with disconnector |
| 6 | Energized split (with circuit breaker) |
| | High flexibility, switching with circuit breakers |
| | Highest flexibility, switching with disconnector |

connected together in normal service, e.g., by a closed bus-coupler or bus-section circuit breaker, which will give the highest availability and best use of the busbar.
- To limit the short circuit current. In this case bus-coupler circuit breaker or bus-section circuit breaker will be kept in the open position.
- To prevent load current from exceeding the rated values of the busbars.
- The ability to arrange the incoming and outgoing feeders to match system conditions.

*Note*: The ability to arrange incoming and outgoing feeders can be done at two stages:

- During the design phase: the feeders are physically connected to the substation with an initial plan to match system conditions.
- During the operation phase: the arrangement can be changed to match changing system conditions.

Operational flexibility is the analysis of the substation ability to reconfigure the feeders and split up the substation.

Some configurations allow the substation to be split up into more than two parts. However, for the purpose of this book, we consider flexibility by focusing only on the ability to split the substation in two separate electrical parts. This will help to manage and balance power flows to meet network security, stability, and efficiency targets.

The scores are defined as follows:

- 1 – it is not possible to split the substation into two separate electrical parts.
- 6 – it is possible to split the substation into two separate electrical parts, and there is a high level of flexibility about how to do it (Table 4.3).

## 4.4 Substation Configuration

The attributes for a particular substation will depend on its position within a network and also its relative importance. The attributes or characteristics of the substation are chosen by the selection of the relative weighting, in percentage terms, for the characteristic requested with the weighting totaling 100%.

Choosing the appropriate characteristics of a substation is the key to enabling this guide and assisting the user in finding the most suitable substation configuration. Some examples are given below for typical substation applications and functions:

- Substation connecting to a power station
- Interconnection substation
- Step-down substation (grid supply substation)

For each type of substation, the relative weights are chosen for each of the following criteria or characteristics as described in Section 4.3.1.

- Service security
- Availability during maintenance
- Operational flexibility

The weighting factors are given in percent and sum to 100% for the three criteria.

### 4.4.1 Substation Connecting to a Power Station

The main purpose of this substation is to give the power access to the power system and separate the power plant from the network if a fault occurs. Depending on the nature of the generator and criticality, additional circuits may be required to improve network security, and ensure power is available during network disturbances.

**Service Security**
This parameter is important for this type of substation since the delivery of energy from the power plant to the grid has a high value.

**Availability During Maintenance**
This value will vary significantly depending on the type of generator (e.g., wind farms and nuclear will be very different). The substation maintenance can be coordinated to when power plants normally have yearly maintenance periods where substation material may be maintained.

**Operational Flexibility**
This is once again dependent on the generator configuration; however, normally there is no need to rearrange feeders in this type of substation (Table 4.4).

## 4.5 Interconnection Substation

The main purpose of the interconnection substation is to collect and distribute the power within the grid.

**Table 4.4** Weighting factors for a substation directly connected to a power station

| Power station | Service security | Availability during maintenance | Operational flexibility | Sum |
|---|---|---|---|---|
| Weight factor | 90% | 5% | 5% | 100% |

**Table 4.5** Weighting factors for an interconnection substation

| Interconnection substation | Service security | Availability during maintenance | Operational flexibility | Sum |
|---|---|---|---|---|
| Weight factor | 10% | 10% | 80% | 100% |

**Service Security**
If the power system has redundant interconnection through another path in the network service, security is not as important since power can be transferred through the redundant path even if the whole substation is lost.

**Availability During Maintenance**
In a similar manner to service security, this may not be so important if there are other parts in the network to which power can be transferred during maintenance.

**Operational Flexibility**
Flexibility is likely to be very important for this type of substation in order to achieve service security and availability during maintenance (Table 4.5).

## 4.6 Step-Up/Step-Down Substations

The function of this type of substation is to transfer power from one voltage level to another through transformers, generally to feed distribution grids.

**Service Security**
The service security requirement will depend on whether the system on the secondary side of power transformer can be fed from a different substation. In this particular case, it is assumed that it is possible to back-feed the load fed by these transformers.

**Availability During Maintenance**
This depends on the grid layout on the secondary side of the transformer. If the grid on the secondary side is of a radial nature, then availability is more important compared to when the secondary side is of a meshed nature with more infeed alternatives. It is assumed that availability must be weighted highly.

**Table 4.6** Weighting factors for a step-down substation

| Step-down substation | Service security | Availability during maintenance | Operational flexibility | Sum |
|---|---|---|---|---|
| Weight factor | 30% | 30% | 40% | 100% |

**Operational Flexibility**

Step-down substations should have some flexibility to allow the grid operator to rearrange the substation in order to keep the transformers energized after disturbances (Table 4.6).

It is very important to note that these are just examples. The reader/designer should use their own judgment to determine the weights that are applicable to each project or particular situation. The aforementioned cases should be treated as theoretical examples only. However, the methodology may be used to find the most suitable substation configuration based on the utility's specific requirements (Table 4.7).

The assessment table illustrated above pulls together information from different subsections within this section and enables the user to evaluate the performance of a design. The process requires the designer to:

- Identify the individual scores allocated to each configuration as defined in Section 4.3 against each of the three criteria of service security, availability during maintenance, and operational flexibility using the scoring described in Table 4.3.
- Evaluate the weighted average. The "assessment of circuit configuration" column (yellow fields) shows calculated score for each combination of substation application and substation configuration. The result is obtained by multiplying together the appropriate score for each heading (normalized for the range of scores used for that heading) by the weighting factor assigned to that heading in the particular substation application and then adding the three results together to give a final value. All final results are then multiplied by a uniform factor of 10 to produce more usable values.

Example: H5 configuration used for an interconnection substation:

| | |
|---|---|
| Service security | 2 (out of 6) |
| Availability during maintenance | 3 (out of 7) |
| Operational flexibility | 3 (out of 6) |
| Overall assessment | $\left(\frac{2}{6} \times 0.1 + \frac{3}{7} \times 0.1 + \frac{3}{6} \times 0.8\right) \times 10 = 4.8$ |

The better results are produced by the double busbar, double circuit breaker configurations (2CB), since this methodology does not take into account cost or substation footprint. This configuration is however only used globally in a relatively small number of substations so it is not simply a matter of the designer automatically selecting the configuration that provides the highest result for a particular application.

**Table 4.7** Summary of circuit arrangement assessment

| | Score | Possible consequences in the network because of a primary fault | Possible consequences in the network because of a primary fault when breaker fails to open | Single busbar (SB) | Sectionalizable single busbar (SSB) | H3 configuration (H3) | H4 configuration (H4) | H5 configuration (H5) | Double bus bar with coupler bay (DB) | Double busbar with coupler bay and transfer busbar (DBT) | Triple busbar (TB) | Ring configuration(R) | One and a half circuit breaker (OHCB) | Two circuit breaker configuration (2CB) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Service security*** | 1 | Possible loss of the whole substation | Loss of the whole substation | 1 | 1 | | 1 | | | | | | | |
| | 2 | Loss of one or more feeder but not the whole substation | Loss of more than one feeder or the whole substation | | | 2 | | 2 | 2 | 2 | | | | |
| | 3 | Loss of one or more feeder but not the whole substation | Loss of more than one feeder but not the whole substation | | | | | | | | 3 | | | |
| | 4 | Loss of one feeder | Loss of one feeder and always one feeder more but not the whole substation | | | | | | | | | 4 | | |
| | 5 | Loss of none or one feeder | Loss of one feeder and possibly one feeder more but not the whole substation | | | | | | | | | | 5 | |
| | 6 | Loss of none or one feeder | Loss of one feeder | | | | | | | | | | | 6 |
| ***Availability during maintenance*** | **Score** | **Maintenance of:** | **Consequence** | | | | | | | | | | | |
| | 1 | Any busbar disconnecting switch. | Outage of whole substation | 1 | | | | | | | | | | |
| | 2 | Sectionalizer disconnecting switch | Outage of whole substation | | 2 | | 2 | | | | | | | |
| | 3 | Any busbar or sectionalizer disconnecting switch | Outage of half the substation | | | 3 | | 3 | | | | | | |
| | 4 | Any busbar disconnecting switch | Outage of one busbar, remaining objects in service on the same busbar | | | | | | 4 | | | | | |
| | 5 | Any busbar disconnecting switch | Outage of one busbar, remaining objects in double busbar configuration | | | | | | | | 5 | | | |
| | 6 | Any busbar disconnecting switch<br>Circuit breaker | Remaining circuits in service and open ring split-up substation<br>Split-up of the substation and all circuits in service | | | | | | | | | 6 | 6 | |
| | 7 | Any busbar disconnecting switch<br>Circuit breaker | Outage of one busbar, all objects in service on the same busbar<br>All circuits remain in service | | | | | | | 7 | | | | 7 |
| ***Operational flexibility*** | **Score** | **Definition** | | | | | | | | | | | | |
| | 1 | Not possible to split | | 1 | | | | | | | | | | |
| | 2 | Non-energized split (DS only), no flexibility | | | 2 | | 2 | | | | | | | |
| | 3 | Energized split (with CB), no flexibility | | | | 3 | | 3 | | | | | | |
| | 4 | Energized split (with CB), low flexibility | | | | | | | | | | 4 | 4 | |
| | 5 | Energized split (with CB), high flexibility, switching with DS | | | | | | | 5 | 5 | | | | |
| | 6 | Energized split (with CB) | | | | | | | | | 6 | | | 6 |

| | Weighting factor | | | Assessment of circuit configurations | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Service security** | **Availability during maintenance** | **Operational flexibility** | | | | | | | | | | | |
| **Substations attached to power** | 0.9 | 0.05 | 0.05 | 1.7 | 1.8 | 3.5 | 1.8 | 3.5 | 3.7 | 3.9 | 5.4 | 6.8 | 8.3 | 10.0 |
| **Interconnection** | 0.1 | 0.1 | 0.8 | 1.6 | 3.1 | 4.8 | 3.1 | 4.8 | 7.6 | 8.0 | 9.2 | 6.9 | 7.0 | 10.0 |
| **Step-up/ Step-down substations** | 0.3 | 0.3 | 0.4 | 1.6 | 2.7 | 4.3 | 2.7 | 4.3 | 6.0 | 7.3 | 7.6 | 7.2 | 7.7 | 10.0 |

The table does provide information on the relative technical performance of different configurations when used in particular applications. This can then be used as part of the project decision-making process to establish the preferred option; however, it is the decision of each individual utility to determine the relative ratio of technical to economic weighting, not the guidelines in this book.

## 4.7 Circuit Arrangements

Many countries use one or other of the following circuit arrangements or their variation. There are also configurations that are limited to specific countries or utilities. In the following subsection, only a limited number of circuit arrangements are discussed. There are many variants possible from around the world.

Circuit arrangements can be generally categorized into single and multiple busbar arrangements and ring arrangements.

### 4.7.1 Single Busbar Arrangements

*A substation in which the lines and transformers are connected to one busbar only [IEV 605-01-16]*

In the single busbar arrangement (Fig. 4.1), the lines, and transformers are connected via one busbar disconnector and one circuit breaker to one common busbar, and it is commonly used for a step-down (HV/MV) substation in the distribution network.

This configuration is the simplest, cheapest, and easiest to operate. However it also has the least flexibility and lowest level of security. A fault on the busbar, in a busbar disconnector, or in any circuit breaker results in the loss of the complete substation.

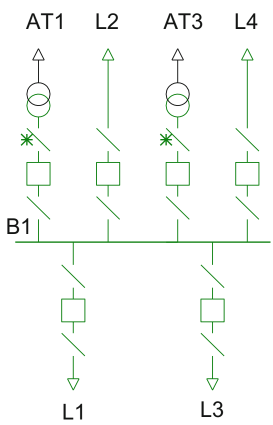



**Fig. 4.1** Single busbar (SB)

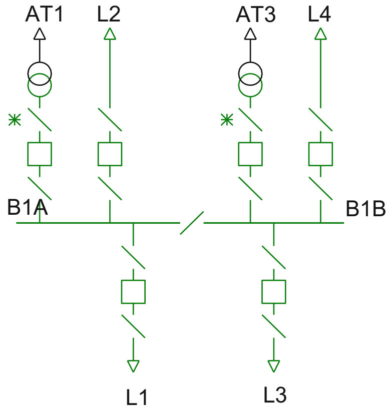



**Fig. 4.2** Disconnectable (sectionalizable) single busbar (SSB)

This configuration does not offer any flexibility from the operational point of view. There is no possibility of splitting the substation, and there are no possibilities to reduce the short circuit level. In this configuration, there are many restrictions to maintain busbar disconnectors because outages of the busbar are required.

The single busbar has a number of possible variations that provide some increase in flexibility and security. The inclusion of a disconnector into the busbar leads to the sectionalizable single busbar (Fig. 4.2).

*A busbar including disconnector(s) in series intended to connect or disconnect two sections of that busbar, off load [IEV 605-02-07]*

This disconnector splits the busbar into two sections that can be operated independently and reduces the short circuit level. The operation of the disconnector is only possible off load. This concept of a disconnectable busbar can be applied to all other busbar configurations.

The inclusion of a transfer busbar offers the possibility to maintain any circuit breaker, transferring any circuit to the transfer circuit breaker (for description see DBT below).

The following H-configurations (H3, H4, H5) are single busbar arrangements with specific arrangements (H-shape) which are normally used to connect a user to an existing transmission line where the line will be looped through via the busbar and the transformers step-down, e.g., a connection to a new factory or alternatively to provide a method to connect generation, e.g., a windfarm into a transmission line (Figs. 4.3, 4.4, and 4.5).

Depending on the planning requirements, the designer has to select the right configuration for their purpose. H4, for instance, is a small SSB arrangement and the substation can be operated in one or in two sections. One section can be under maintenance. H3 and H5 configurations have the advantage of having a sectionalizable circuit breaker that means that the busbar can be split during operation or a failure can be separated selectively.

**Fig. 4.3** H3-configurations

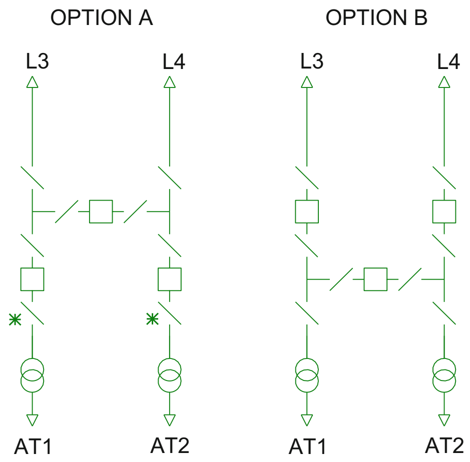



**Fig. 4.4** H4-configuration

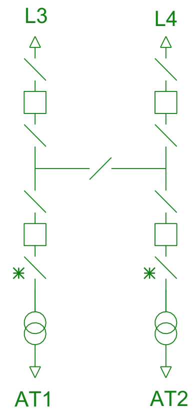
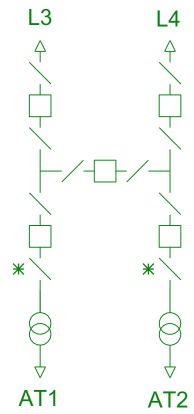



**Fig. 4.5** H5-configuration



### 4.7.2 Multiple Busbar Arrangements

Busbar systems with more than one busbar as described before are called multiple busbar arrangements: Double busbar (Fig. 4.6) and triple busbar arrangements (Fig. 4.8), with or without transfer busbar. The lines and transformers are connected via two or three busbar disconnectors and one circuit breaker to two or three busbars.

**Double Busbar**
*A substation in which the lines and transformers are connected via two busbars by means of selectors [IEV 605-01-17]*

The double busbar arrangement is recommended for large substations where security of supply is important. These are particularly suitable for highly interconnected power networks in which switching flexibility is important and multiple supply routes are available. They are also used for splitting networks, which are only connected in emergency cases (one network on one busbar).

The coupler circuit breaker allows the possibility of keeping half of the station in service following a fault on a busbar, a busbar disconnector, or any feeder circuit breaker.

The configuration provides flexibility by allowing each circuit to be connected to either of the two busbars. The bus-coupler bay makes it also possible to move circuits from one busbar to the other, while they are energized. In this case commutating voltages at busbar disconnectors during the switch over process have to be considered (IEC 62271-102).

Additional flexibility can be provided by adding sectionalizer disconnectors or circuit breakers into each busbar.

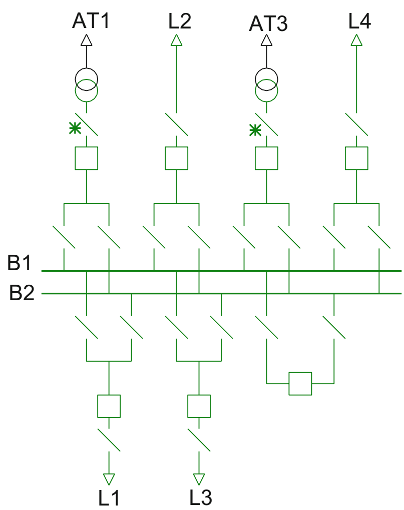



**Fig. 4.6** Double busbar (DB)

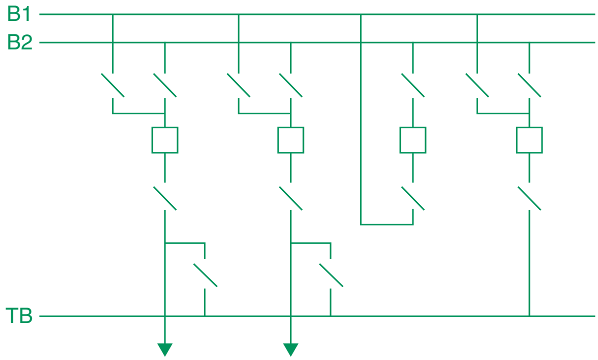



**Fig. 4.7** Double busbar and transfer busbar (DBT)

The main difference between single busbar and double busbar is that if there is a fault on the single busbar, the whole substation is lost, and in the double busbar only, the circuits connected to the busbar with the fault are lost.

To improve the reliability of a double busbar (DB, Fig. 4.6) arrangements, a transfer busbar (DBT, Fig. 4.7) can be added.

**Transfer Bus**

*A back-up busbar to which any circuit can be connected independently of its bay equipment (circuit-breaker, instrument transformer), the control of this circuit being ensured by another specific bay, available for any circuit.*

*Note – This transfer busbar is generally not counted as one of the busbars within a "double" or "triple" busbar substation configuration. [IEV 605-02-05)*

This transfer busbar is a backup busbar, to which any circuit can be connected independently of its bay equipment (circuit breaker, instrument transformer), the control of this circuit being ensured by a specific bay available for any circuit. This arrangement has the same characteristics and functionality as the double busbar configuration, but it is recommended for use when there is a requirement to keep circuits in service during maintenance or repair of the circuit breaker or the busbar disconnectors. A circuit outage is however still required for maintenance of the line and transfer (bypass) disconnectors.

Another option to improve the double busbar arrangements is to add a third main busbar that leads to the triple busbar arrangement (TB, Fig. 4.8). The lines and transformers are connected via three busbar disconnectors and one circuit breaker to the three busbars. This configuration has the same general characteristics and functionality as the double busbar configuration but provides additional sectionalizing possibilities.

One or more coupler bays make it possible to group different busbars and allow a very flexible operation. An additional transfer busbar is also possible.

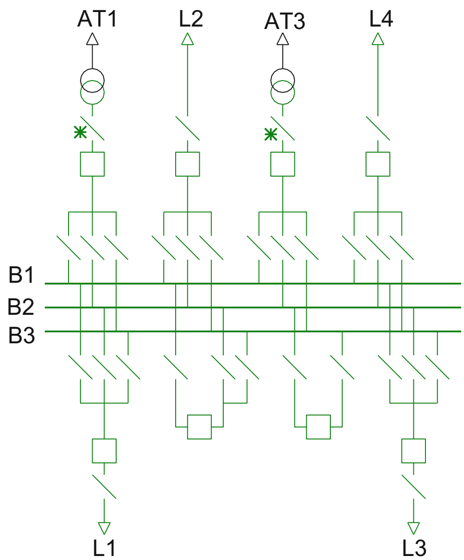
**Triple Busbar**
*A substation in which the lines and transformers are connected via three busbars by means of selectors [IEV 605-01-18]*

Beside the reliable and secure triple busbar arrangement, there are two more circuit arrangements which give the most reliable and secure power supply opportunities based on a double busbar arrangement. The one-and-half circuit breaker (OHCB, Fig. 4.9) and the two circuit breaker (TCB, Fig. 4.10) arrangement.

**One and a Half Circuit Breaker**
*A double busbar substation where, for two circuits, three circuit-breakers are connected in series between the two busbars, the circuits being connected on each side of the central circuit-breaker [IEV 605-01-25].*

*Note: each connection between the two busbars is called a diameter.*

**Fig. 4.8** Triple busbar (TB)



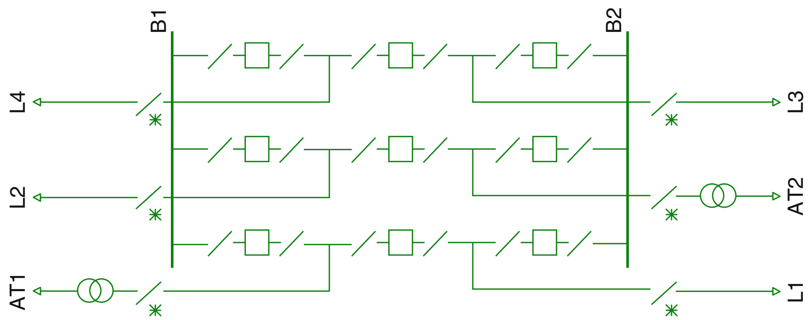




**Fig. 4.9** One-and-half circuit breaker (OHCB)

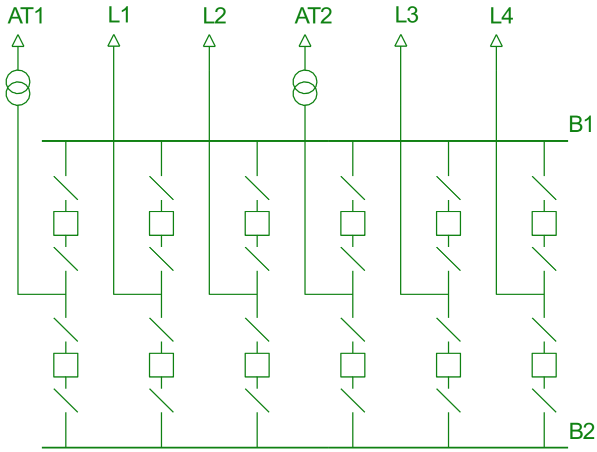



**Fig. 4.10** Two circuit breaker (TCB)

The one-and-half circuit breaker arrangements are particularly suitable for substations handling a large amount of power, such as in generation stations, and for networks, which comprise mainly radial circuits with mesh connections.

It should be noted that in order to cover all switching contingencies, the circuit breakers and associated equipment should be capable of handling the combined load current of two circuits and an allowance for current transfer between the busbar.

Normally it operates with both busbars energized and all the disconnectors and circuit breakers closed.

A primary fault will not cause the loss of the whole substation but only the loss of the faulted feeder or the loss of one busbar without loss of any feeders. A fault on one of the central circuit breakers will result in the loss of two feeders (Ref 585). In this last situation, it is possible to reconnect both feeders, each one to the closest busbar, and the central circuit breaker will stay open until repaired.

Because there are two circuit breakers per feeder, it is possible to maintain any circuit breaker without any feeder outage. Maintenance of a busbar disconnector requires a busbar outage but does not require an outage of any feeder (Ref 585).

It is possible to split the substation in any number of parts with the substation fully energised.

Normally this configuration is a natural evolution of a ring busbar, when the system needs to expand the ring configuration for more than four circuits.

The one-and-half circuit breaker allows some modification, like to reduce the quantity of equipment, connecting two transformers directly to the busbar by only using disconnectors. This configuration is called one-and-half circuit breaker modified, and the other is to use three circuits for each four circuit breakers (circuit breaker and a third). In both cases the availability is reduced, the construction is more difficult (mainly in circuit breaker and ⅓), and for these reasons they are used less.

**Two-breaker Arrangement**
*A double busbar substation in which the selectors are circuit-breakers. [IEV 605-01-24].*

The two circuit breaker arrangement is recommended for substations where the security of supply is particularly important. The configuration is also more flexible than the one-and-half circuit breaker configuration. It can also be used for splitting networks, which are only connected in emergency cases.

The configuration provides flexibility by allowing each circuit to be connected to either of the two busbars. It is also possible to move circuits from one busbar to the other, while they are energized.

It should be noted that to cover all contingencies of switching, the circuit breakers and associated equipment should be capable of handling the combined load current of its own circuit and an allowance for current transfer between the busbars. This is because the double breaker circuit configuration does not have any separate bus-coupler circuits, since each bay is acting as a bus-coupler.

Additional flexibility can be provided by adding sectionalizer circuit breakers into each busbar.

### 4.7.3 Ring Bus and Mesh Substation

*Ring Bus (In practice not used as the definition, see "Mesh" below)*

*Ring substation is a single busbar substation in which the busbar is formed as a closed loop with (only) disconnectors in series within the loop [IEV 605-01-19]*

*Mesh Substation (in practice often referred to as Ring Bus)*

*A single busbar substation in which the busbar is formed as a closed loop with circuit breakers in series within the loop [IEV 605-01-20]*

Though the IEV definitions are different, i.e., ring bus employs disconnectors, while mesh employs both disconnectors and circuit breakers in the busbar closed loop, by custom and practice, the diagram below is referred to by either name thus not recognizing the true definition of IEV 605-01-19. This ring or mesh substation arrangement (Fig. 4.11) requires, besides the disconnectors, the same number of circuit breakers as feeders but allows all circuits to remain in service, while a circuit breaker is maintained. All the circuit breakers and their associated equipment should be capable of handling the combined load current of the different circuits depending on the connections and an allowance for current flow along the busbar. In the design of the control and protection system, each circuit protection must operate on two

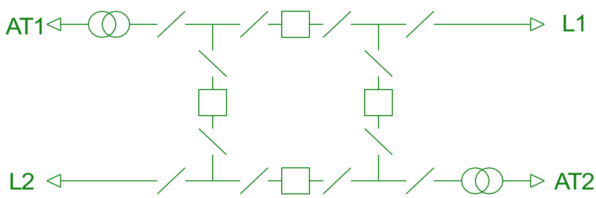



**Fig. 4.11** Ring (or mesh) configuration (R)

circuit breakers, and each circuit breaker is controlled by two circuit protection systems.

A ring busbar is often used as the first development of an intended ultimate development as a one-and-half breaker configuration. However, more than six circuit breakers in a ring are not recommended due to operational difficulty. Therefore, conversion of the ring configuration to a one-and-half breaker configuration should be considered when the extension is required.

A primary fault will not cause the loss of the whole substation but only the loss of the faulty feeder. If a circuit breaker fails to open, it will cause the loss of an unfaulted feeder. The maintenance of any element in the substation will require the opening of the ring, with a consequent reduction of security.

## 4.8 Selection Process

Selecting a specific substation configuration is not an absolute science; however, this section will attempt to provide some guidelines to assist in the configuration selection process.

The typical steps to be followed are listed below.

- **Step 1** – Identify the compliant substation configuration based on type and location (e.g., is this a power station substation, main transmission substation, or distribution substation) and the user preference/standard (e.g., power station substations are double busbar, main transmission stations are ring type, etc.). If this is predetermined by utility policy or customer choice, then the configuration decision is set and no more design optimization is possible. The designer is limited to the choice of technology and layout designs within the prespecified configuration. If the configuration is not predetermined, the next steps are to be followed.
- **Step 2** – Using the theory described in Sect. 4.4; determine the relevant weighting factor for each of the assessment criteria; service security, availability during maintenance, and operational flexibility for the substation type.
- **Step 3** – Establish the substation configuration effectiveness. The weighting factors selected in step 2 are multiplied with the substation configuration index described in Sect. 4.3 of this Chapter.
- **Step 4** – Once the calculations are complete, establish whether more than one configuration meets the criteria. If only one remains, establish the costs.
- **Step 5** – If more than one configuration remains compliant, then the designer should establish the impact of other technical influences such as existing technology population, extension to substations, etc. to further refine the choice of configuration.
- **Step 6** – Finally, once the technical configuration(s) have been established, these need to be reviewed with the system planning and system operation engineers to verify if there are any additional inputs or requirements relating to the specific location of the substation in the power network. At this stage it will be necessary to consider cost benefit of the design by considering other life cycle and asset

management criteria such as costs, strategic spares holding, etc. Should the chosen configuration result in a solution that is too costly, it is suggested the process be reviewed objectively to determine if any of the factors were perhaps rated too high or if the type of application was perhaps not appropriately chosen.

These steps are illustrated in the diagram, Fig. 4.12.

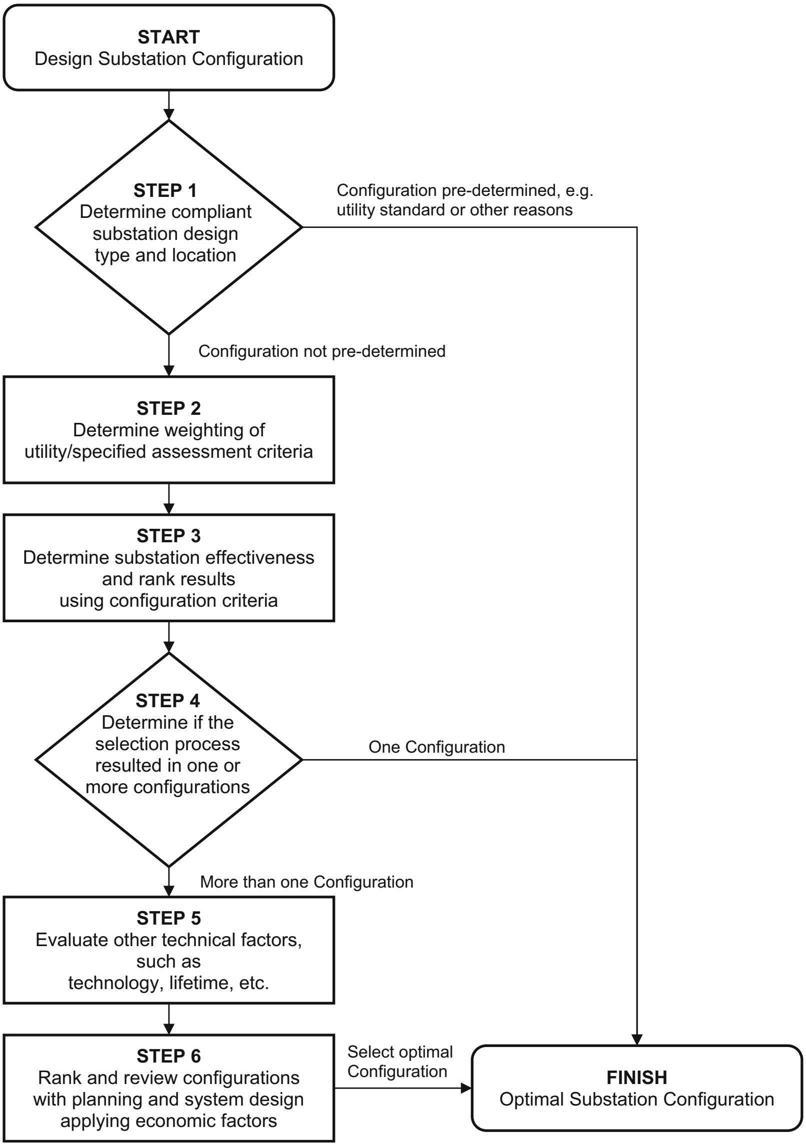



**Fig. 4.12** Decision-making process for selection of circuit arrangement

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# Effect of Safety Regulations and Safe Working Practices on Substation Design

# 5

John Finn

## Contents

5.1 Introduction ........ 42
5.2 Segregation of Live Conductors and Bare Live Equipment ........ 42
5.2.1 Techniques for Segregation ........ 43
5.2.2 Choice of Technique as a Function of the Voltage Level ........ 45
5.3 Clearances ........ 45
5.3.1 Definition ........ 47
5.3.2 Calculation of the Basic Value ........ 47
5.3.3 Determination of the Safety Zone ........ 47
5.3.4 Variations ........ 53
5.4 Earthing ........ 54
5.4.1 General Earth Mat or Grid ........ 55
5.4.2 Safety Earths ........ 56
5.5 Operation of High-Voltage Switchgear ........ 58
5.5.1 Types of Control ........ 58
5.5.2 Locking Off Switches ........ 60
5.5.3 Auxiliary Operating Supplies ........ 60
5.5.4 Current and Voltage Instrument Circuits ........ 61
5.6 Protection Against Fire ........ 61
5.6.1 Limitation of the Damage Zone ........ 61
5.6.2 Extinguishing of the Fire ........ 63
5.7 Fences ........ 64
5.7.1 External Fences ........ 64
5.7.2 Internal Fences ........ 65
References ........ 65

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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## 5.1 Introduction

From the very beginning of the use of electrical power, it has been known that substations present a significant risk to personnel particularly from electric shock. Consequently, the design of electrical substations has always had to take into account the relevant measures to protect people who may be building, commissioning, operating, maintaining, or decommissioning the substation from these and other risks. In this section the basic logic behind the measures to be adopted is presented, and these will be illustrated in many cases by dimensions. Any dimensions presented in this chapter should be considered as minima, and any designer should be aware that utilities throughout the world have usually developed specific requirements for their own substations. These specific requirements that may be incorporated into safety rules or in some cases legal requirements must be complied with when designing substations for a particular utility.

This chapter considers the safety measures that should be taken into account in the design of high-voltage substations while maintaining quality of service.

The following aspects are expanded on within this chapter:

- Segregation of live conductors and bare live equipment
- Clearances
- Earthing (grounding)
- Operation of high-voltage switchgear
- Protection against fire
- Fences

The supervision and control of a high-voltage substation installation requires auxiliary circuits and low-voltage measuring circuits, and the safety implications of these must also be taken into account. It should also be noted that the requirements discussed in this chapter will generally be applicable to substations at all voltage levels from distribution to transmission.

## 5.2 Segregation of Live Conductors and Bare Live Equipment

The techniques used for segregating live conductors and bare live equipment can basically be divided into three main categories:

- Self-protected equipment
- Open equipment rendered inaccessible by screens
- Open equipment rendered inaccessible by distance

### 5.2.1 Techniques for Segregation

a) **Self-Protected Equipment**

This category or equipment, known as “self protected,” is equipment having an insulated or metal casing of any kind. It is constructed in such a manner as to make any contact, even accidental, with live equipment impossible during normal operation.

Such equipment is normally at lower voltages, such as is used in distribution substations; however, with the increasing use of gas-insulated switchgear, it now extends to the highest transmission voltages.

Self-protected equipment can be divided into two main types based on the technology used, and these types are usually also dependent upon the voltage level.

- **Category A**
  For voltages up to about 36 kV, the circuit breaker may be of a drawout type that means that if it is drawn out from the bus bar and feeder (or circuit) connections, then bus bar and feeder disconnectors are not necessary. The disconnection of the circuit breaker is evident from its position in the cubicle.
- **Category B**
  At higher voltages, except for special cases, the circuit breaker is fixed, and the substation is fitted with bus bar and circuit selectors enclosed in metal casings that constitute the protection for the equipment and the conductors. It should be possible to verify the position of these disconnectors at any time. This kind of arrangement is that usually used in gas-insulated switchgear.

Under normal operating conditions, there is no problem in operating these circuit breakers safely. However, maintenance work, which requires the dismantling of the protective casings, may necessitate taking additional safety measures such as checking that the equipment is dead and disconnected and the conductors involved in the work are earthed and may need the erection of screens. The specific measures will differ for each type of equipment and, so it is not possible to give general rules.

Consequently self-protected equipment should be designed in such a way that any contact, even accidental, with conductors and equipment that may be live is impossible. Furthermore, the equipment should include any sequence controls and interlocks necessary for the prevention of dangerous maloperation of any kind.

Where bus selectors and circuit disconnectors are used, it should be possible to verify the disconnection achieved by these:

- Either directly by visual inspection of the position of the blades or of the circuit breaker if it is of a withdrawable type and performs the function of the disconnectors in the withdrawn position
- Or by the use of discrepancy or position indicator lamps which are designed to have impossibility of error in the indication of the position

For such indications to be effective, they must be “active”; this means that the “open” and “closed” positions must both be obtained by the transmission of a signal initiated by the effective position of the disconnector. In the case of luminous indication, two lamps should be used, one corresponding with the open position and one with the closed.

The switchgear must be designed to enable the fitting of mobile earthing connections to the conductors and equipment, if necessary using suitably placed fixed takeoff points. The casings should be designed with any devices to enable the fixing of any mobile protective screens that may be necessary for the carrying out of certain work.

Finally, it is strongly recommended that the users of such equipment should prepare, in conjunction with the manufacturers, a detailed operating procedure for each case concerned and a summary provided to all supervisory staff. It is particularly important for any work that necessitates dismantling of any component of the casing even if only partial.

With gas-insulated switchgear, there are other considerations that often occur when it is necessary to carry out work within a gas chamber. Many utilities will not allow work to be carried out adjacent to a gas barrier if the chamber on the other side of the barrier is under normal working pressure. The designer of the GIS must therefore explain how all work can be carried out within a chamber without the abovementioned condition arising. Furthermore, as gas-insulated switchgear has become so compact, particularly at voltages of 145 kV and below, some utilities insist upon having a buffer chamber between bays to enable safe access to all the parts of the equipment and to ease disassembly when required. This buffer chamber will assist in avoiding working adjacent to a barrier with pressure on the other side.

b) **Open Equipment Rendered Inaccessible by Screens**

When screens are provided, whatever their construction solid or grill, insulating or conducting, brick or prefabricated, or fixed or movable, they must constitute an effective protection for staff against approaching dangerously close to live equipment and conductors during simple inspection and operation and when carrying out work.

Protection walls and screens must be designed and arranged such that:

- They delimit the functional volumes intended to receive equipment related to a given operating component.
- Any normal switching operation may be carried out without opening or dismantling any of their elements, and that it is not necessary to enter into any completely closed cubicle.
- The safety measures, which have to be taken to enable the work to be carried out such as checking that the equipment is not live, fitting short circuiting, and earthing devices and screens where necessary, can be taken without danger to staff or equipment.

c) **Open Equipment Made Inaccessible by Distance**

This technique is based solely upon maintaining suitable distances between the live equipment and conductors, on the one hand, and the operational staff movement areas required for enabling switching operations and carrying out work, on the other.

Determining the required distances depends upon a number of criteria that are explained in Sect. 5.3.

### 5.2.2 Choice of Technique as a Function of the Voltage Level

The choice of technique is usually based on the voltage level of the substation. The following solutions that are not listed in any preferential order may be considered. These solutions follow the normal custom and practice and the technology of equipment offered by the manufacturers:

a) **Up to 1,000 V (rms voltage value in the case of AC)**
   - Maximum use of self-protected equipment and of insulated connections. Failing this, rendering inaccessible by means of screens or by distance

b) **From 1,000 to 25,000 V**
   - Use of open equipment made inaccessible by means of the use of solid screens or grills normally forming functional cubicles.
   - Use of open equipment rendered inaccessible by distance.
   - Use of self-protected material and equipment. This technique is now used extensively with metal-enclosed and metal-clad switchgear.

c) **Above 25,000 V**
   - In the majority of cases, this is achieved by rendering inaccessible by distance.
   - Use of self-protected equipment, particularly when space is limited. This is, of course, the technique used when gas-insulated switchgear is employed.
   - Rendering inaccessible by the use of solid screens or grills is usually reserved for indoor substations using open equipment.

## 5.3 Clearances

There are many different values used for the insulation and safety clearances used by different utilities throughout the world. These clearances have been derived in many different ways, sometimes not following any particular logic related to the operational voltages. In this section the work published by CIGRE in Electra No19 dated November 1971 is used as the basis to explain the logic of how safety clearances may be derived. Many utilities have a similar approach, but the actual figures used may vary, and in some cases, the same name is used but for a different parameter. See Table 5.1 below for a typical example of safety clearances. Furthermore, the techniques and tools used for maintenance have changed over the years, and this is reflected in example, Table 5.1, which shows how this may affect the safety clearances.

The method adopted uses a common rule based on the voltage level of the substation, but the method of application takes into account, in each case, the operating conditions of the equipment. For the purpose of this description, the

**Table 5.1** Determination of safety distances in air

| Niveau de tenue au choc 1 kv / Impulse voltage with stand 1 kv | Distance de non – cmorcege 2 cm / Non-flashover distance CEI values 2 cm | Distances d' éloignement (safety distances): Valeur de bose / Basic value: Valeur de la majoration [b] / Amount of addition [d]: On % 3 / In % 3 | orrondie en cm 4 / Rounded in cm 4 | Valeur de base cm 5 = 2 + 4 / Basic value cm 5 = 2 + 4 | Circulation du personnel (Figs. 3 et 4) / Staff circulation (Figs. 3 and 4): Sou» connexions / Below connections: Zone de sécurité sortie (Portie fie) 6 m / Safety zone (fixed part) 6 m | Valeur totale m 7=5+6 / Total value m 7 = 5 + 6 | A la bosse des isolateurs 8 m / 8 m | Zone de travail en 1' absence d'engins lourde (Fig. 6 [a]) / Work zone in the absence of heavy machines (Fig. 6 [c]): Horizontale / Horizontal: Zsee de secuies (Pertis lias) 9 m / Safety zone (fixed part) 9 m | Valeur totale m 10 = 5 + 9 / Total value m 10 = 5 + 9 | Vinicole / Vertical: Zsee de secuies (Pertis lias) 11 m / Safety zone (fixed party) 11 m | Valeur totale m 12 = 5 + 11 / Total value m 12 = 5 + 11 | Circulation d' engins Fig. V / Vehicle circulation Fig. V: Zòne du sécurité / Safety zone: Gobarit 13 m / Gauge 13 m | Debarement 14 m / Tolerance 14 m | Valeur totole m 15 = 5 + 13 + 14 / Total value m 15 = 5 + 13 + 14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 60 | 9 | 10 | 1 | 10 | 2.25 | – Minimun de 3,00 – | 2.25 | 1.75 | – Minimun de 3,00 – | 1.25 | – Minimun de 3,00 – | A determiner dans chaque cas / To be determined in each case | 0.70 | A determiner dans chaque cas / To be determined in each case |
| 75 | 12 | | 1 | 13 | | | | | | | | | | |
| 95 | 16 | | 2 | 18 | | | | | | | | | | |
| 125 | 22 | | 2 | 24 | | | | | | | | | | |
| 170 | 32 | | 3 | 35 | | | | | | | | | | |
| 250 | 48 | | 5 | 53 | | | | | | | | | | |
| 325 | 63 | | 7 | 70 | | | | | | | | | | |
| 380 | 75 | | 8 | 83 | | 3.08 | | | | | | | | |
| 450 | 92 | | 10 | 102 | | 3.27 | | | | | | | | |
| 550 | 115 | | 12 | 127 | | 3.52 | | | 3.02 | | | | | |
| 650 | 138 | | 14 | 152 | | 3.77 | | | 3.27 | | | | | |
| 750 | 162 | | 17 | 179 | | 4.04 | | | 3.54 | | 3.04 | | | |
| 825 | 180 | | 18 | 198 | | 4.23 | | | 3.73 | | 3.23 | | | |
| 900 | 196 | | 20 | 216 | | 4.41 | | | 3.91 | | 3.41 | | | |
| 1050 | 230 | | 23 | 253 | | 4.78 | | | 4.23 | | 3.78 | | | |
| 1425 | 305 | 6 | 18 | 353 | | 5.48 | | | 4.98 | | 4.48 | | | |
| 1550 | 330 | | 20 | 350 | | 5.73 | | | 5.26 | | 4.75 | | | |

a-Dans le cas d'utilisation d'utilisation d'engins lourds, la zone de securité (Partie variable) est à augmenter de l' encombrement maximal des engins utilisés compte tenu de leurs déploiements et dos haubons éventuels.
b-Cette majoration pout no pas être appliquée lorsque les condition de réalisation des frevoux assurent par allés – mémo le respect dons fous les cas d'une valour do base au moins dgalo â la distance de non amorçage.
c-When heavy machines are used, the safety zone (variable part) should be increased by the maximum dimensions of the machines used taking into account their radius of manceuvre and any guys.
d-This addition may be ignored when the conditions under which the work is carried out are adequate in themselves to ensure maintenance of a basicvalue at least equal to the non-flashover voltage under all conditions.

distances so obtained were defined as "safety distances." These distances should be applied as minima where they exceed any other distances specified for a country or utility, but only in agreement with the utility concerned.

### 5.3.1 Definition

The "safety distance" means the minimum distance to be maintained in air between the live piece of equipment or conductor, on the one hand, and the earth or another piece of equipment or conductor on which it is necessary to carry out work, on the other.

(It should be noted that these distances are in air and do not relate to insulator lengths or creepage distances.)

This "safety distance" is made up of two values as follows:

- A basic value, related to the impulse withstand voltage for the substation, which determines a "guard" zone around the conducting parts.
  (It should be noted that the impulse voltage withstand level is chosen rather than the highest voltage on the system, because for each standard withstand level, there is a precise corresponding non-flashover distance. However, the highest voltage on the system has a number of different impulse withstand levels and hence a number of different distances for non-flashover.)
- A value which is a function of movements to be made by staff or the nature of jobs to be carried out taking into account the devices which will be used. This determines a zone called the "safety zone" within which any danger inherent in the electrical risk has been removed.

### 5.3.2 Calculation of the Basic Value

The basic value must guarantee no risk of flashover under the least favorable conditions. In order to achieve this, it is selected by taking the impulse withstand level for the substation and then looking up the corresponding non-flashover distance in air. This distance is then increased by a safety factor of 5–10% to allow for a slight scatter in the positioning of equipment due to manufacturing tolerances and for slight geometrical differences in the equipment made by different manufacturers. The safety factor can only be guaranteed if the impulse voltage taken as the basis for the calculation of the basic value is never exceeded. This requires that the substation has equipment capable of limiting the incoming surges, for example, surge arresters, spark gaps, or similar devices to provide the required degree of protection. Usually the basic value is the design clearance chosen for phase to earth.

### 5.3.3 Determination of the Safety Zone

In order to derive the safety zone, it is necessary to add to the basic value, determined as described in Sect. 5.3.2, a variable factor based upon:

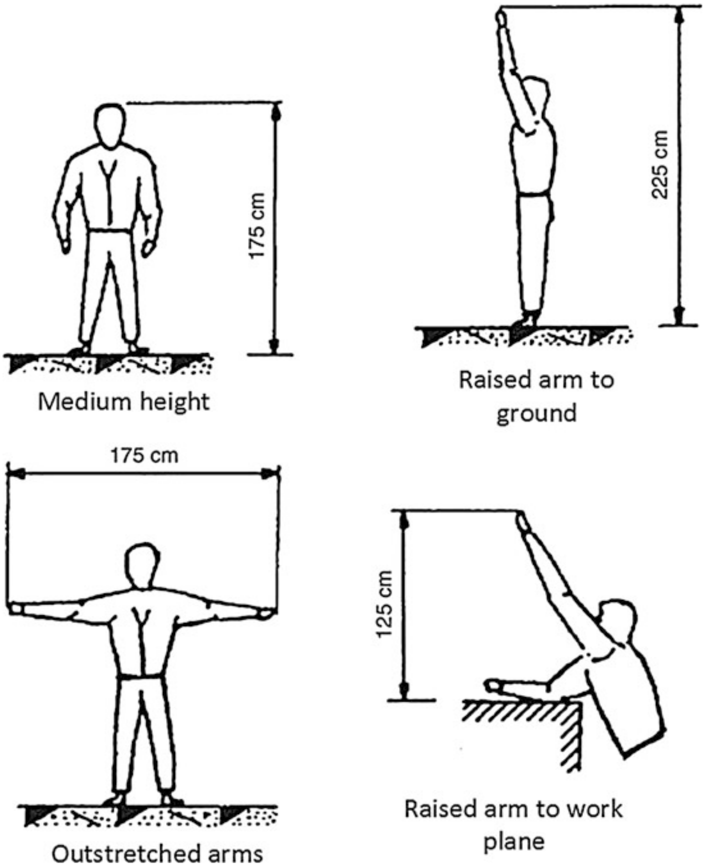


**Fig. 5.1** Average dimensions of plant operators

- The height of the operators
- The nature of the work to be carried out on the equipment
- The operating procedure and taking into account the requirement for movement and access

A method of determining the mean dimensions to be used taking into account the above is given in Fig. 5.1.

These dimensions are basically guidelines and can be increased if considered prudent. Further clearances also need to be taken into consideration.

Table 5.1 summarizes the process of deriving the safety distance.

a) **Movement of Staff**

If there are no grills or screens fitted, then the safety distance between the ground and the lowest live parts must take into account the free movement for the operating staff.

From consideration of the dimensions in Fig. 5.1 above, this height should be equal to the basic value plus 2.25 m (this dimension corresponds to the average height of a worker with his arms outstretched). However, as the basic value for impulse withstand voltages less than 380 kV is very small, a minimum value for the safety distance for staff circulation of 3.0 m is adopted. Also the distance between the base of any post insulator and the ground should not be less than 2.25 m. The insulator is considered as a live component of steadily reducing voltage, and only the lowest metal parts are at earth potential. This is summarized in Fig. 5.2 below.

The distances defined are to be considered as taken from the highest point accessible without climbing in the normal course of movement (such as raised cable ducts, steps, or gratings from which switching operations are performed if these are provided).

When the dimensions mentioned above cannot be achieved, then access to the live equipment and conductors should be prevented by the provision of screens, grills, or enclosures. Examples of such screens or enclosures being:

- A guard rail or safety rail 1.2 m in height separated from the equipment or conductors by a distance equal to the basic value plus at least 0.6 m
- An enclosure or grill of height 2.25 m spaced from the equipment or conductors by a distance equal to the basic value

Examples are shown in Fig. 5.3 below.

b) **Movement of Vehicles**

The variable part of the horizontal safety distance comprises the profile of the vehicle or machine that needs to move plus an amount of 0.7 m to allow for unavoidable inaccuracies in driving (see examples in Fig. 5.4).

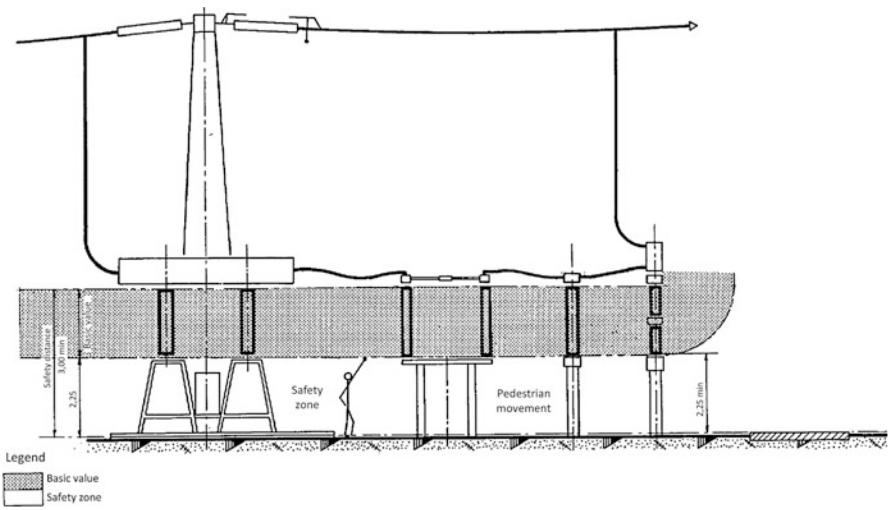


**Fig. 5.2** Staff movement in substations – example of making inaccessible by distance

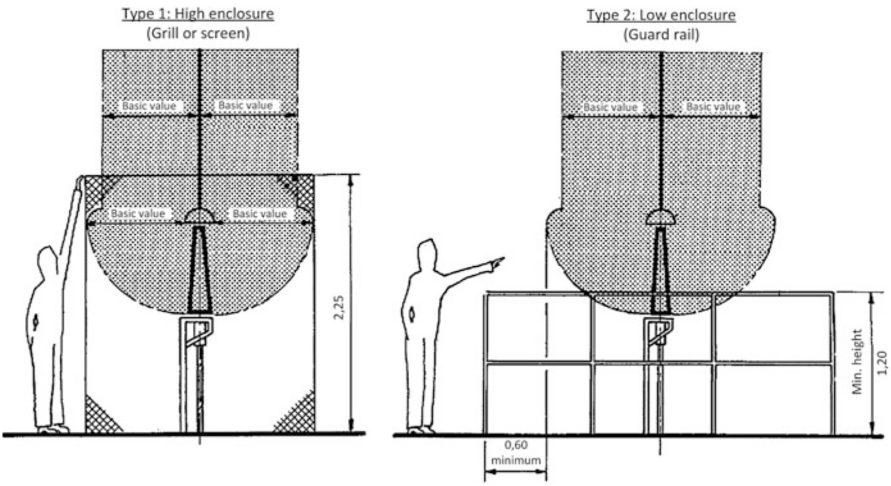


**Fig. 5.3** Staff movements in substations – example of making inaccessible by grills, screens, or enclosures

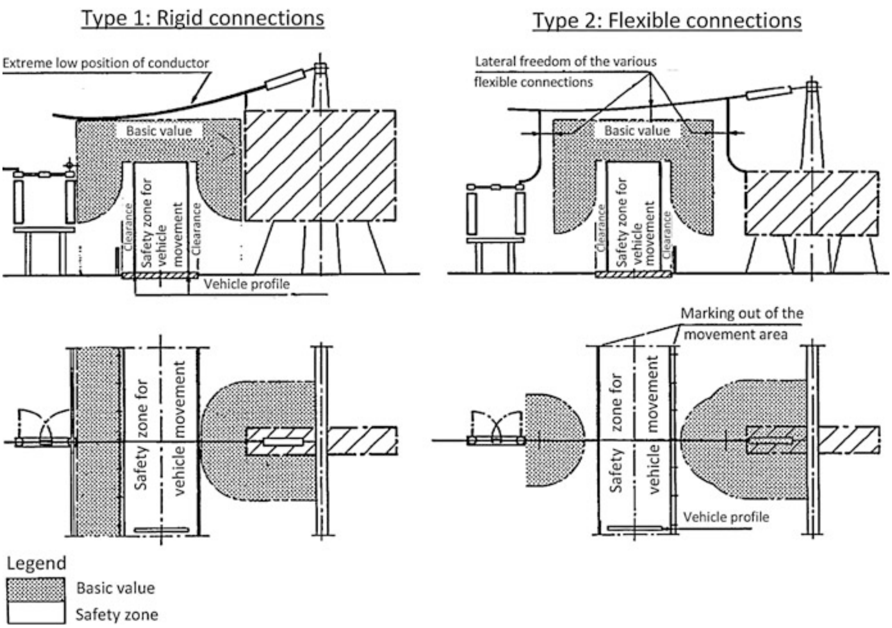


**Fig. 5.4** Examples of vehicle movement within substation – rendering inaccessible by distance

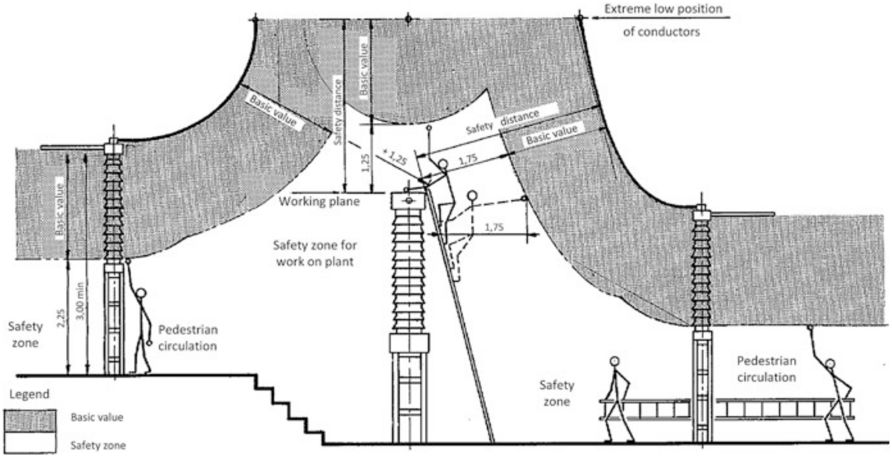


**Fig. 5.5** Example of maintenance work using light tools – rendered inaccessible by distance

c) **Work on Equipment or on a Conductor**

When it is necessary to carry out work in a substation while leaving the adjacent circuits live, then the safety distance from the live equipment is derived using the same principles. It comprises a basic value plus a variable amount determined for each piece of equipment as a function of the mode of operation of the maintenance work intended and of the dimensions of the tools used. However, this safety zone value should never be less than 3.0 m. The safety distance is measured from the extreme position that the live equipment or conductor may occupy to the edge of the equipment that is to be worked on. Under no circumstances should the work involve any penetration into the basic value. In the case of routine maintenance work that does not require equipment other than light portable tools, the variable part may be determined as follows:

- 1.75 m horizontally corresponding to a man with his arms outstretched
- 1.25 m vertically above the working plane corresponding to that part of the worker passing above the plane when his arms are outstretched

An example of this is shown in Fig. 5.5. This is typical of routine maintenance of substation switchgear. Figure 5.6 shows work when a heavy machine is used.

d) **Marking Out the Safety Zones**

It is prudent that the safety zones for circulation are permanently marked out and those for carrying out work are marked out during the period of the work. For circulation zones the following are recommended:

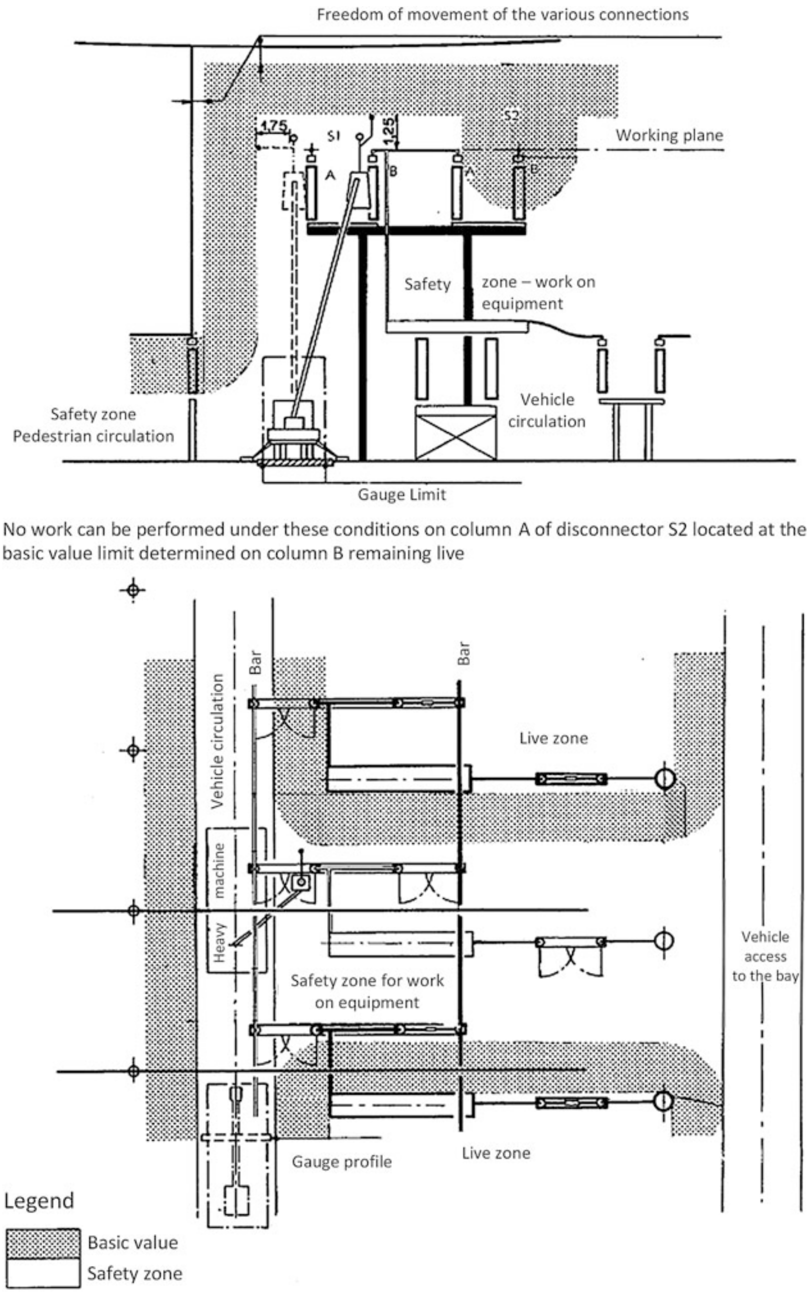


**Fig. 5.6** Examples of work carried out using heavy equipment in plant rendered inaccessible by distance

- Laterally a permanent means of indication remaining visible under all circumstances. Simply painting marks on the road surface would not be sufficient in countries that may have lying snow for considerable periods of time.
- Vertically the placement of a safety gauge at the entry to each road leading into the high-voltage installation. This is to ensure that no load projects beyond the limits of the plant safety distance and that the forks of lifting devices or crane booms are fully lowered.

When work is being carried out in the substation, the safe working area will be clearly marked out using screens, chains, or flags in accordance with the safety requirements of the particular utility concerned.

### 5.3.4 Variations

As explained at the beginning of this section, there are variations between different countries that affect not only the dimensions but also the nomenclature. However, the basic principles are the same that a safety zone is created by taking a basic value based on the impulse withstand voltage and adding to it a distance to allow for the height and movement of personnel. As an example of the changes, in the UK, the basic value is actually called the “safety distance,” and the dimension which is the “safety distance” in CIGRE terms is called the “design clearance for safety,” and values are given for vertical and horizontal. The other differences are that the basic value which is normally the phase-to-earth design clearance, in the UK, is increased by 300 mm and the height which is 2.25 m in CIGRE is 2.4 m. The horizontal reach distance however is reduced from 1.75 to 1.5 m, although it is recommended that the vertical design clearance for safety should be used in all directions where practicable.

All of these clearances were originally derived when work was carried out from ladders or from fixed scaffold platforms. However, in more recent times, the use of mobile elevated working platform (MEWP for short, also commonly known as cherry pickers, see Fig. 5.7) has become commonplace. This has given rise to a new source of danger. When scaffolded platforms were used, the platform height could be controlled such that it did not infringe the safety zone. However, with a MEWP, the height of the platform is infinitely variable within the total reach of the device unless it is restrained by chains. This was first seen as a problem when a fatality occurred because an operative in a MEWP raised the platform higher than would normally be required, infringed the basic value, and was electrocuted. The problem was something which was defined as an “over-sailing conductor.” This is defined as follows:

- Exposed HV conductors above or in proximity to any reasonably foreseeable work area, which would normally remain energized during such work activities

If a conductor over a work area would normally be de-energized when work is carried out below it, then this is not a problem, but where the conductor overhead

**Fig. 5.7** Example of a MEWP being used to carry out maintenance work

belongs to a different circuit to the one being worked on, and so would normally remain live, then this is where problems occur.

In order to avoid these problems, the design of substations should try to avoid the use of over-sailing conductors whenever practicable, and also to make allowance for the possible overshoots when operating a MEWP, both the vertical and horizontal design clearances for safety have been increased by 2 m. This has a significant effect upon the dimensions of the switchgear bays particularly at the lower voltages such as 145 kV. This means that while at one time in the 1990s the whole emphasis on substation design was to make them as compact as possible, this is in direct conflict with the utility operational staff who want safe easy access for maintenance which naturally drives up the bay dimensions. It is therefore important to fully understand the user's requirements before designing a substation for safe working.

## 5.4 Earthing

This section is dealing with the safety aspects of earthing and not with the earthing of main, auxiliary, or instrument transformer neutrals. It is concerned particularly with the substation earth mat or grid and its importance to the safety of personnel. More details of substation earthing systems are given in ▶ Sect. 11.7.

Firstly, consider the different types of hazardous potentials that may arise when an earth fault occurs. These are:

- Rise of Earth Potential or Grid Potential Rise (GPR)
  This is the rise in voltage of the earth system at the substation site above true earth when a fault occurs at the site. In some countries, sites are designated as "hot" or

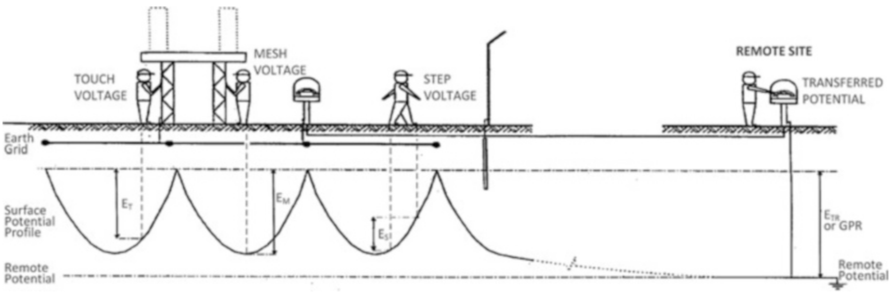


**Fig. 5.8** Hazardous potentials during an earth fault

"cold" depending upon the magnitude of the rise of earth potential. Typically a site with a grid potential rise in excess of 650 V is considered to be a "hot" site.

- Step Voltage
  This is the voltage that can occur between the feet of a person (usually assumed to be 1 m apart) who is walking across the site at a time when a fault occurs.
- Touch Voltage
  This is the voltage between the hand and foot of a person who touches a metal frame or panel in the site at the time a fault occurs. This tends to be more serious than step voltage as the resulting current path is through the heart.
- Mesh Voltage
  This is the voltage that occurs in the center of the meshes within the earth grid when a fault occurs.
- Transferred Voltage
  This is the voltage that can be transferred from a site that has a fault to a remote location where there is no fault present. In theory this transferred voltage can be equal to the full rise of earth potential at the faulted site.

These hazardous potentials are illustrated in Fig. 5.8.

The purpose of the earth mat or grid is to limit these hazardous potentials to values that are not dangerous. The following items are connected to the earth grid:

- Permanently, the various frames and fittings of the plant
- Occasionally, high-voltage conductors or equipment on which it is necessary to carry out work

### 5.4.1 General Earth Mat or Grid

The earth mat must be designed to be totally free from corrosion resulting from the action of the surrounding soil. It has to be designed such that any contact with a metal likely to cause corrosion by electrolytic action cannot occur even accidentally.

The design of the earth mat is a grid of conductors laid approximately 500 mm below the surface of the ground and covering the whole extent of the site. The actual extent will depend upon whether the fence is connected to the substation earth mat or is earthed separately. The pitch of this grid, which is usually relatively small, will be dictated by the calculation of the hazardous voltages.

These calculations take into account:

- The layout of the substation
- The soil resistivity
- The number of earth return paths via overhead line earth wires or cable sheaths
- The earth fault level and its duration

These calculations are a specialized activity, and it may be prudent to place these with a specialized organization equipped with suitable software.

Connection of the equipment frames to the earth mat should be such that in the case of damage to the earth grid or to a connection circuit, no metal component should be disconnected from earth. This condition means that usually a minimum of two conductors will be required; however, connections to the earth grid that are visible above ground can use a single conductor. The earth grid has to be designed to be able to carry the maximum earth fault current for the duration of the earth fault, usually 1 s for voltages in excess of 170 kV and 3 s for voltages below this.

### 5.4.2 Safety Earths

For any work carried out on high-voltage plant, it is necessary to have earthing points either side of the work area for protection of operating personnel against any improper reestablishment of the voltage whatever the cause.

a) **Types of Device**

The required connections to earth can be effected by:

- Earthing switches in a suitable position capable of closing and having a suitable current rating
- Earthing switches that have discharge capability only, operation of which precedes the connection of portable earthing devices capable of carrying the fault current.
- Earthing blades designed solely to pass steep-fronted surges, closure of which must be preceded by a check for absence of voltage and followed by placing of portable earths.
- Solely by the placing of portable earthing devices that should be preceded by a check for the absence of voltage.
- Earth switches associated with the earthing of the line ends of overhead line circuits that are mounted on multi-circuit towers that have a special induced

**Fig. 5.9** Testing of a line end earth switch with whip contacts during 10 kV 400 A inductive breaking duty

current making and breaking duty for electrostatically and electromagnetically induced voltages (Fig. 5.9). It is strongly recommended that line end earth switches are closed during the application or removal of any additional portable earthing devices which may be applied.

- Some utilities, where ferroresonance of power transformers is likely, may use specially designed earthing switches to enable the quenching of the ferro-resonance before re-energizing the circuit. This may be done automatically within an auto-reclose sequence.

b) **Performance of Earthing Devices**

The current values to be used for determining the making capacities and current passing capacities should be the maximum earth fault currents for the substation concerned. The duration of the current usually is 1 s for voltages in excess of 170 kV and 3 s for voltages below this.

c) **Placing of Portable Devices**

The placing of portable earthing devices can be quite difficult because of:

- The relative weight of the components to be moved due to the current-carrying requirement (Note: it is often necessary to connect as many as four portable earths in parallel to carry the fault current.)

- The height of the high-voltage connections to be earthed frequently in excess of 6 m
- The arrangement of the connections that must have a suitable length of horizontal section to enable the temporary connections to be attached
- The environment and in particular the proximity of components which are still live and for which the safety distance may be less than that of the hot stick being used for the application of the portable earths

It should be noted that the portable device will only be effective if the jaws of the device have been adequately tightened at both the high-voltage end and also at the earth end.

In order to minimize these difficulties and increase the level of safety, it is recommended to place takeoff points at the high-voltage and earth end for connection of portable earthing devices, during the construction of the substation. These will normally consist of spigots at the high-voltage end and connection points on the structures at the earth end. These need to be designed to accommodate the size and number of portable earth connections, required to carry the fault current, to be attached. On 500 kV substations, specially designed guided portable earthing devices may be used to increase the level of safety.

## 5.5 Operation of High-Voltage Switchgear

### 5.5.1 Types of Control

a) **Remote Control**

This method of control is now the most common method with control frequently being carried out from a control center remote from the substation. Initially remote control was limited to circuit breakers, disconnectors, and the control of tap changers of transformers. These days most control functions can be carried out remotely. For a device to be remotely controlled, it must have an operating medium which can be electric, pneumatic, or hydraulic or a combination of these.

When the equipment is operated remotely, then maloperation only involves a risk to the equipment itself. To avoid maloperation, precise operating procedures will usually be prepared, and these are frequently supplemented by position compatibility interlocks with other equipment within the bay or throughout the substation.

b) **Local Control Using an Operating Medium**

This usually means operating locally a piece of equipment that is normally operated remotely. In these circumstances, the procedures and interlocks normally applicable during remote control should remain effective. In cases where, if a fault

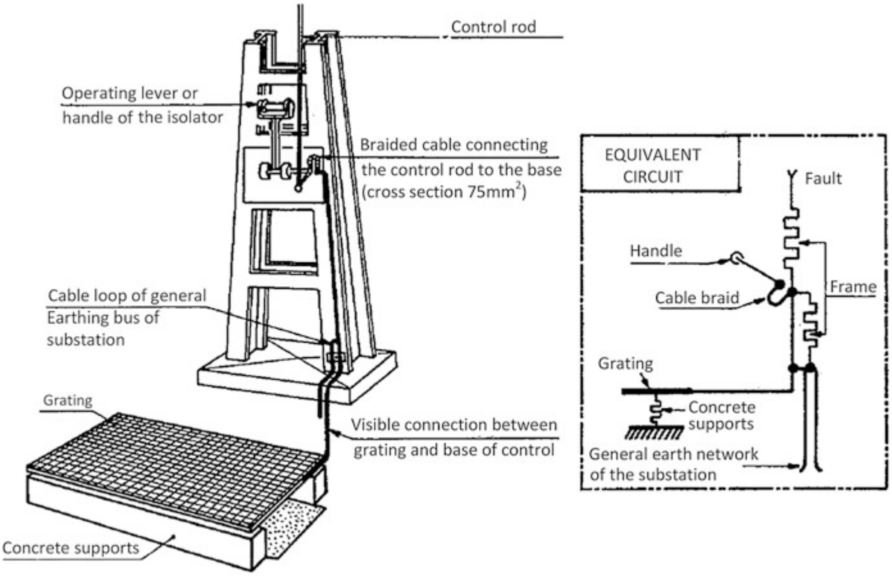


**Fig. 5.10** Installation of an earthed safety grating

occurs during operation, dangerously high voltage may be reached, an operating grating may be provided for the operator to ensure that no current path is possible from the control to earth via his body. This can be achieved in two alternative ways:

- The grating that the operator stands on is connected to the operating handle and also to earth. The voltage, which the operator can experience, is limited by the short length of conductor between the handle and the grating (see Fig. 5.10).
- The grating on which the operator stands is insulated from earth so that there is no current path possible through his body (see Fig. 5.11).

Where the frequency of this type of operation is low, then the grating could be removable and only put in place during switching operations.

c) **Direct Mechanical Local Control**

This relates to disconnectors that are operated by means of a handle or lever integral with the moving parts of the switch. In this case safety of the operating personnel is always involved, and so a fixed grating as shown in either Figs. 5.10 or 5.11 should be provided. These devices should also be fitted with position compatibility interlocks with other equipment within the bay or throughout the substation.

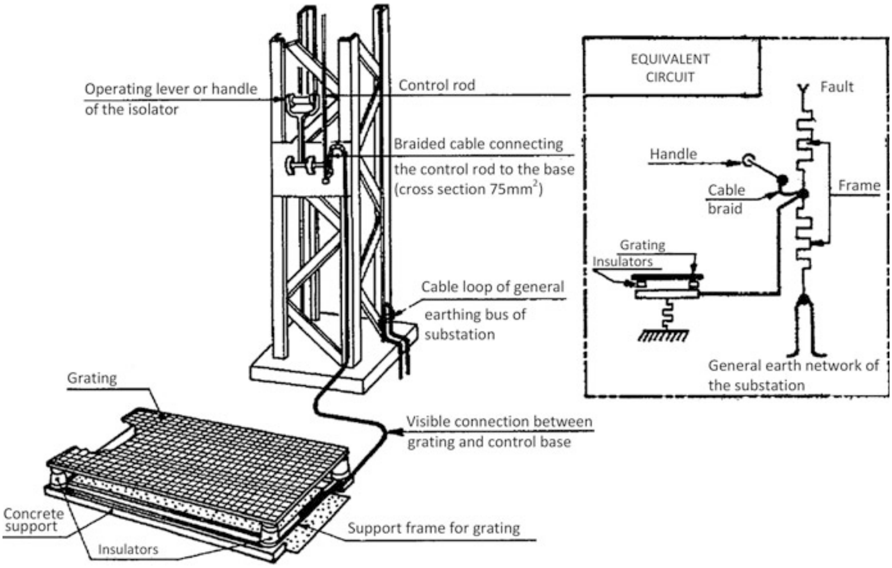


**Fig. 5.11** Installation of an insulated safety grating

d) **Manual Local Control**

This relates to single-phase disconnectors that are operated by means of a hot stick. Fortunately these are not so common these days, and the use of these devices should be strongly discouraged.

### 5.5.2 Locking Off Switches

Independent of any interlock, either mechanical or electrical, it will usually be necessary to be able to lock off a switch. Such locking off is required where it is necessary to ensure the isolation of an area where work is to be carried out.

The locking off should be achieved by mechanically blocking the isolating switch by means of a padlock or other lockable device from which the key can be removed. In addition to locking off, it would normally be prudent to also:

- Place notices indicating that the switch is locked off and the reason for so doing
- Remove from service all remote control devices

### 5.5.3 Auxiliary Operating Supplies

It should be possible to remove from service the auxiliary power supplies used for operating the switching devices without affecting other circuits or bays within the substation. This can be achieved by means of a padlockable switch or valve or a key-operated switch from which the key can be removed. To avoid the risk of removing the auxiliary power supplies for bays other than the one being worked on, the auxiliary power supply distribution should be arranged with separate circuits for each bay.

### 5.5.4 Current and Voltage Instrument Circuits

a) **Current Circuits**

It is frequently necessary to be able to carry out work on the current circuits of protection or other devices while the main circuit is still in service. In order to do this, a method of short-circuiting the current transformers and isolating them from the relevant protection circuits may be required. This can be achieved by specially designed test switches or test blocks or the use of bolted changeover links.

b) **Voltage Transformer Circuits**

It is absolutely essential to be able to isolate voltage transformers on the low-voltage side in order to prevent the back energizing of the primary circuit if test voltages are applied to the secondary side. This can be achieved by removing the fuses or locking off the miniature circuit breaker for circuits running from these devices. If fuses are used, it is prudent to be able to block off access to replace the fuse by means of a padlock as well as putting the fuses into the safety lockout box associated with the work permit.

## 5.6 Protection Against Fire

This section is dealing only with fire associated with power transformers or oil-filled reactors, where the consequences can be particularly serious and extensive because of the large volume of oil that can catch fire and spread widely (Fig. 5.12). For more details on protection against fire, please refer to ► Sect. 11.10.

The recommendations relate to:

- Limiting the damaged area and minimizing damage as far as possible
- Extinguishing the fire in and around the transformer

### 5.6.1 Limitation of the Damage Zone

This can be done in various ways.

a) **Oil Containment**

A bunded area should be provided around the transformer to prevent the spread of any oil that may escape from the transformer tank. These days this is frequently required by law simply because of the environmental effect of oil escaping into the

**Fig. 5.12** A transformer fire in a 400 kV substation

ground and contaminating watercourses. From the fire limitation point of view, the oil passing into the collection tank will normally pass through a flame trap, the simplest form being stone chippings laid on top of a metal grid such that as the burning oil passes through the stone, the flames cannot pass through.

b) **Separation**

Many utilities limit the damage from transformer fires simply by separation. One method of achieving this is that a fire damage zone is calculated based upon experience with oil fires in a bund. Provided that no equipment associated with a bay other than the transformer bay itself and no common substation equipment encroaches into this fire damage zone, then no further protection is provided.

c) **Fire Walls**

Where it is not possible to achieve satisfactory separation, then the construction of a fire wall to protect the equipment that would have fallen into the fire damage zone should be done. This wall will need to be higher than the highest oil-containing part of the transformer (see Fig. 5.13).

d) **Provision of Mobile Firefighting Equipment**

Placing in an area close to where the transformers are located mobile firefighting equipment such that if the fire is detected early enough, it can be extinguished quickly before it spreads.


**Fig. 5.13** Example of fire wall for transformer (during construction)

e) **Fire Blocks in Trenches**

Fire blocks should be located in trenches/ducts in close proximity to the transformer to prevent the spread of burning oil that can damage the insulation of the cables contained within them. These fire blocks will usually consist of sand.

f) **Physical Separation of the Control Circuits**

The control circuits should be located at some distance from the power circuits such that they can remain intact for some time in the event of a serious fire on the power circuit.

## 5.6.2 Extinguishing of the Fire

When designing the substation, allowance should be made for access for public firefighting vehicles to the transformer locations.

In some cases consideration can be given to the provision of purpose-designed fire-extinguishing equipment associated specifically with the transformer. This may use water deluge, water spray, foam, or other methods. Usually when such equipment is fitted, it will be associated with fire detection devices such as heat and smoke detectors that will automatically trigger the fire-extinguishing equipment.

## 5.7 Fences

Fences are usually provided around high-voltage substations. The legal requirements for such fences may vary significantly from country to country. This short section will deal with the external fences and also any fences required within the overall substation area.

### 5.7.1 External Fences

From the safety point of view, the main purpose of the external fence is to prevent the general public from approaching too close to the electrical conductors and equipment for safety. In order to achieve this, fences must be separated from live equipment by a distance at least equal to the horizontal safety distance such that someone outside of the fence has the same degree of protection as those inside. The fence will normally be a minimum of 2 m in height, but in some countries, this minimum height will be greater.

Unfortunately in this modern age, the fences around a substation are also required to prevent unauthorized access to the substation and in some cases to prevent vandalism to the equipment located inside. In some countries in the worst areas for intrusion and vandalism, the fences around substations also incorporate electric fencing over and above the basic fence, and the level of security of such fences can be the same as that used for prisons (see Fig. 5.14).

**Fig. 5.14** External fence around a substation with the same level of security as a prison

### 5.7.2 Internal Fences

There are occasions within substations where the insulation clearance height has not been achieved, and so it is not permissible to allow people to access these areas. This is quite often the case with filter equipment where the capacitor stacks may be mounted at ground level. In these cases it is normal to erect a fence around this equipment which will normally be the minimum height accepted by the utility. In order for it to be safe to access the area within this fenced-off enclosure, the equipment inside the enclosure should normally be dead, isolated, and earthed. To ensure that this is the case, electromechanical interlocks may be used to ensure that the gate cannot be opened until the relevant earth switch is closed and conversely the earth switch cannot be removed until the gate is secured and locked.

## References

Brochure 161: General Guidelines for the Design of Outdoor AC Substations (2000)
Brochure 585: Circuit Configuration Optimization (2014)
ELECTRA No. 019: The Effect of Safety Regulations on the Design of Substations (1971)

# Incorporating New Functionalities Into the Substation

6

John Finn

## Contents


6.1 Introduction ... 68
6.2 General Observations on Substation Design ... 69
  6.2.1 System Impact on Substation Design ... 69
  6.2.2 The Impact on the Substation Single-Line Diagram ... 71
  6.2.3 Impact on the Substation Bay ... 72
6.3 Impact of Technology on Substation Design ... 74
  6.3.1 Mixed Technology Switchgear ... 75
  6.3.2 Compact and Integrated AIS Switchgear ... 75
  6.3.3 Dispersed Generation ... 76
  6.3.4 Reactive Compensation ... 77
  6.3.5 Nonconventional Instrument Transformers ... 78
  6.3.6 Power Flow Control Devices ... 79
  6.3.7 Custom Power Technology ... 80
  6.3.8 Fault Current Limiters ... 80
  6.3.9 HVDC ... 81
  6.3.10 Protection ... 81
  6.3.11 Gas-Insulated Lines, Transformers, and Superconducting Cables ... 82
  6.3.12 Monitoring and Diagnostic Equipment ... 83
6.4 Example of Detail for Line-Commutated Converter HVDC ... 83
6.5 Mobile Substations ... 91
  6.5.1 Introduction ... 91
  6.5.2 Standards ... 95
  6.5.3 Typical Transport Restrictions Associated with Mobile Substations ... 96
  6.5.4 Site Preparations ... 97
  6.5.5 Design Guidelines for Mobile Substations ... 97


J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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## 6.1 Introduction

Substation design aims to provide a cost-effective solution, which as far as reasonably practicable demonstrates high availability, reliability, and operational flexibility. From the utility perspective, this requirement applies to both brand new as well as 30-year-old substations.

The power industry is experiencing unprecedented changes and as a result has to respond in much shorter timescales than it may be used to. The external influences such as climate change, liberalization of networks, and deregulation are greater than ever, and all contribute to driving change within transmission and distribution systems. A summary of the influences that affect the substation design is shown in Fig. 6.1.

The continuing growth of the load and networks provides new challenges to the system operators who have had to seek new and innovative solutions to enable them to continue to operate their networks efficiently. These new functionalities and technologies required by the system operators have to be implemented within the network, and this means that they have to be incorporated into the substations.

One of the factors holding back the implementation of new technology is the lack of experience or confidence with new or different equipment, in addition is the risk of the actual installation and impacts on the existing substation operation. In order to address this situation, a task force was set up to produce a CIGRE Technical Brochure on this subject. The brochure compiles a source of advice, experience, and recommendations from users who have already implemented the technology. The document concentrates on the impact on the design and construction of substations. In some cases, this may fundamentally affect the basic concept of the design and construction of the substation. The brochure contains a number of appendices that give some detailed advice on implementing the specific technologies or functionalities.

The functionality and technology considered can loosely be divided into four areas:

- Dispersed generation
- Power system applications
- Switchgear
- Substation automation and these are summarized in Table 6.1

The scope of the developments is broad including the compaction of equipment, power electronic applications, new communication architecture, and automation and new technology paradigms such as superconductivity.

This chapter summarizes the general content of the CIGRE Technical Brochure No. 380 which was published in June 2009 and also presents the content of one of the appendices for the detail associated with the incorporation of line-commutated converter HVDC into a substation. The reader is advised to refer to the appendices in the brochure for any of the other technologies that they are intending to utilize in their substations.

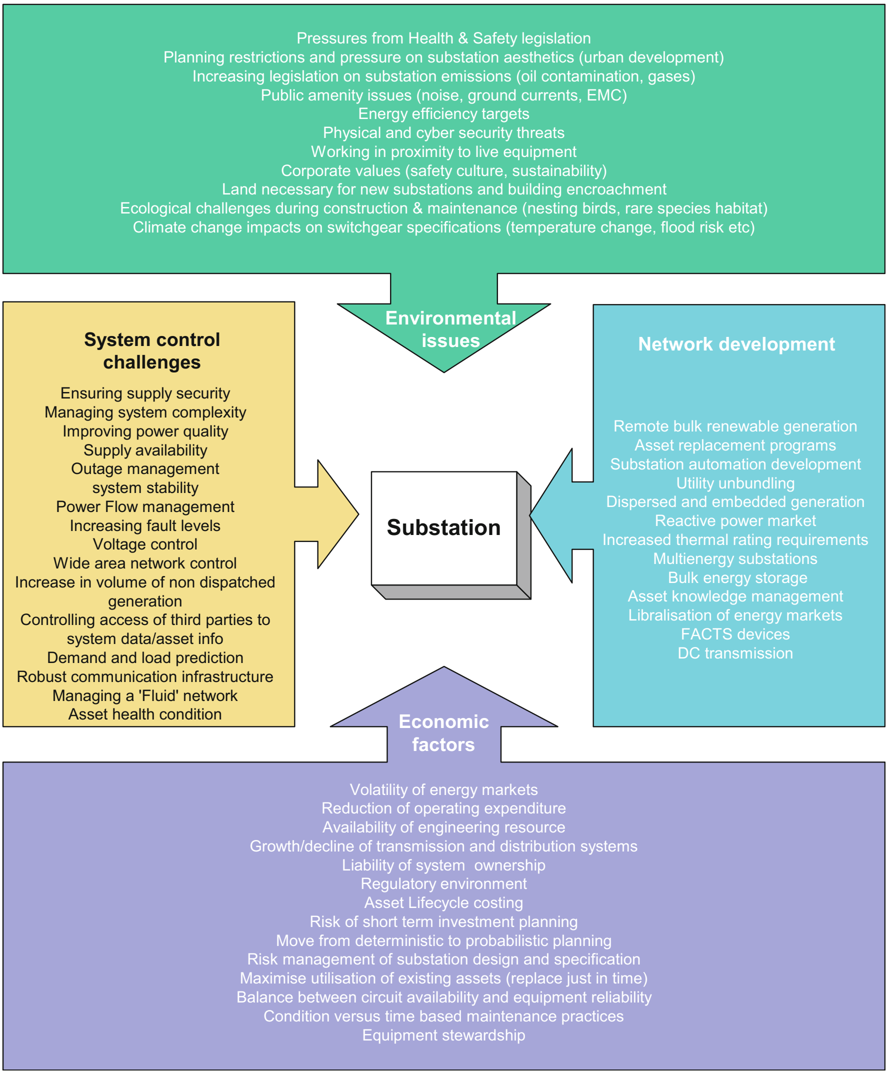


**Fig. 6.1** Summary of the influences on substation design

## 6.2 General Observations on Substation Design

### 6.2.1 System Impact on Substation Design

When we examine the impact of the various influences on substation design, there are a number of issues that are common to many of the scenarios. This section considers these various impacts.

**Table 6.1** Technology matrix

| Functionality area | Technology type | Technology detail | Section no. | Brochure appendix |
|---|---|---|---|---|
| Switchgear | Mixed technology switchgear | Hybrid AIS/GIS | 6.3.1 | A1.1 |
| Switchgear | Compact switchgear | Disconnecting CB | 6.3.2 | A2.1 |
| | | Withdrawable CB | | A2.2 |
| Dispersed generation | Dispersed generation | Wind farms | 6.3.3 | A3.1 |
| Power system applications | Reactive compensation | STATCOM | 6.3.4 | A4.1 |
| | | SVC Thyristor-controlled reactor (TCR) | | A4.2 |
| | | Thyristor-switched capacitor | | A4.3 |
| | | Shunt reactor | | A4.4 |
| | | Shunt capacitor bank | | A4.5 |
| Switchgear | Nonconventional instrument transformers | Current transformers | 6.3.5 | A5.1 |
| | | Voltage transformers | | A5.2 |
| Power system applications | Power flow control | Regulating transformers | 6.3.6 | A6.1 |
| | | Series capacitors | | A6.2 |
| Power system applications | Custom power technology | DSTATCOM | 6.3.7 | A7.1 |
| | | Dynamic voltage regulator (DVR) | | A7.2 |
| Power system applications | Fault current limiters | Neutral earthing resistors and reactors | 6.3.8 | A8.1 |
| | | Series reactor | | A8.2 |
| | | Superconducting FCL | | A8.3 |
| Power system applications | High-voltage direct current | Line-commutated converter HVDC | 6.3.9 | A9.1 |
| | | Voltage source converter HVDC | | A9.2 |
| Substation automation | Protection | Numerical protection | 6.3.10 | A10.1 |
| Power system applications | Gas-insulated lines, transformers, and superconducting cables | Gas-insulated lines | 6.3.11 | A11.1 |
| | | Superconducting cable | | A11.2 |
| | | Gas-insulated transformer | | A11.3 |
| Substation automation | Monitoring and diagnostics | Monitoring and diagnostics | 6.3.12 | A12.1 |

**Primary Plant**

The substation infrastructure is most likely to experience increased power transfers to meet future demands. Greater interconnection of remote generation will require utilities to increase capacity using either series compensation, HVDC, or real-time monitoring to enhance ratings. Inevitably, as equipment is pushed harder, the electromagnetic stress seen by primary equipment will increase, and utilities will need to be able to assess this risk.

The network topologies will need to be much more flexible to meet changing needs; this will see either network expansion or wider application of FACTS devices; the challenge will be coordinating these devices as more appear and possibly interact.

Adverse weather will directly impact on network security, and the substation flexibility will determine the system resilience to these effects. This is in addition to the climate change targets on renewables and emissions.

**Secondary Systems**

The application of wide area monitoring, control, and protection will become more prevalent as system operators are faced with more dynamic networks and large-scale interconnections. Embedded generation and active control within distribution networks will require significant coordination between neighbors and make traditionally separate networks much more interdependent on each other. The communication necessary to support these developments will be central to the security and reliability of the strategy. There is likely to be a greater dependency on these systems to facilitate the changes in power networks.

### 6.2.2 The Impact on the Substation Single-Line Diagram

If we look at the effect upon the single-line diagram (SLD) of the substation, then one of the immediate effects may be the short circuit rating required for the plant within the substation. Depending upon the device being connected, this may require an increase in short circuit level or in some cases (fault current limiters) may enable simplification of the SLD by allowing greater bussing of equipment without too many sections.

The increase in harmonics on the network may give rise to a greater need for filters, either passive or active; however most transmission applications should be specified to reduce or, at least, not worsen system harmonics.

New technologies and integrated applications will affect the substation configuration and insulation coordination dynamics. Application of surge arresters and controlled switching will need to be considered to maintain adequate safety margins. This is particularly important for electronic components, which have a very low tolerance to overvoltages.

**Substation Configuration**

The reliability and maintenance impact of new switchgear should encourage utilities to examine new running arrangements. Much longer intervals between corrective maintenance could lead to different strategies such as replace and maintain offline, rather than in situ maintenance.

For substations incorporating new technologies, consideration needs to be given to the operation and running arrangement when the device has to be disconnected for maintenance or under fault conditions. Reducing the duration of outage or bypass arrangements may be required, and care needs to be taken with the protection arrangements to cover both conditions. The utility will need to consider the relative cost of getting outages in the future against spare switchgear, so that rapid replacement and offline maintenance can be employed. Any element of wide area protection will also need to coordinate with these changes. As substation life cycle costing becomes a more accepted method for design selection, then different single-line diagrams may be considered.

### 6.2.3 Impact on the Substation Bay

Whatever new functionality is employed to affect system level attributes such as fault level, power flow, etc., it is invariably going to have a significant impact at the bay level.

a) ***Physical Environment***

Once the substation configuration is defined, detailed design can take place to specify aspects of the substation and equipment.

Space is an obvious limitation in most substations where new equipment needs to be installed. The space requirements need to consider the connectivity required with other plant items, the required electrical clearances, clearance required for electromagnetic effects, access for initial installation, and maintenance. The impact on civil works may include oil containment and fire requirements if the new devices introduce oil-immersed transformers, and if air-cored reactors are present, care has to be taken with the reinforcing bar arrangements, structures, and earthing to avoid heating from closed loops.

Climate change is going to have an increasingly direct impact on switchgear specifications such as operational temperature ranges and on the physical location of equipment (e.g., mechanism boxes).

Substation marshalling must be designed to ensure immunity to interference generated from any new applications installed in the substation which may induce transients into site cabling. The use of optical fiber will help to alleviate this problem. Special care is needed in the design of the earthing system, to ensure safety while avoiding interference into control circuits and avoiding large circulating currents flowing due to electromagnetic induction.

Audible noise can have a significant effect on the equipment specification and subsequent testing. At the design stage, the various options should be investigated such as indoor build, location, or operational modes before writing very onerous equipment specifications.

A new directive on EMC regarding substations as fixed installations will require the designer to consider any effects more critically since the substation is now seen as a source and will need to demonstrate compliance with the standards.

b) ***Impact on Equipment***

There is a move toward modularity and design standardization in an effort to reduce costs. This does mean utility specific adaptations are more difficult to make, and traditional utility procedures may require review.

**Primary Plant**

Ongoing $SF_6$ gas containment and tightness is a major concern among utilities; life cycle factors need to be addressed at the specification and installation stage to ensure the desired objective of zero leakage can be reasonably achieved. Any new switchgear, especially at transmission voltages, will require $SF_6$ gas handling; this will require training and certification under new EU regulations.

Utilities will need to specify current transformers and voltage transformers with a view to meeting future digital protection and control needs.

**Substation Automation**

Substation automation will experience the greater change as interfacing new to old legacy wiring, the transfer to powered relays, and isolation from the instrument transformer secondary (high impedance). There will also be a high degree of technology obsolescence.

Secondary asset replacement occurs more frequently than primary, and switchgear interfacing is proving to be one of the most complex challenges. The fact that the secondary wiring may need to be changed a couple of times during the life of the switchgear results in long outages to facilitate the replacement. IEC 62271-3 aims to address some of the issues facing primary and secondary integration. Therefore, in order to facilitate faster secondary asset replacement, additional costs may need to be incurred at the primary asset investment stage.

The implementation of IEC 61850 is underway, and utilities need to develop their application requirements and the associated interfaces to any system management tools.

As utilities move from copper multi-core to fiber-based marshalling systems, this forces the utility to establish standard termination and data protocols. Utilities need to develop their own IEC 61850 configuration requirements. New tools and training will be necessary to configure multifunctional protection "black boxes" safely and reliably.

Substation and network communication is a major issue. Before many of the new initiatives can be considered, rules about ensuring secure portals, management of firmware changes, and software version control and access must be resolved. Ensuring that utility personnel can interrogate and download fault records or settings is necessary while at the same time preventing unauthorized access.

As more functionality is incorporated into equipment or wide area systems are developed, the testing according to existing standards may require some interpretation and development, both in the factory acceptance tests and more importantly at final commissioning.

**Ancillary Equipment**
Most of the new functionality will increase the pressure on auxiliary systems. The steady-state loading is increasing, and dependency on the DC supply is becoming more important than ever.

Additional AC supplies will be required for cooling of components and additional DC supplies for the control and protection. The protection design needs to consider the particular requirements of the new types of device and also the impact these devices may have upon the performance of existing system protections such as distance relays. Interlocking may be required for both operational and safety reasons.

c) ***Substation Operations***

One of the common requirements for most of these new functionalities is that existing maintenance strategies may need to be reviewed. In many cases this may require procedural changes; however, in a number of cases, specific strategies will be required. This may result in training for substation staff or alternatively service agreements with the supplier. In both cases, the costs can be large whether it is in terms of contracts or substation resource tied up in training.

Where diagnostic tools are employed such as condition monitoring or analysis, provision for maintenance or calibration of these services will need to be made (exchanging one maintenance intensive system for another), albeit the latter does not tend to incur outages.

New skill sets will be required by substation staff, particularly in the field of information systems and possibly software programming. Staff will need to be IT literate, to interrogate secondary systems, implement test procedures, and perform diagnostics on substation automation.

The manner in which condition monitoring (CM) is employed will enable the utility to optimize its maintenance and asset replacement strategies. The utility will need to concentrate on how the information is used within the organization to maximize any benefit; liberal application of CM without a good input into the maintenance and asset management decision-making tools will be ineffective.

## 6.3 Impact of Technology on Substation Design

This section outlines some of the options (functionality) available and breaks these down into categories. It *does not* provide a recommendation on the suitability of the solution but an indication of the range of applications the technology has been used to address.

### 6.3.1 Mixed Technology Switchgear

In an attempt to address safety and space restriction associated with new build or asset replacement, manufacturers are trying to increase reliability by using highly engineered GIS for AIS applications. Also termed mixed technology switchgear, these solutions incorporate the benefits of GIS and flexibility of AIS for outside applications. At present, these have been limited to specific applications where space is at a premium.

| Mixed technology switchgear<br>Appendix 1 | Key impacts |
|---|---|
| Hybrid development of GIS and AIS systems for outdoor application | Reduced life cycle maintenance compared to conventional AIS |
| | Smaller footprint |
| | Identify equipment failure replacement strategy and necessary provisions |
| | May challenge existing safety practices, so new maintenance practices may be necessary |
| | Essentially dead tank design |
| | Can enable new optimized substation designs |
| | Outdoor GIS so need to ensure joints/seals are adequately robust to the environment for the asset lifetime |

Although GIS is much less likely to fail and requires significantly less maintenance, the provision for maintenance and equipment spares to minimize unavailability and disturbance to the network is all the more critical. This needs to be agreed with the manufacturer or engineering support division at the time of equipment purchase.

### 6.3.2 Compact and Integrated AIS Switchgear

Integrated switchgear combines functions together, generally in a compact manner to provide a synergy of equipment. Typical examples include integral support/surge arresters and circuit breaker with integrated disconnection facilities. There are many advantages offered through these solutions; however the utilities need to change their procedures and systems to reap the benefits.

| Compact and integrated switchgear<br>Appendix 2 – circuit breakers | Key impacts |
|---|---|
| Withdrawable circuit breaker, disconnecting circuit breaker | Reduced life cycle maintenance compared to conventional AIS |
| | Smaller footprint |
| | May challenge existing safety rules, new maintenance practice and equipment necessary |
| | Enables optimized substation design |

### 6.3.3 Dispersed Generation

This is a huge and expanding subject ranging from domestic micro-generation up to offshore wind farms. The nature of the generation technology, voltage level, and location will create different conditions. The preference for remote generation sites introduces many system issues, such as the nature of transmission to the load centers and provision of services/maintenance, etc., which will determine the type of solution specified.

While the increased use of dispersed generation may alleviate voltage control problems within the main interconnected network, remote generation (possibly even offshore) is going to require additional reactive compensation to enable transmission to the load centers. This may be an area where power electronic-based solutions become feasible whether it is HVDC or dynamic compensation to provide fault ride through capability. The future for HVDC may be more likely as economics, and rights of way issues demand higher power flows through either existing routes or new under-grounding is justified.

a) ***Dispersed Generation***

Dispersed generation may take many forms, such as wind power, photovoltaic, small diesels, fuel cells, etc. The generation may be connected at different voltage levels within the distribution network and may be three-phase or single-phase connected. This gives rise to a whole range of impacts upon the performance of the system including voltage regulation, voltage unbalance, harmonics, frequency variation, power flow direction, short circuit current levels, and fault detection.

Monitoring and awareness of dispersed generation is necessary to manage network operation, especially where system contingency is concerned. Wide area control and protection is frequently mentioned as a possible resolution to these issues; however except for special protection schemes (inter-tripping), there is very limited application (Appendices 10 and 12 provide some advice on protection and diagnostic systems).

Inevitably, most of these systems incorporate some element of power electronic conversion to interface with the existing power system. One of the key functions for power electronics in the future will be to provide the interface between the existing power system and many of the emerging applications such as photovoltaic (PV), energy storage, and superconductivity. Many of the integration issues associated with power electronics are covered in Appendices 4, 7, and 9 on reactive compensation, custom power, and HVDC, respectively, all of which incorporate power electronics to varying degrees. In this scenario, custom power will be the more relevant section; however small DC will also be likely.

b) ***Wind Farms***

The type of wind turbine technology employed will determine the dynamic response available to control network disturbance and the associated protection and control required to provide a reliable connection to the grid.

While different countries have different connection codes, issues of fault ride capability, intermittency, and compliance are challenging the industry to innovate. In most cases, dynamic compensation is necessary to manage these contingencies either through turbine control or external power electronics (SVC, STATCOM) or both.

Quality of supply issues will need to be more carefully monitored as wind farms and distributed energy resources begin to proliferate.

Circuit availability and outage management may also become a major issue regarding the substation configuration, depending on the availability required by the generator, since units are maintained individually rather than en masse. Reliability of the connection transformer and cable between the wind farm and grid connection will become the determining factor.

| Dispersed generation<br>Appendix 3 | Key impacts |
|---|---|
| Distributed generation, CHP, PV, micro-generation, wind farms | AC or DC interfaces with existing network, depending on size and distance |
| | Require new connection infrastructure and communications |
| | Grid compliance may be necessary for larger generation at point of connection. This may require additional reactive compensation |
| | Need to review tolerance of new protection and control settings to system fluctuations |
| | May require wide area control (WAC) and monitoring to enable TSO to manage transmission planning, post-fault coordination |

### 6.3.4 Reactive Compensation

Voltage control is a very extensive field, catering for steady-state and dynamic system conditions. The changing nature of generation and its location will have a profound impact upon the design of substations needed to feed demand and are remote from the immediate point of connection of the generation. Reactive compensation may need to be relocatable to justify the expenditure.

Where a number of reactive compensation devices are employed in a localized area, careful calculation of the dynamic control setting will be necessary to ensure that hunting or poor response does not occur when the system is disturbed.

All this reactive compensation could increase the risk of resonances on the network, while low loss design equipment is reducing the amount of resistance in the system and therefore the damping. Generally, the corrective measures should be connected locally to the device that is causing the effect so that the substation affected will be the one that includes the new device. The more advanced applications with sophisticated control system should be designed to neutralize any potential resonance effects.

**Switched Capacitor and Reactor Banks**

Mechanically switched banks have been employed for many years to control steady-state voltage levels; however the installed capacity is increasing significantly as utilities no longer centrally design and must manage new generation and closure of existing plant.

Circuit breaker switching duties must be considered, and care must be taken to ensure that electromagnetic VTs and surge arresters are designed to deal with any discharge duties when connected in capacitor circuits.

**Dynamic Compensation**

While the proliferation of steady-state voltage support equipment is extensive, the same cannot be said of dynamic equipment. Fast-switching post-fault voltage support is necessary to prevent system instability, and only power electronic switches can respond in this time frame. The introduction of distributed generation and a requirement for fault ride through capability is being addressed to some degree using dynamic compensation.

| Reactive compensation<br>Appendix 4 | Key impacts |
|---|---|
| Shunt connected equipment to provide steady-state voltage support and dynamic system compensation post fault<br>Steady state: fixed/switched capacitor banks, shunt reactors<br>Dynamic: SVC, STATCOM | Power electronics require reliable control systems and cooling circuits |
| | Specific maintenance strategy to ensure availability. Power electronic auxiliary systems, strategic spares, capacitor cans |
| | Relocatable design may be necessary if generation patterns change |
| | Requirement for coordinated control if more than one reactive control device is installed on-site |
| | Step voltage, transients and resonances for switched units |
| | Monitoring of dynamic performance |
| | Magnetic fields and acoustic noise near air-cored reactors |
| | Circuit breaker switching duty or point on wave control for mechanically switched units |

### 6.3.5 Nonconventional Instrument Transformers

The use of nonconventional instrument transformers usually enables saving of space, structures, and foundations within the substation. Typical examples include integral optical CTs on circuit breakers, voltage, and current measurements in one device. There are many advantages offered through these solutions; however the development of IEC 61850 and application of the process bus in substations is required before the full benefits can be realized.

| Nonconventional instrument transformers<br>Appendix 5 – NCIT | Key impacts |
|---|---|
| Nonconventional instrument transformers (NCIT) | Smaller footprint |
| | Eliminates safety risks from primary system |
| | Requires DC supply to power transducer electronics and protection relays |
| | Can be integrated into existing switchgear (GIS) or attached to AIS |
| | Interface challenges between NCIT and non-digital protection |

### 6.3.6 Power Flow Control Devices

Flexible AC transmission systems (FACTS) are commonly referred to as devices capable of controlling the power in a circuit or substation. Most of the recent developments are based on power electronic architectures; however some of the features can also be achieved with electromagnetic applications.

Electromagnetic devices such as phase shifting transformer (PST) and quadrature booster (QB) are based on transformer principles and employ tap changers to control real power, which is used to inject a voltage into the circuit which effectively changes the power angle and enables the power flow in that circuit to be controlled.

Power electronic-based series compensators such as the thyristor-controlled series compensator (TCSC) provide a smoothly controllable impedance to reduce the impedance of lines and to mitigate sub-synchronous resonance. Static synchronous series compensator (SSSC) allows control through an injected voltage.

Independent active and reactive power flow control can be provided by the interline power flow controller (IPFC) and the unified power flow controller (UPFC). The convertible static compensator (CSC) combines all functionalities of STATCOM, SSSC, UPFC, and IPFC.

| Active power flow control devices<br>Appendix 6 | Key impacts |
|---|---|
| Power flow control devices in a circuit, to increase/decrease capacity, to control thermal constraints<br>E.g., phase shifting transformer, quad booster, TCSC, UPFC | Equipment ratings need to be equivalent to circuit rating |
| | Must be robust to through faults and transient conditions. The circuit reliability should be no worse than before |
| | Location of FACTS device can significantly impact effectiveness |
| | Requires a bypass facility for maintenance/fault condition |
| | Need to study impact on circuit protection, particularly distance protection |
| | Need to establish resonance, sub-synchronous, and reactive power impact of any new equipment installed |
| | Reliability of cooling systems on equipment availability particularly power electronics |
| | Spares provision for power electronics and capacitor units |

### 6.3.7 Custom Power Technology

Essentially, distribution and industrial applications, these have been developed to improve the power quality or conditioning of the customer's supply. They are seeing wider application in distributed generation connections.

Applications covered include dynamic voltage restoration (DVR) that provides power during short supply interruptions and a Distribution STATCOM which maintains voltage quality. Other devices include active filtering and solid-state transfer switch that through fast coordination can transfer bus supplies to provide uninterruptible supply.

| Custom power technology | |
|---|---|
| Appendix 7 | Key impacts |
| Distribution and industrial voltage level equipment for power quality control, fault ride through, and fast switching<br>E.g., DSTATCOM, DVR, and solid-state switch | Very application specific, therefore tailored solution |
| | Auxiliary systems determine equipment reliability |
| | Require protection system review, high-speed communication, and transient monitoring to get the most out of the solution |
| | Similar issues to that of FACTS and HVDC power electronic applications |
| | Spares provision |

### 6.3.8 Fault Current Limiters

These devices take many forms and can help a utility to control fault current levels as it develops and expands. Simpler solutions include reactors, but more exotic designs are considering high-temperature superconductors (HTS), resonance triggers, and power electronics. On a larger scale, back-to-back HVDC can also provide asynchronous connection between grids. All have benefits and drawbacks, but it is up to the utility to identify the most relevant for its needs. Reliability of performance is probably one of the most important requirements, since failure to control fault current can easily result in equipment failure.

| Fault current limiter | |
|---|---|
| Appendix 8 | Key impacts |
| Equipment capable of controlling fault current to a designed level, protecting local switchgear from overstressing<br>Mixture of conventional and novel technologies – series and neutral reactors to resonant series transformers | Energy dissipation and cooling between fault operation (reclose) |
| | Coordination and impact on protection settings, particularly downstream |
| | Bypass facility |
| | TRV duty if circuit breakers are employed adjacent to the FCL |
| | May need to consider a relocatable solution (following asset replacement) |
| | Reliability of any control system |
| | Strategic spares for complex systems |

### 6.3.9 HVDC

HVDC is well established; however the pressure on network capacity and emergence of new technologies are challenging some of the existing limitations with conventional HVDC (line-commutated converter thyristor) designs.

Recent developments in voltage source converter (VSC)-based DC can provide a complete power transfer solution for distribution and increasingly transmission systems.

| HVDC<br>Appendix 9 | Key impacts |
|---|---|
| Direct current transmission, requires converter and inverter station for AC<br>Classic line-commutated converters using thyristors or voltage source converter technology | Significant power flow increase (for large DC links) |
| | Reactive compensation will be necessary (VSC DC to a lesser degree) |
| | Harmonics and EMC may need to be addressed depending on the technology chosen |
| | Significant land take will be necessary for HVDC station |
| | Impact on local protection and control strategies. Fast power reversals |
| | Pollution performance of outdoor DC insulation |
| | Reliability of the valve cooling system(s) |
| | Strategic spares strategy to ensure high availability |

### 6.3.10 Protection

Although substation automation is changing, it is in response to the fast pace of communication protocol development, typified by the development of the Internet. The development of the substation communication protocol IEC 61850 will probably be the most dramatic element seen in the substation for a long time. Implementation of this will enable interoperability between different IEDs and greater equipment information exchange made accessible to interested parties via the Internet.

There are also some drawbacks with this change, the greater likelihood of early equipment obsolescence (from a utility perspective), information and cyber security, and greater reliance on automation where systems utilizing neural networks or artificial intelligence (AI) technology adapt to changing and evolving system needs.

Phasor measurement, GPS tracking, and fast data transfer enable wide area protection and control to be deployed, to prevent system instabilities developing and causing blackouts.

| Protection<br>Appendix 10 | Key impacts |
|---|---|
| Application of numerical protection and IEC 61850 protocol | Protection setting on multifunctional devices (hundreds of settings to check). Default not necessarily secure |
| | Intelligent electronic devices (IED) functionality |
| | Protection engineers require training |
| | Control of firmware updates and revision control |
| | Ethernet connectivity and security control |
| | Interfacing between old and new protection systems |
| | Service agreements |

### 6.3.11 Gas-Insulated Lines, Transformers, and Superconducting Cables

a) **Gas-Insulated Lines**

Gas-insulated line (GIL) technology is different from traditional GIS in the construction and insulation medium. Welding improves the gas tightness, and there is no need for any intrusive maintenance, thus providing a very robust conductor. A gas mixture of $SF_6$ and $N_2$ is used to insulate the conductor. This design enables a high-capacity, safe conductor system to be installed within the substation boundary. It can also be surface mounted, so burying and the associated costs and risk with civil works are reduced.

b) **Gas-Insulated Transformers**

The design of a gas-insulated transformer enables the unit to be more compact enabling the unit to be installed in a confined space. The absence of oil means that the fire risk is removed, so it can be located close to (or beneath) public accommodation. A large quantity of $SF_6$ gas is required (similar to a GIS substation), so procedures for gas handling need to be carefully considered regarding faulted conditions, maintenance, etc.

c) **Superconducting Cables**

The application of superconducting systems in the substation has been discussed for decades, but commercial and technical exploitation is slow, although a few demonstrations at MV are underway. Although, the attraction of low loss high current conductors is obvious, integrating them into existing networks is proving a challenge. The impact of equipment failure, through cryogen leakage, effect of system faults, and the cryogenic system itself, is of great concern, especially in an industry where maintenance budgets are constantly under pressure to be reduced.

The topic is not addressed in detail, as any pilots are still very much in the prototype stage.

| High-capacity conductors and gas-insulated transformers | |
|---|---|
| Appendix 11 | Key impacts on substation design |
| Gas-insulated lines<br>Superconducting cables<br>Gas-insulated transformers | Gas handling equipment and practice for large volumes of gas. GIL gas mixture (10–20% $SF_6$) |
| | Fault recovery program and rating of adjacent plant to handle redistributed current post fault |
| | Reliability/redundancy of cryogenic cooling for superconducting cables |
| | Opportunity to build underground or consider substation compaction |
| | Eliminates the key sources of substation fire hazards |
| | Post-fault repair strategy to minimize outages |

### 6.3.12 Monitoring and Diagnostic Equipment

Through the development in sensor technology, again transferred from other industries, there is the increasing capability to monitor everything. Many utilities are faced with the dilemma of replacing or supplementing traditional maintenance regimes with these systems. There are significant challenges when integrating these systems into the utility decision-making tools, and to some extent, the reliability of the monitoring system itself can be questionable. Utilities need to identify what the value in condition monitoring is and how it will be used.

| Monitoring and diagnostics | |
|---|---|
| Appendix 12 | Key impacts |
| Condition monitoring and plant diagnostic tools<br>E.g., GIS PD monitoring, transformer nursing units, online circuit breaker timing | Reliable data interpretation and advisory systems |
| | Equipment may be more maintenance intensive than the primary plant – monitoring equipment may reduce equipment reliability |
| | Cost benefit justification |
| | Do not install CM unless it is necessary! |
| | Communications infrastructure necessary to access information in a timely fashion |
| | Security issues regarding third-party access to substation info systems |
| | Control of software/firmware updates |

## 6.4 Example of Detail for Line-Commutated Converter HVDC

In this section an example of the detail available in the Appendices of the brochure is given for line-commutated HVDC. The numbering used is that taken from the brochure.

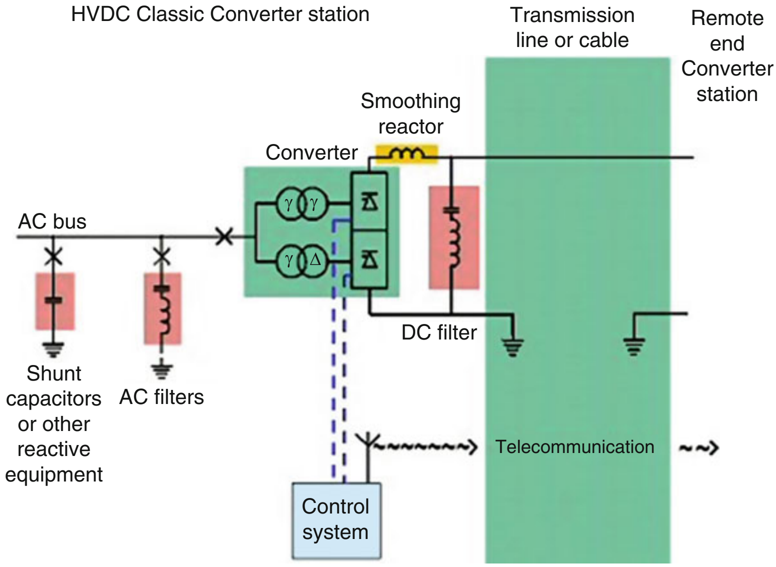


**Fig. 6.2** Typical configuration for a classic HVDC converter station

### A9.1 Line-Commutated Converter HVDC

Conventional or classic HVDC (Fig. 6.2) is typically referred to as line-commutated converter HVDC, because the switching technology is based on the use of line-commutated thyristors. These power electronic switches are triggered into conduction by a gate signal, and conduct until the current passes through zero, such that the switch off is achieved by natural commutation. Single thyristors have ratings in the order of 8 kV/2kA so can handle large power transfers.

Conventional HVDC benefits larger power transfers, when economic trade-off is considered and a bipole link can transmit up to 3000 MW.

A HVDC converter station is similar to a generator in terms of its impact on the substation environment. The index below lists a standard set of possible impacts.

| Basic system changes | | | |
|---|---|---|---|
| Impact index | Impact | Important notice | Appendix |
| Fault level | Major | Can be used to isolate networks | A9.1.1 |
| Power flow | Major | Key purpose of HVDC is to provide controllable bidirectional power interchange between sending and receiving ends of the link | A9.1.1 |
| Frequency | Major | Loss of the link can cause the frequency to change significantly, similar to losing a generator or large load | A9.1.2 |
| Voltage | Major | Load rejection can cause large overvoltages | A9.1.3 |
| Thermal rating | Major | Additional power flows may affect existing limits | A9.1.1 |

(*continued*)

| Basic system changes | | | |
|---|---|---|---|
| Impact index | Impact | Important notice | Appendix |
| Unbalance | None | | |
| Harmonics | Major | Converters will generate harmonics | A9.1.5 |
| Impedance | None | | |
| Resonances | None | | |
| Losses | Minor | Lower system losses than equivalent AC power transfer | A9.1.6 |
| Single-line diagram impact | | | |
| Impact index | Impact | Important notice | Appendix |
| Short circuit rating | None | | |
| Operational switching | Major | Operated and dispatched similar to a generator. Wide area protection and control may be necessary particularly in weak networks | A9.1.7 |
| Filtering | Major | HVDC station design incorporates harmonic filtering | A9.1.5 |
| Compensation | Major | Significant reactive compensation necessary | A9.1.8 |
| Installation | Major | Significant new build for converter station and new bays will be necessary to connect the AC link | A9.1.9 |
| Maintenance | Major | HVDC maintenance is complex. AC bays will require same maintenance as any other generator bay | A9.1.10 |
| Bypass | None | | |
| Commissioning | Major | Extensive program required to test HVDC converter controls significant involvement of all parties | A9.1.11 |
| Insulation coordination | Minor | Same as general insulation design. Extensive use of surge arresters | A9.1.12 |
| Impact on detailed substation design | | | |
| Impact index | Impact | Important notice | Appendix |
| Protection (external) | Major | Same as general protection design. Impact of faults on AC filters, SVCs, and busbar protection. Possible need for wide area protection scheme | A9.1.13 |
| Protection (internal) | Minor | HVDC converter protection is complex and incorporated into the control system | A9.1.14 |
| Control | Major | Extensive control of converter station necessary – requires coordination with substation control. Wide area control? | A9.1.15 |
| Comms | Major | Any WAC will require reliable fast communication links | A9.1.16 |
| Land and layout | Major | Significant land take for the converter station, additional bays will be required in the AC compound to connect the link into the existing AC network | A9.1.17 |
| Visual impact | Major | Significant. Tall valve hall, large layout for AC and DC switchyards | A9.1.18 |
| External pollution | Major | DC field will attract dust to insulators, larger bushings will be required | A9.1.19 |
| Audible noise | Major | AC filter compound and converter transformers will be big sources of acoustic noise. The impact on the local community needs to be considered | A9.1.20 |

(*continued*)

| Impact on detailed substation design | | | |
|---|---|---|---|
| Impact index | Impact | Important notice | Appendix |
| EMC | Major | Valve hall and AC filter compound will generate high EMC levels. Need to ensure compliance with new regs | A9.1.21 |
| Electrical clearances | None | AC switchyard – no different to existing design clearance. DC yard will be different | A9.1.22 |
| Safety clearances | None | AC switchyard – no different to normal rules. DC switchyard will require attention | A9.1.22 |
| EM fields | Minor | Reactors will generate high EM fields. High currents will also be present in the DC and filter yards | A9.1.23 |
| Civils | Major | Extensive works required for the valve hall, DC, and filter yards. New bay foundations will be required for connection into AC substation | A9.1.24 |
| Containment | Major | DC transformers and reactors will require bunding | A9.1.25 |
| Auxiliaries | High | Significant services required for HVDC station, may drain resources of existing AC substation. Cooling systems for converter valves, SVCs, and transformers | A9.1.26 |
| Equipment ratings | None | Should be designed to match existing substation equipment | |
| Busbar layout | Major | Connect into existing substation, may require extension in order to add new bays | A9.1.27 |
| Earthing | Major | Earth return method adopted on the HVDC converter station can affect the existing substation earth. Earthing transformer will be necessary for any delta connections | A9.1.28 |
| Monitoring | Major | Large degree of monitoring required to ensure operational compliance | A9.1.29 |
| Testing | Major | Significant type testing and FAT for HVDC converter station. Testing of existing protection may be necessary | A9.1.30 |
| Relocatability | None | | |
| Spares requirement | Major | Significant for HVDC station. AC spares will be determined by the availability level sought | A9.1.31 |
| Hazards | Major | Large-scale project | A9.1.32 |

## Advice & Recommendations

### A9.1.1 Fault Level and Power Flow

Operation of the HVDC link will determine the power flow through the substation and can be considered as a power flow controller. The fault current contribution into the substation will need to be coordinated with the HVDC control scheme. The rating of switchgear in the AC substation will need to be checked.

### A9.1.2 Frequency
Loss of the link may cause system frequency fluctuations. This is a particular problem in weak networks.

### A9.1.3 Voltage
Link load rejection or commutation failure can cause fundamental frequency over-voltage during load rejection and recovery.

The reactive compensation in the HVDC station should be specified to control any reactive current output to maintain the AC voltage within acceptable margins. The coordination control with the transformers is necessary to reserve sufficient capacity for a sudden voltage deviation.

### A9.1.5 Harmonics
Harmonic filters are necessary to control any harmonics generated by thyristor switching. These occupy a significant element of the DC and AC yard depending on system compliance requirements. Rating and configuration during various directional flow and outage conditions needs to be carefully examined.

Ref: CIGRE Brochure 139 Guide to specification, design, and evaluation of AC filters.

### A9.1.6 Losses
The losses concerning the substation are associated with AC filters, auxiliary supplies for SVC. The DC losses are not really in the scope of this work. However the overall HVDC transmission loss is lower than the AC equivalent, depending on the loading.

### A9.1.7 Operational Switching
It will be necessary to review the local network switching regime to optimally integrate the HVDC and manage contingency. This may also be coordinated as wide area control to manage power flow and fault conditions.

### A9.1.8 Reactive Compensation
Similar to harmonic filtering, a significant degree of reactive compensation will be necessary to provide dynamic compliance during system fault conditions. Again, space requirements will be significant. For details on the specific reactive compensation issues, see Appendix 4.

### A9.1.9 Installation
This is a major project and will require major resource allocation. A large number of new bays will be necessary to connect in the DC link, filters, and reactive compensation into the AC substation.

### A9.1.10 Maintenance
There will be a major maintenance activity associated with the converter station, filters, and SVCs. Possibly the converter station may be awarded as a separate

contract with the manufacturer. Auxiliary systems require the most attention involving routine inspections for coolant levels and fluid checks. Aspects relating to reactive compensation are covered in Appendix 4. Coordinating maintenance outages with other system works will be a key planning challenge, since availability of the DC link is similar to that of a generator.

### A9.1.11 Commissioning

This is a significant system event and will need to be coordinated with the network operator well in advance. Tests will include power reversals, which can dramatically affect local network security. Specialist skilled engineers will be required.

Ref. CIGRE Brochure 97: system tests for HVDC installation.

### A9.1.12 Insulation Coordination

The DC switchyard voltage is generally equivalent to peak phase to phase of the AC. Electrical clearances are similar; however insulation creepage needs to be longer. The impact of overvoltages due to link problems needs to be analyzed.

### A9.1.13 Protection (External)

Same as general protection design. Study the coordination between short/grounding faults' protection of SVCs and external protection. Need to limit the sensitivity of external protection to DC faults. Most HVDC links require some type of special protection scheme to coordinate the network response and prevent instability. Typically, this will be unique to the network and difficult to test.

### A9.1.14 Protection (Internal)

HVDC converter protection is integrated into the control scheme. Application will require significant input from the manufacturer.

### A9.1.15 Control

Extensive control of the converter station is necessary and requires coordination with substation control. Possibility of wide area control may depend on system fault level. Operation during pole outages will need to be agreed.

### A9.1.16 Communications

Any wide area control will require reliable fast communication links. The integrity and reliability of this path is important, as spurious signals are not desirable.

### A9.1.17 Land Take

There will be significant land take for the converter station, and additional bays will be required in the AC compound to connect the link into the existing AC network.

### A9.1.18 Visual Impact

Planning permission will very likely be required as the impact will be significant: tall valve hall, large layout for AC and DC switchyards, new circuit, or cable route.

**A9.1.19 External Pollution**

DC insulation is more sensitive to the effects of external pollution, as a DC field will attract dust to insulators. The creepage needs to be increased above that of AC insulation, typically 40 mm/kV (based on phase to phase voltage).

**A9.1.20 Acoustic Noise**

There are a number of potential sources of noise. In particular, the AC filter compound (air-cored reactors), converter transformers, and SVCs will be big sources of acoustic noise. Their location arrangement and load profile should be designed to minimize noise at normal operation.

Ref. CIGRE brochure 202 HVDC stations audible noise.

**A9.1.21 EMC**

The valve hall, active filters, and reactive compensation valves will all be sources of EMC. Building design and cubicles should be specified accordingly to contain these sources. Cabling between modules should also be screened. Conversely, the valve firing circuits need to be hardened against interference. The use of light triggered thyristors should alleviate this risk.

**A9.1.22 Clearances**

There should be no changes to clearance in the AC substation. Clearances associated with DC will generally align to impulse and switching overvoltages. DC insulation creepage is longer than the equivalent AC voltage, so structures may need to be larger to accommodate longer insulators.

**A9.1.23 EM Fields**

Magnetic field issues associated with reactive compensation and AC filters are discussed in Appendix 4.

**A9.1.24 Civils**

The converter and associated AC yard will require substation earth works. Reinforcement in the presence of magnetic fields will need to prevent current induction in metallic loops (insulated rebar). Structures in the DC switchyard may be larger than their AC equivalent on a per phase basis.

Plans should be established for the replacement of large plant items following either an equipment failure of asset replacement.

**A9.1.25 Oil Containment**

The converter transformers and DC reactors will require oil containment bunds. It may be necessary to consider a fire barrier between the transformer and adjacent equipment on other circuits to prevent a fire on the transformer from damaging equipment on the other circuits.

#### A9.1.26 Auxiliaries

The converter station will require a new LV supply. New capacity should be installed rather than extend the existing system. Additional DC supplies will also be required for the control and protection. Risks associated with power electronic systems are also covered in A4, A6, and A7.

#### A9.1.27 Busbar Layout

A number of new bays will be necessary. The running arrangement should aim to accommodate the flexibility offered by the DC link. Pole outage conditions should also be considered to maintain some availability during faults or outages.

#### A9.1.28 Earthing

The type of earth return method adopted on the HVDC converter station may affect the existing substation earth. Any earth return mode can impose detrimental currents into neutrals.

The reactive compensation will require an earthing transformer for delta connections.

#### A9.1.29 Monitoring

High accuracy instrument transformers and quality of supply monitoring will be necessary to ensure compliance of harmonic levels – similar to generator. A system side transient fault recorder and data logger should also be installed to assist with resolving any abnormal operational events. The converter and compensation systems will all have sophisticated fault recorders built in.

#### A9.1.30 Testing

A major type testing program may be required at the development stage for the technology. Most testing will be associated with FAT on control and protection systems to prove dependability and reliability. Manufacturer assistance due to special equipment such as thyristor, cooling equipment control, and valve monitoring will be required. This along with commissioning requires careful coordination with the system operation as any effects can be wide spread.

#### A9.1.31 Spares

The provision of spares can be significant for HVDC stations. The criticality will depend on the required availability. Key items to consider are replacement valves and control boards. Spare transformers and reactors need to be financially justified. For the AC switchyard capacitor units, spare or redundant reactors and cooling parts are useful. Essentially the spares kept will be dependent on the availability level sought. Items with long lead times that affect link availability should be selected.

#### A9.1.32 Other Hazards

The HVDC switchyard contains a mixture of technologies and should only be accessible to trained personnel.

## 6.5 Mobile Substations

### 6.5.1 Introduction

In recent years, a number of utilities have implemented different forms of "mobile" substations employing a high level of off-site construction (e.g., B3-102, 2012). The underlying aim is the ability to provide new/extended/replacement substation facilities at short notice and with a reduced site construction period compared with traditional solutions. Transmission and distribution owners are coming under pressure to respond rapidly to changing user demands, and the ability to respond flexibly to these demands is one element in delivering smarter grids for the twenty-first century.

Mobile substations have found a wide range of applications and, however, can be categorized into three broad types:

- Type A: mobile (designed for frequent relocation at short notice)
- Type B: relocatable (designed for occasional relocation as planned works)
- Type C: prefabricated (not designed as relocatable, only for transfer from assembly area to site)

Typical applications for mobile substations are illustrated in the following examples:

a) **Emergency replacement of failed equipment (Type A)**

Grid failures or outages caused by component failures, natural disasters, or even terrorist attacks require a rapid response. A mobile substation can be quickly transported to the affected site and high-voltage connections established through a simple interface, e.g., through outdoor bushings.

For these applications, the mobile substation is utilized as a standby unit to limit the impact of blackout situations (Fig. 6.3).

b) **Duplicating substation functionality to facilitate outages (Type B)**

The impact of planned outages can be mitigated through the use of mobile substations. By connecting the mobile substation to substitute for the equipment being worked on, the affected circuit (e.g., line, transformer, generating unit) can remain in service during much of the work.

This procedure can most effectively be applied to mid- and long-term projects such as refurbishment and replacement of substation components (Fig. 6.4).

c) **Requirement for temporary additional capacity (Type A/Type B)**

A mobile substation can be used to provide power supplies while a permanent substation is under construction, allowing the utility to respond quickly to unexpected changes in demand.

Also, a mobile substation can be used to meet additional power demand due to seasonal loadings or special events (Fig. 6.5).


**Fig. 6.3** Emergency mobile substation being transported to site

**Fig. 6.4** Mobile substation next to main substation

**Fig. 6.5** Mobile substation being used to meet additional power demand

d) **Meeting short-term load requirements (Type B)**

One of the challenges for transmission and distribution is providing for short-term customer loads. This may include a customer such as a remote mining site that requires power for a number of years but not expecting a life of more than 15 years. The development of a permanent substation may therefore be uneconomic for the utility, and a form of mobile substation that can be relocated is justified.

The "skid mount" substation in Fig. 6.6 was developed by Ergon Energy in Queensland, Australia, for short-term power connections up to 10MVA and for a connection point life of up to 15 years. The units are fully self-contained with switchgear, power transformer, and control and protection systems. These units are intended to be used in groups to provide a short-term distribution substation with the required number of customer feeders. The substation can be relocated once it is no longer required at the original site.

e) **Early grid connections (Type B/Type C)**

Renewable generation technologies, such as wind farms or photovoltaic arrays, have shorter construction time requirements in comparison with conventional generating units, and provision of timely grid connection can be challenging.

**Fig. 6.6** Skid mount substation (courtesy Ergon Energy, Australia)

The use of prefabricated substations can allow these systems to be connected to the grid much faster than normal designs, thus facilitating early realization of benefits.

f) **Shorten site works (Type B/Type C)**

A prefabricated substation can be installed and commissioned faster than a regular substation. Both the primary and secondary electrical works are largely complete before delivery to site, and the modular construction simplifies the civil and construction works.

These features can be particularly important where skilled local resources are not readily available, for example, in areas of low population density, poor economic development, or with military security situations.

In other cases a mobile substation can avoid high costs related to the transport of qualified personnel to the substation location, such as a wind farm offshore platform. In these situations, the use of "prefabricated" substations can be justified, even though the installation may be permanent (Fig. 6.7).

g) **Avoiding stranded assets (Type B)**

Mobile substations can potentially be relocated and reused. The increased performance of modern substation assets can lead to the substation life significantly exceeding that of its application. If the substation is designed to be relocatable, then it can be transported to another site rather than become a "stranded asset" (Fig. 6.8).

**Fig. 6.7** Example of a prefabricated substation for permanent installation on-site. (Courtesy Ergon Energy, Australia)

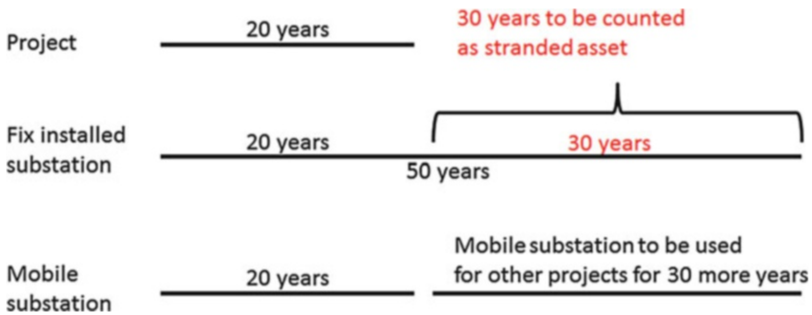


**Fig. 6.8** Mobile substation avoids "stranded assets"

### 6.5.2 Standards

Due to the need for compactness, mobile substations may utilize GIS technology with many designs based on compact switchgear assemblies with the addition of integrated control/protection facilities.

Many of these units, particularly those intended for emergency use, incorporate a transformer and LV switchgear; however this is not a defining characteristic. HV switchgear configurations can be defined by the user; however where rapid deployment is required, there are advantages in keeping the HV interfaces simple and restricting size to facilitate transport.

Thus, in addition to individual product standards covering the design/testing of the functional components of the substation, the following existing system standards are partly relevant to mobile substations:

- IEC62271 High-voltage switchgear and controlgear – Part 202: High-voltage/low-voltage prefabricated substation
- IEC62271 High-voltage switchgear and controlgear – Part 205: Compact switchgear assemblies for rated voltages above 52 kV
- IEC61936 Power installations exceeding 1 kV a.c – Part 1: Common Rules

In general these product/system standards adequately address the functional (performance) and routine testing requirements of mobile substations. However, they do not necessarily consider the specific requirements for construction and site testing of mobile substations, and recommendations are required on this issue. In some circumstances (depending on the application), it may not be appropriate for mobile substations to fully comply with conventional standards regarding, for example, foundations/structures and environmental conditions. This is currently not addressed by standards, and reference to CIGRE guidelines and recommendations would be beneficial.

In some circumstances, it is necessary for mobile substations to comply with standards from other technical areas. For example, Type A mobile substations are generally permanently mounted on road vehicles and must comply with local standards and regulations applicable to such vehicles. This may include a requirement for periodic inspection and testing.

### 6.5.3 Typical Transport Restrictions Associated with Mobile Substations

The transport restrictions will typically depend on the application and the local road regulations.

For Type A units, the ability to rapidly deploy the substation to a range of different locations without the need for specific approval/permitting will limit the size/weight of the individual components. These limits may be set by local legislation, but the constraints of the road infrastructure in the area of operation must also be considered. Mobilization should ideally be to pre-identified sites, thus allowing pre-assessment of the transport requirements (e.g., surveying of bridges and culverts along the proposed route) and development of contingency plans to facilitate rapid deployment.

In some cases, users have opted to split a Type A substation into a number of modules (which can rapidly be connected at site) to help avoid transport limitations.

For a Type B substation, consideration can be given to the maximum capabilities of the transport infrastructure to access the application site(s) when designing the transport modules. As movements are planned, specific authorizations can be considered, and the use of specialized vehicles may be appropriate.

Where the facility to relocate is critical, it is important that the substation design takes into account both the initial application site and any sites to which the unit may be relocated in the future.

For a Type C substation, movement is only envisaged once. For these structures, it is reasonable to require temporary works and highly specialized equipment to access the installation site.

### 6.5.4 Site Preparations

A key requirement for a mobile substation is the facility to rapidly and safely deploy and commission the installation, whether it is to form part of an existing substation or it is a stand-alone installation.

For Type A units, this deployment may be required during a network emergency or in challenging weather conditions (i.e., storms). It is therefore important that a level of preplanning is undertaken to ensure that the connection and commissioning activities are straightforward and that all necessary materials and tools are available. In some cases, it may be beneficial to prepare the primary connection points in advance of deployment. Type A substations are generally designed to minimize the need for site preparation at the time of connection. A suitable site must be identified, generally flat and level (although facilities for levelling the unit are often provided) with easy access for the transport vehicle and the facility to make a connection to the high-voltage system. The site would typically be prepared using crushed rock to provide hard standing and to achieve very short connection times; these works should ideally be completed in advance of need.

If the mobile substation is to be located outside an existing substation compound, then consideration must be given to provide suitable fencing (to prevent unauthorized access to the installation) and earthing.

For Type B substations, the intended duration of the application needs to be considered. Unless the deployment is short-term, it is likely that the installation will have to fully comply with applicable local standards for electrical installations.

Type C substations would typically be provided with civil works meeting the local requirements for permanent structures. They can, however, be expected to be of simpler design than would be necessary for a conventional substation.

### 6.5.5 Design Guidelines for Mobile Substations

Transport requirements may restrict the external dimensions of the mobile substation, and consideration must be given to designs that facilitate rapid deployment at site. This may include plug in bushings to avoid oil handling when bushings have been removed for transport.

Other measures may include special considerations to enable the rapid connection between different items of primary plant when the substation reaches the final site (e.g., cable drums with already terminated plugs for quick and easy connections).


**Fig. 6.9** The “NOMAD” mobile substation includes cable reels for rapid connection to pre-prepared substations (courtesy Ergon Energy, Australia)

The NOMAD mobile substation below has a transformer with switchable voltage ratio and vector group settings (66 or 33 kV primary, 22 or 11 kV secondary, and two vector groups). These setting changes can be carried out using external switches and do not require access to the transformer tank (Fig. 6.9).

Apart from primary connections, another aspect of connecting a mobile substation is the integration of secondary systems (control and protection) into the existing network and interfacing with an existing substation.

Communications to enable connection to the network SCADA system may be required, and this can be achieved by onboard satellite systems or other means of connection.

Integration into existing protection systems can be extremely challenging. Some applications can be implemented with very basic protection functionality (although it must be confirmed that a minimum standard is provided so as to achieve safety and avoid overstressing switchgear). Where a basic protection scheme is not suitable, it is important that preplanning has been undertaken at the existing substation. For example, connection of a mobile substation on an existing busbar may require adaptation of the existing busbar protection system, and this may take time to achieve if not preplanned.

For the shortest connection and commissioning times, arrangements of primary and secondary connections should be preplanned. The philosophy of providing pre-wired and pretested “sockets” for both primary and secondary connections that enable connection of mobile substations appears to provide the fastest connection times. Prepared checklists and commissioning procedures are recommended to ensure error-free connection under emergency or time-constrained conditions.

# Substation Specification and Evaluation

# 7

John Finn

## Contents


7.1 General Introduction ........ 101
7.2 Conventional Specifications ........ 102
7.2.1 Location and Spatial Constraints ........ 102
7.2.2 Effects of Environment on Substation ........ 102
7.2.3 Circuit Definitions, Terminal Points, and Physical Boundaries ........ 103
7.2.4 Basic Information for Civil Works ........ 103
7.2.5 Basic System Parameters (Repeat for Each Different Voltage in the Substation) ........ 104
7.2.6 The Required Switching Configuration ........ 104
7.2.7 Secondary System Requirements ........ 104
7.2.8 Standards and Regulations ........ 106
7.2.9 Health, Safety, and Environment ........ 106
7.3 Evaluation of Substation Concepts ........ 107
7.3.1 The Life Cycle of a Substation ........ 107
7.3.2 Method of Substation Evaluation ........ 107
7.4 Functional Specifications ........ 113


## 7.1 General Introduction

In order for the utility or asset owner to obtain the substation that they require, it is necessary for them to clearly specify their requirements. This is usually done by producing a conventional specification in conjunction with a set of commercial terms and conditions.

When the responses to the tender enquiries are received, then it is necessary for the customer to evaluate the different responses received. The main aspects in evaluating tenders are given in this section.


J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com



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Finally, a brief look is taken at functional specifications which at one time were thought would be necessary to encourage innovation.

## 7.2 Conventional Specifications

This section provides some basic pointers to assist in the preparation of specifications. It is essential that all of the relevant information related to the site and the incoming circuits be provided. This information will include.

### 7.2.1 Location and Spatial Constraints

The location of the site should be defined, usually by giving northings and eastings of one corner of the site. A drawing will also normally be provided showing the maximum available site area with dimensions in the east/west and north/south directions.

The site drawing will show any bench marks or levels (if available) located on the site and the locations of each of the external circuit entries (current and future, if known).

The level of the site above the national bench mark/sea level and any changes in level across the site should be shown in the site drawing referred to above.

### 7.2.2 Effects of Environment on Substation

The following environmental conditions for the site will normally be provided:

- Wind conditions in terms of either wind speed or pressure
- Maximum levels of snowfall and information on soil frost
- The maximum and minimum temperatures and also the maximum average temperature to be considered for the design
- The percentage humidity and rainfall data for each month at the site is to be considered

The following information will also usually be provided:

- Ice (thickness of ice on conductors to be considered in design)
- Seismic level (in terms of g value in each direction and frequency, if applicable)
- Required creepage level (in accordance with IEC 60815 in mm/kV)
- Keraunic level (thunderstorm days/yr)

In certain cases information on flood levels, sandstorms, etc. may need to be provided.

### 7.2.3 Circuit Definitions, Terminal Points, and Physical Boundaries

(a) **Overhead Lines for Each Overhead Line Circuit**

The voltage and the name of the circuit together with the grid point location for the center of the terminal tower. The dimensions of the tower preferably with a tower drawing. If a double or multiple circuit tower, each circuit should be clearly identified. The orientation of the tower relative to the site together with the phasing information. The conductor type, size, and tension required on the spans from the tower to the substation. The rated and short circuit currents for the conductors. Details of the earth wire(s) and termination requirements for the earth wire(s) into the substation.

(b) **Power Cables for Each Cable Circuit**

The voltage and the name of the circuit. The type of the cable XLPE/LPOF, etc. and the number of cables per phase together with the conductor size in square millimeters. The route of the cable across the site. The method of bonding to be applied on the cable sheaths. If oil filled cable, the space required and preferred location for the oil tanks. Details of any pilot cables in terms of number of pilots and number of cores in each and details of any pilot marshalling cabinets.

(c) **Transformers**

For each power transformer the open circuit voltage ratio, rating, cooling method, vector group (including tertiary if required), impedance, tap changer (on load, off load, off circuit), tapping range and steps, noise level (including any requirement for noiseproof enclosures), termination details, and capitalized value for losses.

(d) **Auxiliary Supplies**

The voltage and rating required for the LVAC supply and the number and rating of the circuits (unless this is to be decided by the supplier) should be defined and any requirement for the auxiliary supplies to be metered with tariff metering. The DC battery voltages, duration for battery autonomy, and segregation requirements should be defined.

### 7.2.4 Basic Information for Civil Works

The minimum ground bearing pressure, earth resistivity, and thermal resistivity of the soil together with any site investigation reports and borehole results. The level of the water table at the site, if known. The requirements for the finished levels at the site and whether level, sloping, or terraced. The requirement for removal of spoil and if any contaminated soil is present. The area allocated for the contractor's site establishment. The fencing and security requirements to be applied. The interface points with roads, water supplies, and drainage. The detailed requirements for any buildings on the site including the dimensions of the rooms, heating, ventilating and air conditioning requirements, as well as the finishing requirements. The locations of any known buried services existing within the site boundaries.

### 7.2.5 Basic System Parameters (Repeat for Each Different Voltage in the Substation)

The following data relevant to the system parameters applicable to the site will need to be provided:

| | |
|---|---|
| Nominal system voltage | kV |
| System highest voltage | kV |
| Minimum system voltage | kV |
| Basic (LIWL) impulse level | kVp |
| Switching impulse level | kVp |
| Power frequency test voltage | kV |
| Short circuit level (three-phase) | kA |
| Short circuit level (one-phase) | kA |
| Short-time current duration | s |
| System neutral earthing | Solid/resistance/reactance/ Petersen coil/ ungrounded |
| Earth fault factor, max. time | s |
| Substation neutral earthing for star/delta winding | Solid/resistance/reactance/ Petersen coil/ungrounded |
| Frequency | Hz |
| Allowed frequency variation (+/−) | % |
| Phase shift between voltage systems | |

### 7.2.6 The Required Switching Configuration

The required switching configuration for each of the bus bar systems to be provided within the substation should be defined. This will normally be done by providing a single-line diagram for the substation, which will also show the relative disposition of the various circuits on each bus bar.

### 7.2.7 Secondary System Requirements

(a) **Control Centers**

Details of the control centers that the substation control system is required to interface with should be provided, for example, National Control Centre and/or District Control Centre.

This information should include the manufacturer of the equipment used at the control center together with the protocol used and software version.

(b) **Control System**

Details of the required substation control system will include:

- Control functions
- Status indications
- Alarm indications
- Analogue measurements
- Spare point allocations
- Display requirements
- Redundancy
- Any special automatic control functions, e.g., automatic tap change control
- Fault recording capability
- Event recording requirements
- Remote access requirements

(c) **Protection**

The details of the protection to be supplied for each circuit and bus bar system should be defined including the required fault clearance time. The requirements for the protection to have adjustable settings and be able to store fault records, if required, should be defined. If there is existing equipment at the remote ends of the overhead line or cable circuits, then details of the existing equipment will need to be provided. In addition to the main protection the backup protection, circuit breaker fail, and autoreclose requirements should be specified. Any specific requirements for test facilities such as test switches or sockets also need to be specified.

(d) **Metering**

The circuits requiring energy metering should be defined including the parameters MWh and/or MVArh together with the direction and accuracy. In addition, requirements for check metering, remote repeat facilities, and different tariffs should be defined.

(e) **Communications**

The methods of communication to be provided should be defined. This may include power line carrier, fiber optics, microwave or pilot cables, or combinations of these. Furthermore specific requirements such as bandwidth, allocated frequencies, etc. will need to be given. The information to be communicated such as telephony, data, protection signaling, and intertripping together with the speed and security requirements will need to be defined.

### 7.2.8 Standards and Regulations

It is necessary to define the national legal requirements that may be applicable to the substation. Most utilities will normally have a set of their own standards or specifications relating not only to the substation but also to the various items of plant to be installed. These specifications will usually take preference over specifications such as the IEC, ANSI, VDE, or other international or national technical specifications.

### 7.2.9 Health, Safety, and Environment

Here the customer will define their requirements for health, safety, and environment. These may include regulations on handling particular materials or substances.

(a) **Safety Requirements**

These will cover all of the relevant safety aspects to be taken into account in the design, construction, operation, and maintenance of the substation. Some typical examples being:

- National safety standards
- The utility's safety rules and procedures
- Step, touch, and ground potential rise voltages if different from recognized standards
- Specific minimum clearances for work
- Restrictions on live working
- Substation security requirements
- Lighting requirements

(b) **Environment Requirements**

The impact that any new equipment has on the environment has to be closely controlled. A few of the typical aspects that may need to be defined are listed below:

- Maximum noise level for the site (usually as sound pressure at a distance)
- Electric field at ground level
- Magnetic field at a specified boundary
- Particular aesthetic requirements such as maximum height of structures and buildings, specific style of building to be used, color of porcelain, etc.
- Oil damage prevention
- Archaeological restraints (information on any archaeological artifacts)
- Any specific environmental laws or regulations that the supplier must comply with

## 7.3 Evaluation of Substation Concepts

### 7.3.1 The Life Cycle of a Substation

A life cycle definition and model of electrotechnical systems in general is well described in an international standard [IEC 60300]. According to this document the life cycle of a substation is defined: "The life cycle of a substation is the time interval between a substations's planning and it's decommissioning."

The life cycle of a substation is separated in life cycle phases. Two life cycle models for substations, a three-phase and a six-phase model, were derived from the general models of electrotechnical systems (Table 7.1).

### 7.3.2 Method of Substation Evaluation

A wide variety of methods of evaluation have been developed. Depending on the evaluation subject and circumstances, they are more technically or economically oriented, precise or pragmatic, short, or very time-consuming in their application. For the evaluation of substation concepts, we look for a combined economical-technical-environmental evaluation method, which can be adapted to the needs of its users. Powerful methods are described in international standards and regulations, such as the value management [VDI 2800], the life cycle costing [IEC 60300], or the model of the Life Cycle Assessment [ISO 14040].

Economical evaluations are the prerequisites to stay competitive. They range from the pure investment cost evaluation to the complete life cycle cost evaluation including capitalized cost. The additional evaluation of income, interest, and taxes over the life cycle results in the economic value added. If additional qualitative

**Table 7.1** Life cycle phases of electrotechnical systems and substations

| Electrotechnical system [IEC 60300] Three-phase model | Six-phase model | Substation three-phase model | Six-phase model |
|---|---|---|---|
| Acquisition | Concept and definition | Acquisition | Planning: tendering, offering, evaluating, contracting |
| | Design and development | | Design: basic and detail design |
| | Manufacturing | | Procurement, production, and site preparation |
| | Installation | | Installation, testing, and commissioning |
| Ownership | Operation and maintenance | Ownership | Operation and maintenance |
| Disposal | Disposal | Disposal | Extension, refurbishment, decommissioning |

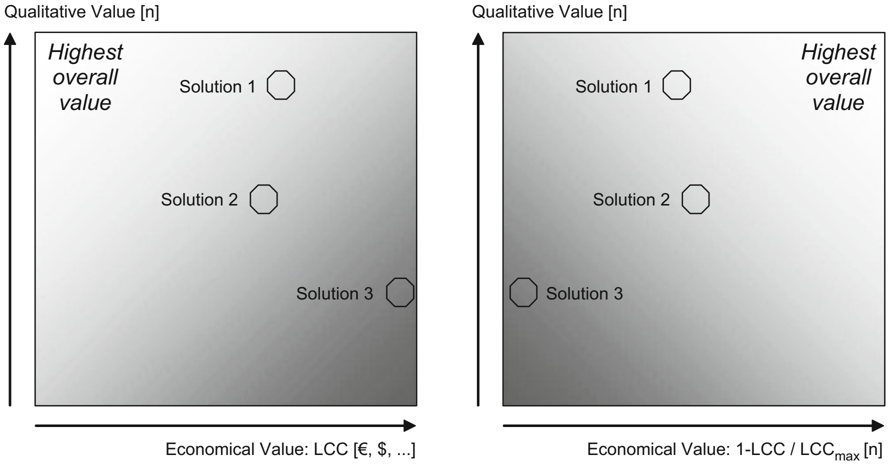


**Fig. 7.1** Evaluation portfolio for economical and qualitative values

values have to be considered, the value management method or Life Cycle Assessment can be applied.

The developed method of substation evaluation described below is a pragmatic combination between the economical on one side and technical, environmental, and business partner evaluation on the other side. There are two dimensions of evaluation:

- Economical evaluation
- Qualitative evaluation

Both dimensions are evaluated and documented in a two-dimensional portfolio (Fig. 7.1).

Description of the evaluation process:

1. Perform economical evaluation. This is usually straightforward and is done for all elements that could be directly expressed in monetary terms including initial investment cost as well as operation and maintenance cost of the life cycle of a substation.
2. Perform qualitative (technical, environmental, and business partner) evaluation. Decide which values can be put into monetary terms (economical dimensions). If further qualitative values have to be considered, for example, references of offered solutions, experience of former or existing business partnerships, required sustainability of business relationship, or corporate citizenship, a second dimension of evaluation is set up.
3. Perform overall evaluation. The economical and qualitative values are visualized in the evaluation portfolio.

A list of examples of economical and qualitative values is shown in Table 7.2.

**Table 7.2** Values of substation evaluation

| Life cycle phases | | Economical values | Qualitative values |
|---|---|---|---|
| Acquisition | Planning | Tender/acquisition cost | Bidder references<br>Bidder presence in country<br>Bidder local organization |
| | | Offer/evaluation cost | Compliance with the scope of supply<br>Compliance with documentation<br>Quality of supply |
| | | Contracting/legal cost | Bidder asset management capability |
| | Design | Development cost | |
| | | Engineering cost | |
| | Procurement/production/site preparation | Land acquisition cost | Community acceptance<br>Environmental/visual impact<br>EMC, EMF generated |
| | | Civil works | |
| | | Equipment/system cost | |
| | | Training cost | |
| | | Transportation cost | Compliance with delivery time<br>Delivery time |
| | Installation, testing, and commissioning | Installation cost | Qualification of installation, testing, and commissioning personal |
| | | Testing cost | |
| | | Commissioning cost | |
| Ownership | Operation | Running losses | Operational flexibility<br>Safety<br>Air pollution/climate tolerance<br>Seismic tolerance<br>Performance reserve |
| | | Building maintenance | |
| | | Switchyard maintenance | |
| | Preventive maintenance/planned unavailability | Loss of revenue | Warranties<br>Compliance with maintenance/repair time |
| | | Outage planning admin. Cost | |
| | | Customer/generation constraint penalties | |
| | | Labor | Qualification of maintenance personal |
| | | Material | Capacity to supply spare parts |

(*continued*)

**Table 7.2** (continued)

| Life cycle phases | | Economical values | Qualitative values |
|---|---|---|---|
| | | Travel expenses | |
| | Corrective maintenance/ unplanned unavailability | Loss of revenue | Compliance with outage time |
| | | Customer/ generation constraint penalties | |
| | | Labor | |
| | | Material | |
| | | Travel expenses | |
| Disposal | Extension | Extension cost | Extendibility |
| | | Cost of adapting to future requirements | Independence of interfaces |
| | Refurbishment | | Flexibility of scheme |
| | Decommissioning | | |
| | Disposal | | Environmental disposal impact |

(a) **Economical Evaluation**

The economical evaluation is based on the life cycle cost method [IEC 60300]. The life cycle costing process is based on the life cycle model. Models of substation life cycles are given in Table 7.1, and examples of economical values are given in Table 7.2.

In recent years a wide variety of life cycle cost evaluation examples have been published. However, the life cycle cost evaluation process is proficiently described in IEC [IEC 60300] for general electrotechnical systems. For the evaluation of substation concepts, the process is detailed below and simplified where possible:

- Define life cycle phases of the substation and develop cost breakdown structure.
- Define product/work breakdown structure.
- Estimate the cost.
- Summarize cost, either direct or capitalized.
- Optional: Analyze optimization potential by sensitivity analysis.

According to IEC 60300-3-3 [IEC 60300], the following life cycle model and cost breakdown structure is defined:

$$LCC = Cost_{acquistion} + Cost_{ownership} + Cost_{disposal}$$

(i) **Cost of Acquisition**

The acquisition cost comprises all costs beginning with the planning process up to the installation, testing, and commissioning of the substation up to handover to the asset owner. Table 7.2 provides a list of typical acquisition costs. Planning and design cost, such as tendering, acquisition, offer, evaluation, and legal and contracting costs, can be used, but often they do not differ between the evaluated solutions. The main components are system cost (circuit breaker, disconnectors, earthing switches, current and voltage transformers, control and protection systems, transformers and associated protective devices, and auxiliary equipment), cost of land acquisition, training cost, and cost of installation.

(ii) **Cost of Ownership**

This cost portion contains all costs of the service period during the lifetime of the equipment. Due to the long time of this aspect, these costs should be capitalized. The cost of ownership consists of three major cost elements: operating cost, preventive maintenance cost, and corrective maintenance cost:

**Operating Cost**

Operating cost covers running losses, building, and switchyard maintenance excluding the maintenance of the switchgear.

**Preventive Maintenance Cost**

The preventive maintenance cost comprises labor, material, and travel expenses to maintain the switchgear equipment. Labor and travel expenses depend on location and could differ significantly from country to country. Depending on network conditions, there may be additional planned unavailability cost.

Planned maintenance cost

- Depends closely on the applied maintenance strategies

Planned unavailability cost

- Occurs during scheduled maintenance and construction, e.g., for substation extension. Normally the redundancy of the substation layout should enable planned unavailability cost to be avoided.

**Corrective Maintenance Cost**

Corrective maintenance cost comprises unplanned maintenance and unavailability cost.

Unplanned maintenance cost

- All unexpected failures that result in maintenance activities are covered by the unplanned maintenance cost.

Unplanned unavailability cost

- All cost related to interruption of energy flow not resulting from any scheduled activity is summarized as unplanned unavailability cost, normally following major failures.

(iii) **Cost of Disposal**

These costs have to include all costs of extension, refurbishment, decommissioning, and disposal after use and after subtracting earnings that can be received by selling the reusable materials like aluminum, copper, etc. These costs are also capitalized.

Calculations of life cycle cost of a substation sometimes cover a period of time that is longer than the individual lifetime expectation of parts of the equipment. In particular, the relay and control equipment often has a shorter lifetime than the lifetime of the primary equipment, for example, only half of it. Consequently, the reinvestment cost of such equipment has to be taken into account until the end of the calculation period is reached.

Life cycle cost for HV substations is calculated for a very long period of time, about 30 to 50 years dependent on the type of substation. Therefore, depreciation in the value of the assets has to be respected. The calculation can apply the method of discounted cash flow in order to determine the net present value.

In addition to depreciation, the effects of inflation can also be taken into account.

(b) **Qualitative Evaluation**

The qualitative evaluation covers the evaluation of technology, environment, and of the business partners (solution provider or asset owner). It is based on the value management method, the Life Cycle Assessment [VDI 2800, ISO 14040], and life cycle model of a substation. A number of models of qualitative approaches for substation evaluation have been published in recent years, and the evaluation method of value management process is suggested for the qualitative evaluation of substation concepts. The steps are as follows:

- Define qualitative evaluation criteria along the life cycle. Table 7.2 shows a selection of possible evaluation criteria.
- Weight the selected evaluation criteria, ranging from 0 to 1. The sum of weight should be one.

- Evaluate degree of realization ranging from 0 to 1.
- Multiply weight and degree of realization for every evaluation criteria that is the qualitative value.

(c) **Overall Evaluation**

The economical and the qualitative evaluations are put in a portfolio diagram (Fig. 7.1). The economical value scale can be either in absolute life cycle cost (most economical solutions are on the left-hand side of the portfolio) or in relative numbers between 0 and 1 (most economical solutions are on the right-hand side of the portfolio). The qualitative value scale is a number between 0 and 1 (high-quality solutions on the upper side). With the second presentation method, the best overall solution is indicated by the longest vector distance from the origin.

## 7.4 Functional Specifications

At the turn of this century due to the liberalization of the energy market, the electricity transmission and distribution business were changing rapidly. Grid owners and utilities (asset owners) believed that they required solutions with high overall economic value. It was felt that this may best be achieved by various innovative substation concepts. It was considered that the conventional way of specifying substations and evaluating tenders may not be able to adequately respond to innovative solutions and may even be impeding the introduction of innovation, and so a CIGRE Brochure No. 252 was produced looking at the possibility of producing functional specifications.

The functional specification considered consisted of four parts: **Boundaries, Functional Requirements, Commercial Conditions, and Evaluation Criteria.**

The substation has to fit into an existing network, be connected to incoming and outgoing circuits, as well as consider the environmental and legal aspects. These aspects we can consider as **Boundaries** to the new substation, and these must be clearly defined in a functional specification. For example, boundaries may include high-voltage terminal points; environmental aspects; spatial constraints; civil information; the laws, grid code, and standards to be followed; safety regulations; and other basic system parameters.

The **Functional Requirements** of a particular substation define the actual and future needs of the asset owner. These needs include the required capacity and availability, which will be subject to penalty/bonus schemes together with requirements for flexibility and future extendibility. The substation can be considered as a box with a number of input and output nodes or connection points. The asset owner has to define the connectivity required between these nodes and the capacity of power transfer required with its associated availability.

With any specification or contract documents, there are sets of **Commercial Conditions**. With a functional specification, certain special commercial conditions will be required which are not normally included in a conventional contract. In Brochure 252, these special conditions are considered and defined.

When solution providers are allowed more freedom in their tender preparation, the asset owners must state clearly in the functional specification how the tenders will be evaluated, as is required by the competition legislation of public procurement. The evaluation of tenders based on functional requirements is also made more complicated as the solutions may differ from each other more than with the previous detailed conventional designs. In order to evaluate each solution, **Evaluation Criteria** and weighting factors need to take into account the running, operating, and maintenance costs. This is most likely to be achieved in financial terms by considering the life cycle cost (LCC) together with weighting factors for flexibility, extendibility, and availability. The factors to be used in this LCC for evaluating the bids need to be defined by the asset owner to ensure that they correctly reflect the importance that he attaches to each aspect. Consequently, an evaluation formula is created which enables both the solution provider and the asset owner to calculate the evaluated cost of the substation. This is important for the solution provider to enable him to compare different solutions which he may be considering and then choose the one which gives the lowest evaluated cost for this particular asset owner thus making his offer attractive.

For anyone interested in the concept of a functional specification, Brochure 252 pursues the development of a functional specification, and an example specification is prepared. However, the brochure concludes that such functional specifications are unlikely to replace conventional specifications in the short term, as the difficulties, time, and cost of preparing, evaluating, and administering such a process, including the commercial aspects, exceed the benefit which can be achieved.

# Type of Contract for Substations (In House or Turnkey)

8

John Finn

## Contents

8.1 Introduction .......... 116
8.2 Advantages of Turnkey .......... 116
8.2.1 Simplification .......... 116
8.2.2 Variety of Options .......... 116
8.2.3 Implementation of New Technologies .......... 117
8.2.4 Better Price Certainty .......... 117
8.2.5 Time Schedule Certainty .......... 117
8.2.6 Reduced Asset Owner's Resources .......... 117
8.3 Disadvantages of Turnkey .......... 118
8.3.1 Loss of Control .......... 118
8.3.2 Requirement for Detailed Up-Front Documentation .......... 118
8.3.3 More Complex Evaluation .......... 118
8.3.4 Limited Number of Bids .......... 118
8.3.5 Risk of Poor Construction Quality .......... 118
8.3.6 Risk of Solution Provider Insolvency .......... 119
8.3.7 Risk of Inferior Quality Equipment .......... 119
8.3.8 Higher Cost .......... 119
8.3.9 Loss of Engineering Expertise Within Asset Owner .......... 119
8.4 Transition from In-House Projects to Turnkey Projects .......... 119
8.4.1 The Summation of Two Experiences .......... 120
8.4.2 Sharing for Success .......... 120
8.5 Key Actions to Minimize the Disadvantages of Turnkey Projects .......... 121
8.5.1 Organizational Aspects .......... 121
8.5.2 Establish a Basic Framework for the Execution of the Project .......... 121

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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## 8.1 Introduction

Traditionally utilities have had a very high level of technical expertise particularly related to their own systems, substations, and the need for any special requirements for equipment. To ensure that these needs are met fully, the traditional way of contracting was for the project to be managed "in-house" and the design, procurement, installation, and commissioning of substations to be carried out by the utilities' own staff.

However, due to the deregulation of the power industry coupled with the shortage of skilled specialized resources worldwide, fewer utilities have managed to retain sufficient capability to carry out this "in-house" approach. This has led to an increase in "single source" or "turnkey" solutions being adopted for both the build of new substations and the extension of existing ones. The turnkey approach is not new, having been employed since the early 1970s; it is being adopted more commonly by utilities and government bodies worldwide as they strive to achieve tighter deadlines for medium- to large-scale projects.

Adopting a "turnkey" approach enables the asset owner to turn over the responsibility and risk associated with the project in exchange for a higher cost and loss of control over the implementation of the project. They may also gain some innovation and learn from some of the solution provider's experience in other countries but at the cost of losing the detailed understanding and knowledge of the design and equipment that may make maintenance more difficult in the future.

In this chapter, we will look at the advantages and disadvantages of "turnkey" projects to assist in the decision as to whether to employ a traditional or "turnkey" approach and provide some basic guidelines to make the transition.

## 8.2 Advantages of Turnkey

### 8.2.1 Simplification

In a turnkey project, the asset owner deals with a single entity, namely, the solution provider who provides the design, procurement, construction, and commissioning services for the complete project. This makes the project management task much easier for the asset owner.

### 8.2.2 Variety of Options

The asset owner will receive a number of bids each having their own approach to the project. This may provide the asset owner with a number of options and solutions that he may otherwise have not been aware.

### 8.2.3 Implementation of New Technologies

Turnkey projects can facilitate the introduction of new technologies within a particular utility. On “in-house” projects, the asset owner would normally encounter difficulties when trying to introduce new technologies due to the conservatism and risk aversion of stakeholders in their organization. The solution provider will be looking for ways to make his bid more competitive and attractive and under the strict contractual performance requirements will be using reputable equipment manufacturers who will be at the forefront of development of new technologies. Furthermore, the solution provider may assume the risks involved and provide all of the services necessary for acceptance of the new technologies by the asset owner.

### 8.2.4 Better Price Certainty

Turnkey projects are usually fixed price projects. Within his contractual agreement, the solution provider assumes the risk associated with the design, procurement, installation, testing, and commissioning of the project within the agreed timescales. Provided that the contract has been set up correctly (including tight clauses on currency exchange, escalation costs on equipment and materials, construction adjustments, etc.), the asset owner has fewer risks and claims for cost overruns, and adjustments can be minimized if not avoided completely. If claims do arise, then their management and settlement is simplified. Furthermore, the time taken to determine the total project cost is reduced.

### 8.2.5 Time Schedule Certainty

As the service provider is responsible for the design, general contracting, and execution of the project, they must provide a guarantee that the project will be completed on time and achieve the required performance. This gives confidence of achieving the required in-service date which may be critical for system performance. The contract can provide compensation in the event of schedule delays, for example, liquidated damages or penalties.

### 8.2.6 Reduced Asset Owner’s Resources

The turnkey solution places a much lower demand on the resources of the asset owner as the main work and activity is performed by the solution provider and the asset owner’s role is reduced to overseeing and ensuring compliance with the contractual requirements.

## 8.3 Disadvantages of Turnkey

### 8.3.1 Loss of Control

With an "in-house" project, the asset owner retains total control of the project and can make changes and adjustments to the project during its implementation without significant financial penalty. With a turnkey project the total control and evolution of the project is taken out of the asset owner's control making changes and adjustments difficult and expensive to introduce.

### 8.3.2 Requirement for Detailed Up-Front Documentation

In an "in-house" project, the teams implementing the project are all familiar with the usual requirements, and small changes can easily be made as the project develops. With a turnkey project the asset owner must define in detail exactly what they want to avoid costly changes occurring later. This requires significant additional up-front resources to produce the detailed documentation and specifications required, possibly even requiring assistance from an external consultant at additional cost.

### 8.3.3 More Complex Evaluation

With a turnkey project the asset owner will probably receive a number of bids from different solution providers where each bid potentially may involve different concepts. In such situations it may be difficult for the asset owner to correctly evaluate the proposed solutions, compare prices, and select the best proposal.

### 8.3.4 Limited Number of Bids

Substation projects will normally involve significant risks, particularly for refurbishment and retrofit projects. This may limit the number of bidders prepared to bid for the project and result in reduced competition. With fewer bidders the bidders may increase their price to ensure that they safely cover the increased risks.

### 8.3.5 Risk of Poor Construction Quality

If during the project the solution provider encounters unexpected problems or delays, then there may be a tendency to skimp on the construction quality in order to complete the project on time. This indicates the need for proper construction quality checking being built into the project.

### 8.3.6 Risk of Solution Provider Insolvency

In the turbulent financial times that we live in, there is a risk that even quite large companies may become insolvent very quickly. As the whole of the project execution lies with one organization, then this would mean a major disruption to the project should that company become insolvent. It is very important that a thorough prequalification process is carried out including evaluation of their financial standing and existing assets and liabilities together with requesting financial guarantees such as letters of credit from solid financial institutions.

### 8.3.7 Risk of Inferior Quality Equipment

Given the competitive pressures on solution providers at the time of bidding, the selection of equipment is likely to be dominated by lowest price rather than life cycle considerations such as quality and reliability. The exact equipment being offered should be checked and any expected extra costs taken into account in the evaluation.

### 8.3.8 Higher Cost

The cost of turnkey projects will tend to be higher because of the risks that have to be taken by the solution provider. Furthermore there may be additional costs associated with system integration such as updating existing records, integration of protection, control, telecommunications, and metering into the utility's operating system. However, some turnkey contracts do incorporate modifying remote end protection, integration of telecommunications systems, and metering so this may alleviate these unexpected costs to some extent.

### 8.3.9 Loss of Engineering Expertise Within Asset Owner

As the asset owner does not have involvement in the detailed design or a "hands-on" approach during the construction, the expertise of the staff may be reduced to production of specifications and project management. If turnkey projects become the norm, then the expertise in detailed engineering and construction may be lost.

## 8.4 Transition from In-House Projects to Turnkey Projects

A turnkey contract is an ideal opportunity for the asset owner and the solution provider to share their experience and to learn from each other.

### 8.4.1 The Summation of Two Experiences

The asset owner has in-depth knowledge and experience of his own network and substations. He will be able to share with the solution provider the critically important data required to ensure that the completed substation will meet his requirements and expectations.

The solution provider, due to his worldwide experience, will have acquired knowledge from widely different standards, tools, and situations and so able to advise the asset owner on network evolution and novel substation arrangements.

### 8.4.2 Sharing for Success

While this balance of knowledge and experience is obvious in theory, in reality the relationship between the two partners can be awkward initially. It can involve some difficult changes in the frame of mind of the partners.

The engineering departments of the well-established utilities may take a defensive attitude, as they see their jobs threatened, and this is not conducive to a successful cooperation.

In order to create the necessary positive spirit, relevant communications channels will need to be created. These could involve daily meetings between the asset owner's engineering team and the solution provider's design staff, with larger monthly meetings being organized to decide key issues. It may be prudent to set up a coordination team consisting of one or two staff from each side to provide a quick and effective link to resolve queries and issues that may arise. The solution provider's staff must not feel embarrassed to draw on the wealth of experience held by the asset owner's staff on their particular network.

For staff of an asset owner used to doing "in-house" projects, the change to doing "turnkey" projects involves a change in the way that things are done. For in-house projects, there is no need for detailed planning specifications since the in-house engineering staff is familiar with most of the requirements and informal communication between departments can clarify any missing information. On the other hand for turnkey projects the asset owner's planning team has to produce a specification in sufficient detail for the solution provider to bid for the job and then to implement it after contract award. This is particularly the case for the engineering department where the inherent knowledge of the staff averts the need for detailed specifications on in-house projects. All of this type of information that was previously communicated informally must be written down in detailed specifications or communicated formally in letters, memos, or official interface meetings. This can mean that the use of in-house standards which were slightly out-of-date but used internally with modifications has to be formally revised or cancelled for use on turnkey projects. If the standard is cancelled, then the solution provider will propose the use of international standards, which may not incorporate the special features that the asset owner requires.

Another factor is that the asset owner's engineering staff is used to taking ownership of the projects when done on an in-house basis, but this is not their role on turnkey projects. They must be actively discouraged from "preferential engineering," i.e., trying to force the solutions previously used for in-house projects onto the solution provider. Their role has to become one of reviewing and making constructive suggestions for the effective and speedy implementation of the project.

The important thing is that all people working on the project must remain focused on the success of the project in terms of cost, quality, and time and set aside any personal preferences.

## 8.5 Key Actions to Minimize the Disadvantages of Turnkey Projects

### 8.5.1 Organizational Aspects

Many of the disadvantages mentioned above can be overcome by taking the following steps:

- The asset owner retains a project management team to define the owner's needs as well as monitor the progress of the work.
- The asset owner provides comprehensive documentation to clearly define the deliverables (scope), time frame (schedule), and cost of the project.
- The asset owner retains some control over critical aspects of the work, possibly including quality control of the construction phase of the project.
- The asset owner carries out a thorough prequalification process of bidders including evaluation of their financial standing and existing assets and liabilities together with requesting financial guarantees such as letters of credit from solid financial institutions.
- The asset owner may need to be very specific with regard to the major equipment by clear specifications. It may also be advisable to insist on the use of only prequalified manufacturers and types of equipment.

### 8.5.2 Establish a Basic Framework for the Execution of the Project

The project process can be planned in four stages (ISO 9001):

- **Stage 1 – Preliminary Design**
  This is performed at the beginning of the project to define the main technical solutions and the material selection and to validate the design intent. An approval review meeting should take place to conclude this preliminary phase as technical agreement is an essential step to proceed to Stage 2.

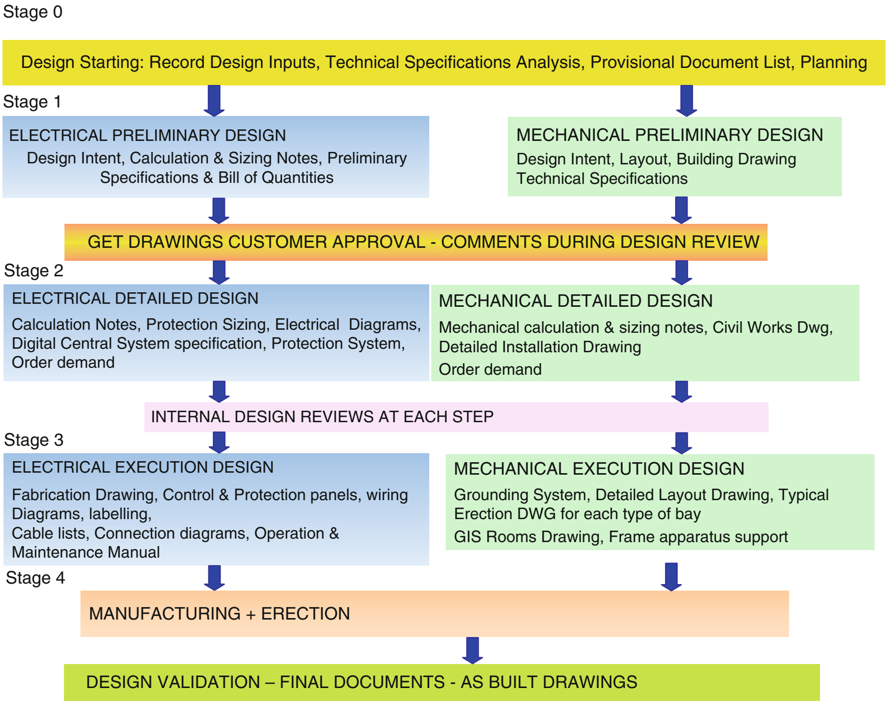


**Fig. 8.1** Design framework for a turnkey project

- **Stage 2 – Detailed Design**
  Conceptual data from Stage 1 is used to develop the detailed construction design of the substation.
- **Stage 3 – Project Execution**
  The manufacturing, delivery, and construction proceed in line with the documents developed during Stage 2.
- **Stage 4 – Project Completion**
  The project is completely handed over, as built drawings produced and warranty dates agreed.

The engineering associated with these stages is illustrated in Fig. 8.1.

For more detailed information on all aspects of turnkey projects, please refer to CIGRE Technical Brochure 439 – Turnkey Substations published December 2010.

# 9 Innovation and Standardization of Substation Equipment

Colm Twomey

## Contents


9.1 Introduction ........ 123
9.2 Definitions ........ 124
9.2.1 Standardization ........ 124
9.2.2 Innovation ........ 125
9.3 Standardization Versus Innovation ........ 127
9.4 Guidelines for Controlled Introduction of Innovation ........ 128
9.4.1 Future Development Structure ........ 129
9.4.2 Future Development Strategy ........ 132
9.4.3 Future Development Road Maps (Implementation Plan) ........ 133
9.4.4 Future Development Projects (Execution Stage) ........ 135
9.5 Integrating Innovative Solutions into the New Generation of Standards ........ 136
9.5.1 Introduction ........ 136
9.5.2 Review of Initial Pilot Project ........ 137
9.5.3 Scoping ........ 138
9.5.4 Implementation Process and Issues ........ 138
9.5.5 Rollout ........ 139
9.5.6 Review Process ........ 139
9.6 Summary ........ 140


## 9.1 Introduction

In recent years, there has been a significant move to introduce innovation into substation equipment. This has been largely driven by manufacturers and solution providers in response to technical developments and commercial pressures. New innovative products have been introduced to the utilities, which can offer many benefits such as reduction of maintenance cost, ease of operation, and simplifying


C. Twomey (✉)
Substation Design, ESB International, Dublin, Ireland
e-mail: Colm.Twomey@esbi.ie



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the substation design. In order to really benefit from these innovative products, the utilities may be required to revise their design philosophy and application standards.

Utilities, however, tend to be more conservative, for very good reasons, as they have to consider the whole of life aspects of the plant including the management of ongoing maintenance activities, and consequently their approach tends to favor proven familiar designs that are often rooted in "standardization." Utilities believe that standardization has many benefits such as lower substation cost, proven operating procedures, proven equipment, and simpler spare requirements. The application of new concepts and innovations in substation design is frequently considered as introducing risk.

Substation standardization has many advantages and benefits. At the same time, new technology and innovations can add great value and could also bring many benefits to substation design, construction, operation, and maintenance. It all depends on how relevant and valuable these are to the utility and whether the risk is worth the gain. Utility application standards need to be regularly updated to reflect the new equipment and the design changes associated with the new equipment. Failure to update the utility application standards can result in outdated installations which therefore become obsolete with little benefit to engineers and designers.

## 9.2 Definitions

### 9.2.1 Standardization

#### 9.2.1.1 Product Standard

"Product Standard" is most often used to mean international or nationally published documents that define the characteristics of equipment or subsystems used as components of installations. Examples of this usage are IEC standards such as 62271-100 or 61850 or IEEE standards such as 1525, C37.2.

#### 9.2.1.2 Application Standard

These are more local documents written by utilities, manufacturers, or others to set out in some detail how the components or systems designed to a "Product Standard" are applied together to achieve the required performance. These utility standards often quote the equipment "standards" and may be referred to as "application standards."

Utilities develop application standards for a number of reasons; typically, these include national legislation regarding health, safety, environment, and security. These standards can also extend to incorporating good practice to help reduce construction errors and outage time, reduce cost, improve safety, ensure knowledge sharing, and simplify operating and maintenance procedures.

Utilities normally select substation configurations that are applied for each voltage level by using certain equipment for each substation layout together with the method of protection and control for each arrangement. Other materials such as substation hardware, substation cables, and other material are predetermined.

These arrangements are normally pre-engineered and are defined as substation standards. This is an example of application standards.

### 9.2.2 Innovation

Innovation results from the examination and implementation of scientific and technical developments, the integration of those developments to create "better" products or systems in terms of their cost, efficiency, and/or performance. They can be classified into "product innovation" and "system innovation."

#### 9.2.2.1 Product Innovation

1. Product innovation can be regarded as the process that improves equipment beyond the range of the conventional standards and changes the performance, design, and size of the equipment. Gas-insulated switchgear, digital relays, and non-conventional instrument transformers are examples.
2. Another type of product innovation creates a new category of products. It is invented by modularization or combination of equipment that is either conventional type or new concept type. This type of product innovation redesigns the layout of substations without changing their circuit structure, and it can reduce the footprint of air-insulated substations. Two examples are shown below to illustrate how innovation can be used to optimize equipment layout and improve reliability.

**Example 1**
Figure 9.1 illustrates the use of mixed technology switchgear (hybrid) in a single bus bar configuration instead of conventional AIS. The innovative product is the hybrid module, which incorporates two disconnectors, a circuit breaker and associated CTs within a single GIS module. From the design standpoint, this equipment has several advantages over the AIS equipment. The physical size of the substation in both length and width has been reduced compared to conventional AIS equipment. In addition, this equipment is considered more reliable since the disconnectors are sheltered from the environment within the GIS enclosures, simpler civil works are required as foundations are smaller, and steel requirements are reduced.

**Example 2**
Figure 9.2 illustrates the use of the rotating circuit breaker/disconnector in an H station design. The innovative product is the combined circuit breaker/disconnectors. The single device incorporates the bus bar disconnector, circuit breaker, and the lineside disconnector. (Note that the location of the CT is actually changed as it is now on the line side of the circuit disconnector compared to the original design.) The advantage of this approach is that the site area for the station is significantly reduced as shown by the two diagrams and foundation requirements are also much less. The circuit breaker rotates such that the top connection disconnects from the bus bar and the bottom connection disconnects from the CT.

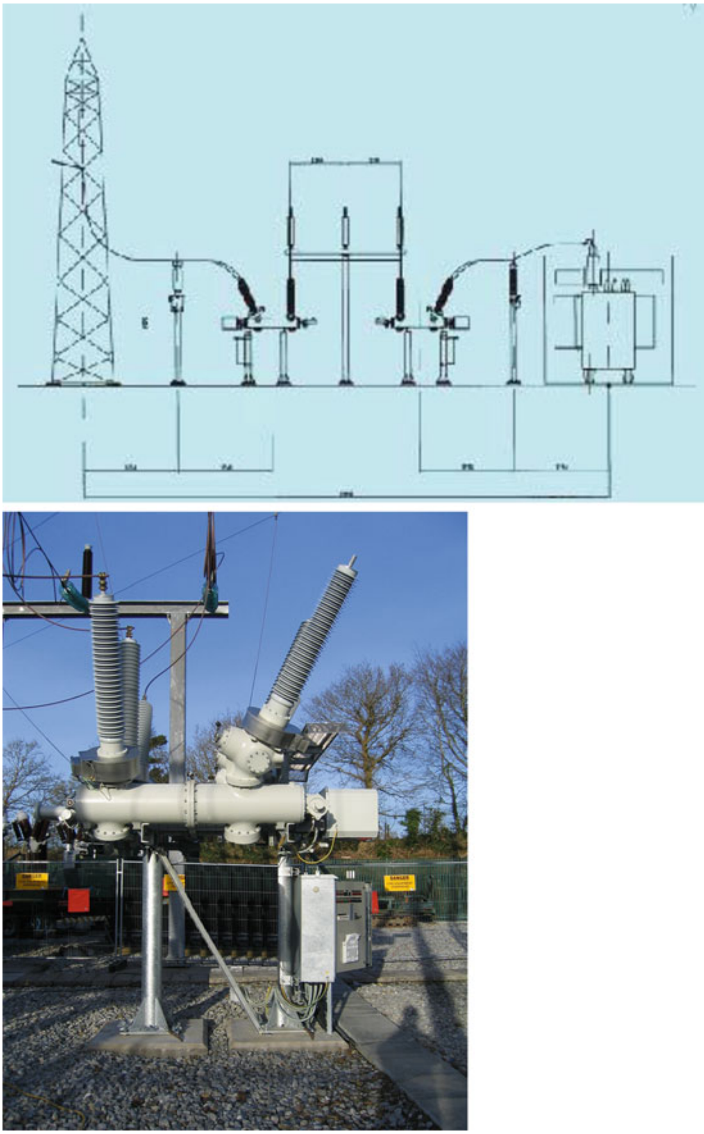

**Fig. 9.1** Example of hybrid modules used in a single-busbar substation

#### 9.2.2.2 System Innovation

Innovation can also be considered in the context of the power system where the improved performance of a product can result in a different architecture or procedure being introduced to take maximum advantage of the product. The development of microprocessor-based equipment to replace the electromechanical-type relays can be

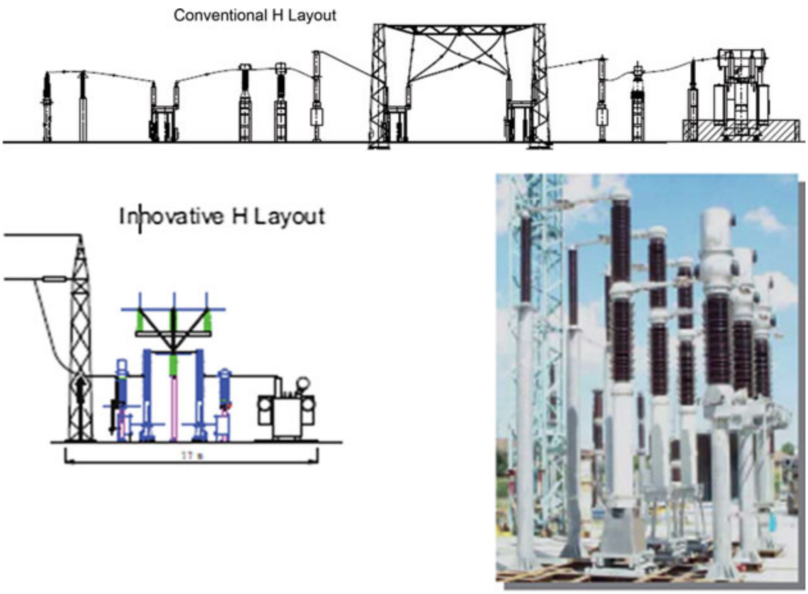


**Fig. 9.2** Example of innovative solution to save space in "H" station layout

considered as one of the major innovations, resulting in a major improvement in the power system protection, metering, and control. Another major innovation is the development of fiber optics that made a great improvement in terms of security, speed, and reliability to communications between substation equipment and remote control center or in the communication between protective relays located in different substations.

## 9.3 Standardization Versus Innovation

Technical Brochure 389 "Combining Innovation with Standardization" investigated the main reasons why utilities would wish to use standardization and also their reasons for using innovation. Additionally, the reasons why solution providers and consultants wished to pursue innovation were also explored.

The results showed that the reasons for standardizing were virtually the same as those for innovation. The top eight reasons for wishing to standardize or innovate and the thinking and techniques behind them were explored together with the most common difficulties encountered in implementing either a standardized approach or an innovative approach.

The most common reasons for innovation or standardization were:

- Reduce plant and equipment costs.
- Reduce maintenance costs.
- Reduce engineering costs.
- Improve operation (function and flexibility).
- Health, safety, and environmental improvements.
- Reduce project duration.
- Reduce installation costs.
- Existing equipment obsolescence.

The most common reasons for difficulties in implementing innovation or standardization were:

- Time
- Costs
- Staff resistance
- System operation practices
- Operator interface
- Training
- Environmental
- Company organization
- Health and safety (H&S)
- Legislation

## 9.4 Guidelines for Controlled Introduction of Innovation

In this section, some guidelines are given for those companies seeking to introduce innovation in a controlled way.

In the first stage of the process, special attention should be paid to the different innovation proposals that will face the organization, because not all of the "strange" or new projects are innovations. Therefore, it is important to define what exactly innovation is. It could be technological innovation or simply the adoption of a new process or way of working in the organization.

Suggested definitions for innovation, research, and development may be as follows:

- Innovation is the activity that leads to the release of new products, processes, or considerable improvements over the existing ones. This could be translated into improvements, the creation of new products through the implementation of advanced technologies or the adaptation of another sector's technologies, the acquisition of advanced know-how (patents), and its implementation.
- Research is the basic and planned investigation to discover new knowledge and a better understanding in the scope of the science and technology. The research is

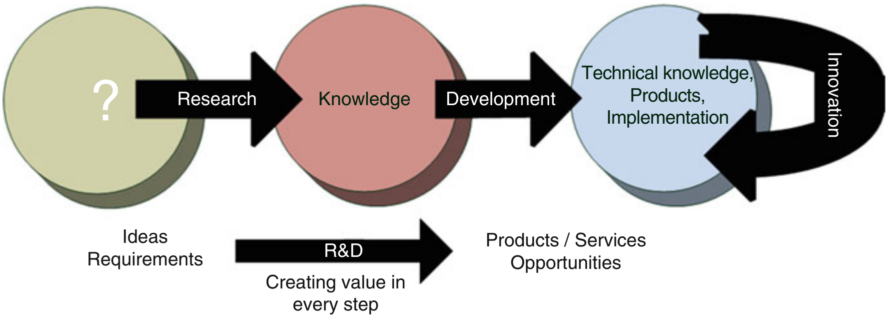


**Fig. 9.3** Creating value

materialized in original research, new knowledge, experimental studies, and feasibility studies.

- Development is the application of the research results or other scientific knowledge, in order to produce new materials, equipment, or systems. The result of the development could be new products, prototypes, pilot projects, or conceptual formulae.

In the following Fig. 9.3, a road map summary for the innovation concept is shown, as well as the necessary stages from the identification of the new requirement until the final product or service (or opportunity).

Considering all the information from the previous sections, and the experience of different companies (utilities and solution providers) in introducing innovation in a controlled way, we would suggest that the following guidelines may be taken into account.

These guidelines may be grouped as follows:

1. Future development structure
2. Future development strategy
3. Future development road maps (implementation plan)
4. Future development projects (execution stage)

### 9.4.1 Future Development Structure

When an organization is considering the development of innovation projects, the first step that needs to be taken into account is setting up a dedicated development unit or structure which leads everything related with innovation inside the company or which is responsible for the introduction of a particular innovation.

For the success of the innovation introduction process, it is really important that the senior management of the company is involved in this structure and committed to achieving the change required, providing material support and direction to implementation.

The development group should completely control the introduction of innovation and be in charge of the management of the different development processes in the company. They should define and review the innovation company's strategy and control the fulfilling of the different future development objectives through, for instance, innovation and project portfolios.

When defining a future development management model or structure, there are a number of options that can be taken into account.

From the resources point of view, the future development structure could be external or internal:

- **External Future Development Structure**
  A company may choose this kind of structure because the internal resources (human resources) are limited. However, a small internal group should supervise this external help by defining the main objectives (specifications) and validating the results. In addition, the senior management of the company must be involved to define strategies and a project-leading group appointed to manage projects.

  Although the company can get the desired results, one of the major disadvantages of this model is the loss of knowledge within the company.
- **Internal Future Development Structure**
  All the structure belongs to the organization; therefore, this option consumes more of the company's resources.

  In contrast to the previous option, all the innovation knowledge will remain within the organization.

  Finally, both structures may be united through open innovation where external and internal resources work in the same team.

From the organization point of view, it can be distributed or centralized:

- **Distributed Future Development Team**
  In this model, there is a group which manages the support of the different business units; cross-functional teams are then in complete interaction. Technicians belonging to the different departments of the company can help on a part-time basis in the innovation projects. Consequently, although the innovation resources are limited, the resultant structure is in deep contact with the core business.

  This kind of organization is suitable for, but not limited to, the external structures explained previously.
- **Centralized Future Development Team**
  There are one or more dedicated units with their own human resources. This way of working will provide faster answers and solutions. However, this group could easily lose contact with the real needs of the company.

  It is suitable for the internal structures explained above.

  After having chosen the most suitable structure from these options, the resultant structure needs to focus on the following objectives:

#### 9.4.1.1 Company's Innovation Necessities: Definition

This future development plan provides a long-term global vision for the business that will be developed in different short- and medium-term projects. In order to achieve this global challenge, the defined structure must take cognizance of:

- The various needs of the company (considering the different business units)
- The state of the art of the different processes or products in which the company is involved or interested in
- Opportunities offered by the surrounding environment: new technologies (technological watch)
- Identification of the barriers to fulfill specific milestones

#### 9.4.1.2 Future Development Culture

The company's senior management team, which participates in this group, should also promote every business unit's participation, with innovative ideas and suggestions, in order to set up the desired culture. For the success of this promotion and participation, specific innovation training programs should be developed showing:

- What exactly is innovation?
- Benefits and advantages for the organization.
- How can they face innovation?
  - How to manage it?
  - Future development plan and strategy definitions.

Each of the business units should participate in the future development plan definition as is shown in Fig. 9.4:

#### 9.4.1.3 Future Development Plan Evaluation

Once the innovation structure has been developed and the different budgets have been defined, this development group should evaluate all the innovation processes. For instance, the following processes may be put forward:

- Managing the innovation portfolio
- Using stage gates to manage innovation projects
- Industrialization/commercialization

Therefore, innovation process indicators should be set up, identifying possible improvements in the overall innovation process and suggesting the corresponding solutions.

#### 9.4.1.4 Knowledge Management

The future development structure should manage the company's technological knowledge. Special attention should be paid to specific training processes that show within the company all the future development efforts (projects) and the results obtained within the company.

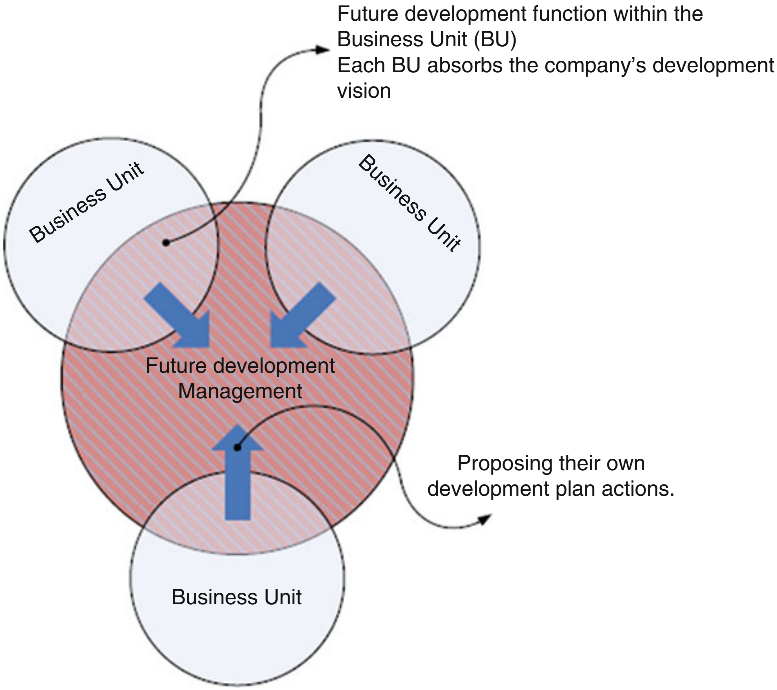


**Fig. 9.4** Future development culture

### 9.4.2 Future Development Strategy

Once the future development structure has been established, an appropriate innovation strategy should be defined. In order to find the most effective one, the strategy has to be developed in accordance with the overall company's strategy (i.e., the objectives of the company).

Therefore, the future development team should focus its efforts and decisions on maximizing the value to the company. Otherwise, they will never get the required resources to develop the final strategy. In summary, if no value is obtained, innovation will never be worthwhile.

Once this step has been taken, it is suggested that the management group define the required resources (man-hours and budget) in order to fulfill the predefined strategy and objectives. Therefore, it is very important that the senior management of the company is involved in the definition of this new development strategy.

The defined innovation strategy will involve every part of the company. In order to achieve the ultimate company's objectives, every business unit within the company will face their own innovation challenges and objectives.

In the next picture, an overview of the different factors that may influence the strategy elaboration is shown (Fig. 9.5).

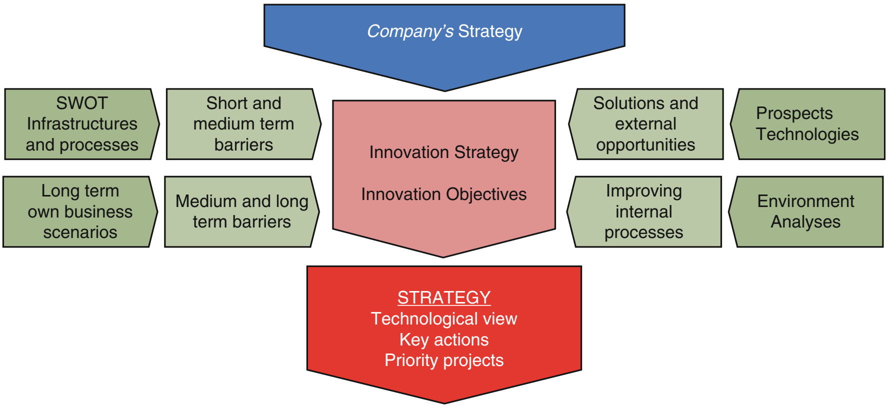


**Fig. 9.5** Strategy influence factors

This future development strategy should be defined on a medium-/long-term basis, considering all the possible benefits and risks when developing the different innovation proposals. The strategy and the associated innovation ideas should also integrate both requirement and technology evolutions on a short-/medium-/long-term basis.

For the success of the strategy, it is very important to communicate it properly within the company, at all levels. Every unit should participate in the objective definition and should also be informed about the different objectives and principles behind each process (setting up the desired future development culture), as well as the proposed planning in order to participate actively in the related projects. This communication function, as a task of the future development team, is fundamental to create the desired future development culture.

The strategy, and the consequent objectives, should be reviewed frequently.

### 9.4.3 Future Development Road Maps (Implementation Plan)

The strategy will be deployed around a few priority innovation ideas. Each of them will have assigned a road map (covering the short, medium, and long term) that will allow the future development team to identify the gaps and barriers. These will trigger some of the projects.

There are two different approaches for the road map development (Fig. 9.6):

1. Top-down: The plan is defined from the organization's global strategy.
2. Bottom-up: The different business units propose their own actions in order to fulfill their short-term necessities. The defined future development plan will cover the different gaps identified when comparing all those business unit (BU) necessities with the company's strategy (SWOT (strengths, weaknesses, opportunities, threats), analysis, etc.). The resultant actions will be gathered in a global plan to accomplish with the defined strategy.

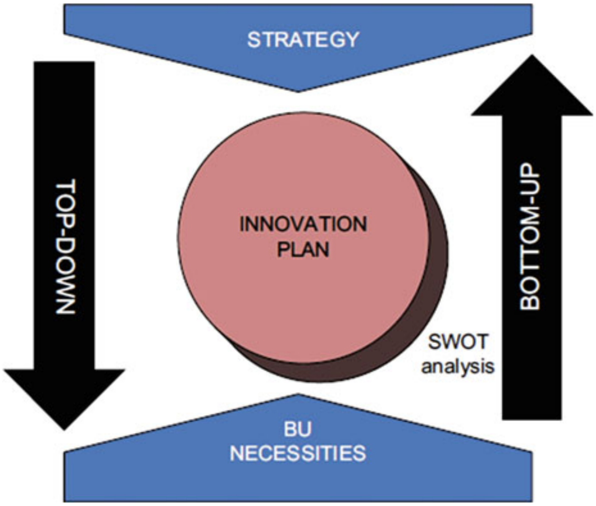


**Fig. 9.6** Road map approaches

The different steps that an innovation implementation plan should consider can be summarized as follows:

- Setting up the project portfolio
- Portfolio management process

These two stages are normally carried out during the strategy definition by the future development team. During the project portfolio definition, the following points could be taken into account:

- Identify clearly the objectives, to have a clear vision and develop key parameter indicators:
  - *What do you want?* Normally a new requirement to be covered or an existing procedure or application to be improved.
- Innovation introduction is often difficult due to various reasons:
  - Utilities are rather conservative companies; people normally are not fond of changes. If it works at present, why should I change it?
  - Initially, companies do not want to be the first ones to apply an innovative solution. Therefore, a deep justification is needed.

In order to get the required resources, innovation projects must add value to the company and the following have to be measured for all projects:

- Reduction in costs and time (e.g., by reducing maintenance, facilitating operation, etc.)
- Social, environmental reasons
- Technical reasons

In addition, the justification should include a risk management analysis, both for the global innovation portfolio and for the associated projects. The resultant proposals have to be balanced:

- Risk balanced, including low, medium, and high technical risk projects
- Balanced by the timing of innovation (long, medium, and short term)

Therefore, on a project basis, it is necessary to study not only the advantages but also the difficulties and challenges involved when introducing innovation:

- External benchmarking is always useful, learning from others that may have faced similar problems.
- Where and when are you going to innovate?
- How much does it cost? Investment return rates have to be calculated from the beginning of each project.
- Possibilities of the final product, are there new opportunities?

### 9.4.4 Future Development Projects (Execution Stage)

This last stage normally includes:

- Project management, including the definition of deliverables (e.g.: partnership, needs of business units, technology, project value, etc.), at each project stage
- Execution or application

These two last stages belong to the implementation project plan. A strong implementation team (project team) will be in charge of this part.

In summary, after having developed and clarified the necessary future development structure and strategy during the innovation project stages, the following steps are normally considered:

- Innovation procedures or processes must be introduced gradually, *step by step*:
  - Identify options that fulfill the requirements.
  - Concept proof and design a pilot project.
- Collaboration: During this implementation stage, coordination and communication between the affected areas are very important:
  - The different business units involved in the project should participate from the beginning (not only during the design stage but also during the application and final evaluation); this is a major issue and a key to the future success of development projects.
  - A close collaboration between the different companies in the electrical sector (utilities, consultants, and solution providers) is vital during the whole life cycle of the application, including post-delivery support.
- Communication: In order to publicize the results and the new products or processes, *communication and training programs* should be developed within

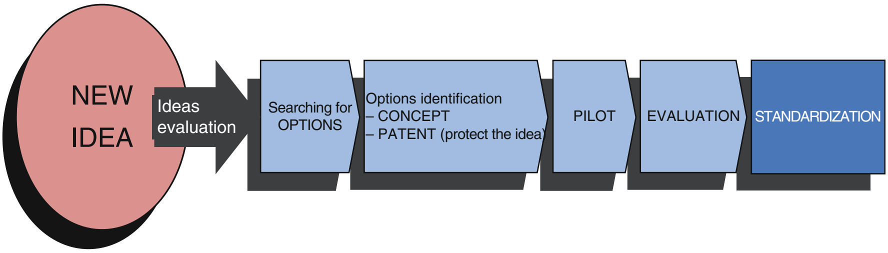


**Fig. 9.7** Innovation project steps (stage gate)

the company. All of the involved business areas should be informed regularly about the progress made.

- Evaluation or testing plan:
  - Once each project step has been finished, an evaluation must be done to ensure that the defined objectives have been achieved and the final viability (through the defined key parameter indicators).
  - In order to decide whether the final products or process is acceptable for the company, all the conclusions from the future development team must be discussed, “Have the initial objectives been achieved?”
- Certification and standardization:
  - If the future development team, including the senior managers of the company, consider that the application of innovation adds value to the company, its treatment should be extended as a company standard.

In conclusion, companies should implement an innovation process and only once that process succeeds should it be standardized and introduced to the rest of the company (Fig. 9.7).

## 9.5 Integrating Innovative Solutions into the New Generation of Standards

### 9.5.1 Introduction

As described in Sect. 9.4, the process of integrating innovation into a new company application standard begins with the specification for the innovation, i.e., introduction of the innovation should be considered from the beginning as the first step in the creation of a new standard.

The specification for the innovation should include, taking care to avoid being too prescriptive or limiting, any relevant interface or operational requirements that will facilitate its introduction into existing operational and construction environments.

The maximum benefit will be gained from a new standard where there is a sizable ongoing construction program. If the foreseen work program over the next number

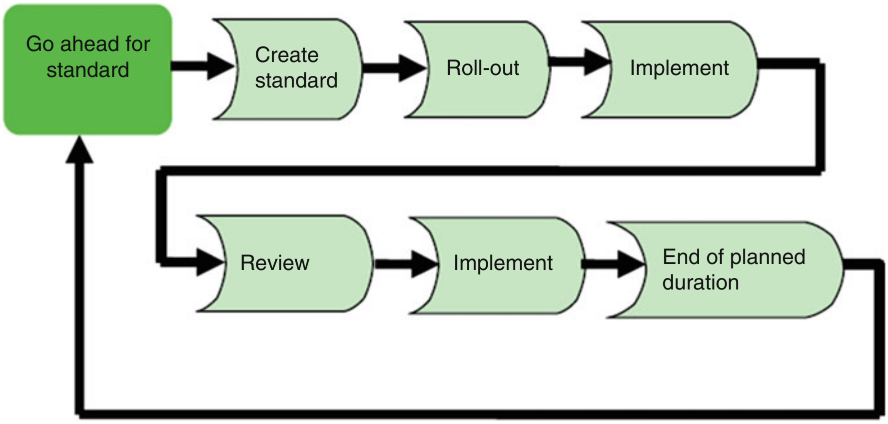


**Fig. 9.8** Standardization process

of years (say 3–5 years) is small, then the effort involved in creating a new standard may not be worthwhile.

Introduction of a particular standard may impact on any or all of the following areas:

- Design/engineering
- Procurement
- Construction
- Commissioning
- Operation
- Maintenance

Therefore the decision to create a standard needs to be a considered one (Fig. 9.8).

### 9.5.2 Review of Initial Pilot Project

The innovation is likely to have been deemed worthwhile trying based on the results of a feasibility study which itself is likely to have been based on a number of assumptions, e.g., budget costs.

Therefore, the results of the innovative solution pilot project must be reviewed against the planned objectives, e.g.:

- Reduction in procurement cost
- Reduction in installation cost
- Reduction in engineering cost
- Reduction in project cycle time

In considering the installation and engineering costs, the one-off development costs associated with the first implementation must be excluded.

There is likely to be pressure from the asset management function to get the new standard into service as quickly as possible to get the earliest use of the planned benefits.

A careful assessment is required as to whether or not the pilot project has produced an outcome that is to an adequate standard across all of the required areas to allow this. Premature introduction of a new standard is likely to result in a period where ongoing changes are required to the "standard." Too much of this will lead to disillusionment with the whole standardization process.

Since actual product is now available, it is now possible (and essential) to get either a sign-off or a list of specific issues that need to be considered from the construction, commissioning, operation, and maintenance functions.

Depending on the level of outstanding issues, a further iteration of the pilot process with an improved design may be required before considering standardization, i.e., avoid premature lock-down of the design.

### 9.5.3 Scoping

The scope of the new standard must be clearly defined so that all parties are clear what is included in the standard and also what is not included, to prevent subsequent misunderstandings over any changes. This scope may not necessarily include all parts of the pilot project.

The physical interfaces of the new standard design with other standards or with variable parts of the standard must be clearly defined.

### 9.5.4 Implementation Process and Issues

Formal agreement to the new standard must be obtained from all relevant parties, in particular asset managers, commissioning staff, and operating staff.

The situations in which the standard is to be applied should also be agreed. The pilot project is likely to have been set up around the most common situation, e.g., the use of MTS (mixed technology switchgear) in new greenfield single-busbar substations.

Once the standard has been created, it should be agreed how widely the standard is to be used in related situations, e.g., for extensions to existing substations, for refurbishment in existing stations, for use in double-busbar substations, etc.

If this decision is not made at the beginning, there should be an understanding that use of the new standard must be considered first in any new situation. Any decision not to use it must be reserved to senior management.

The approved list, which should be as short as possible, of variants to the standard design must also be defined. With HV equipment standards, for example, a small number of options in current transformer rating may be required to allow the standard to be applied successfully in all parts of the network. A certain element of overprovision may be required as standard to reduce or remove the need for expensive customization.

The new standard must be fully documented, e.g., drawings, material lists, order details, configuration details, test procedures, etc. with this information made easily available to all who may need to use it.

The planned duration for the new standard must be agreed. This must be as long as possible, at least 3–5 years, for any real benefit to be gained from the effort put into the standardization process.

Procurement positions must be set in place to ensure that, as far as possible, all of the required material will be available for the planned duration of the standard. This may be particularly necessary for digital protection or control equipment and may require a certain element of advance purchase toward the end of the required period. In addition to the obvious situations due to hardware change, this should also be considered in cases of software version change.

The final point is to ensure that a formal approval process, which should be biased to say no, is in place to deal with any proposals for revisions before this review date, e.g., on safety or performance grounds. The approval level for this process must be at a senior enough level to ensure that a refusal to modify the standard is enforceable.

As mentioned earlier a standardized design will not always be the optimum solution for a particular project. Strong management control is therefore essential to stop individual efforts to “improve” or “optimize” the standard.

### 9.5.5 Rollout

A new standard cannot be successfully rolled out by stealth. A formal planned rollout process of briefings, demonstrations, trainings, etc. will be needed to provide adequate visibility of the new standard. These need to cover the justification for and expected benefits from the standard as well as details of the standard itself.

Visible management support will be needed during this process to promote take-up of the standard by the various affected parts of the company. This support is also required to encourage users to keep the larger picture in mind when faced with some of the compromises associated with adoption of standards. This support is likely to have to be maintained for a considerable period to encourage the development of an open-mind approach toward any problems that may arise during standard implementation.

The rollout process must also be actively planned so that all necessary designs, materials, procurement documentation, special tools, etc. are in place before staff needs to use them to apply the new standard.

All of the above are even more important if a standardization process is being introduced for the first time.

### 9.5.6 Review Process

As mentioned above the new standard should be put into place for a long enough period to get a return from the standardization effort, of the order of 3–5 years. However, it would be counterproductive to insist that absolutely no changes can be permitted for this period.

A reasonable method of dealing with this issue is to also agree a planned review date, perhaps halfway into the planned duration of the new standard.

A process should be introduced whereby proposed changes or improvements to the standard are submitted to a review group that either rejects them or accepts them as providing a tangible benefit. However, it is important that any resulting change is then parked until the review date when a single composite revision of accepted changes can be introduced.

An exception to this process will be required to deal with any safety-related issues that may need immediate implementation. However strong management control and a robust review process are essential to ensure that genuine safety issues are involved rather than a “safety” flag being used to push a change proposal which in reality should be handled through the change control review process described above.

## 9.6 Summary

As mentioned in the introduction to this chapter, there would seem to be advantages in both innovation and standardization. Throughout the chapter the way in which innovation can be implemented in a controlled fashion and then converted into an updated standard is explained. Throughout this process, certain observations became apparent as follows:

- The reasons for standardization and innovation tend to be the same.
- Constraints and difficulties against standardization and innovation tend to be the same.
- Innovation may be in procedure, system, or equipment.
- The key drivers for standardization and innovation are:
  - The reduction of true total cost
  - Reduction of system operational risk
- Identification of innovation opportunities and the subsequent development into a standard require dedicated teams, resource, and budget allocation.
- A structured approach to innovation is essential and needs to be value-driven.
- Involvement of all levels and functions within the business is essential; senior management must accept and drive the innovation.
- Standardization maximizes the value of innovation.
- Development of the innovation to an application standard also requires a structured, value-driven process.

Finally, as an industry we cannot afford to stand still and live with standard designs that are many years out-of-date. It is essential that innovation continues such that the latest, most cost-efficient technology may be exploited. However to maximize the benefits to be derived from this technology, the application of carefully developed standards is essential, such that the innovation of today becomes the standard of tomorrow.

# Part B

# Air-Insulated Substations

*Koji Kawakita*

# Introduction to Air-Insulated Substations 10

Koji Kawakita

## Contents

10.1 Site Location ........ 145
10.2 Site Layout ........ 145
10.3 Conceptual Design ........ 146
10.4 Project Management Plan ........ 147

An air-insulated substation (AIS) is one where the main circuit potential is insulated from the ground by air using porcelain or composite insulators and/or bushings. AIS is fully composed from air-insulated technology components such as circuit breakers, disconnecting switches (disconnectors), surge arrestors, instrument transformers, power transformers, capacitors, busbars, and so on, and the components are connected to each other by stranded flexible conductors, tubes, or buried power cables. AIS is the most common type of substation, accounting for more than 70% of substations all over the world.

Therefore, electrical engineers are recommended to develop a good understanding of AIS design before learning about gas-insulated switchgear (GIS) and mixed technology switchgear (MTS), which are developed based on AIS technologies. The pros and cons of using either AIS, GIS, or MTS technologies are described in CIGRE technical brochure #390 and in Part D.

This Part B describes the issues to be considered in the design and construction of a new AIS substation. Figure 10.1 shows the general work flow for establishment of any new substation and applies also to GIS and MTS as well as AIS.

K. Kawakita (✉)
Engineering Strategy and Development, Chubu Electric Power Co., Inc., Nagoya, Japan
e-mail: Kawakita.Kouji@chuden.co.jp

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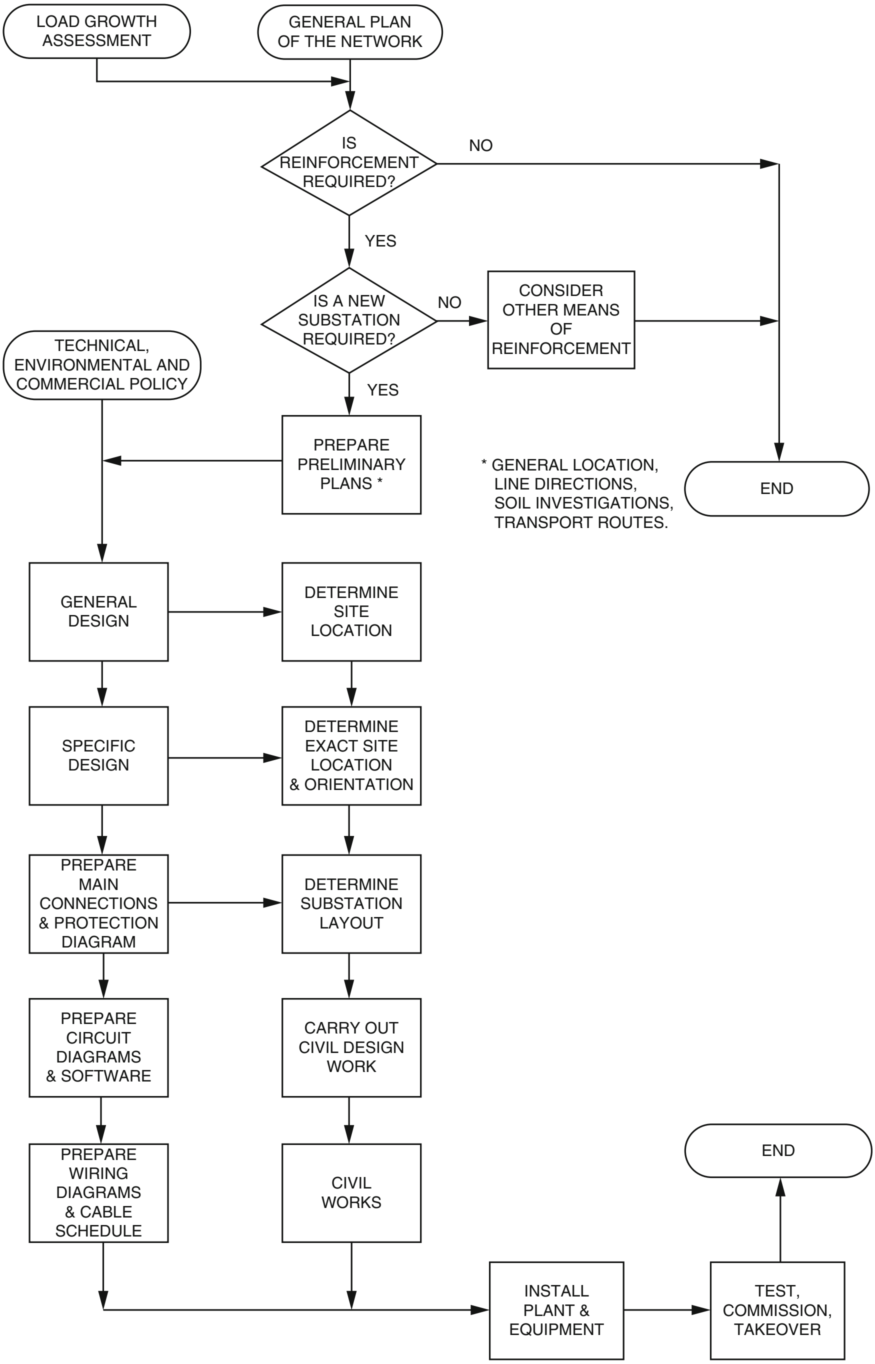


**Fig. 10.1** Establishment of a new substation

## 10.1 Site Location

The choice of a site location for a new substation is a compromise between technical, economic, environmental, and administrative factors.

In simple terms the problem is often to find the most suitable location within a geographic region where the substation can be built, given the total number of circuits, the destination of the lines, and the rated nominal power of the transformers.

Typically, in the whole region, climate and altitude are almost the same, but technical and environmental factors vary depending on the site location.

The first step is to locate the range of possible sites, which are as level as possible, with enough available area, at reasonable cost; with acceptable access for heavy transport, within the general required location; and without any major restrictions on line corridors, where the substation can be erected with minimum environmental impact.

It is often advantageous to locate sites near to existing line corridors or even at crossing points. Sometimes such places simply do not exist, and the choice will be confined to places that have only some of the above characteristics.

Once the possible sites have been located, an analysis is then made for all the technical and environmental aspects of each one, including costs, potential environmental impacts, and the preventive or corrective measures that can be taken to avoid or reduce them. It is also necessary to assess the likely social acceptance of the project.

This analysis then provides the criteria for deciding on the most suitable substation site, bearing in mind the degree of feasibility and the project cost of each alternative. If no suitable site is found, the process may be reinitiated within another general area.

Further information about site location is given in CIGRE technical brochure #161.

## 10.2 Site Layout

In the choice of a site layout for a substation, the number of outgoing lines or feeders of different voltage levels, the number of main transformers, the required busbar configurations, and the possibility of future extension as well as compensating equipment options need to be considered carefully, not only for the original installation period but also for the needs of the future. It should be noted that the lifetime of the substation may extend beyond 50 years.

It is very important to allow sufficient space for future extension. Sophisticated network planning may be needed to estimate the necessary reserve space to accommodate the ultimate substation layout. If no better design approach exists, then allowing 100% reserve of outgoing feeders may be used as an estimate. The space required depends essentially on the present and future function of the substation.

Extension work such as building of new bays, reconstruction of existing bays, or extension of the set of busbars may be difficult and expensive if there has been no previous planning or allowance for them.

Regularly substations are established with the minimum equipment and then completed over future years. There is little point in providing the whole installation from the beginning as some equipment may be unused possibly for many years requiring maintenance just like the other substation items to keep it in good condition.

In some cases when building a reduced installation initially, a different configuration may be provided to be ultimately expanded into the final arrangement, e.g., ring bus to 1½ circuit breaker scheme, mesh to double bus, etc. Sometimes it is best to provide a partially equipped piece of equipment that can be fully equipped in the future, e.g., dummy disconnector acting initially as a busbar support without moving blades or mechanism.

To allow for load growth, power transformers can have fans fitted later if required, etc.

It is important to define the number and the size of the main transformers required at the final stage of development. The initial peak demand on a power transformer is dependent upon a number of factors such as the network configuration, standby philosophy, and rate of load growth. It is possible to optimize cash flow by installing a transformer suitable for foreseeable load over an initial period with the intention of replacing it with a larger unit if this becomes necessary. Company standardization policies also feed into this decision (see also ▶ Chap. 9).

The outgoing line corridors should be planned so that there are a minimum number of crossings between different circuits.

More information about site layout is given in CIGRE technical brochure #161.

## 10.3 Conceptual Design

The conceptual design establishes the key parameters for the substation, and so careful attention must be paid at this design stage to ensure that the design addresses the key concerns of all stakeholders. The conceptual design should reflect the general business development guidelines and maintenance strategies of the network operator and should be deduced project-wise from a long-term orientated company template.

From another viewpoint, conceptual engineering should lay down all the basic specifications that have a major influence on network cost, network reliability, and societal acceptance. On the other hand, conceptual engineering should also offer the opportunity to stimulate competition among the potential service providers and should offer the network owner the flexibility to either carry out the detail engineering in-house or to outsource it, depending on the availability of resources.

The following are general conceptual design points to be considered.

- Basic elements
  - Functions of the network
  - Types of substation
  - Structure of a substation
- Parameters determined by the network
  - Main equipment parameters
  - Fault clearing time with respect to system requirements
- Planning of a substation
  - General location
  - Extent of the substation
  - Busbar configurations
  - Fault current levels
  - Neutral point earthing
  - Control in general
  - Protection in general
  - Maintenance requirements
- Typical switching arrangements
  - Service continuity
  - Choice of switching arrangements

More information about conceptual design is given in Part A and in CIGRE technical brochure #161.

## 10.4 Project Management Plan

A project management plan should be prepared at the beginning of a project in order to optimize the execution of the substation project.

One of the most important aspects is achieving balanced critical path management with the following key points included in the project planning:

- Project work flow
- Project time schedule
- Project engineering interface

During the normal execution of a substation project, these three points may not always be planned or performed in series since the work is done by many concerned people and restrictions of social requirements or regulation may apply. In the course of the project, there could be many natural gaps between planned activities and actual work sequence. A good project management plan must account for such gaps and for out-of-sequence activities. The challenge in project execution is to consistently find a suitable way to minimize the gaps in activities and move the project forward smoothly.

Project management requires clear understanding, imagining, and evaluation of any influences that may arise due to out-of-sequence events for the above three key points. In such instances, the success of the project depends on the ability to take leadership and realign the project team efforts to the most effective path. When it is difficult to determine the effective path, the priority of events should always be considered in the order of flow/time/engineering.

More information about project management planning is given in CIGRE technical brochure 439. Although this brochure deals with turnkey projects, the basic concept is applicable to all types of substation projects.

# Basic Design and Analysis of Air-Insulated Substations

# 11

Colm Twomey, Hugh Cunningham, Fabio Nepomuceno Fraga, Antonio Varejão de Godoy, and Koji Kawakita

## Contents

11.1 General .......... 151
11.2 Substation Layout .......... 151
11.2.1 First Step: Busbar Phase Disposition .......... 152
11.2.2 Second Step: Selection of Busbar Conductors .......... 154
11.2.3 Third Step: The Disposition of the High-Voltage Equipment in Each Standard Type of Circuit .......... 156
11.2.4 Fourth Step: The Type of Connection Between the Busbar and the Individual Circuit .......... 157
11.3 Electrical Clearances .......... 166
11.4 Insulation Coordination .......... 169
11.4.1 Protection of Substation Against Traveling Waves on Incoming Lines .......... 171
11.4.2 Impact of Traveling Waves on a Substation .......... 172
11.4.3 Protection .......... 173
11.5 Bus and Conductor .......... 174
11.5.1 Current Ratings .......... 174
11.5.2 Electrical Clearances .......... 175
11.5.3 Mechanical Forces .......... 175

C. Twomey (✉) · H. Cunningham
Substation Design, ESB International, Dublin, Ireland
e-mail: Colm.Twomey@esbi.ie; Hugh.Cunningham@ESBI.IE

F. N. Fraga
DETS, Chesf, Departemento de Engenharia, Recife, Brazil
e-mail: fabionf@chesf.gov.br

A. V. de Godoy
Generation Director of Eletrobrás, Casa Forte, Recife, Brazil

K. Kawakita
Engineering Strategy and Development, Chubu Electric Power Co., Inc., Nagoya, Japan
e-mail: Kawakita.Kouji@chuden.co.jp

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11.6 Structures ........ 180
11.6.1 Concrete ........ 181
11.6.2 Steel ........ 181
11.6.3 Aluminum ........ 182
11.6.4 Wood ........ 182
11.7 Earthing (Grounding) and Lightning Protection ........ 183
11.7.1 Functions of a Substation Earth Grid ........ 183
11.7.2 Earth Grid Resistance Value ........ 185
11.7.3 Soil Resistivity Measurements ........ 187
11.7.4 Design Touch and Step Voltage Limits ........ 187
11.7.5 Transferred Voltages and Hot Zones ........ 188
11.7.6 Earthing of GIS ........ 191
11.7.7 Control of Electromagnetic Interference ........ 192
11.7.8 Earth Grid ........ 192
11.7.9 Design Earth Fault Current ........ 194
11.7.10 Earth Grid Conductor ........ 195
11.7.11 Exceptional Cases ........ 196
11.7.12 Verification of Earthing System Model ........ 199
11.7.13 Protection Against Direct Lightning Strokes ........ 199
11.7.14 GIS ........ 200
11.8 Contamination (Salt and Dust Pollution, Creepage Distance) ........ 201
11.9 Audible Noise ........ 205
11.9.1 Introduction ........ 205
11.9.2 Characteristics of Transformer Noise ........ 205
11.9.3 Propagation of Sound ........ 206
11.9.4 Noise Level Limits ........ 206
11.9.5 Noise Level Measurement ........ 207
11.9.6 Calculation of Noise Levels ........ 208
11.9.7 Methods of Substation Noise Control ........ 208
11.9.8 Transformer Noise Control Measures ........ 210
11.9.9 Other Noise Sources and Control Measures ........ 212
11.10 Fire Protection ........ 213
11.10.1 Fire Protection Systems ........ 214
11.10.2 Transformers ........ 217
11.10.3 Cables ........ 219
11.10.4 Control, Relay, and Cable Rooms ........ 219
11.10.5 Other Measures in the Substations ........ 220
11.10.6 Conclusions ........ 221
11.11 Seismic (CIGRE 1992) ........ 221
11.11.1 Seismic Design Procedures ........ 222
11.11.2 Practical Means to Enhance the Seismic Performance ........ 224
11.11.3 Conclusion ........ 228
11.12 Foundations, Buildings, Cable Trenches, Oil Containments, Etc. ........ 229
11.12.1 Foundations ........ 229
11.12.2 Buildings ........ 231
11.12.3 Cable Trenches ........ 233
11.12.4 Oil Containment ........ 234
11.13 Fences, Gates, Security, and Animal Deterrents ........ 238
11.13.1 Fencing ........ 238
11.13.2 Gates ........ 239
11.13.3 Substation Security ........ 242
11.13.4 Animal Deterrents ........ 242
References ........ 244

## 11.1 General

Following the conceptual design process described above in ► Chap. 10, the basic design process determines the detailed designs required to implement the conceptual design decisions. These detailed designs are determined in accordance with international or local standards, laws, rules, and recommendations.

The detailed designs cover a number of areas which are covered in the following parts of this chapter. Many of these areas are interrelated.

There are two important concepts in the substation layout definition: the busbar configuration (Cigre WG23.03 2000) and the substation layout.

The busbar configuration is the electrical arrangement of the high-voltage equipment (CIGRE JWG B3/C1/C2.14 2014), or it is the connection configuration of electrical system components (lines, transformer, switchgear, generators, etc.) in a specific point (busbar). The selection of a busbar configuration is an important initial step of the substation design. The optimization of this configuration is described in ► Chap. 4 of this book.

The substation layout is the disposition or arrangement of high-voltage equipment, busbar (types and levels), and connections of system components (lines, transformer, switchgear generators, etc.) chosen to implement the selected substation configuration.

The process starts with the overall substation layout which has dependencies on safety clearance and insulation withstand requirements and on the allowable loads applied to substation equipment and structures. The allowable loads in turn may influence the type of HV conductor used which may in turn have a further impact on the layout.

Audible noise, fire protection, and seismic requirements affect the civil and structural design details as do the loads applied to the HV equipment. The civil design is also greatly influenced by the details of the soil characteristics which will influence the type of foundations and footings required to support substation equipment and structures.

As implied above, a number of iterations of the overall process may be required to achieve the most appropriate or economic solution.

Going through the whole process from first principles on every project does not promote efficiency, so it is likely to be worthwhile developing standard designs which then can be applied either in full or with a small degree of site-specific customization, if required.

## 11.2 Substation Layout

Developing a substation layout is more than implementing the particular HV equipment configuration selected during conceptual design, although this is a large part of the work.

The main and initial decisions are the technology definition and the busbar configuration. In order to design the layout of the substation, it is essential that the circuit configuration for the substation is known. For details of the different circuit configurations available and how to choose the correct one for a particular substation, please refer to ► Chap. 4.

The substation layout is the disposition or arrangement of high-voltage equipment, busbar (types and level), and connections of system components (lines, transformer, switchgear, connections to generators, etc.) chosen to implement the selected substation configuration.

To develop the substation layout, in addition to the busbar scheme, the technology (AIS, MTS, GIS), short circuit levels, the load in the circuits, safety clearance, and insulation withstand requirements must already have been defined. It is important to observe that for one kind of busbar configuration, a number of different layouts can be developed.

Final layout is defined by the selected arrangement of busbar equipment, the type of busbar (rigid conductors or flexible conductors), the disposition of the high-voltage equipment in each standard bay of the circuits in the substation, the type of connection between the circuit and the busbar, and the disposition of the circuits in the connection to the busbar.

For a typical AIS substation layout, there are usually three height levels:

- **HIGH-VOLTAGE EQUIPMENT (BAY) LEVEL**: This is the level for interconnection of high-voltage equipment items, e.g., disconnectors and circuit breakers.
- **BUSBAR LEVEL**: This is the level of the busbar.
- **CIRCUIT ENTRANCE LEVEL**: This is the level of circuit that is connected to the substation, for example, the level of the transmission line entrance.

Usually each of these three levels are positioned at different physical heights; however, sometimes some may have the same height. It depends upon the busbar configuration and the design requirements. There are advantages and disadvantages for each possible height at which the busbar may be placed (Fig. 11.1).

The following four steps are required for the process of developing the layout of an AIS substation with conventional equipment:

- Busbar phase disposition
- Selection of busbar conductors
- The disposition of high-voltage equipment in each standard bay
- The type of connection between the busbar and the individual circuit

### 11.2.1 First Step: Busbar Phase Disposition

The phase disposition of the busbar may vary from one busbar configuration to another (Giles 1970). In single busbar arrangements, there are two possibilities: vertical disposition and horizontal disposition. These possibilities are shown in Fig. 11.2 below, but normally only the horizontal disposition (a) is used at voltages

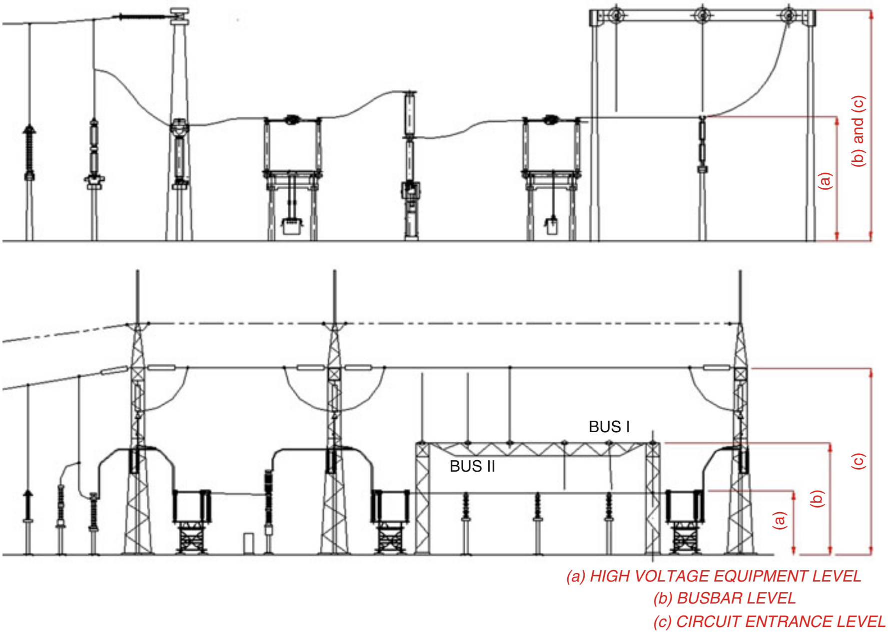



**Fig. 11.1** Different levels of a substation layout

**Fig. 11.2** (**a**, **b**) Busbar disposition possibilities for single busbar configuration

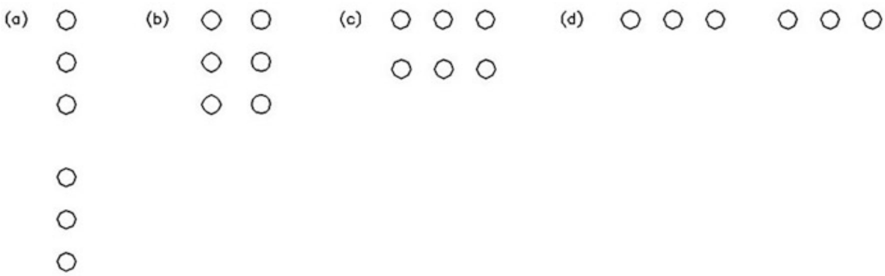




**Fig. 11.3** (**a**–**d**) Busbar disposition possibilities for duplicate busbar configurations

higher than 36 kV. The vertical disposition (b) is not normally used because of the difficulty of maintenance and the risk of one phase falling (collapsing) onto another.

In duplicate-busbar configurations (single busbar and transfer, double busbar, etc.), there are four possibilities that are shown in Fig. 11.3 above.

Although there are four possibilities of disposition (Giles 1970), normally the horizontal disposition (d) is the preferred option. There are two main reasons for this option, namely, the possibility of collapse of one busbar or phase of a busbar above the others and in the dispositions (a) and (c) it is difficult to separate the two maintenance zones for the busbars and to provide independent access to them (Giles 1970).

In some countries and in certain situations, disposition (c) has been used, in order to reduce the required site area, even though maintenance activity may be more difficult and dangerous.

Sometimes the combination of two dispositions or the use of another disposition is possible (Giles 1970), but it is not common in AIS using traditional technology.

Whatever the disposition used, it is essential that the phase-to-phase and phase-to-ground clearance distances in air must achieve the requirements of insulation coordination and safe maintenance and circulation around the substation.

### 11.2.2 Second Step: Selection of Busbar Conductors

The selection of the busbar consists of the following elements:

- The definition of the type of conductor (rigid or flexible)
- The material type (aluminum, aluminum alloy, or others)
- The size or section (which is defined by the calculation of the required current rating in each point of the busbar)

To define the substation layout, only the type of conductor is essential. The other elements are important but not necessary in this step of the process.

For higher voltage levels, aluminum alloy tubes are frequently employed as it can be more difficult to arrange bundle conductors with equivalent diameter suitable to contain corona effect to an acceptable limit (Cigre WG23.03 2000).

Even though the rigid conductor option is considered more economic and simple, it is necessary to evaluate the options in each country and each company. The cost is normally influenced by the availability of the materials in each country and region. The simplicity of the application of rigid conductors depends upon the culture of the country and the culture of the company. Some companies and their service providers have significant experience with flexible conductors and prefer to use these.

To assist in the selection of the type of conductor, Working Group 23.03 produced a table (Table 11.1) showing the advantages and disadvantages of rigid and flexible conductors for the busbars in substations.

When the design engineer makes the choice of rigid or flexible conductors, this decision simultaneously defines the busbar support system. Normally the use of flexible conductors is associated with the use of metallic or concrete structures with suspension insulation, and the use of rigid conductors is associated with the use of pedestal-mounted insulation, although it is possible to use rigid conductors with suspension insulation.

**Table 11.1** Comparison of rigid and flexible conductors

| Rigid conductor solution | Flexible conductor solution |
|---|---|
| **Advantages**<br>Simplicity, easy reading of operation configuration<br>Plant disposition with only two levels<br>Easy access to the transformers or to the switch yard for maintenance<br>Easy substation extension<br>Easy verification of electrodynamic force effect<br>Short erection time<br>Lower grounding area for plant installation | **Advantages**<br>Use of the same material employed for overhead lines<br>Bundle multiple conductors with appropriate diameter to reduce corona effect in ultrahigh-voltage substations are relatively easily fulfilled |
| **Disadvantages**<br>Temporary bypass of circuit breakers on both sides of busbars is not so easy<br>Possibility of mechanical resonance between the tube structure and the wind gust frequency can be prevented by the use of suitable damping devices<br>Difficulty for availability of tubes and support material in some countries | **Disadvantages**<br>Complex layout also for simplex schemes<br>Difficult verification of withstand against electrodynamic forces<br>Busbar over passes are required<br>Considerable environmental impact due to three levels of conductors in the substation<br>Considerable construction cost<br>Difficulty in employing pantograph and semi-pantograph disconnectors<br>Difficulty in substation extension |

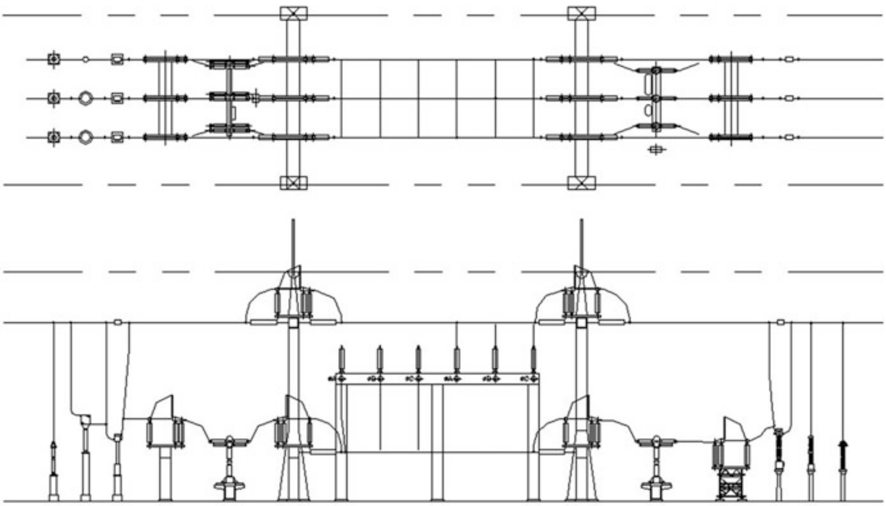


**Fig. 11.4** Busbar with flexible conductors: plan and elevation drawing

Figure 11.4 shows typical plan and elevation drawings for a busbar with flexible conductors. Figure 11.5 shows typical plan and elevation drawings for a busbar with rigid conductors.

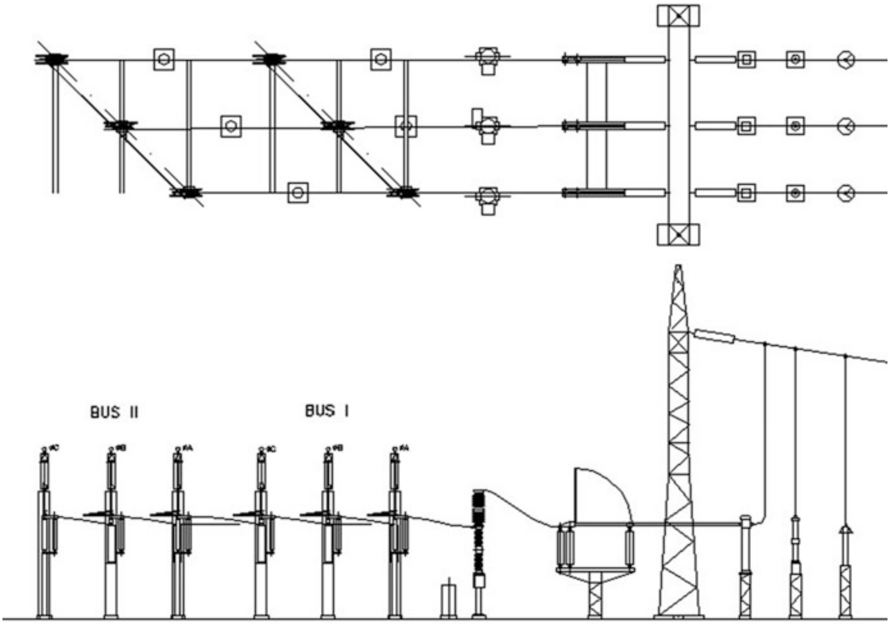



**Fig. 11.5** Busbar with rigid conductors: plan and elevation drawings (Carlos 1991)

### 11.2.3 Third Step: The Disposition of the High-Voltage Equipment in Each Standard Type of Circuit

As mentioned earlier, a particular busbar configuration can generate different substation layouts. The third step is to transform the busbar configuration into a layout, with plan and elevation drawings. Nowadays with sophisticated 3D CAD software available, a 3D model of the substation can be created which can allow a virtual walk-through of the complete layout.

In this step, if the design engineer has all the information for the high-voltage equipment, the dimensions from the factory drawings can be used to connect each equipment item to another in the same positions as shown on the busbar configuration of the standard bay.

The main requirement is to ensure that all the phase-to-ground and phase-to-phase distances (CIGRE 2009) and the safety regulations (CIGRE 1971) are complied with. In the definition of the high-voltage equipment disposition, it is necessary to:

(a) Respect all the phase-to-phase project distances between equipment of different phases or poles of the three-phase equipment.
(b) Respect all the clearances to ground parts, like soil and structure, including the space for maintenance (CIGRE 1971).

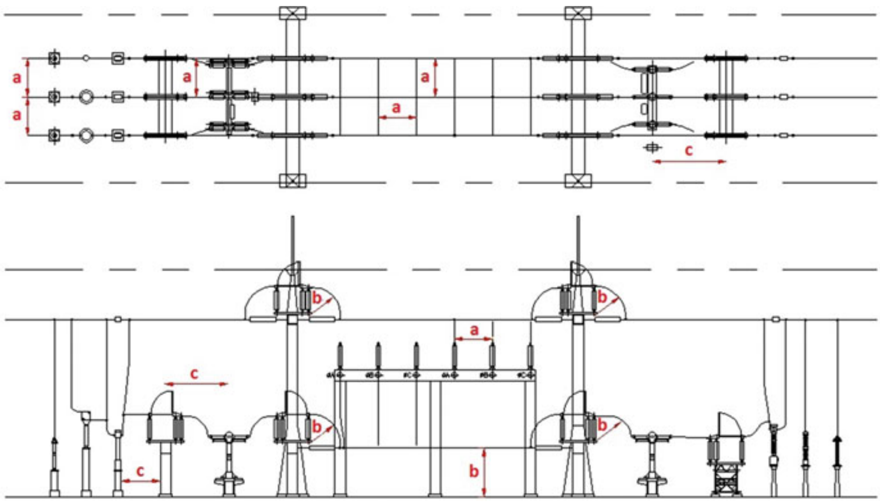



**Fig. 11.6** Double busbar circuit configuration, plan, and elevation drawing

(c) Ensure that the minimum space to carry out maintenance on one piece of equipment in relation to the next closest equipment of the same phase, for example, the distance of phase "a" pole of the circuit breaker to the phase "a" pole of the associated disconnector, is adequate to do the maintenance of one independent of the other.

All equipment is important for the substation layout, but the disconnectors have special importance in the layout. There are some types of disconnector that must be applied to the connection of two points in the same level (center break, side break, vertical opening, rotating center post, etc.), and there are others that must be applied to the connection between two levels of conductors or busbars (pantograph-type vertical, semi-pantograph-type vertical, and vertical reverse). The designer must choose the best option for each specific point (Fig. 11.6).

### 11.2.4 Fourth Step: The Type of Connection Between the Busbar and the Individual Circuit

When the disposition of the busbar conductor, the type of conductor, and the disposition of the bay are decided, it is necessary to connect the bay to the busbar. There are two main situations: single busbar and double busbar.

In the **single busbar**, there are four different possibilities using disconnectors that make the connection on the same level (such as a disconnector with vertical opening or a disconnector with double opening and others) (Figs. 11.7, 11.8, 11.9, and 11.10):

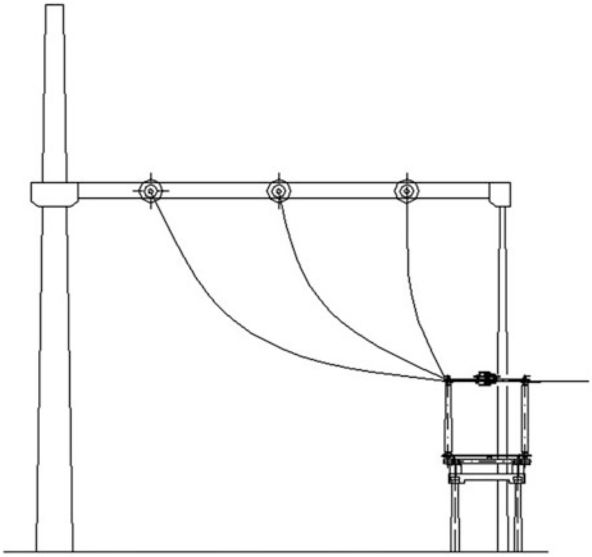


**Fig. 11.7** Flexible busbar with flexible connection: elevation drawing (Carlos 1991)

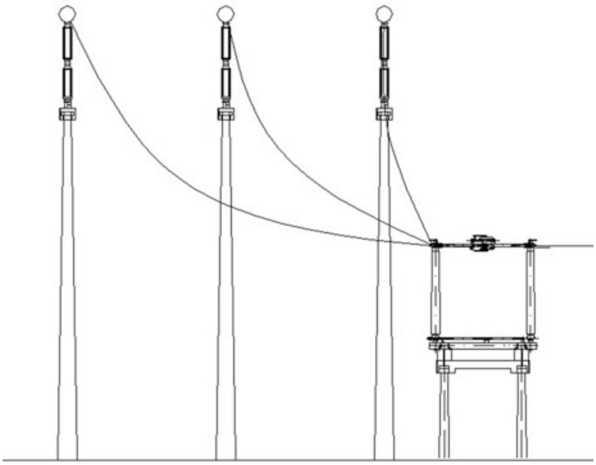


**Fig. 11.8** Rigid busbar with flexible connection: elevation drawing (Carlos 1991)

(a) Classic connection: flexible busbar with flexible connection
(b) Classic connection: rigid busbar with flexible connection
(c) Classic connection: flexible busbar with rigid connection
(d) Classic connection: rigid busbar with rigid connection

These different possibilities using disconnecting switches can be adjusted using connections on different levels (such as pantograph disconnectors and others).

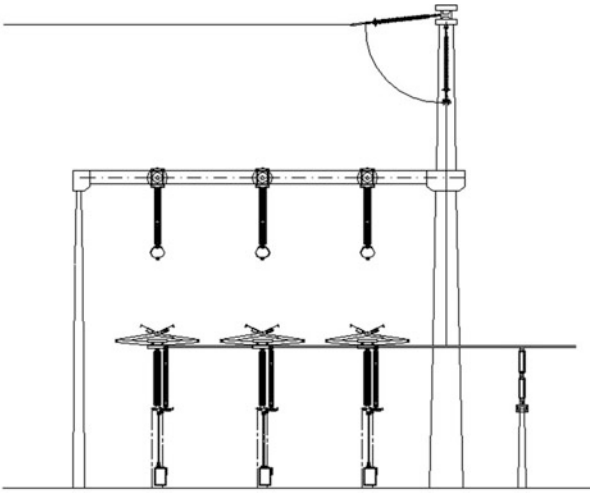


**Fig. 11.9** Flexible busbar with rigid connection: elevation drawing (Carlos 1991)

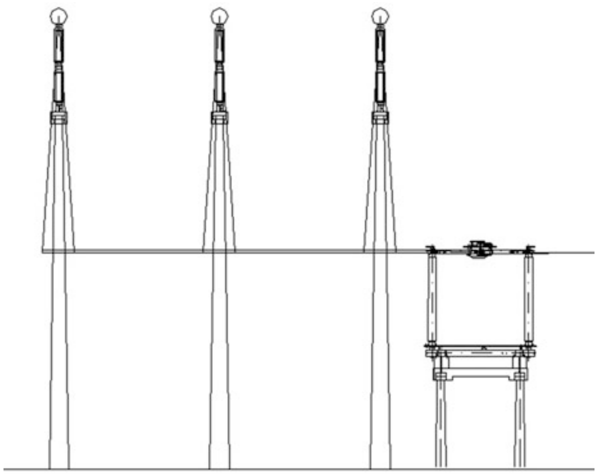


**Fig. 11.10** Rigid busbar with rigid connection: elevation drawing (Carlos 1991)

In the **double busbar**, there are some different possibilities using disconnectors to make the connection. Three different examples are shown in the figures below (Figs. 11.11, 11.12, and 11.13).

When the decisions related to these four steps are taken, it is possible to develop the overall substation layout. The layout for each of the standard bays can be produced and the connection of these bays to the busbar made to complete the overall substation layout.

The overall substation layout also depends on required safety clearances and insulation withstand requirements and on the allowable loads which can be applied to the substation equipment and structures. These allowable loads in turn may

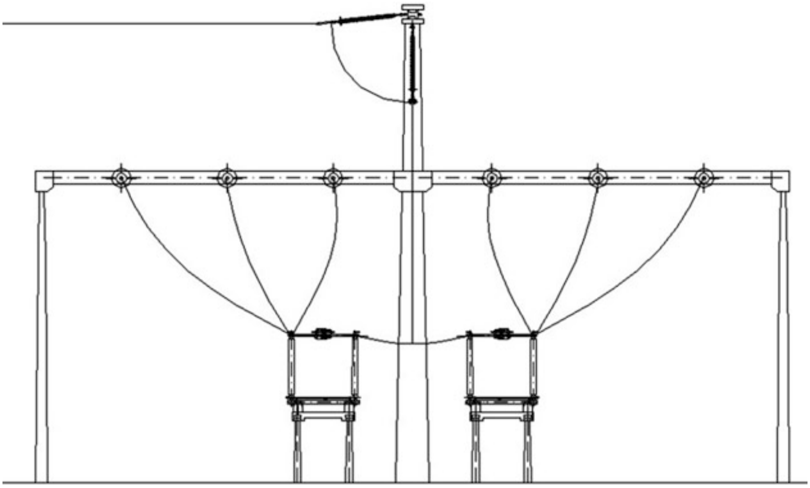


**Fig. 11.11** Connection with classic disconnector to flexible connection: elevation drawing (Carlos 1991)

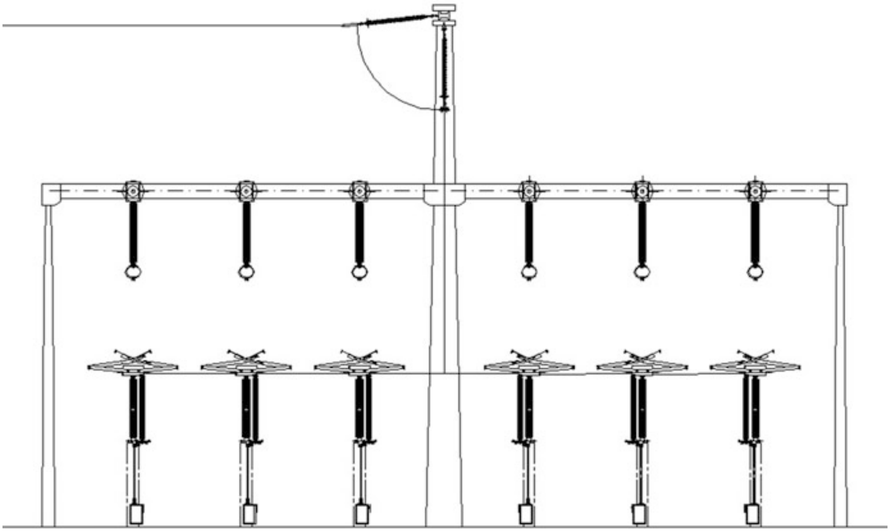


**Fig. 11.12** Connection with pantograph disconnector to rigid connection: elevation drawing (Carlos 1991)

influence the type of HV conductor which can be used, and this in turn may have a further impact on the layout.

The layout must also consider and include appropriate provision for (TB161 (Cigre WG23.03 2000)):

- Minimizing the thermal loading on busbars or HV connections by appropriate arrangement of circuits on the busbar

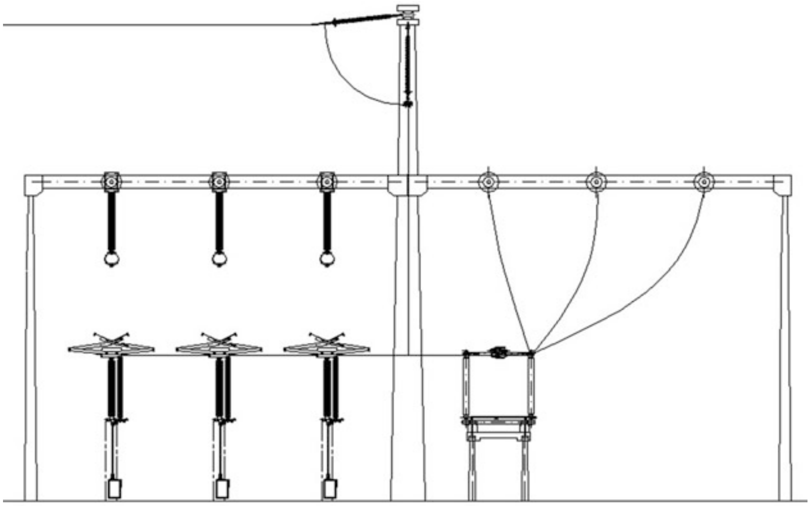


**Fig. 11.13** Connection with pantograph disconnector and classic disconnector to rigid and flexible busbars: elevation drawing (Carlos 1991)

- Future extension(s) with additional circuits
- Future uprating, e.g., an increase in the size of a transformer
- Future change in configuration, e.g., single busbar to double busbar, ring to 1½ circuit breaker
- Interface with incoming HV overhead lines or underground power cables
- Access for delivery of heavy equipment
- Access for equipment maintenance and replacement which minimizes the need for outages on circuits other than the one being worked on (this may impose restrictions on the number of adjacent bays which are allowed or on the spacing between bays)
- Security
- Any necessary storage or lay-down areas
- Water storage for firefighting (if required)
- Environmental mitigation measures

Layouts should also minimize the impact of any failure of in flyover spans or overhead earth wires which may result in a conductor falling on a busbar by ensuring that any such failure cannot affect more than one busbar.

From a security point of view, it would be preferable to avoid busbar flyovers altogether, but this may not be possible in some busbar configurations. In others it may be possible only if the circuits are arranged on the appropriate sides of the busbar or if particular designs of busbar disconnector are used.

Traditional layouts are based on the use of disconnectors on each side of every circuit breaker to allow the circuit breaker to be maintained with minimum impact on the rest of the substation. As circuit breakers have become more reliable, the need for this degree of isolation capability has reduced. If a designer wishes to remove some disconnectors, then reliability calculations are required (refer to ▶ Chap. 4).

However one readily usable form of isolation on each circuit is still normally required to allow the circuit to be isolated from the busbar.

If a small footprint is essential, one approach is to use a layout with back-to-back bays which allows two circuits, one on each side of the busbar, to be connected into a single bay width on the busbar.

As an alternative, a number of solutions are also available which combine multiple functions into single pieces of equipment (see various papers on compact solutions), e.g.:

- Disconnecting circuit breaker (a circuit breaker which also meets the requirements for a disconnector)
- Withdrawable circuit breakers
- Rotating circuit breakers with integral disconnector arms
- Dead-tank circuit breakers incorporating current transformers in one or both bushings
- Live-tank circuit breakers incorporating nonconventional current transformers
- Disconnectors incorporating nonconventional current transformers
- Disconnectors or post insulators incorporating surge arresters
- Installing the fixed terminals for double side-break disconnectors on adjoining equipment

As is typical in substation design, the space-saving benefits gained using this type of approach may need to be balanced against the implications of the design on maintenance or replacement requirements.

An alternative way to meet the requirement for a small footprint is the use of gas-insulated switchgear (GIS) or mixed technology switchgear (MTS) which is covered in later ▶ Chaps. 15 and ▶ 26, respectively.

Elegant layout solutions are sometimes possible using shared structures, e.g.:

- A row of adjoining gantry structures where there is one less girder than the number of masts
- Flyover support structures which are integrated into busbar support structures

While these normally save space and may reduce the initial cost, the designer must consider the outage impact if one of these structures becomes faulty and must be repaired or replaced.

The following sections show sample layouts for the more commonly used busbar configurations. It should be noted that many variations are possible on each example. With the longer maintenance intervals on circuit breakers, the use of bypass disconnectors and transfer buses is becoming less common.

The layouts shown assume that adequate space is available. If this is not the case, it is often possible to modify the layout by trading increased overall height for reduced footprint (Figs. 11.14, 11.15, 11.16, 11.17, 11.18, 11.19, 11.20, and 11.21).

In many locations, the reduction of the visual impact of the substation may be an important design requirement. The most effective way of achieving this is to use GIS

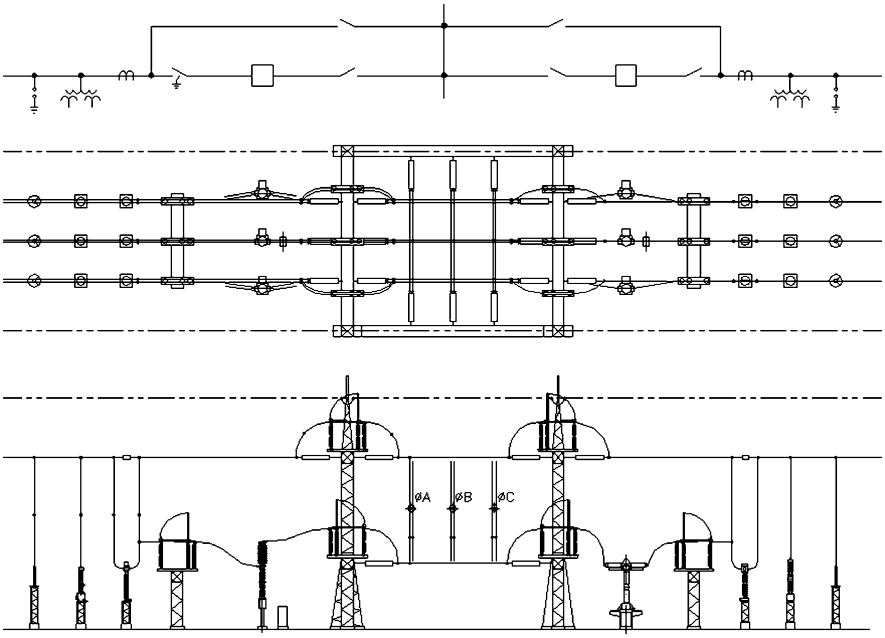



**Fig. 11.14** Single busbar with bypass (plan view and elevation)

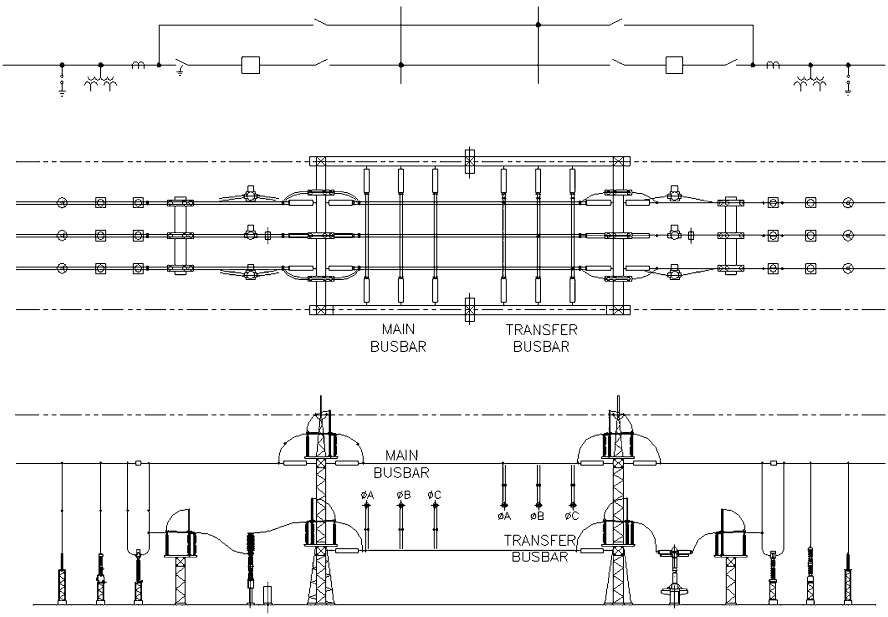



**Fig. 11.15** Single busbar with transfer busbar (plan view and elevation)

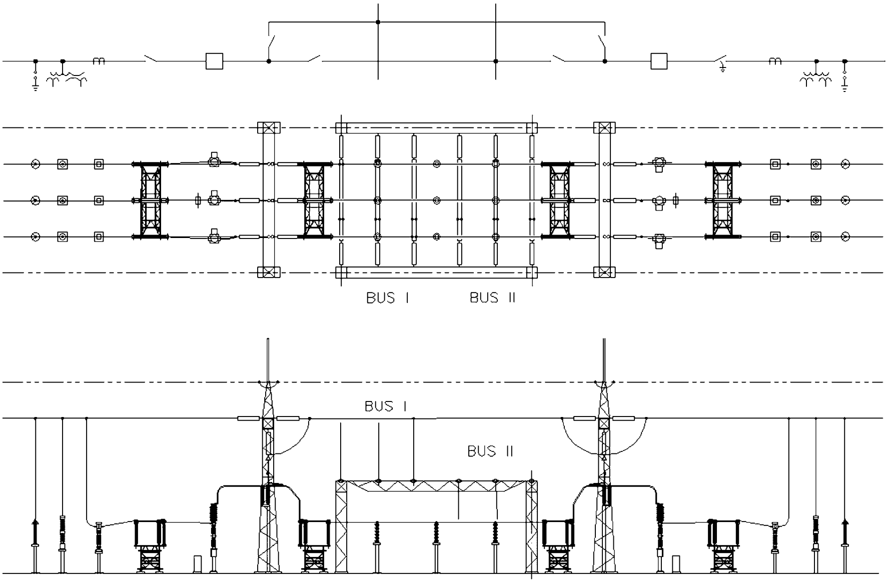



**Fig. 11.16** Double busbar with three disconnectors (plan view and elevation)

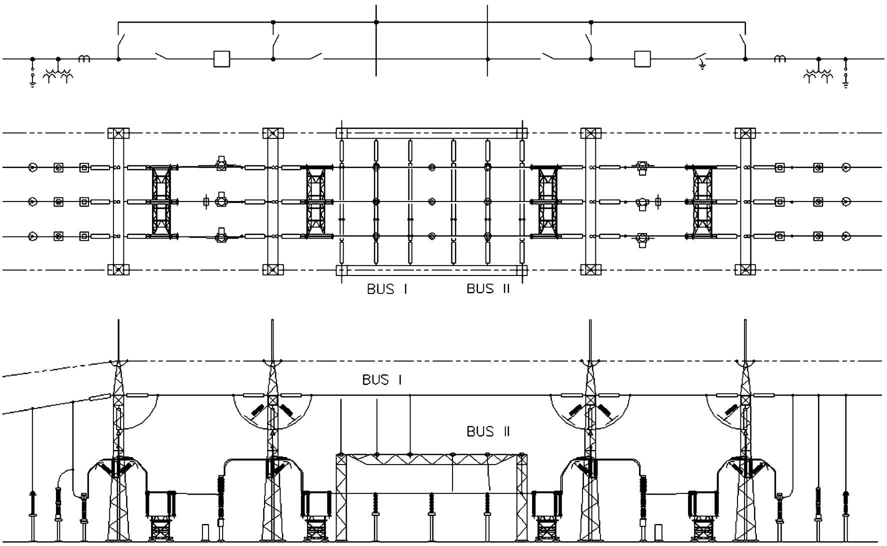



**Fig. 11.17** Double busbar with four disconnectors (plan view and elevation)

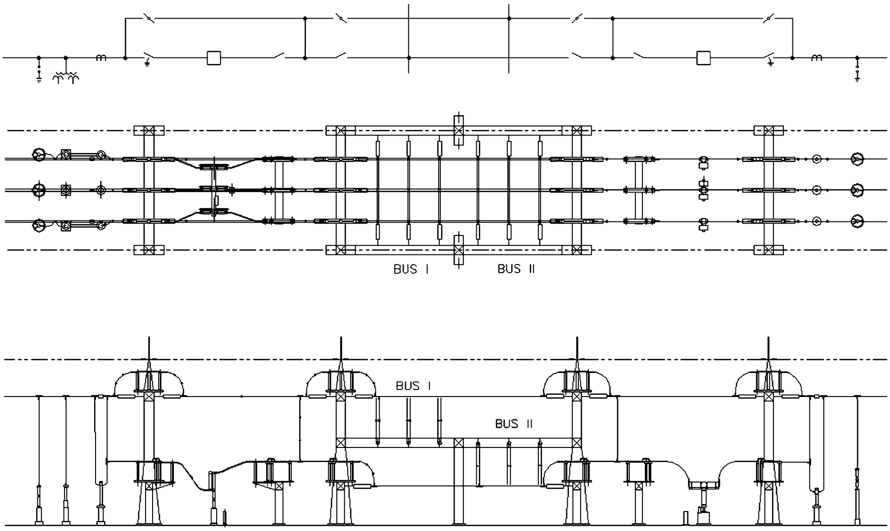



**Fig. 11.18** Double busbar with five disconnectors (plan view and elevation)

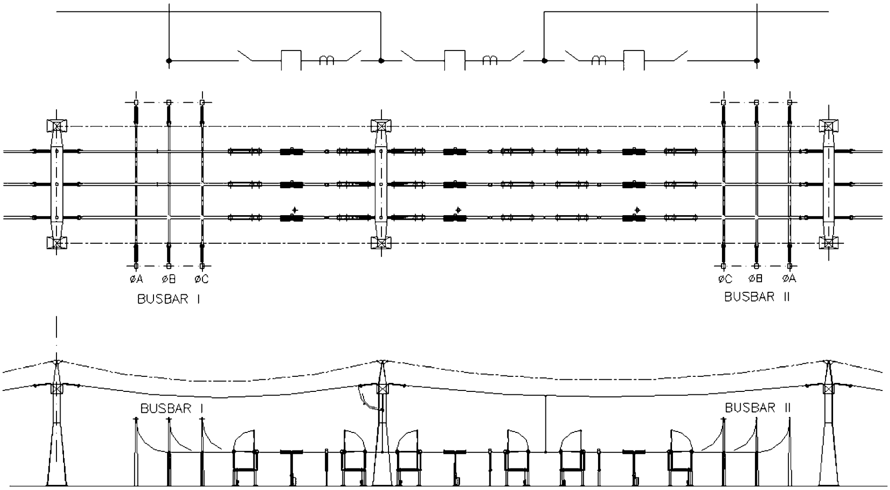



**Fig. 11.19** 1½ circuit breaker: plan view and elevation

installed indoors in a building with connections to external circuits by underground cable. If an AIS solution is being retained, then a low-profile layout using tubular conductors and with lattice steel structures replaced by alternative designs (e.g., tubes) tends to be less obtrusive (TB221 (CIGRE 2003)).

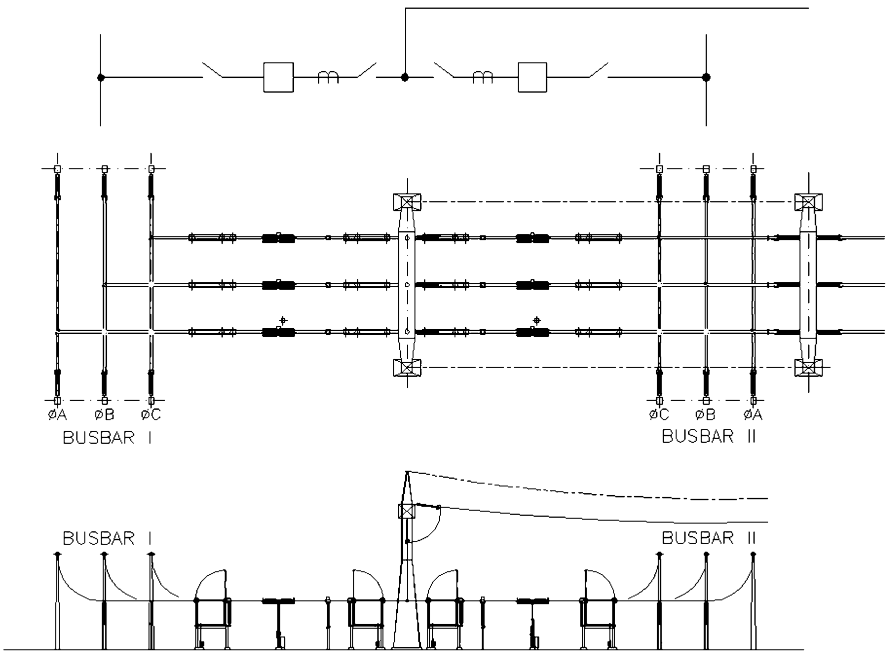



**Fig. 11.20** Double busbar, double circuit breaker (plan view and elevation)

Ideally a substation should be installed on a flat site. However this is rarely achieved, and some degree of ground preparation is required either by excavation to achieve the required level or by dividing the site into several levels. Cutting into a hillside can reduce the visual impact of a substation by taking the installation off the skyline. Some visual treatment of the slopes between the terraces may be required. As it is good practice not to remove large quantities of excavated material from site, the layout should allow for reuse of the material on other parts of the site or relocation of the excavated material into berms outside the substation compound which have the benefit of providing some element of visual screening (TB221 (CIGRE 2003)) (Fig. 11.22).

## 11.3 Electrical Clearances

The definition of the required electrical clearances in air is fundamental to the design of the AIS substation. (It should be noted that at altitudes in excess of 1000 m, the reduced air pressure results in the need for larger clearances. For details refer to ► Sect. 12.1.) The clearances are required as it is not practical to test the entire AIS substation installation with test voltages to confirm the required insulation level.

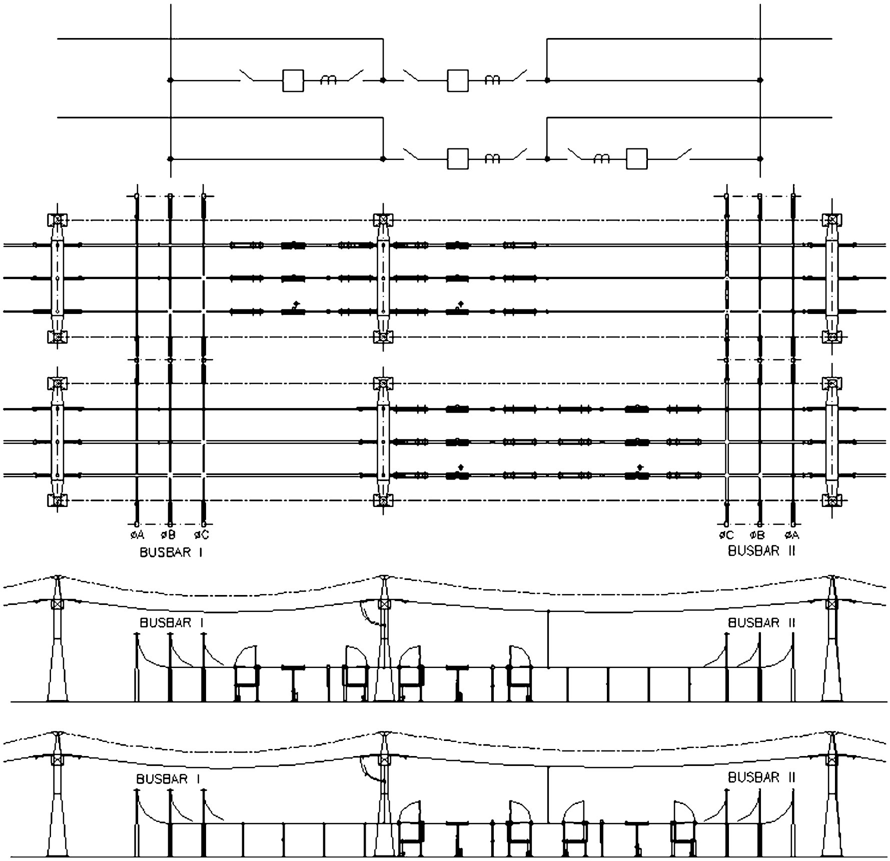



**Fig. 11.21** Ring busbar: plan view and elevation

These clearances ensure that the substation design minimizes the risk of a breakdown of insulation and that the substation can be operated reliably. The way in which these clearances are derived is explained in ▶ Sect. 5.3. In addition, IEC 61936-1 (IEC 2010) gives some guidelines on appropriate values which may be considered. Many countries have national standards and regulations which define these requirements also.

The values of the minimum distances to live parts in air also depend upon practical experience, and therefore, some differences can be found when comparing rules in different jurisdictions.

The specified electrical clearances must be maintained under all normal conditions. Exceptionally, reduced electrical clearances may be allowed, for example, in the case of conductor movement caused by short-circuit current or by extreme wind.

The design of the substation must restrict access to danger zones, taking into account the need for operational and maintenance access.

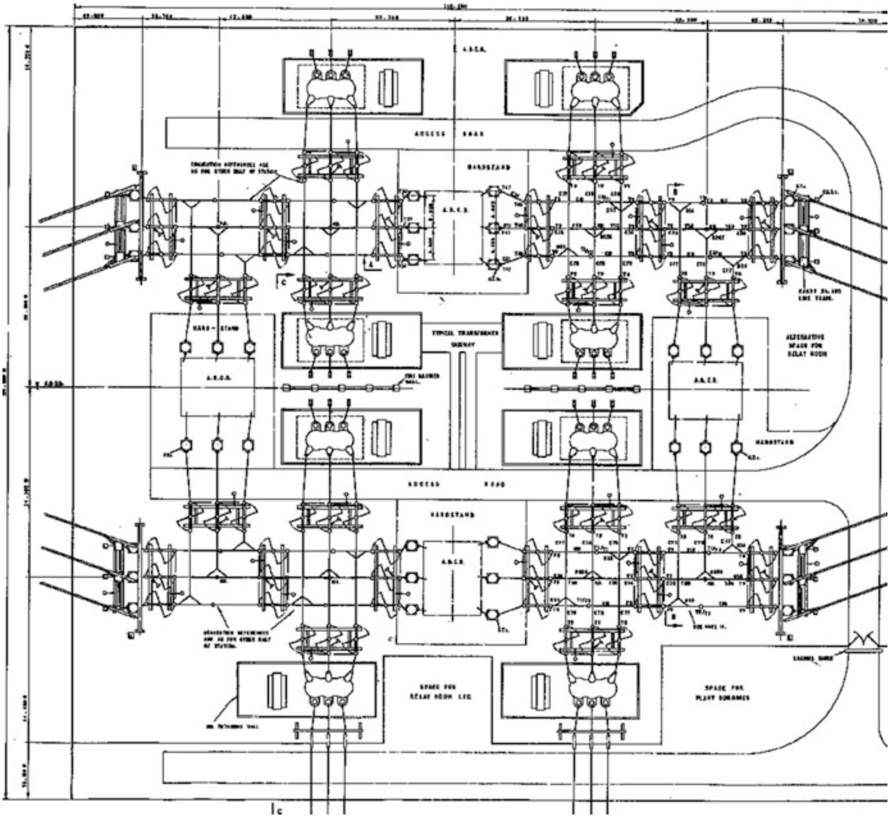


**Fig. 11.22** Overall plan view of four-switch mesh with two transformers banked on each corner

External fences, or walls, are required particularly for AIS substations (see ▶ Sect. 5.7). Where safety distances cannot be maintained, permanent protective facilities are required (CIGRE 1971).

The main clearances which the AIS substation designer needs to consider are as follows:

- Phase-to-phase clearance: this is the clearance, metal to metal from one phase of a circuit to another phase.
- Phase-to-earth clearance: this is the clearance between the live metal and any earthed metal support/structure or ground.
- Insulation height clearance: this is the clearance from the bottom part of any insulator to the ground (usually at least 2.25 m (CIGRE 1971)) which is intended to prevent personnel from breaching clearances when standing adjacent to the structures. Consideration of potential levels of snow in a substation is required when selecting a value for this clearance.

- Safety distance vertical: this is the clearance from any live metal to the working plane of the equipment to be worked on, e.g., basic value plus 1.25 m (CIGRE 1971) (N.B. many utilities use the circulation clearance value for this rather than this lower figure).
- Safety distance horizontal: this is the clearance from the nearest live equipment to the edge of the equipment to be worked on, e.g., basic value plus 1.75 m (CIGRE 1971).
- Clearance for circulation around the substation: this is the distance from live equipment to the ground or walkway, e.g., the basic value plus 2.25 m (CIGRE 1971).
- Any special clearances, for example, the additional clearances used when using a mobile elevated working platform (MEWP).

Refer also to IEC 61936 (IEC 2010) for further guidance on clearance value application.

The following table describes additional clearances which may also need consideration by the substation designer; IEC 61936 (IEC 2010) gives further guidance on some of these (Table 11.2).

## 11.4 Insulation Coordination

Networks are required to operate satisfactorily not only under normal operating conditions but also in the presence of transient and temporary overvoltages. Overvoltages can vary widely in amplitude, duration, and wave shape. They may be categorized as follows:

- Lighting overvoltages
- Switching overvoltages
- Temporary overvoltages

In order to reduce the incidence of circuit outage and equipment failure, it is necessary that the following should be coordinated to meet the anticipated electrical stresses:

- Rated voltages of equipment
- Insulation withstand levels
- Clearance in air
- Creepage distances on the external insulators
- Use of shield wires on overhead lines and over substations
- Tower footing resistances
- Ratings, numbers, and location of surge arresters

The essential objective of the insulation coordination study is to bring the above parameters into prescribed relationship with one another.

**Table 11.2** Additional clearances and separation requirements for substation design

| Requirement | Description |
|---|---|
| 1. Protective barrier clearances | Within an installation, minimum protective clearances shall be maintained between live parts and the internal surface of any protective barrier (part providing protection against direct contact from any usual direction of access) |
| 2. Protective obstacle clearances | Within installations, minimum clearance shall be maintained from live parts to the internal surface of any protective obstacle (part preventing unintentional direct contact, but not preventing direct contact by deliberate action) |
| 3. Boundary clearances | The external fence of outdoor installations of open design |
| 4. Minimum height over access area | The minimum height of live parts above surfaces or platforms where only pedestrian access is permitted |
| 5. Clearances to buildings | Where bare conductors cross buildings which are located within closed electrical operating areas, clearances to the roof shall be maintained at maximum sag |
| 6. Clearance to external fences or walls and access doors | Unauthorized access to outdoor installations shall be prevented. Where this is by means of external fences or walls, the height and construction of the fence/wall shall be adequate to deter climbing. Additional precautions may be required in some installations to prevent access by excavation beneath the fence |
| 7. Minimum height of live parts above vehicular passageways within substations | Requirement to ensure vehicles do not breach clearance requirements to live parts. Care should also be taken with regard to persons entering or exiting vehicles such that they do not breach clearances |

For a substation designer, all equipment installed in a substation must take the rated power frequency voltage of the network into account. The temporary overvoltages at power frequency caused by e.g. sudden loss of load or earth faults; switching overvoltages, and lightning overvoltages must also be considered. In order to determine its capability, it is subject to voltage tests as follows:

(a) Lightning impulse withstand voltage (1.2/50 micro sec)
(b) Switching impulse withstand voltage (250/2500 micro sec)
(c) Power frequency (50 or 60 Hz) (wet and/or dry)

Additionally an oscillating voltage or chopped wave test may be required.

The set of standard test voltage values determines the insulating level. Standard insulating levels are defined in IEC60071 (IEC 2011a).

The necessary insulation level depends on the insulation coordination, i.e., on the properties of the different parts of the network (mainly lines), on the protection used against overvoltages (surge arresters are very effective), on altitude, and also on the reliability of the substation (permissible probability of flashover), and may vary in different parts of the same substation (Cigre WG23.03 2000).

Guidelines on the completion of an Insulation Coordination Study are given in IEC60071 (IEC 2011a).

### 11.4.1 Protection of Substation Against Traveling Waves on Incoming Lines

The sources of traveling waves on incoming lines are as follows:

- Back flashovers

Where a transmission line is shielded and its tower footing resistances are of the order of 10 Ω or less, a lightning stroke to a shield wire or a tower will normally discharge to earth innocuously.

However, if the line is not shielded or if the tower footing resistances in the vicinity of the stroke are high, a stroke to a shield wire or tower may raise the potential of the tower far above that of a phase conductor – depending on the current of the stroke. A "back flashover" will occur from tower to phase conductor. This will be followed by a power frequency earth fault current in the ionized path, flowing in the opposite direction to that of the surge current.

A back flashover will set up a traveling overvoltage wave of extremely high rate-of-rise on the phase conductor.

- Direct stroke to phase conductor

Where a transmission line is not shielded, direct strokes to the phase conductors are more likely to occur. Occasionally, a direct stroke to a phase conductor will occur even in the case of a shielded line. With good shielding designs, "shielding failures" should represent no more than 1% statistically of all strokes to the line. Generally, strokes resulting in shielding failure will have lower values of surge current.

Direct strokes will be transmitted along the line as traveling overvoltage waves with steep wave fronts.

- Induced overvoltages

Air-to-ground lightning strokes occurring within 1 km of the line, or strokes discharged through line earthed structures without back flashover, will induce overvoltages in the phase conductors. The overvoltages are transmitted along the line as traveling waves. Amplitudes will depend on the stroke current but will rarely exceed 220 kV so that, while induced overvoltages may account for a large proportion of lightning flashovers on distribution networks, they are of little importance at transmission voltages. Furthermore, they are not particularly steep-fronted.

### 11.4.2 Impact of Traveling Waves on a Substation

The majority of lightning overvoltages affecting substations enter the substation as traveling waves on the overhead lines.

However generated, a lightning overvoltage wave will travel on the line with a velocity of $3 \times 10^8$ m/s – the speed of light. It will travel in both directions from the point where the conductor is struck, so that the impedance is effectively half the surge impedance of the conductor.

Traveling waves resulting from direct strokes to phase conductors have very steep fronts. Depending on their amplitude, they may flash over at an adjacent tower. When flashover occurs, the impedance through which the discharge current flows drops from half the surge impedance of the conductor to the surge impedance of the tower plus tower footings, resulting in a short wave tail. Generally, when a surge discharges to earth on a line tower, the substation equipment is no longer seriously threatened.

Traveling waves are subject to attenuation due to the ohmic losses in the conductor. If the overvoltage has a value exceeding the corona inception level, further attenuation will occur resulting in a reduction in the steepness of the wave front. Traveling waves imposed on phase conductors more than 2 or 3 km from the substation generally do not present a threat to the substation equipment. However, a direct stroke to a phase conductor or a back flashover near the substation may enter it as a very steep-fronted wave, which does present a serious hazard.

If, for reasons of pollution control, the line insulation level is very high compared to that of the substation, a lightning stroke may not flash over on the line but may enter the substation in its full severity. In such cases surge arresters at the line entries must be considered, even in a case where the line is shielded.

Traveling waves are reflected at electrical discontinuities, e.g., at open circuit breakers, at junctions of overhead lines with underground cables, and at transformers or GIS. These reflections may result in a doubling of the voltage on the terminal equipment, representing a serious hazard. Assume that a step voltage of amplitude U enters a substation as a traveling wave:

- $Z_1$ is the line surge impedance.
- $Z_2$ is the surge impedance of the terminal equipment.

The voltage across $Z_2$ will be:

$$2\,U\,[Z_2/(Z_1 + Z_2)]$$

and the amplitude of the reflected wave will be:

$$U\,[(Z_2 - Z_1)/(Z_2 + Z_1)]$$

In particular if $Z_2 = \infty$, as for open circuit breaker, the voltage at the terminal equipment will be doubled.

Similarly, where a line terminates at a transformer, the voltage will be virtually doubled due to the capacitance of the transformer.

On the other hand, if there are a number of lines connected to a substation busbar, the amplitude of the overvoltage at the busbar is given as:

$$2\,U/N$$

where N is the number of lines.

Thus three or more connected lines will result in a reduction in the amplitude of the incoming wave.

### 11.4.3 Protection

Surge arresters are usually installed adjacent to all power transformers, shunt reactors, power cables, and GIS and perhaps on incoming line entries to AIS installations in order to protect these items against traveling waves, whether resulting from lightning or switching.

Coordinating rod gaps have been used for the discharge of lightning surges instead of surge arresters. These are employed because they are simple, fairly predictable, and relatively inexpensive. However, a serious disadvantage with their use is the fact that operation always results in an external flashover and a circuit tripping. Furthermore, they provide poor protection against steep-fronted impulse waves because of the inherent time lag for flashover in air. With the advent of reliable and relatively inexpensive metal oxide, surge arresters rod gaps are no longer recommended. Coordinating rod gaps should not be used in association with surge arresters.

Surge arresters are internationally recognized as the most effective overvoltage protection for vulnerable substation equipment. In all cases they operate on the principle of the nonlinear resistor which is highly conductive at impulse voltage levels but non-conductive, or drawing only a small leakage current, at operating voltage levels. The surge current drawn by the nonlinear resistor causes a voltage drop across the source surge impedance, limiting the voltage drop across the protected equipment. The surge is diverted to earth through the arrester without causing a circuit outage.

The modern type of surge arrester is the metal oxide (MO) gapless arrester, sometimes referred to as “zinc oxide (ZnO)” arrester, which has superseded the silicon carbide (SiC) gapped arrester.

The correct MO arrester for a particular application is that which provides adequate protective margins against impulse overvoltages while at the same time enduring normal operating voltage and temporary overvoltages (TOVs) throughout its life cycle without failure or serious degradation. Increasing the margins against transient overvoltages will decrease the margins against TOVs and vice versa.

Where pollution levels are high, the margins against normal operating voltage and TOVs must be conservatively determined. Conservative margins against operating voltage and TOVs are also desirable where the severity of the TOVs is not fully known or where there is some doubt about the long-term consistency of arrester performance at power frequency voltage.

Where there is a considerable distance between the arrester and the protected object, the overvoltage experienced by the protected object will be higher than if the arrester were mounted close to the protected object.

Increased distance results in a reduced protective margin. With a knowledge of the surge arrester protection levels and the insulation withstand levels of the protected object, a "protective distance" can be calculated which will represent the furthest distance the arrester may be placed from the protected object while still providing a recommended margin for safety.

► Section 12.4 provides details on the design, selection, and application of surge arresters.

Some particular issues arise in the application of surge arresters to GIS, and these are covered in ► Chap. 17.

## 11.5 Bus and Conductor

Selection of appropriate conductors and busbar designs can be a challenge in AIS substation design. Countless options and combinations of options are available for selection. As part of this process, the designer must consider the following aspects when determining the optimal solution for his design:

- Current-carrying requirement (continuous and short circuit)
- Environmental considerations (ice, wind, solar radiation, etc.)
- Physical constraints of the particular substation site
- Future requirements of the substation
- Corona and radio interference

The fundamental decision of whether to use tubular or stranded conductors can be difficult, as each has their merits and disadvantages. Some of the criteria for consideration for this selection are given in Sect. 11.2 (Table 11.1). The most important design considerations are described in the following sections.

### 11.5.1 Current Ratings

The instantaneous load flow within a substation depends on the state of the entire electrical network. Usually a complete network analysis including consideration of development to meet future needs is required to determine the nominal values of currents flowing in an individual substation circuit. While designing a substation, it is necessary to consider the following two aspects of the effect of current:

- The thermal effect (including induced currents)
- The mechanical effect on conductive items of plant and their support structures

Precise thermal modeling of equipment is very difficult as many factors influence the resultant temperatures of conductive parts, e.g., previous loading, ambient temperature, wind speed, and solar conditions. Thermal design is therefore empirical and proven by type tests covering both nominal current and short-circuit current ratings. Standard procedures have been devised to predict the thermal behavior of conductors, particularly with respect to sag.

It may be possible to assign a short-term current rating in excess of the nominal, but the analysis leading to this must ensure that no “hot spots” (transformers, terminals, busbar support points) are overlooked. Methods of calculating short-circuit effects are given in IEC Standard 60865-1 (IEC 2011b).

### 11.5.2 Electrical Clearances

The specified electrical clearances must be maintained under all normal conditions. Exceptionally, reduced electrical clearances may be allowed, for example, in the case of conductor movement caused by short-circuit current or by extremely strong wind. More information about electrical clearances is given in Sect. 11.3.

### 11.5.3 Mechanical Forces

HV equipment support structures should be designed to withstand the normal and exceptional loads that act on them during their operational lives. They should also be designed so that their operational behavior is acceptable and in accordance with expectations, such as deflections and sags remaining within a permissible range, having an acceptable strength and level of vibrations, and so on. The loads are as follows:

**Weight**
In addition to the dead weight of apparatus, conductors, structures, etc., temporary loads must be considered, especially the weight of ice (depending on the local climate) and loads imposed by maintenance staff access. Temporary stresses during erection must also be considered (lifting of structure, asymmetric pull of conductor, etc.).

**Wind Loading**
The wind pressure may substantially influence the strain exerted on structures and footings and may also reduce the clearances between conductors (in case of turbulent wind) or between the conductors and grounded structures. Standard values for wind speed are recommended by IEC, but local conditions must be considered. When calculating the wind loads on bundle conductors, the screening effect from the other sub-conductors may be taken into consideration. The effect of wind on insulator strings should also be taken into account. The wind loads can be transmitted to apparatus through either rigid or flexible connections.

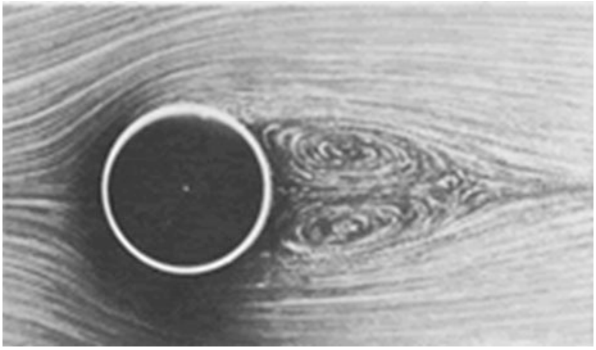


**Fig. 11.23** Laminar flow around a cylindrical obstacle (CIGRE 2009)

**Aeolian Vibrations**

Under certain conditions, wind can encourage oscillations of tubular conductors. This is known as Aeolian vibration (See Fig. 11.23). Special care should be taken against the effects of Aeolian vibration in rigid tubes.

These vibrations are due to an effect known as "von Kármán vortex street" and can be managed (damped) either by installing a flexible cable inside the tube or in some cases by the use of external dampers. The flexible cable acts as an impact damper (efficient if acceleration of the movement is greater than gravity). To calculate the maximum frequency of the Aeolian force, it is necessary to have meteorological information regarding wind speeds of the general area. The maximum frequency is calculated as follows (CIGRE 2009):

$$f_a = \frac{51.75 \times V_w}{d_{bo}}$$

where:

- $f_a$ maximum Aeolian force frequency in Hz
- $V_w$ maximum wind speed for laminar flow in km/h
- $d_{bo}$ outside diameter of bus tube in mm

The fundamental mechanical (or natural) frequency for a tubular conductor in Hz is given by CIGRE WG 23-11 (1996):

$$f_c = \frac{\gamma}{\ell^2} \times \sqrt{\frac{E \times J}{m}}$$

where:

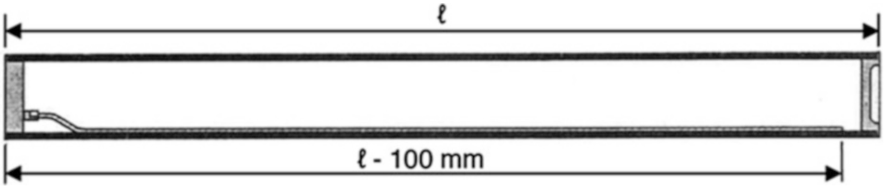
- $f_c$ fundamental mechanical frequency for a tubular conductor in Hz
- $\gamma$ fundamental frequency factor based on rigid bus bar boundary conditions
- $\ell$ span length of tubular conductor in meters

- $E$ modulus of elasticity in N/m$^2$
- $J$ moment of inertia in m$^2$
- $m$ mass per unit length of bus tubing and damping conduct or (if present) in kg/m

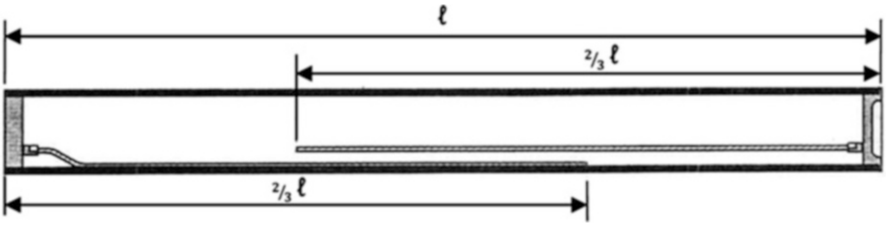
As an indication that damping may be required, $f_a$ and $f_c$ need to be calculated. If $2f_c > f_a$, then either the bus span length needs to be changed or dampers are to be employed. When determining the need for vibration damping, a conductor damper can be used to provide damping over a frequency spectrum including the second and third modes.

The inserted flexible cable should be of the same material as the bus tubing to prevent corrosion due to electrochemical differences. The weight of the cable should be from 10% to 33% of the bus conductor weight (CIGRE 2009).

For tubes with outer diameter 80–120 mm (inclusive), the figure below shows the damping conductor configuration for fitting.




For tubes with outer diameter in excess of 120 mm, the figure below shows the damping conductor configuration for fitting.




**Thermal Expansion**

Operational temperature variations result in longitudinal expansion or contraction of the busbars. The thermal expansion or contraction in length of the conductor as a result of a change in temperature can be computed using the following equation (CIGRE 2009) and (IEEE 2008):

$$\Delta L = \alpha \times L_i \times \left(T_f - T_i\right)$$

where:

- $\Delta L$ is the change inspan length (m)
- $\alpha$ is the coefficient of thermal expansion(1/°C)

- $L_i$ is the conductor span length at the initial temperature (m)
- $T_i$ is the initial installation temperature (°C)
- $T_f$ is the final temperature (°C)

In rigid busbar assemblies with insulators supporting the rigid bus conductors, restrained thermal expansion or contraction of the conductors results in compression or tension of the conductors and can cause bending of the insulators. To avoid or minimize the thermal expansion effects, provisions should be made for expansion in any bus-conductor span. These provisions may be made with expansion fittings for long buses or by considering deflection of a bus conductor, bus-conductor bends, insulators, or mounting structures for short buses. The tension or compression force generated in the conductor due to thermal expansion $\Delta L$ is given by (IEEE 2008):

$$F_T = \frac{E_c \times A_c \times \Delta L}{L_i}$$

where:

- $F_T$ is the thermal force (N)
- $A_c$ is the conductor cross section area ($m^2$)
- $E_c$ is the conductor material Young's modulus ($N/m^2$)

With flexible busbars, the ambient temperature significantly impacts the sag and tension of the strain conductors. In general, conductors should have minimum sag. However, when considering the imposed temperature effect, the associated tension needs to be balanced with economics considering the imposed temperature effect. If necessary, spring bolts and tension springs can be used to maintain controlled tension within a span to limit changes in conductor sag.

**Earthquake**

Earthquakes occur in different parts of the world. Substation planners should consider the probability and the expected severity of a possible earthquake. Because the horizontal acceleration is about 0.3–0.5 g (the vertical acceleration is less than 50% of the horizontal) and the frequency of the earthquake is 0.5–10 Hz, 275–500 kV equipment that resonates in this frequency band may be damaged. Busbar support insulators are particularly vulnerable. Tubular aluminum conductors are also thought to resonate during earthquake, and, if required, "dampers" or "slide supports" may be fitted.

Equipment in the substation is liable to suffer from damage where the ground conditions are not stable. Therefore, particular attention should be paid to site preparation to ensure solidity of the ground. See Sect. 11.11 for further information.

**Short-Circuit**

The mechanical phenomena which are consequences of short-circuit currents in substations must be considered in the design. These phenomena influence the design arrangements and mechanical strength requirements of substation components. In particular, the mechanical strength of apparatus, insulators, and conductors and the supporting structures have to be considered. In addition, in substations with flexible conductors, conductor displacements and the resulting reductions in electrical clearances can be significant.

Short-circuit mechanical effects within substations depend, in particular, on the type of conductors used for the busbars of the substation and the connections in the bays, namely, rigid conductors (tubes) or flexible conductors (cables). The mechanical effects of short-circuit currents in such bus systems are quite different in both cases.

Generally equipment is type tested in a short-circuit laboratory to determine its dynamic behavior. The short-circuit strength of the busbars is usually only calculated, the calculation methods being verified by testing of typical busbar arrangements. IEC Standard 60865-1 (IEC 2011b) can be used both for rigid and flexible connections; the background to the calculation methods is detailed in CIGRE TB105 (CIGRE WG 23-11 1996) and CIGRE TB214 (CIGRE WG23.03 2002).

Always consider the two-phase isolated fault condition for clearances and the two- or three-phase fault condition for maximum interphase stress. Where bundles of flexible conductors are used, in addition to the swing-out force, drop force and pinch effects must be considered, and the recommendations for limitation of pinch detailed in the CIGRE TB214 (CIGRE WG23.03 2002) followed.

**Combinations of Loads (Load Cases)**

Equipment and supporting structures, including their foundations, should withstand the anticipated mechanical stresses during the expected service life of the installation. The probability of simultaneous occurrence of various mechanical loads will be dependent on local conditions and requirements.

These loads shall be classified into two load cases. In each of these load cases, several combinations shall be investigated, the most unfavorable of which shall be used to determine the mechanical strength of the structures.

The normal loads are as follows:

- Dead weight (of equipment, conductor, structure)
- Static conductor tension
- Wind loads on conductors and equipment ice loads
- Maintenance and/or erection loads

In the exceptional load case, normal loads are acting simultaneously with one or more of following occasional loads:

- Short-circuit loads
- Earthquake loads whenever necessary
- Switching forces
- Loss of conductor tension

All this load data and their combinations form the input data for further calculations for support and gantry structures as well as for foundations. Normally national standards and regulations as well as client requirements define the different safety factors for the normal and exceptional load cases. These factors need to be considered in the design of steel structures and the foundations. However, care needs to be taken to avoid simply summing the various safety factors for steel and concrete which could lead to high civil work costs. This means the input data for the foundation does not include the safety factor for steel.

**Corona and Radio Interference**

Corona discharges occur on air-insulated conductors when the electric field intensity at the conductor surface causes ionization in air. The field intensity at the initiation of the discharges is known as "corona onset gradient." Electromagnetic interference (EMI) is caused by the corona. However, the substation designer should be aware that EMI can be produced at any voltage by arcing due to poor bonding between HV conductors and associated hardware.

In any design, substation HV conductor corona will probably occur to some extent. There is no physical law that supports any specific onset voltage. The probability that corona will occur depends on many factors (e.g., bus contamination, weather, surface scratches, and field voltage gradient). The designer's challenge is to select a HV conductor and to specify HV hardware that will achieve acceptable corona performance.

Care is required in the 123–245 kV range for composite insulators used in substations as assemblies, which are corona-free when used on overhead lines without corona rings, may be subject to corona requiring corona rings when used with lower clearances and different layouts in substations.

Fitting of busbar end caps is good practice to reduce corona at the ends of the tubular busbars. More information about corona calculation methods can be found in IEEE 605 (IEEE 2008).

All devices must satisfy the specified level of radio noise. The limits of radio noise are stated by national standards. International rules are IEC-CISPR Publication 1 and IEC-CISPR Recommendation No 30.

In order to design the busbar system and finalize the selection of the conductors, calculations must be completed to confirm that the proposed design is fit for purpose. IEC and Cigre have produced standards and guides which can be used for this analysis: Cigre TB105 (CIGRE WG 23-11 1996), Cigre TB214 (CIGRE WG23.03 2002), IEC 60865-1 (IEC 2011b), and IEC 60865-2 (IEC 2015).

## 11.6 Structures

Structures are required to support and fix the various items of high-voltage equipment and installation material used in a substation. They must be designed to meet the same loads and forces that are described in Sect. 11.5 above. Calculation of loads is usually covered by national standards and regulations which specify safety factors and load combinations.

Structures include terminal gantries and support structures for circuit breakers, disconnectors, instrument transformers, surge arresters, post insulators, etc. Whereas reinforced concrete (and sometimes wood) may be used for HV substations in some countries, nowadays support structures of HV, EHV, and UHV substations are commonly made from welded or bolted open profile steel lattice, or of tubes. In some cases aluminum structures are used for their low weight, resistance to corrosion, and suitability for use in strong magnetic fields (in the vicinity of air-cored reactors), but it should be noted that the buried portion must be made of steel in order to avoid electrochemical corrosion.

The visual impact of the taller structures is becoming an increasingly important design issue, and special architectural treatments in relation to form and color are now being seen in some installations.

### 11.6.1 Concrete

Concrete structures may have a similar lifetime to steel, but they are vulnerable to corrosive or moist atmospheres which may result in damage to the concrete due to expansion of the reinforcing material. Overall lifetime is very sensitive to the level of quality control applied during fabrication. The sensitivity to ambient conditions would tend to favor off-site fabrication where it should be easier to ensure appropriate conditions.

Concrete structures are generally heavier than steel which may drive a requirement for larger foundations and may take longer to assemble and erect if cast on-site. If prefabricated, assembly costs may be similar to steel.

If availability of appropriate steel is difficult, then concrete structures may be a reasonable alternative.

### 11.6.2 Steel

Steel probably performs better than concrete except perhaps in the area of corrosion resistance.

Steel can be protected by hot-dip galvanizing or zinc spraying, but the provision of good-quality durable finishes of the appropriate thickness is not cheap. In many environments, it is likely that this finish will have to be supplemented by painting at some stage during the lifetime of the structure. An important contribution to durable finishes is immediate repair and touch-up of any scratches which may be caused during transport and installation of the structures. In hostile environments, the use of metal-rich or multilayer epoxy paint finishes on top of the galvanizing may be justified. In more benign environments, the use of paint alone may be adequate.

The most common types of steel structure are:

- Large standard sections such as universal columns
- Tubes
- Lattice construction using small angle or flat members

The use of standard sections can facilitate design and also the availability of material. Transport and handling of larger structures may be somewhat awkward.

Tubular structures typically would present a cleaner appearance than standard sections, but fabrication is more expensive, and design of attachments is more difficult. There are also some subtle design issues which must be considered in relation to facilitating appropriate surface treatment of inner surfaces and also ensuring that rainwater is not trapped inside structures.

Lattice structures can produce a lesser visual impact than the other two types, but this may be counterbalanced in some cases by the larger overall size of lattice structures which can have some impact on substation dimensions. Design of lattice structures is also more complicated than that of large section or tubular structures.

Lattice construction makes transport very straightforward as the individual component parts are quite small and light. They also minimize the amount of material used and can also facilitate repair of any damage as individual members can be replaced quite easily. However surface treatment of the large number of components is expensive, and the level of site assembly required is labor-intensive. Any subsequent repainting that may be required will also be labor-intensive. A design issue which must be considered with lattice structures is their potential to make it very easy to climb the structures, so anti-climb measures may be required.

### 11.6.3 Aluminum

The inherent corrosion resistance of some aluminum alloys and their high strength to weight ratio are attractive in structural design. Aluminum structures are likely to be more expensive than steel, but the reduced lifetime costs may make it cost-effective in some situations. However selection of the appropriate alloy is important, and electrochemical interaction issues with fasteners, etc. must be carefully managed. The availability of the material and the availability of local aluminum fabrication facilities would also have to be taken into account. As mentioned above care is required if any part of an aluminum structure is intended to be located below ground level.

### 11.6.4 Wood

The development of modern wood treatment methods may make the use of wood feasible and economically appropriate in some situations at least up to the HV level, especially where the raw material is available locally. Engineered laminates may be needed to meet some loading scenarios. Care is required with the design of the interface of a wooden structure with ground level to avoid situations which would tend to promote rot.

## 11.7 Earthing (Grounding) and Lightning Protection

### 11.7.1 Functions of a Substation Earth Grid

A substation earth grid has two main functions:

(a) Operational
To provide a means of carrying currents to the general earth, under normal and fault conditions, such that the design and operating parameters of the equipment are not exceeded and unwanted discontinuities in supply are avoided
(b) Safety
To ensure that persons, animals, or equipment in the environs of a substation or in remote locations are not exposed to dangerous voltages during the flow of earth fault currents in the earth grid

Other functions of the earth grid are to provide a means for the discharge of lightning and switching surges to earth and for the earthing of high-voltage equipment during maintenance.

The operational function is fulfilled when:

- The earth grid and the connections to it from the transformer neutral points are fully rated for the most onerous prospective earth fault currents.
- The grid resistance to remote earth is not so high that it will limit the earth fault current below a minimum value necessary for correct operation of the protective relays.

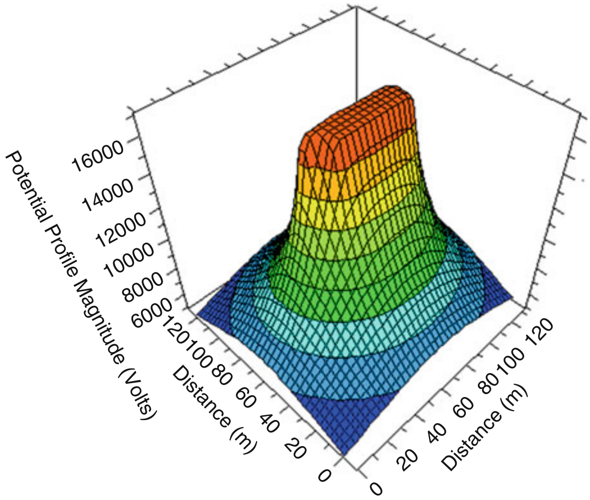
The safety function is fulfilled:

- When the earth grid and the connections to it from equipment, housings, and structures are such that touch and step voltages within or in the vicinity of the substation and transferred from the earth grid to external locations over telephone circuits or low-voltage power circuits or by any other means are maintained within safe limits such as those defined by IEEE Standard 80-2000 (IEEE 2000a) or IEC EN 50522 (CENELEC 2010).

The overall earthing system controls the effects of the temporary earthing path established by a person exposed to a voltage gradient in, or in the vicinity of, the substation.

During earth fault conditions, the flow of current to earth will produce voltage gradients within and around a substation. Figure 11.24 shows this effect for a substation with a relatively simple rectangular earth grid in homogeneous soil. Because of this rise, there are voltage gradients (Fig. 11.24) around the substation, which may be shown as surface voltage contours (Fig. 11.25). These voltage gradients can cause various problems outside the substation property.

**Fig. 11.24** Surface voltage gradient plot (3D)



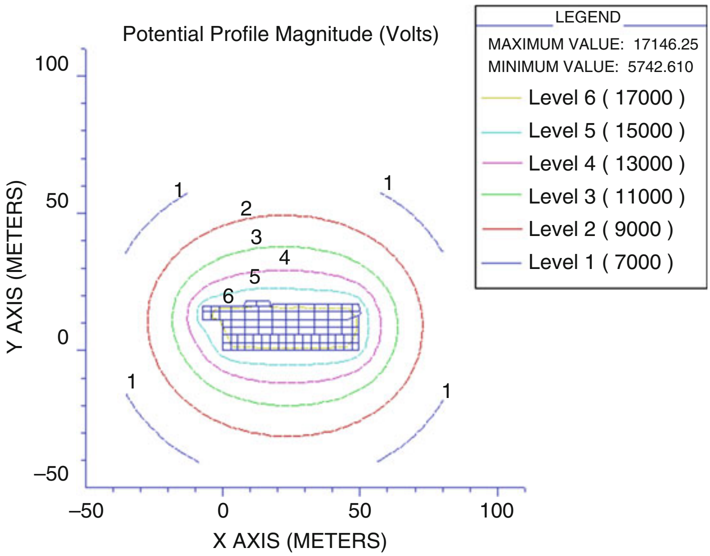




**Fig. 11.25** Surface voltage contour plot (2D)

During earth fault conditions, the maximum voltage gradients along the earth surface may endanger a person in the area. Moreover, hazardous voltages may develop between metal structures and equipment frames that are connected to earth and nearby surfaces on which a person may stand.

The following circumstances can contribute to hazardous voltage gradients and a risk to personnel:

- Relatively high value of earth fault current
- High soil resistivity
- Distribution of earth fault currents such that a significant ground return current flows
- Presence of an individual at such a point, time, and position that the body is bridging two points with a voltage difference
- Insufficient contact resistance to limit current through the body to a safe value under the above circumstances
- A fault duration such that the duration of the flow of current through the human body is for sufficient time to cause harm

The effects of an electric current passing through the vital parts of a human body depend on the duration, magnitude, and frequency of this current. The most dangerous consequence of such an exposure is a heart condition known as ventricular fibrillation, resulting in immediate arrest of blood circulation.

The magnitude and duration of the current conducted through a human body at 50 or 60 Hz should be less than the value that can cause ventricular fibrillation of the heart. This limiting value of current varies with the duration of the exposure and according to EN 50522 (based on IEC/TS 60479-1) varies from 50 mA for a 10 s exposure duration up to 900 mA for a 0.05 s exposure duration. The earthing system should be engineered such that its safety function is met by limiting the step voltage and touch voltage generated during earth faults to values which limit the magnitude of the human body current to values which are too low to cause ventricular fibrillation.

High-speed clearance of earth faults reduces the probability of exposure to electric shock and reduces the duration of current flow through the body, which limits the severity of bodily injury. The allowable earth fault current value may therefore be based on the clearing time of primary protective devices or that of backup protection.

For additional information about the criteria and the design of earthing systems for personnel safety, see IEEE 80, Guide for Safety in AC Substation Grounding (IEEE 2000a), and EN 50522 Earthing of power installations exceeding 1 kV AC (CENELEC 2010). For guidance on the effects of current on the human body, see IEC 60479 (IEC 2005).

### 11.7.2 Earth Grid Resistance Value

There is no absolute value of grid resistance which may be specified as a maximum never to be exceeded. However the earth grid resistance should be kept as low as reasonably possible in order to fulfill the operational function. In each case the earthing system should be designed to achieve safe touch and step voltages within the substation property.

The relevant definitions are as follows:

- **Step voltage** – the difference in surface potential experienced by a person bridging a distance of 1 m with the feet without contacting any grounded object (IEEE 2000a)
- **Touch voltage** – the potential difference between the ground potential rise (GPR) and the surface potential at the point where a person is standing while at the same time having a hand in contact with a grounded structure (IEEE 2000a)
- **Safe current** – the current which can flow through the human body without a threat to the life and health of the exposed person (IEC 2005)

Maximum touch and step voltages are set to levels which will limit the current flowing through an exposed person to the safe current level.

The following factors influence the earth grid resistance:

- Soil resistivity
- Area covered by the earth grid
- Shape of the earth grid
- Mesh size of earth grid
- Material/resistivity of earth grid conductor
- Cross-sectional area of earth grid conductor
- Burial depth of earth grid

Equation 1 is a simplified equation used to calculate earth grid resistance as defined in IEEE (2000a) Clause 14:

$$R_g = \frac{\rho}{4}\sqrt{\frac{\pi}{A}} + \frac{\rho}{L_T} \tag{1}$$

- $R_g$ substation ground resistance (Ω)
- $\rho$ soil resistivity (Ω-m)
- A is the area occupied by the grounding grid ($m^2$)
- $L_T$ is the total length of conductors (m)

Equation 1 assumes a simple grid and uniform soil resistivity which are rarely the case. This equation can be used to gain an approximate idea of the earth grid resistance. In nearly all cases, more complex analysis is needed.

While resistivity of earth grid conductor, cross-sectional area of earth grid conductor, and burial depth of earth grid are not considered in this equation, they do have a small effect on the earth grid resistance (see (IEEE 2000a) Clause 14 if more information is required).

In order to calculate the earth grid resistance for a substation, the use of a proprietary software package is recommended.

### 11.7.3 Soil Resistivity Measurements

An important step in modeling the performance of an earthing system is the determination of an equivalent electrical model of the surrounding soil and rock. This can be achieved by taking soil resistivity measurements in the vicinity of the site being studied and through careful interpretation of the results of such measurements.

Soil resistivity measurements should be taken in accordance with the "Wenner 4-probe method" as described in a paper by Frank Wenner (Wenner 1915) and (IEEE 1983). Analysis of the soil resistivity measurements should be carried out as (IEEE 1983), with analysis by computer-aided methods strongly recommended.

In many cases in analyzing the soil resistivity measurements, it will be possible to arrive at a simplified horizontally layered model of the soil structure around and below the earthing system; however occasionally a more complex model will be required. Such complex models include vertically layered, cylindrical, and hemispherical or block soil models.

Knowing the resistivity of each of these soil layers or shapes will help to determine the earth grid resistance, earthing system impedance, and touch voltage and step voltage performance. The resistivity of the deep soil layers or bedrock will have a major effect in determining the overall modeled resistance/impedance of the earth grid/earthing system. Accurately determining the bedrock resistivity is of particular relevance in cases where the earthing system is very large; it is important that the extent of soil resistivity measurements taken should take account of this. Topsoil resistivity will also have a significant effect on touch and step voltages and on the applicable safety limits (see Sect. 11.7.4 below).

As a general guideline, it is recommended that, where possible, the extent of soil resistivity measurements taken should be sufficient to determine, with reasonable accuracy, (a) the resistivity and thickness of the topsoil layer and (b) the resistivity of the bedrock.

Uniform or horizontal two-layer soil models can be used in hand calculations to determine the performance of an earthing system; however more complex soil models can only be used as part of a computer-aided design. In many cases a horizontal two-layer soil model is typical, representative of a thin layer of lower-resistivity topsoil on top of higher-resistivity bedrock. Horizontal three-layer and four-layer soil models are also common and may provide a more accurate representation of the soil structure at a site, for example, where a lower-resistivity water table or different rock type is encountered at some distance below the surface.

### 11.7.4 Design Touch and Step Voltage Limits

Design touch and step voltage safety limits can be calculated using appropriate proprietary software or by simplified equations given in IEEE (2000a) or CENELEC (2010).

The simplified equations from IEEE (2000a) are given below. This particular version is based on a 50 kg body mass, 50 Hz frequency, a fault clearance time equal to the design earth fault clearance time selected, and topsoil resistivity as indicated below.

$$E_{touch50} = (1000 + 1.5C_s.\rho_s)\frac{0.116}{\sqrt{t_s}} \tag{2}$$

$$E_{step50} = (1000 + 6C_s.\rho_s)\frac{0.116}{\sqrt{t_s}} \tag{3}$$

$$C_s = 1 - \frac{0.09\left(1 - \frac{\rho}{\rho_s}\right)}{2h_s + 0.09} \tag{4}$$

where:

- $E_{touch50}$ is the touch voltage in V
- $E_{step50}$ is the step voltage in V
- $C_s$ is the surface layer derating factor
- $\rho_s$ is the resistivity of the surface material (Ω-m)
- $t_s$ is the duration of shock current (s)
- $\rho$ is the resistivity of the earth beneath the surface material (Ω-m)
- $h_s$ is the thickness of the surface material (m)

In the absence of site-specific measured surface layer resistivity data, typical resistivities and thicknesses of surface layers should be assumed as a starting point for the calculation of the safety limits.

Typical values for surface layers are 0.05–0.2 m of crushed rock or 0.05 m of tarmacadam.

### 11.7.5 Transferred Voltages and Hot Zones

Problems that a high ground potential rise (GPR) may cause outside the substation property include:

- Hazardous step voltages
- Hazardous transferred touch voltages at fences and other metallic objects
- Equipment damage to infrastructure belonging to other utilities such as telecommunications cables and junction boxes

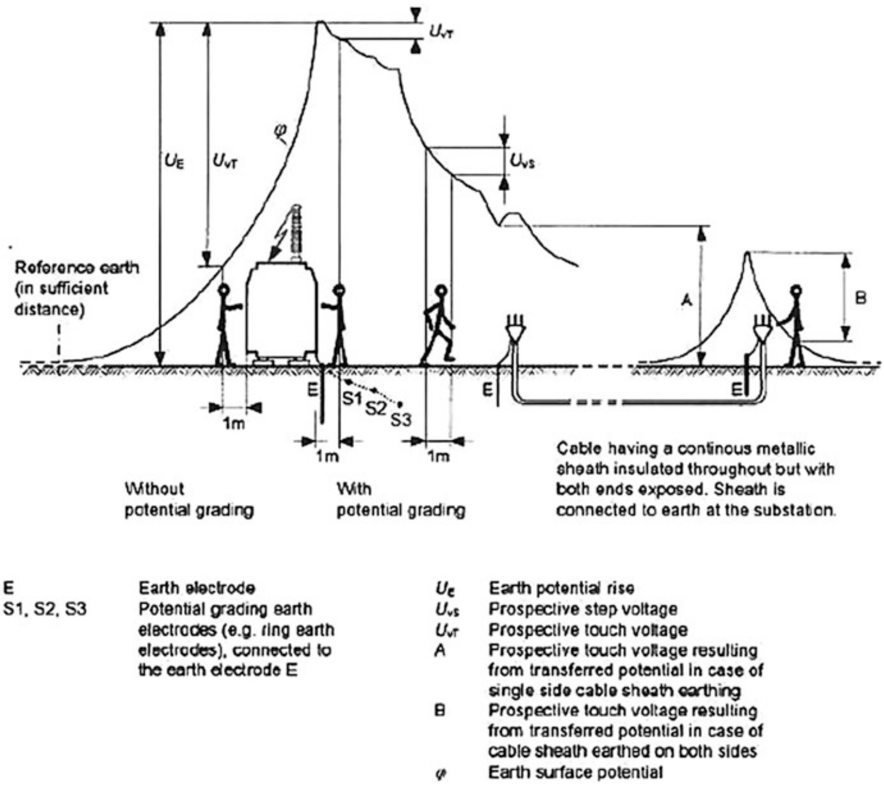



**Fig. 11.26** Example for the surface potential profile and for the voltages in case of current-carrying electrodes (CENELEC 2010)

Hazardous transferred touch voltages may occur where a metallic object, such as a fence, is earthed at a location and then traverses areas of different voltages levels. The metallic object is then at a different voltage to the ground over which it travels. A person touching such a metallic object exposes themselves to that voltage difference in the form of a touch voltage.

This situation is shown by "A" and "B" in the following sketch from CENELEC EN 50522 (CENELEC 2010) (Fig. 11.26).

Voltages may be transferred along the following metallic paths:

- Fences
- Shield wires
- Cable sheaths/screens
- LV neutrals
- Railway lines
- Gas pipelines
- Other long metallic structures

It is not always possible to model all of the above metallic objects as part of an earth grid calculation. However, if any of the above is in the vicinity of the substation site, they should be tested during a current injection test.

Surface voltage contours are also known by other names such as the "zone of influence" (ZOI) or the "hot zone" of a substation. These terms simply refer to specific surface voltage contours. IEEE 367-1996 (IEEE 2002) states that this voltage level should be agreed between the authorities concerned.

A simplified calculation of the dimensions of specific surface voltage contours is given by IEEE (2002) Clause 9.7.1:

$$\phi_e = \frac{\rho I_e}{2\pi d} \tag{5}$$

where:

- $\varphi_e$ is the voltage on the surface of the earth (voltage level)
- $\rho$ is the soil resistivity
- $I_e$ is the earth fault current
- $d$ is the distance from the center of the grid

This equation assumes a simple grid and uniform soil resistivity which is rarely the case. This equation can be used to gain an approximate idea of the size of the ZOI contour. In nearly all cases, more complex analysis is needed.

One way of determining the ZOI or the hot zone is to use the voltage levels given in ITU-T K.33 (ITU-T 1996). These voltage levels are shown below in Table 11.3 which gives relevant voltage levels for different fault-clearance times. Therefore the relevant hot zone is dependent on fault-clearance time.

Examples of situations which require appropriate design to prevent danger to property or to life are as follows:

**Telephone Circuits**

Incoming telephone cables should not transfer more than the relevant admissible limit voltage (see Table 11.3) to remotely installed equipment as damage to equipment or injury to humans may result (ITU-T 1996). If the GPR exceeds the

**Table 11.3** Admissible voltages for different fault clearance times

| Duration of faults (s) | Admissible limit (V) |
|---|---|
| $t \leq 0.1$ | 2000 |
| $0.1 < t \leq 0.2$ | 1500 |
| $0.2 < t \leq 0.35$ | 1000 |
| $0.35 < t \leq 0.5$ | 650 |
| $0.5 < t \leq 1.0$ | 430 |

admissible voltage, then the incoming telephone cable must be isolated by using one of the following methods:

- An isolating transformer
- An underground telecommunications cable,with an adequate insulation rating, which shall be terminated at a point in the hot zone which does not exceed its insulation level as described above
- A fiber-optic connection

A typical insulation level for standard telephone service underground cables is 2 kV.

Therefore, as well as the admissible voltage level given from Table 11.3, there is also a need to know the extent of the 2 kV surface voltage contour.

Therefore a cable insulation level of, for example, 600 V, would necessitate running the highly insulated cable a much longer distance away from the substation. The junction box terminating the telecommunications cable must be located outside the "hot zone." Connection from the junction box to the substation building must be by the highly insulated cable.

**Distribution Voltage Power Circuits**
The following situations should be avoided in design practice:

- A distribution system design which permits transmission substation grid voltages to be exported directly on cable sheaths to distribution substation earth grids. This may be tolerated in dense urban cable networks where it can be shown beyond reasonable doubt that, due to the close proximity of numerous earth electrodes and the widespread incidence of buried cables as well as gas and water mains, electrical hazards due to transferred voltages will not arise in the present or the future.
- Under no circumstances should an LV (e.g., 400/230 V) supply enter or leave a transmission substation. Where an LV line in the vicinity of the substation runs in a radial direction from the substation, an examination of the transferred voltages should be made.
- The neutralizing of LV networks in the vicinity of a substation may result in transferred voltages.

Standby supplies to transmission substations from distribution networks should enter the substation on dedicated circuits arranged to prevent the export of grid voltages. The transformers should be mounted within the substation earth grid perimeter.

### 11.7.6 Earthing of GIS

There are some particular issues which must be considered in the design of the earthing system for a GIS installation, and these are covered in ► Chap. 21.

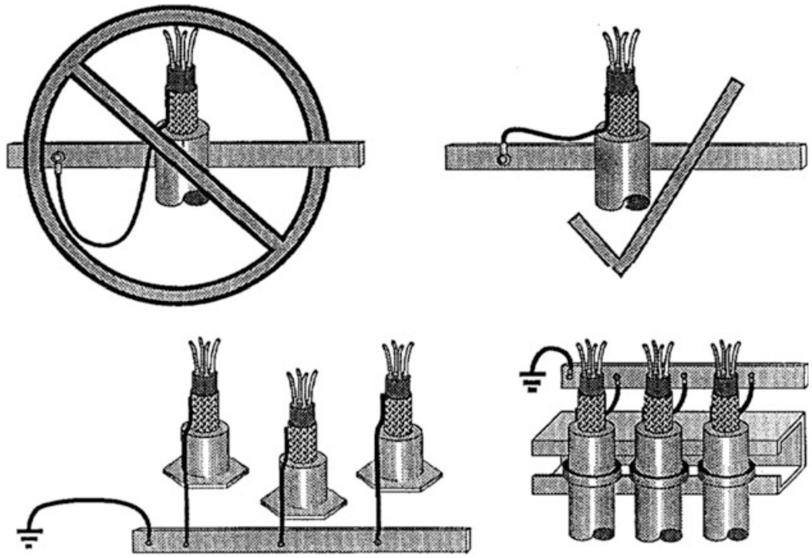


**Fig. 11.27** Cable screen earthing

### 11.7.7 Control of Electromagnetic Interference

Electromagnetic interference (EMI) due to different noise sources in AIS and GIS may cause maloperation or even damage to the equipment.

Earthing-related control measures to reduce the effect of EMI are:

- Exclusive adoption of screened secondary cables, if necessary with special screen construction. Generally it is advantageous to earth the screen at both ends. Screen earthing must be short and of low impedance.

Care in earthing cable screens. The following (Fig. 11.27) sketches from CIGRE TB 088 (CIGRE 1994) show examples of poor and good practice in regard to earthing of cable screens. In particularly hostile environments, e.g., in an EHV GIS switchroom, it is recommended to ensure good screen connection of GIS air bushings and multiple connections to adjacent metallic structures and reinforcement steel.

- Earthing conductors are recommended to be laid in parallel to cables in trenches to reduce screen current and to inductively couple the secondary system and the earthing system.
- See ► Chap. 21 for GIS – other specific measures.

### 11.7.8 Earth Grid

The substation earthing grid is formed of buried conductors and is complemented, in some cases, by conductors that are above ground.

The underground conductors are buried at a depth of about 0.5–0.8 m, laid out to form a grid and jointed at points of intersection. Backfill material should be well compacted around the grid conductor in order to ensure minimum contact resistance. Where there is a choice, soil which is likely to have a lower resistivity should be selected in accordance with the earthing design for that site.

The grid is designed so as to limit conductor temperature, touch voltages, and step voltages to the maximum allowable values under specified fault conditions.

Care is required during installation to ensure that all components are capable of carrying the prospective earth fault currents, without deterioration, throughout the life of the substation.

Joints should be of low resistance and should be fully rated, mechanically sound, secured against loosening, and, if necessary, protected against electrolytic action. Suitable compression or exothermic-type connections are recommended rather than bolted connections.

Earth rods may be driven into the ground around the perimeter of the earthing grid and bonded to the grid to reduce the overall resistance to earth. The quantity and length of the earth rods will depend upon the resistivity of the soil and the required resistance value. Additional earth rods are sometimes required immediately below (or adjacent to) certain items of equipment which require high-frequency earthing such as capacitor voltage transformers and surge arresters.

All conductors (other than circuit conductors) which might become charged as a result of induction or electrical fault are bonded to the earthing grid as are the neutral points of primary equipment (according to the requirements of network neutral point effective grounding). Consideration should be given to the high-frequency or transient performance of the earthing conductors both in the choice of conductor material and also in the way the conductors are installed on-site. For example, the use of stranded conductor may not be suitable as a low impedance path in transient current conditions. In addition, measures may be required to reduce the risk of copper theft in relation to exposed earthing conductors.

In order to limit touch and step voltages, the earthing grid should be bonded to other buried conductors such as metal pipelines, metal-armored cables, and rail lines. Where these buried conductors extend outside the substation, special attention must be paid to earthing in order to prevent a hazardous rise in ground potential. Where there are railings, handrails, railways, etc. in the vicinity of the substation, they should be made discontinuous at appropriate intervals.

If required, adjacent railway lines should have nonconducting “fishplates” inserted to reduce transferred voltages along the rail; such insertions should be arranged such that the rolling stock cannot short-circuit all the discontinuities simultaneously. Particular attention should be paid to fences, etc. running in radial directions away from the substation.

Particular attention is also required for the earthing treatment of substation gates and the direction of opening and also perimeter fences. The fence may be inside or outside the earth grid and may or may not be connected to the earth grid, depending on the site earthing design. Selection of the appropriate treatment for earthing is important and depends on whether the fence is the outer or only fence, whether or not it is a property boundary fence, and what level of public access must be considered. Guidance is given in IEEE (2000a).

If there are telephone lines or low-voltage power supply cables in the vicinity of the substation, limitation of ground potential rise to acceptable levels may cause considerable extra costs. The most effective way to limit the ground potential rise is to use buried shield wires of high conductivity.

The layout of the earthing grid has an effect on high-frequency transient ground potential rise phenomena (see CENELEC (2010) and IEC (2005)). This is particularly applicable to GIS installations, but certain measures are also required in AIS substations especially in relation to surge arrester and instrument transformer earthing.

### 11.7.9 Design Earth Fault Current

A number of current types and paths are relevant in deciding the actual current to be used for earthing system design.

Some considerations include:

- Neutral point earthing method (TB 161 (Cigre WG23.03 2000) 2.3.5)

Electrical networks may be:

- Effectively earthed (earth fault factor up to 1.4)
- Noneffectively earthed (earth fault factor, e.g., 1.7), e.g., resistance earthed or resonant earthed
- Isolated

In the first case, the earth current may be 60–120% of the short-circuit current. If the conductivity of the soil is poor (resistivity of 2000 Ω-m or greater), special attention must be paid to the magnitude of the substation potential during an earth fault. In this case it is possible to limit the earth-fault current and dimension the insulation level of the three-phase transformer neutral point correspondingly. Alternatively the potential rise of the earthing grid may be limited by ensuring that the earth wires of outgoing overhead lines are of good conductivity and, in extreme cases, have cross-sectional areas equivalent to those of the phase conductors:

- Earth-fault short-circuit level: This is the current that flows in faulted phases as a result of an earth fault
- Earth-fault current: This is the current that flows through the impedance of the earthing system to remote earth as a result of an earth fault
- Switchgear rating: This is the maximum current for which the switchgear is rated
- Earthing-conductor rating: This is the maximum current for which the earthing conductor is rated

In the calculation of the design earth-fault short-circuit level, the worst-case probable earth fault should be used. In accordance with local policy, this could be one of the following;

- System design fault level
- A predicted value (with a factor of safety applied) for some period into the future where short-circuit levels can be calculated from a future network model
- A value (with a factor of safety applied) based on an existing network model where no future network model exists

The design earth-fault short-circuit level may differ from the design earth fault current. The earth-fault current is the current that passes through the impedance of the earthing system to remote earth. The difference is due to the following factors:

- Circulating currents in locally earthed transformer neutrals
- Fault current returning to source via alternative parallel paths such as shield wires, cable sheaths, etc.

It is noted that while future network developments may increase short-circuit levels in many cases, the earth-fault current may actually be reduced due to the addition of shield-wire and cable-sheath connections.

### 11.7.10 Earth Grid Conductor

The buried grid is usually made of copper strip or stranded copper cable and the earth rods of copper-covered steel, although other materials such as galvanized steel and cast iron may be used. When copper conductors are used, precautions should be taken to prevent electrochemical reactions with steel structures.

The conductors must be sized to carry the ultimate design earth-fault short-circuit current foreseen to flow through the particular conductors, e.g., different ratings may be required for connections between HV equipment and the buried grid compared to those required for the individual buried grid conductors for the design duration which should not be less than the fault-clearance time of the backup protection. In doing so the temperature of the conductor should not exceed a value which may result in a deterioration of compression or bolted joints. Typical maximum allowed temperatures are in the range of 250–350 °C.

For calculation of the minimum conductor size required to carry a specific current without exceeding a specific temperature, see Eq. 6. For the calculation of the maximum current a conductor can carry without exceeding a specific temperature, see Eq. 7. Both equations are from IEEE (2000a) Clause 11.3:

$$A = I\frac{1}{\sqrt{\left(\frac{TCAP \times 10^{-4}}{t_c \alpha_r \rho_r}\right)\ln\left(\frac{K_o + T_m}{K_o + T_a}\right)}} \tag{6}$$

$$I = A\sqrt{\left(\frac{TCAP \times 10^{-4}}{t_c \alpha_r \rho_r}\right)\ln\left(\frac{K_o + T_m}{K_o + T_a}\right)} \tag{7}$$

where:

- I is the rms current (kA)
- A is the conductor cross section ($mm^2$)
- $T_m$ is the maximum allowable temperature (°C)
- $T_a$ is the ambient temperature (°C)
- $T_r$ is the reference temperature for material constants (°C)
- $\alpha_o$ is the thermal coefficient of resistivity at 0 °C in 1/°C
- $\alpha_r$ is the thermal coefficient of resistivity at reference temperature $T_r$ in 1/°C
- $\rho_r$ is the resistivity of the ground conductor at reference temperature $T_r$ in μΩ-cm
- $K_o$ $1/\alpha_o$ or $(1/\alpha_r) - T_r$ in °C
- $t_c$ is the duration of current in seconds

TCAP is the thermal capacity per unit volume J/($cm^3$.°C) taken from Table 1 ((IEEE 2000a) Clause 11.3)

Table 11.4 below shows the values for commercially hard-drawn copper which is used as an earth grid conductor. Using these values, Fig. 11.28 below shows a plot of conductor current vs. required cross-sectional area for a number of different temperatures.

Solid strip conductor may be preferred for certain applications, e.g., in indoor substations. In soils that are highly corrosive, strip conductors are preferred because of a smaller surface area than stranded conductors, thus making them less susceptible to corrosion. The strip cross sections must be such as to allow for the drilling of the hole sizes needed for connection to other earthing conductors.

In soils which are chemically corrosive to copper, some allowance should be made for a gradual reduction in the cross section of the conductor over the life of the substation. This is a matter of judgment. An alternative approach could be to use selected backfills around the earth conductor to reduce corrosion. Some level of periodic inspection could be justified in both approaches to check the degree of corrosion and/or that the backfill is still in place.

### 11.7.11 Exceptional Cases

On some sites, although internal touch and step voltages may have been effectively controlled by a reduction in the mesh size, grid resistance and perimeter voltage gradients may remain unacceptably high due to a high soil resistivity or a small grid area.

**Table 11.4** Properties of commercial hard-drawn copper ((IEEE 2000a) Clause 11.3)

| Description | Material conductivity (%) | $\alpha_r$ factor at 20 °C (1/°C) | $K_o$ at 0 °C (0 °C) | Fusing temperature $T_m$ (°C) | $\rho_r$ 20 °C (Ω·cm) | TCAP thermal capacity [J/(cm$^3$·°C)] |
|---|---|---|---|---|---|---|
| **Copper commercial hard-drawn** | 97.0 | 0.00381 | 242 | 1084 | 1.78 | 3.42 |

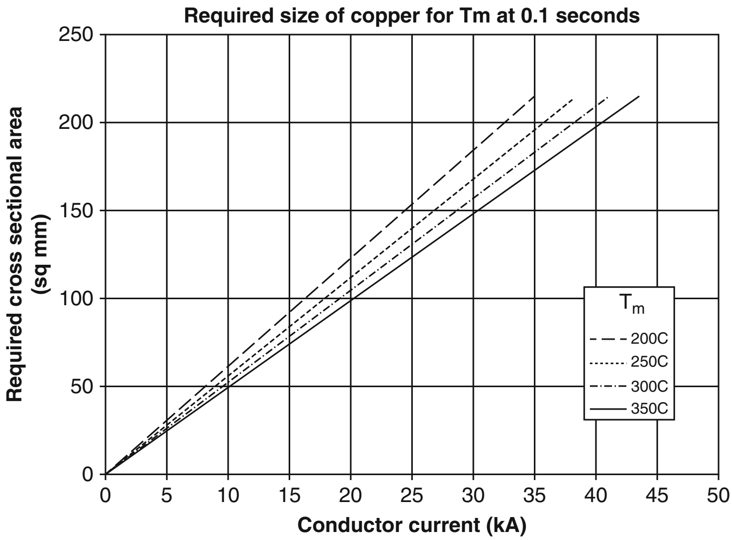



**Fig. 11.28** Conductor cross-sectional area versus current for various final temperatures

Considerable benefits may be derived from the following:

- Cable Sheaths

In urban locations, a proportion of the earth fault current may be drawn off in power cable sheaths which are bonded to the earth grids at both ends, thus interconnecting the grids of adjacent transmission substations.

- Shield Wires

Transmission line shield wires will similarly draw off earth fault current. The proportion will depend on the earthing at tower footings, soil resistivity at tower footings, conductor properties of the shield wires and phase conductors, and the position of shield wires relative to phase conductors. Any evaluation of the effect of shield wires will require information on all of the above. However, this data may not be readily available. While contributing to a reduction of electrical hazards within a substation, it should be noted that shield wires may also serve to propagate such hazards by transferring the earth grid voltage to several line towers.

- Deep Earth Rods

Deep earth rods are used in some countries where boring is easy and there is a certainty of reaching soils of significantly lower resistivity at greater depths.

- Chemical Treatment: Use of Special Clays

Drilled wells, 150–250 mm diameter, filled with chemically treated material or special clays, such as bentonite, may be considered in certain circumstances for small electrodes at industrial sites. Bentonite, being hygroscopic, draws moisture from the surrounding soil. But it needs moisture to retain its beneficial characteristics. It has advantages over other chemical treatments in that it is stable, is non-corrosive, and does not leach away in time. Apart from their high cost, these methods are unlikely to provide a fully effective solution for a transmission substation earth grid. These solutions only improve the contact resistance between the earth grid and the soil; they do not sufficiently improve earth grid resistance.

- Satellite Earth Grid

Where there is an area of known low resistivity in the vicinity of the substation, a satellite earth electrode may be installed there and connected by buried or overhead earth conductors to the substation grid. However, this solution may solve one problem by creating another, in the form of transferred voltages. A careful analysis of these voltages will be required. Beyond a distance of 3 or 4 km from the substation, the longitudinal impedance of the interconnecting conductor is likely to render this solution ineffective.

- Reinforced-Concrete Structures

At indoor substations, power stations, and especially hydroelectric power stations, the concrete-encased foundations and structures may be used as an auxiliary electrode which is bonded to the substation earth grid. Concrete is hygroscopic, and in damp conditions, it has a low resistivity of 30–90 Ω-m. However, under a building, it will dry out in which case its resistivity may increase by a factor of 20. In all cases earthing systems should be designed to be safe considering primary earth electrodes.

In specific designs the effectiveness of cable sheaths, shield wires, counterpoises, and satellite earth grids in drawing off earth fault current is best evaluated by carrying out current injection tests before and after these elements have been connected to the substation earth grid.

Where substations are built on rocky sites, a satisfactory grid design is more difficult to achieve. However, the following make a satisfactory earth grid design more achievable:

- If site development requires a low-lying area to be in filled, the imported fill material should be of low resistivity.

- An extra heavy surface layer of crushed stone may be used at particularly hazardous locations on the site to reduce surface voltages.
- If the overburden is of low-resistivity soil, an expensive solution may be avoided by recognizing the fact that the actual touch and step voltages will be a smaller proportion of the grid potential rise than if the soil conditions were uniform.

### 11.7.12 Verification of Earthing System Model

Before a substation is commissioned, the grid resistance and touch/step voltages must be verified by field measurement as described below. A close correlation between the calculated and measured values of grid resistance may not always be expected. Test conditions should be carefully examined and compared with modeled data in order to explain any substantial discrepancies.

There are two methods of measuring a substation grid resistance:

- The Megger method, described in IEEE (1991) or IEEE (1983)
- The Fall-of-Potential (current injection) method which is well described in CENELEC (2010) and IEEE (1983)

For small simple earth grids, in locations remote from distorting influences, there is reasonable correlation between the two methods. For complex sites the correlation is very poor. The current injection method is the most appropriate method for the majority of transmission substations.

Again, considerable care is necessary in the interpretation of results.

The value of grid voltage and the values of touch/step voltages measured for a particular value of injected current should be recorded and the results extrapolated to values corresponding to the design fault levels. This information and all locations at which touch and step voltages are measured should be indicated on a substation drawing showing the switchgear layout.

In cases where shield wires and/or cable sheaths are connected to the substation earth grid during a current injection test, the magnitude and phase angle (relative to the injected current) should be measured on each cable sheath or earthing connection to a shield wire end mast.

### 11.7.13 Protection Against Direct Lightning Strokes

A substation should be protected against direct strikes by lightning where there is a significant probability that lightning discharges will occur. The following are characteristics of the lightning phenomena that make it difficult to engineer the direct stroke protection:

- The unpredictable, probabilistic nature of lightning
- The lack of data due to the infrequency of lightning strokes in substations
- The complexity and economics involved in analyzing a system in detail

There is no known method of providing 100% shielding short of enclosing the equipment in a solid metallic enclosure. The uncertainty, complexity, and cost of performing a detailed analysis of a shielding system have historically resulted in rules of thumb being used in the design of lower-voltage facilities. Extra high-voltage (EHV) and ultrahigh-voltage (UHV) facilities with their critical and more costly components usually justify a more sophisticated study to establish the risk vs. cost benefit.

A four-step approach can be used in the design of a direct lightning stroke protection system:

(a) Evaluate the importance and value of the facility being protected.
(b) Investigate the severity and frequency of the lightning phenomena in the area of the substation facility and the exposure of the substation.
(c) Select an analysis method consistent with the above evaluation and then layout an appropriate system of lightning stroke protection.
(d) Evaluate the effectiveness and cost of the resulting design.

The frequency of the lightning phenomena is often defined by the ground flash density (GFD) or by the keraunic level. GFD is defined as the average number of strokes per unit area per unit time at a particular location. Keraunic level is defined as the average number of thunderstorm days or hours for a given locality.

Two typical methods for the analysis of the effectiveness of a direct lightning stroke protection system are:

1. The classical empirical methods with:
   (a) Fixed angles
   (b) Empirical curves
2. The electro-geomatic model

For additional information about severity of lightning phenomena and protection system analysis, see IEEE 998, guide for direct lightning stroke shielding of substations (IEEE 2012a), IEC 62305 Protection against lightning (IEC 2013), and IEC 61936-1 Power installations exceeding 1 kV AC (IEC 2010).

Protection against direct lightning strokes is carried out using either overhead earth wires or lightning rods or perhaps a combination of both. It may be easier, at least for larger installations, to get an efficient protection using earth wires. Special attention has to be paid to the elimination of the risk of earth wires falling down onto the switchgear or at least to ensuring that the consequences of such an event are acceptable in relation to the impact on the system. Lightning rods may be mounted on freestanding structures or on vertical extensions of substation support structures.

### 11.7.14 GIS

As mentioned above, surge arresters are normally provided on transformers and shunt reactors in open-air transmission substations. Where overhead lines convert to underground cables, it is normally necessary to install arresters at the junction points because of the wave reflections which occur at these points.

GIS substations connected to overhead lines require a different approach to open-air substations. In this case it is *always* necessary to install surge arresters on the line entries in order to protect the GIS. Shielding of the overhead lines for at least 2–3 km from the substation is also necessary. The arresters are usually open-air type, and if they are mounted within a few meters of the GIS with short connection leads, they will protect a comparatively large GIS, including any connected transformers. Where the GIS is a major installation of considerable length, the line-entry surge arresters may not be sufficient. In that case metal-clad gas-insulated arresters may be necessary in addition to the line-entry surge arresters. Note that busbar-connected surge arresters on their own are not satisfactory as they do not protect open line circuit breakers or line disconnectors.

Each GIS case must be separately analyzed taking into account the number of line entries, the use of shield wires, the insulation strength of the line as compared to that of the GIS, the configuration of the GIS, the proposed locations of the transformers, and the surge arresters. For further information on GIS earthing, refer to ▶ Chap. 21.

## 11.8 Contamination (Salt and Dust Pollution, Creepage Distance)

Salt or dust pollution is a challenge for grid operators managing air-insulated substations located near the ocean or any sandy flat or farm basin. For example, high winds blowing from the ocean toward inland substations are bound to lead to mineral layers contaminating the insulators' sheds, decreasing the leakage distance. The leakage distance then may not be long enough to ensure the electrical withstand or tracking resistance between the grounded support frame and the live equipment connected to the network voltage.

This salt pollution impact may be worsened when combined with other environmental factors such as industrial, agricultural pollution, icing rains, or any kind of activities producing microscopic flying debris (salt crystals, pollen, vegetal cuttings, steel plant residues, conductive dusts), likely to stick on insulator sheds. Special care should be taken when designing an AIS substation for additional factors from location surroundings such as proximity to the sea. TB 614 (CIGRE 2015) Substation Design for Severe Climatic Conditions gives guidance on this topic.

**Assessing Contamination Risk**

Before trying to mitigate a risk, it is essential to assess and rank it according to a common and measurable scale.

Table 11.5 below provides a specific creepage distance (SCD) as used in the 1986 edition of IEC 60815 (IEC 2008) that was based on the system voltage. For a.c. systems this is the phase-to-phase voltage. The 2008 edition introduced the USCD which refers to the voltage across the insulator, i.e., for a.c. systems the phase-to-earth voltage. Both SCD and USCD are specified as a minimum value, and the table gives the correspondence between commonly used values of SCD and USCD.

**Table 11.5** IEC 60815-1 (2008), Table J.1: correspondence between specific creepage distance and unified specific creepage distance (mm/kV) (IEC 2008)

| Pollution level as IEC 60815:1986 | Specific creepage distance for three-phase a.c. systems | USCD |
|---|---|---|
| | 12.7 | 22.0 |
| I Light | 16 | 27.8 |
| II Medium | 30 | 34.7 |
| III Heavy | 25 | 43.3 |
| IV Very heavy | 31 | 53.7 |

Examples of how the table is to be used:

| Rated system voltage (kV) - Um | Previous pollution level | USCD (mm/kV) | Insulator creepage distance (USCD × Um/√3) |
|---|---|---|---|
| 420 | III (heavy) | 43.3 | 10,500 mm (420 in) |
| 225 | IV (very heavy) | 53.7 | 6975 mm (275 in) |

Based on this classification, it is possible to build a risk map to take into account the salt pollution to which AIS is exposed.

Conducting specific on-site measurements such as:

- Volumetric conductivity of a pollutant measured with directional probes
- ESDD methodology to assess the equivalent density of salt layer at the surface of insulators
- Numbers of previous flashovers for several leakage distances of on-site insulators
- Leakage current measurements for live insulators on-site
- Measurements of the superficial electrical field above live insulators

IMPORTANT: when conducting on-site measurements, it is essential that the measured insulator has been connected (even without any load) to the voltage network permanently, as the electrical field plays an important part in attracting the pollutants due to electrostatic forces.

Additional factors can also be taken into account to assess the salt pollution risk. Below is a non-exhaustive list of those factors:

- Main wind orientation
- Rain level
- Temperature
- Specific or severe climatic events (hurricane, icing rain, sticky ice, fog, etc.)
- Industrial pollution

The four-level scale combined with the measurement procedures gives strong and reliable keys to properly design AIS, built in a climatically and environmentally challenging site.

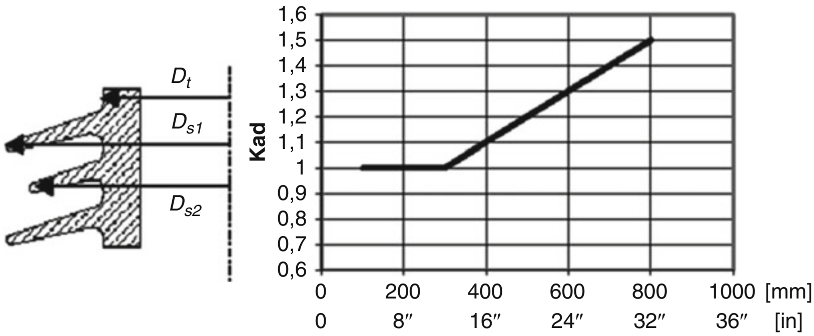



**Fig. 11.29** Insulator alternative long and short (ALS) shed profile (CIGRE 2015)

**Table 11.6** Leakage distance constant for level of contamination (CIGRE 2015)

| Average diameter ($D_{average}$) of the insulator disks in mm (in) | $K_{ad}$ to add to the minimum leakage distance in mm (in)/kV |
|---|---|
| $D_{average} < 300$ mm (12 in) | 1.0 (0.039 in) |
| 300 mm (12 in) $< D_{average} < 500$ mm (20 in) | 1.1 (0.043 in) |
| $D_{average} > 500$ mm (20 in) | 1.2 (0.047 in) |

**Design Standards for Long-Term Approach**

A proper design for AIS when dealing with pollution, salt pollution in particular, consists of defining the minimum leakage distance long enough to avoid the triggering of the insulators with no specific maintenance means (live washing, greasing, etc.). A GIS substation enclosed in a building is an alternative to AIS for network operators, in mitigating the salt pollution risk.

The best way to avoid insulator tracking due to salt or industrial pollution is to take the risk into account early in the design stage of an AIS project. Once the pollution risk is assessed, usual design values for the leakage distance are given in Table 11.5.

Beside the minimum leakage factor in mm (in)/kV, the average diameter of an insulator has also to be considered when designing AIS for constant winds and pollution. Designing for salt contamination from heavy windstorms is particularly difficult. An empirical relation based on experiments and measurements described in the IEC 60815-1 illustrates that the pollution withstand decreases when the average diameter of the insulator disks increases. That leads to add another factor Kad (as in coefficient for average diameter) such as shown below (Fig. 11.29):

This empirical relation can be approximated with the following values (Table 11.6):

The influence of the average diameter of the several insulators (insulator chain, surge arrester, busbar, switchgear/breaker/instrument transformer support, etc.) in AIS is very important, if one wants to mitigate the tracking risk due to salt pollution. The diversity of insulator diameters found in the several equipment types may compose a variety of different pollution classes at the same substation. This diversity has a lot to do with the required insulator strength needed for the configuration of bus designs.

For instance, in 400 kV technology, the biggest diameters are usually found in the instrument transformers ($D_{average} > 300$ mm (12 in) often) and can lead to the use of a higher pollution class for those specific equipment. The necessity for increased creepage comes from phenomena associated with the aerodynamics. A low air-pressure pocket is formed on an insulator on the opposite side to the wind. In this low-pressure area, contamination sticks to the insulator forming a conductive line. As the insulator diameter reduces, there is a corresponding reduced opportunity for contamination to deposit.

Coastal salt deposits will form when sustained winds from the direction of the ocean are present for long periods. If hard rains are present every 8–10 days or showers are present every 3 days, contamination will not build up under normal conditions.

Rain or precipitation has a large impact on insulator contamination. Light rain for a short period of time can be almost as detrimental as fog. Once the contamination is moist, water shedding forms a conductive path. An opportunity for flashover is present. The lower the level of emissivity or contamination then the lower the probability of arcing and flashover.

The use of RTV or silicone coating for insulators can improve an insulator's performance. The value is that the coatings make the insulators hydrophobic. The water beads up instead of sheeting, so no conductive path can be developed to create a flashover of the insulation. Silicone products are also self-cleaning and will repel most levels of pollution that is non-acidic. New products are available that can be applied with a paint sprayer, drastically reducing outage time and improving consistency of coating. Figure 11.30 shows an example of an insulator that has been sprayed with silicone coating.

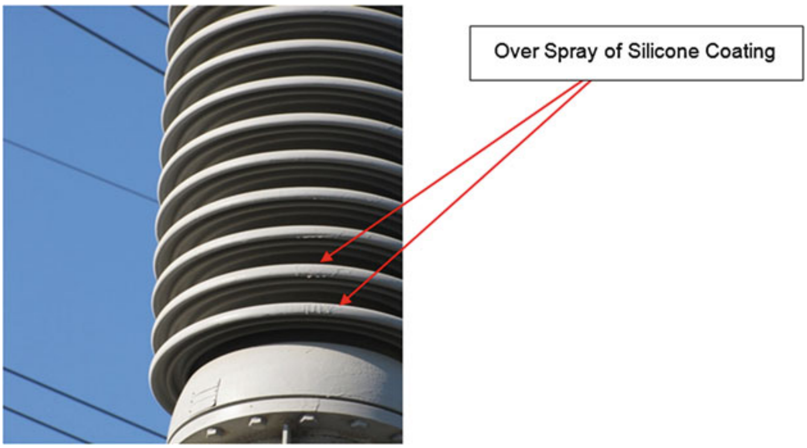



**Fig. 11.30** 230 kV underground cable termination sprayed with silicone coating (CIGRÉ 2015)

## 11.9 Audible Noise

The content of this section is heavily based on Giles (1970) and Sahazizian et al. (1998).

### 11.9.1 Introduction

There are two major sources of noise in substations:

- The continuous noise generated by the operation of power transformers and reactors
- The momentary noise produced by the operation of high-voltage circuit breakers or load interrupters

Other noise sources in substations include corona discharges, arcing during operation of switches, etc.

By far the most important source of noise is that generated by power transformers and reactors. These pieces of equipment generate a continuous humming noise that might be disturbing for communities living near the substation. The likelihood of a noise-provoked complaint will depend on its level relative to the background noise level and whether or not it has certain audible characteristics (a continuous note, distinct impulses, or the noise is irregular).

Experience seems to indicate that a difference of 10 dB or higher between the rating level and the background level indicates that complaints are likely, a difference of 5 dB may be of marginal significance.

Expansion of urban and suburban areas in recent decades has resulted in many substations which were originally built in rural locations being located within and in direct proximity to residential areas. In these new situations, the noise level generated by the equipment in the substation might not be found acceptable, and corrective measures are often required to reduce the level of noise to acceptable levels.

In addition, public concern regarding industrial noise has increased over the past few decades, and new, more stringent regulations and bylaws have been introduced to limit noise levels in residential communities.

These events make audible noise an important concern and one to which the utility industry must give full consideration during the planning and retrofitting of existing substations.

### 11.9.2 Characteristics of Transformer Noise

The primary source of noise from transformers is due to magnetostriction (or electrostriction) of the iron core. A secondary but much lower source arises from the electromagnetic forces between the individual turns of the windings. The principal frequency of the resulting vibration is twice that of the supply frequency, i.e., 100 or 120 Hz, and, because the magnetostriction characteristic of iron is nonlinear, higher harmonics, i.e., third, fourth, etc., are also generated. This harmonic content of a noise plays a major role in contributing to the annoyance of the noise as perceived by individuals. The level and the number of significant harmonics and the probability of complaint about the noise increase with flux density. Since the flux density is controlled by the magnetizing current and the total noise output is proportional to the exciting voltage times the magnetizing current, the noise output remains essentially constant for a given voltage even though unpredictable variations in the radiation pattern occur with time. The noise output is normally unaffected by load.

### 11.9.3 Propagation of Sound

In an unobstructed outdoor environment, the energy from a point source of sound propagates in accordance with the "inverse-square law" – this means that as the sound spreads outward from the source, the energy decreases as the square of the distance. Thus for each doubling of the distance, the sound energy decreases by a factor of 4, i.e., 6 dB. This theoretical attenuation usually applies quite well for distances ranging up to 150 m and greater. Beyond this distance, it is subject to the effects of ground and atmospheric absorption, inhomogeneities such as these are associated with turbulence, moderate and high winds, and temperature gradients.

In addition to the foregoing, the increase in noise level propagated due to temperature inversion seldom remains constant and normally varies with time over periods ranging from a few seconds to a few minutes due to changing conditions in the atmosphere. This modulation of the noise, particularly of the type generated by transformers, is another factor that increases the subjective reaction as compared with that for a steady noise.

### 11.9.4 Noise Level Limits

There is a wide variety of regulations and bylaws in use around the world to control audible noise levels in the community. In some countries noise level regulations have been developed to suit local conditions. The majority of these are qualitative, although a number of the larger communities and some cities have had quantitative regulations in various forms.

The result is that, typically, transformer noise should be slightly audible during the quietest period of the day and inaudible during the rest of the day when people are normally active. Experience shows that transformer noise levels 10 dB above the lowest ambient noise level result in complaints from the community, while a 5 dB increase does not normally produce a response. A 5 dB cushion, however, is considered to be the minimum required to accommodate the temporal variations in radiation pattern and the atmospheric effects previously discussed.

The above general rule has been found to apply particularly in the design of new installations. It is also applicable to old installations, but there will be some existing substations where noise treatments will be difficult to install due to space and clearance limitations.

Existing substations have to comply with newer, more restrictive noise regulations sooner or later, typically once complaints are received about the elevated noise level of a particular substation.

While in some countries the new regulations might not apply to existing installations in general, utilities are concerned with community acceptance and as "good corporate citizens" will modernize their installations to meet the requirements of the latest regulations and bylaws.

The following table gives typical noise limits specific to particular settings (Table 11.7):

### 11.9.5 Noise Level Measurement

The main points to be considered and suggested guidelines for the measurement of noise levels are as follows. Guidance on measurement techniques and instruments is given in ISO 1996 Parts 1, 2, and 3 (ISO 2016; ISO 2007; ISO 1987).

**Table 11.7** Typical noise limits

| Location | Time of day | Noise limits |
|---|---|---|
| I. Purely residential | Day | 45–50 dB |
| | Early morning/evening | 40–45 dB |
| | Night | 35–45 dB |
| II. Mixed residential | Day | 50–60 dB |
| | Early morning/evening | 45–50 dB |
| | Evening | 40–50 dB |
| III. Commercial/industrial | Day | 60–65 dB |
| | Early morning/evening | 55–65 dB |
| | Night | 45–55 dB |
| IV. Industrial | Day | 65–70 dB |
| | Early morning/evening | 60–70 dB |
| | Night | 55–70 dB |

**Table 11.8** Number of measuring points for substations and length of property line of substation

| Length of property line of substation | ≤300 m | 300–500 m | 500–1000 m | 1000–2000 m | 2000–3000 m | ≥ 3000 m |
|---|---|---|---|---|---|---|
| **Number of measuring points** | 12 | 16 | 20 | 24 | 32 | 40 |

(a) Number of Measuring Points

Measuring points should be established at equal distance along the property line. Suggested total numbers of measuring points for various lengths of property line are given in Table 11.8 below.

(a) Measurement Locations

The noise level of substations should be measured at the property line.

The exact measuring point is generally recommended to be 1.2 m above ground level. If the sound is shielded by a fence or any other structure, a measurement point of 0.3 m above that of the fence/structure is recommended.

(b) Ideal Measuring Environment

- Ambient temperature: 5–35 °C
- Humidity: 45–85% (CIGRE 1980a)
- Wind velocity $\leq$ 3 m/s

In the event that the wind speed is >3 m/s, outdoor measurement is not recommended as the background noise is not constant.

(c) Measuring Equipment

Measurement equipment should have valid calibration.

### 11.9.6 Calculation of Noise Levels

In general, the energy from a point source of sound decreases as the square of the distance increases. However, that is influenced by the reflection and/or absorption by buildings and equipment in the substation.

The energy of sound generated from equipment under operation can be reduced by the type, location, and distribution of the surrounding equipment.

Basic calculation methodology is detailed in (CIGRE 1980a). Software packages can be used to calculate the predicted noise levels and also to assess the impact of surrounding equipment and hence identify the distribution of substation equipment which produces the lowest level of noise.

An example of such an assessment showing noise level contours is shown below (this example courtesy of Chubu Electric Power Co., Japan) (Fig. 11.31).

### 11.9.7 Methods of Substation Noise Control

Methods used to mitigate noise problems in substations will depend on factors such as:

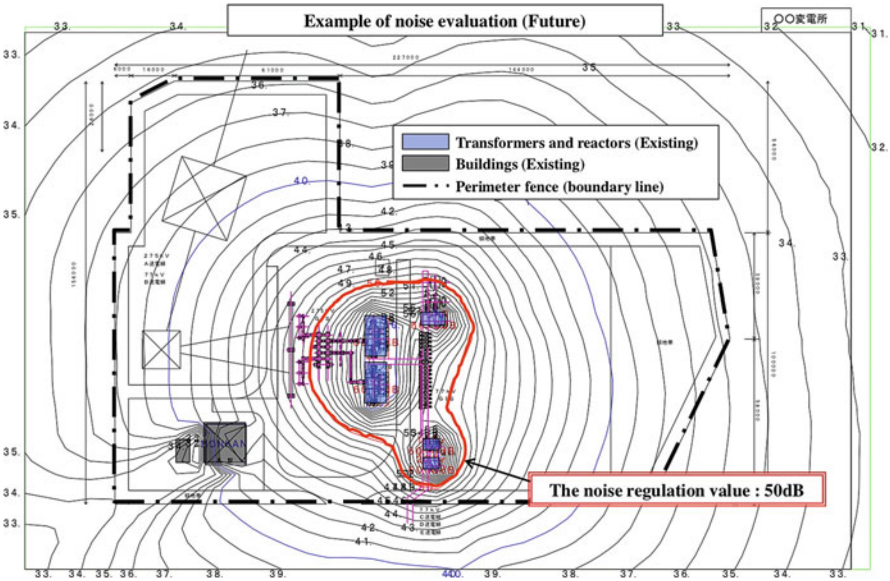



**Fig. 11.31** Example of a substation noise assessment

- The degree by which the noise level exceeds the approved level for the area in which the substation is located.
- The economics of various solutions – the analysis has to take into account the life cycle cost of the installation, as well as the benefits the utility may acquire by addressing concerns of the community.
- Operational and maintenance implications of installing a particular sound mitigation solution around transformers and/or reactors.
- In existing substations, issues related to the constructability of the sound-mitigating solution (can it be done with the equipment live, is there a need for rerouting of power and/or control cables, etc.).

A general control measure is, where possible, to design the site layout such that noise sources are located as far as possible from noise-sensitive properties.

The first step in the process of mitigating a noise problem at a planned or existing substation is to determine the noise reduction required at the point of the recipient, which is usually the most critical location on the property line of the substation.

The noise reduction requirement is the total level of untreated transformer noise minus attenuation with distance minus lowest ambient level or the permitted community level plus the 5 dB margin mentioned in Sect. 11.9.4 above.

Once the noise reduction requirement has been established, the most appropriate measures, or combination of measures, required to produce the required noise reduction must be selected.

### 11.9.8 Transformer Noise Control Measures

The following represents the most widely used methods available for minimizing noise levels created by transformers. The newer methods are described in greater detail:

(a) Install equipment on resilient mountings (to minimize transmission of vibration to civil structures)
(b) Use of transformers with low noise levels
In recent decades manufacturers have made significant steps toward reduction of basic noise levels of power transformers and reactors. Levels up to 10 dB below the standard levels are practical, and the costs range up to 1% of the cost of a standard transformer per dB depending on the size. Higher reductions are not normally economically viable compared with other methods of control.
In existing substations, replacement of an old transformer with a new, low-noise unit might prove to be the best solution if the replacement is dictated also by other factors (end of life of transformer, history of failures of the unit, chronic oil leaks, etc.).
(c) Landscaping
Planting of well-grown trees on the outside of the fence line in the direction of the desired noise reduction is one of the solutions that would provide moderate noise reduction. Landscaped soil berms covered with grass and with bushes on the crown is another noise-reducing solution which also provides a means of blending the substation into the community.
(d) Simple Open-Roof Barriers
The level of noise reduction obtained with this solution depends on the height of the barrier above the transformer and its relation to the elevation of the neighborhood that is targeted for noise reduction. Typically a noise reduction of 8–13 dB could be achieved with such a barrier. The barrier may be constructed from a variety of materials, such as steel plate, masonry, etc.
(e) Sound Enclosure
This enclosure is installed around all four sides of a transformer. Depending on the level and directions of noise reduction needed, the enclosure can be without or with a roof. The roof of such a sound enclosure has to be custom designed for a particular transformer. Adequate space must be provided between the tank of the transformer and the walls of the enclosure for maintenance staff to pass. Also, sufficient space must be provided to enable the opening of the doors of the mechanical box of the transformer. Reductions of up to 20 dB are possible if proper attention is given to the details of the construction. Coolers of the transformer are installed outside the enclosure to assure the design rating of the transformer (Fig. 11.33).
(f) Low-Frequency Sound Insulation (LFSI) Panel
An effective countermeasure for an existing shunt reactor and/or transformer is the low-frequency sound insulation panel (LFSI panel), designed to minimize low-frequency noise production.

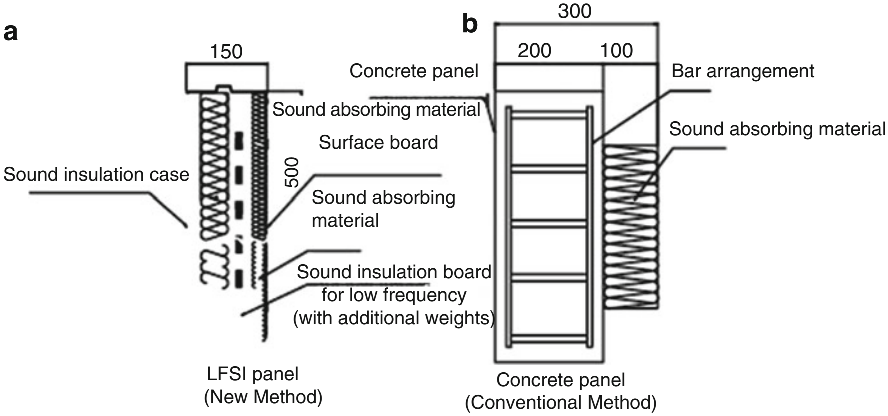



**Fig. 11.32** Structure of soundproof panel. New application using LFSI panel as per (**a**); and conventional method using concrete panel is shown in (**b**)

**Fig. 11.33** Example of a sound enclosure (Canada)

The new soundproof panel is composed of sound-absorbing materials and a sound insulation board with additional weights that are necessary to reduce the vibration created by the sound insulation board (Fig. 11.32).

Although the conventional concrete panel does provide some insulation by way of the mass effect of its heavy material, the LFSI panel has a higher permeable reduction in low-frequency noise in spite of its lightweight design.

(g) Tight-Fitting Enclosure

This solution comprises a total steel plate enclosure (including a steel roof) around the transformer. This solution is commonly known as the "tea cozy" solution. In this arrangement, the walls are installed close to the tank, there being typically a 10 to 15 cm space filled with acoustically absorbing material. Strategically placed doors allow access to the mechanical box of the transformer, to the tap changer, etc. Such enclosures could provide a noise reduction of up to 22 dB.

With solutions (c), (d), and (f), it is necessary to provide means for absorbing the buildup of sound within the barrier or enclosure. This can be accomplished by providing a lining of 8–10 cm of glass or mineral wool or by forming resonators (by drilling a suitably proportioned hole) in some of the cells of the concrete block for construction of the walls of the barrier or enclosure.

Transformers installed inside barriers or enclosures have to be mounted on vibration isolators. Most commonly used isolators are steel springs. These insulators prevent vibration of the barrier or enclosure (and creation of additional noise) due to ground-borne vibration from the transformer.

Consideration must also be given to the ventilation of the sound enclosures. Heat generated by the operation of transformers builds up in the enclosure, and appropriate ventilation is required to remove the heat from the enclosure. Low-noise and low-speed fans have to be installed so that they do not affect the overall performance of the enclosure.

Coolers are not normally a problem, but when reductions of 20 dB or more are required, it is necessary to provide suitable flexible connections in the oil piping to minimize the transmission of vibration and thus the generation of noise by the coolers. Installation of high-efficiency, low-noise type of fans on the coolers has to be considered in such situations. The use of two-speed fans that will be operational at maximum speed only under full load conditions of the transformer is also an option.

Sound barriers may also act as fire barrier walls.

(h) Active Sound Cancellation

This method uses a separate sound using an amplifier and speaker system that is equal in amplitude and opposite in phase to the unwanted noise in order to provide cancellation. The method has been demonstrated to be feasible and to provide useful reductions in the range of 10 dB. Outside this sector, the noise level increases because energy is being added to the local environment.

### 11.9.9 Other Noise Sources and Control Measures

(a) Circuit Breakers

- Problems occur particularly with air-blast designs and with some types of breaker operating mechanisms.
- Only likely to be a problem where regular switching (e.g., voltage control switching) is performed.

Control Measures

- Select equipment with inherently low noise levels (in general, choose $SF_6$ single-pressure designs and avoid pneumatic mechanisms).

- Install equipment indoors (conventional building construction provides a reasonable level of attenuation).
- Fit silencers to compressed air exhaust vents.

(b) Electrical Discharge (Corona)
- Random noise (hiss or crackle), particularly in damp weather conditions
- Generally not a problem in substations since the noise is broadband high frequency and attenuates rapidly with increasing distance from the source

Control Measures
- Select equipment which has been designed and tested to achieve low levels of corona discharge.
- Clean insulators at appropriate intervals.

(c) Auxiliary Plant (Diesel Generators, Compressors)
- Continuous noise when in operation.
- The extent of the problem depends on the frequency and duration of use. Noise is normally broadband and attenuates rapidly with increasing distance from the source.

Control Measures
- Select equipment which has been designed to minimize environmental noise levels.
- House equipment within an acoustic enclosure or building (dependent on the level of attenuation required).

(d) Alarm Sirens
- Continuous penetrating noise when in operation

Control Measures
- Ensure all such devices are fitted with timers which switch off the external sound after a reasonable period, e.g., 20 minutes.

## 11.10 Fire Protection

This section is based largely on CIGRE 23-01 Fire Protection Systems and Measures in Substations from 1984 (CIGRE 1984).

Fire protection measures in HV substations depend on the philosophy and standards of the utility. For many utilities the primary means of managing the risk of consequential damage from a fire is to design sufficient separation clearance distances between items of plant and buildings. Each country or utility has its own concept in this field, and for this reason, it is difficult to summarize a general global philosophy. However, it is possible to give some general concepts.

The aim of a fire protection system is:

- To minimize the hazard to the operators and the public and to protect the environment
- To limit the fire damage
- To protect the adjacent equipment
- To minimize the loss of customer’s service

When choosing a fire protection system, the following should be considered:

- The low probability of a fire
- The cost of the fire protection system
- The reliability of the fire protection equipment

The degree of protection required is related to the criticality of the installations or other adjacent facilities.

In accordance with these principles, most utilities use fire protection systems in outdoor and/or indoor installations to reduce the damage to power transformers and to adjacent apparatus, equipment, and buildings in the substations. Other reasons are the possibility of air pollution, the protection of the environment (wood, houses, etc.), and the safety of personnel.

A smaller proportion of utilities do not have fire protection systems, generally because the risk fire is considered to be low and the investment and operations and maintenance cost is not justified.

Most utilities use local, national, or foreign standards (e.g., National Fire Protection Association USA) for fire protection installations.

The following paragraphs describe different fire protection systems, specific cases of application for the power transformers, cables, control, relay and cable rooms testing, maintenance and training aspects, fire experiences, and other measures taken in substations.

### 11.10.1 Fire Protection Systems

A water-spray protection system is generally preferred for outdoor installations (Fig. 11.34).

Gas installations are common for indoor substations. These systems should use clean gaseous agents that are electrically nonconducting and gaseous and do not leave a residue on evaporation. Nitrogen and carbon dioxide systems are available. Halon systems are no longer used due to their greenhouse gas impact. Recent publications have described the emergence of hypoxic fire protection systems where the level of oxygen in a substation building is controlled to a lower level such that it will not support fire (Sahazizian et al. 1998). High-expansion foam and powder installations also exist (Renton 2013).

A fire protection method for a particular substation is chosen based on the substation criticality, the risk of fire, the extinguishing effect, the limitation of damage to adjacent equipment, and the safety of personnel.

Water-spray systems are only used for transformers and mainly based on fine water spray and, to a lesser degree, on droplets of water. Its effect is always mentioned as cooling and sometimes both cooling and smothering. Gas systems are also becoming more common for transformers. Figure 11.35 illustrates one such using nitrogen.

The operation time is normally between 5 and 10 minutes. The usual supply is a storage tank with pump, gas-pressurized tank, or the town water supply. Some utilities also rely on river or canal water depending on the location of the substation.


**Fig. 11.34** Transformer fire suppression system using water in Romania


**Fig. 11.35** Transformer fire suppression using nitrogen in Romania

Reserve water for fighting reignition is not normally kept. Generally the quantity of water used varies from 2000 to 6000 l/minutes and depends on the size of the protected transformer (10–25 l/minutes/m$^2$ transformer surface).

The working pressure of the water supply is normally 7–10 bar. Usually the nozzles for outdoor installations are not designed for a maximum wind speed.

For indoor installations, $CO_2$ installations are mainly provided for 0.5–3 kg $CO_2$ per $m^3$, an operating time from 0.5 to 3 minutes, and a normal operating pressure of 50–60 bar.

High-expansion foam installations are rarely used in practice. Fixed fire-protection systems are most common. In about half of the cases investigated, portable ones as well as a combination of fixed and portable systems are used. Almost all the fixed fire-protection systems are operated automatically.

Smoke detectors (indoor) and bimetal and quartzoid bulb detectors are common fire-detecting elements. In some cases, other types of detectors are found, e.g., optical, pneumatic rate-of-rise, plastic tube, and heat-detecting cable. One detecting element fitted per 10–25 $m^2$ of substation is typical. The most preferred qualities are detection reliability, short detection time, immunity to interference, and false alarm prevention.

Fire-detecting elements used to be the criteria for starting the firefighting system. Some utilities have protecting relays alone or in combination with detecting elements (gas, differential, pressure, frame leakage relays, etc.).

Some utilities have compressed air between 2.5 and 8 bar in an independent detecting pipe system, which releases the extinguishing system when the pressure has fallen to 1–3 bar, respectively.

Pressure relays with alarm are used against accidental leakage of air pressure.

The maximum time allowed between the release of the detection equipment and automatic operation of the firefighting system is usually between 5 and 30 s. This time can be minimized by:

- Using transformer protection relays as initiators
- Adjustment of the air pressure in the detecting system
- Shortening of the distance between water and gas supplies and the transformer
- Adjustment of the dimensions of the pipe system

The signal from the detecting system is centralized for almost all the unattended remotely controlled substations. For attended substations, the signal is also centralized for many utilities.

The automatic water deluge or emission valve is usually electrically operated. Pneumatic and hydraulic operations are often found in connection with water spray systems.

A combination of two of these operation systems is also found.

To prevent inadvertent operation of the fire protection system, many utilities use two-criteria initiation such as the following examples:

(a) Two detectors in series
(b) Temperature and gas relays or frame leakage for gas systems
(c) Detecting element and open position of circuit breakers
(d) Detecting element and differential relays

Most utilities use automatic fire alarm equipment with bell, siren, or flashing light for local personnel with SCADA alarms to a control center. In some cases, there is a direct alarm connection to the fire brigade.

### 11.10.2 Transformers

The ground surface area between transformers and coolers is not generally protected individually in most utilities.

In most substations, transformers are situated between fire barriers (walls) of concrete or other materials. This however depends on the distance between transformers and the distance to adjacent components (9–15 m). In most cases, the height of the walls is related to the height of the transformer tank and the dimensions of conservator or bushings with an overlap to a maximum of 0.3–2 m. The length of the barriers mostly varies with the dimensions of the transformer tank and coolers with an overlap to a maximum of 2–6 m, or with the dimensions of the oil-containing pit. Walls between the transformer and its coolers are rare in outdoor installations, noise-attenuation considerations excepted.

In some utilities provisions are made to drain water and oil from the fire area into a containing pit below the transformers. Sometimes, several pits are connected to each other and/or (then) to a separate oil tank. Some utilities drain oil and water into an underground drainage system to a holding pond. In almost all countries, the minimum volume of the oil-containing pit is sufficient to keep the oil contents of the transformer and the coolers.

In most cases this volume can also contain the water of a water-spray installation from a storage tank or from a hydrant during a certain time, rainwater sometimes combined with some gravel and finally some spare volume to allow for firefighting water or foam.

In many countries, provisions other than oil-containing pits are made to prevent burning oil from spreading from the vicinity of the damaged transformer, such as bunding at a minimum distance of 1–2 m from the perimeter of the transformer and the coolers, so creating a containment bund for 100–110% of the total oil volume, or at the perimeter of the oil-containing pit (100–150 mm high), grading of the ground surface area dependent on the reach of the sprinklers or trenching around the base of the transformer.

In nearly all cases, provisions are made to aid the extinguishing of burning oil under the transformer and nearby, such as:

- A 200–300 mm layer of broken stones inside a bund or pit
- A 200–250 mm layer of broken stones (50–120 mm) around the transformer and underneath the coolers supported by a galvanized grill when an oil pit is present which gives a cooling and air smothering effect
- A gravel-filled pit
- A concrete cove with a small opening
- Sand available near the transformer

Provisions are normally made to lead the burning oil to an oil-containing pit as quickly as possible, such as:

- Sloping surface to the oil-containing pit or fall to a sump
- Sloping pit bottom to pipes of sufficient dimensions sloped to lead the oil to a separate oil containment pit with a layer of stones large enough to catch all the burning oil

- Allowance of approximately 10% slope from the transformer base to a drainage system connected with a holding pond or basin

Many countries use facilities for separating oil from water, by manual operations when separators are not reliable and the substation is attended or automatically in the oil-containing pit, an oil-separation system, or a separate oil tank of a special design.

When transformers are situated very close to a building and the transformer bushings are mounted through the wall, no special measures are taken against the risk of fire in most countries which accepted this design.

Passive precautions are rare such as:

- Sealed openings or passage protected against penetration of smoke and gasses.
- Fire-resistant wall material (concrete) during a certain time (1–3 hours), or noncombustible panels on the wall.
- Walls and ceiling designed to withstand pressure rise in the transformer cell.
- In unattended HV substations, the walls are equipped with a water spray installation.

In most countries, there are no minimum clear spaces between transformers and between transformers and buildings.

Sometimes such clear space varies up to 12.5–15 m between transformers and 20–30 m between transformers and substation fence or buildings or with the voltage level of the system.

**Protection of Power Transformers Themselves**

There is a tendency to protect larger outdoor transformers better than smaller ones, but this depends on the transformers used by the utilities concerned. Generally, indoor oil-filled power transformers are protected against the risk of fire. Fire protection systems are mainly used on the transformer tank and the coolers or on other components (conservator).

Typically, the system piping of fire protection installations is not attached to the transformer tank and the coolers but supported separately from the transformers, which are protected in the fire area by the firefighting system. These support systems are generally not protected against the risk of explosions.

Usually more than one transformer is connected to one storage or pressure tank.

In most utilities, the maximum number of transformers connected to one storage or pressure tank ranges between two and four. The maximum distance between a storage or pressure tank and a connected transformer varies from 30 to 40 m in most cases. In a few countries, water will be released on all transformers simultaneously when a fire on one of them is detected.

Transformer coolers are almost never protected against the danger of explosions from bushings, measuring transformers, or lightning arresters, often because of previous experience with an explosion with consequential damage. In many cases, special electrical relays are installed to protect power transformers against fire or explosions. Apart from Buchholz, differential, and pressure relays, impedance, wave protection, surge suppressors, sudden pressure, temperature rise, and oil level-actuated tripping relays have also been used for fire and explosion detection.

To protect transformers against explosions, additional items are used such as:

- Pressure relief valves, sometimes on the on-load tap changer only
- Expansion tubes, sometimes with a membrane
- Special covers, rupture disks, or diaphragm

### 11.10.3 Cables

Most utilities consider the need for fire protection of power and control cables in indoor and outdoor HV substations by passive protection of cables, for example, by fire barriers or similar methods. Only a few utilities apply active protection of cables by using special materials or special additives to normal insulating materials in order to improve the behavior of power and control cables during fire conditions. In these utilities, the measures are chiefly aimed at reducing the propagation of fire.

In general, surveys indicate that the use of these special cable types has increased. Before 1970, special cables were only used in 3 utilities, from 1970 to 1975 in 6 utilities, and from 1975 onward in as many as 11 utilities based on a 1984 survey (Aanestad et al. 1984a, b).

Nearly all utilities have taken measures to reduce the fire propagation with fire barriers of different materials. Some have used concrete, steel or foam material, mineral, and stone wool for these fire stops. In one country, several utilities have used vermiculite/plaster (1 – sand, 2 – cement, 4 – vermiculite) or Silicone fire stops. In other countries, fire protection paint or coat is used in important and expensive installations.

In some cases, the power and control cables are installed separately by using various materials, such as steel plates of a minimum fire resistance rating of 5–10 minutes, concrete, or brick (0.5–2 hours).

### 11.10.4 Control, Relay, and Cable Rooms

Fire-protection systems and/or measures can be used in control, relay, and cable rooms to avoid the risk of damage of most critical apparatus and of secondary injuries. These fire protection systems are usually activated by automatic detectors. Manual control equipment with hand-operated valves placed outside the fire zone and manual remote control from one or more points are less frequently found.

Most utilities installing fire-detecting elements in their substations have two or three kinds of fire-detecting elements. Almost all utilities have some form of smoke detection fitted. The bimetal or optical detector is also common, but quartzoid bulb and plastic tube detectors are rarely used.

For fire alarm, most of the utilities use a bell, a siren, or a flashing light, and some have a direct alarm connection to the fire brigade.

In some cases, it is a safety rule to disable the fire-protection system before personnel enter the control, relay, or cable rooms. If the fire-protection system is operating, the ventilating system is stopped, and the ventilation valves are closed in most utilities. The ventilation valves are closed, e.g., pneumatically, by electrically operated solenoid, interlocked with circuit breaker or remote control. Blowers to dispel gas after the fire has been extinguished are rare.

There is no clear prescription as to the time, after which it is allowed to enter a control, relay, or cable room when the firefighting system has stopped. Some utilities indicate a period of 0–1 minutes, others when the experienced staff considers the situation to be safe.

Testers for $O_2$ deficiency are also installed.

Many utilities use fire barriers in the control, relay, or cable rooms. They have fire walls, bulkheads and sometimes fire-resisting doors, self-closing doors, or rooms completely separated from adjacent and underground rooms. This fire resistance rating material is achieved by using brick, ferroconcrete, or steel. Walls, doors, etc. have a fire resistance capability when separated rooms are used.

### 11.10.5 Other Measures in the Substations

Generally, the protection measures described above are considered sufficient for most utilities. Sometimes other measures are prescribed, e.g., not using oil circuit breakers in indoor substations. Few buildings are specially protected against the risk of fire damage, and the material used does not typically have a minimum fire resistance rating. When a minimum fire resistance rating is specified, it is generally achieved by the use of concrete and brick. In this case, the resistance duration time is between 2 and 4 hours.

Apart from the power transformers, the other equipment, e.g., circuit breakers, instrument transformers are not protected.

Generally, no fire-protection systems or other measures cover the whole substation, when these systems or measures exist, they concern:

- The remote detectors and the alarms
- The use of dry chemical extinguishers
- The use of noncombustible materials and barriers between components, fire pits, etc.

Warning notices are often used in the substations and consist of:

- The identification of the fire equipment
- Notices on the doors of the transformer rooms and of those rooms still protected by gas systems
- Fire-protection system operating instructions

The major points to effective fire escape practices in a substation are as follows:

- The open design of the outdoor substations which ensures access for the fire brigade and proper escape for operating personnel
- The existence of alternative exits in every room containing oil-filled equipment
- A prescribed number of oxygen breathing apparatus

### 11.10.6 Conclusions

According to the fire experiences of utilities reported in surveys, power transformers in substations are considered the principal cause of potential fire damage in substations.

The risk of fire damage due to other components in a substation such as instrument transformers, circuit breakers, reactors, cables, control and relay rooms, etc. is usually considered of lower importance.

To minimize the risk of fire damage, two kinds of protection are generally used:

- The active protection which consists of a direct method to attack an existent fire, e.g., fire protection system
- The passive protection which means measures to prevent propagation of fire or to limit damage, e.g., fire barriers, fire-resistant material, etc.

The use of fire-protection measures is mainly based on two criteria:

- Protecting the environment including people and personnel
- Minimizing the loss of customer's service and/or the cost of repair

Based on these criteria, a number of methods have been used by utilities all over the world, as described above.

Some utilities take the decision to not provide for fire protection measures in outdoor substations and some only in unattended outdoor substations. In the latter case, generally a remote alarm is present, which transmits the signals of the detection equipment. In indoor installations situated in city centers or near houses, fire protection systems are generally installed, often to meet local fire regulations.

## 11.11 Seismic (CIGRE 1992)

The stable supply of electricity is an increasing social need in industrialized countries. If facilities are damaged by an earthquake, the supply of power may be stopped for a considerable period of time, and it will have a disastrous influence over the social activities in the area. Within the power supply network, substations are the most vulnerable components to earthquakes, because of the architecture of high-voltage switchgear and the mechanical reactions at the connections. So, the equipment in a substation which is susceptible to earthquakes must have sufficient strength to withstand the earthquakes.

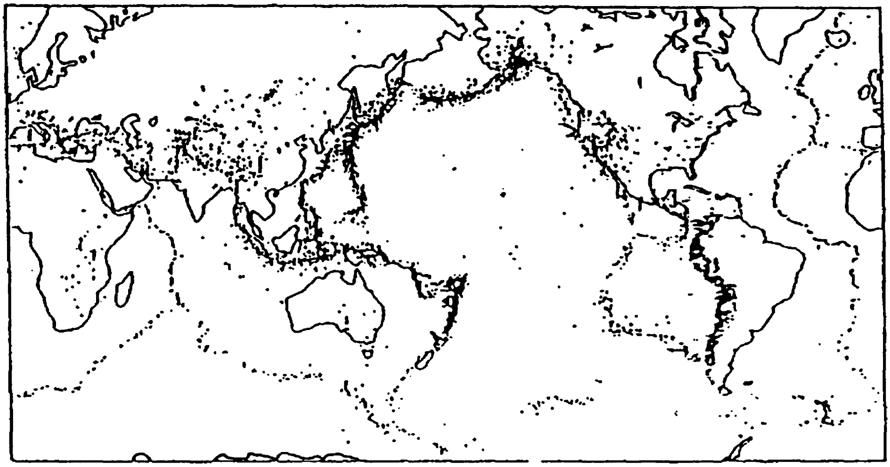


**Fig. 11.36** Distribution of epicenters of recorded earthquakes (magnitude >4)

Figure 11.36 shows the epicenters of earthquakes with a magnitude (Richter scale) greater than 4 recorded in the period from 1961 to 1967. Referring to this figure, the recorded earthquakes are distributed over wide areas in the world. The probability is high particularly in the areas all around the Pacific Ocean and along a wide strip running from Indonesia to the Mediterranean Sea. About 80% of all the earthquakes are recorded in these areas.

### 11.11.1 Seismic Design Procedures

The waveforms and the procedures used in the seismic design of substation equipment have not been unified internationally, since the conditions are different in different countries. The design methods are classified from the viewpoints of the waveforms and the design procedures as in Figs. 11.37 and 11.38, respectively.

For the simplicity of application to equipment in the field, a response spectrum method on a single degree of freedom system (SDOF) is applied to evaluate the seismic performance of a given equipment. An equipment is represented as a single degree of freedom system in the procedure, and all the analysis can be done manually without the help of a computer.

A typical evaluation procedure is shown in the flowchart (Fig. 11.39).

As an evaluation result, if safety factor ($S_f$), where "strength of material" divided by "calculation of bending stress," is greater than specified value, the equipment possesses acceptable strength.

Detailed procedures and calculations in accordance with Figs. 11.37, 11.38, and 11.39 are described in Cigre Electra # 140_3 (CIGRE 1992).

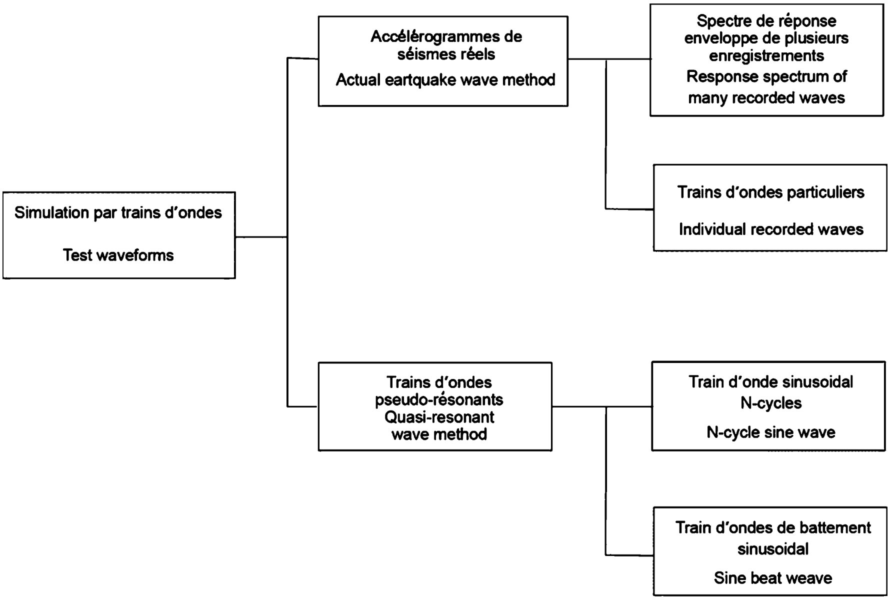



**Fig. 11.37** Classification of test waveforms

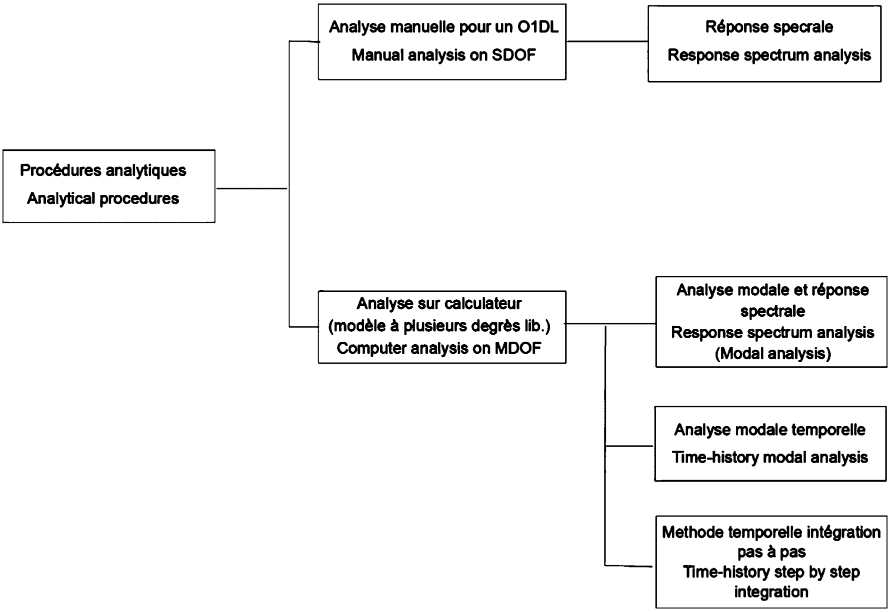



**Fig. 11.38** Classification of analytical procedures

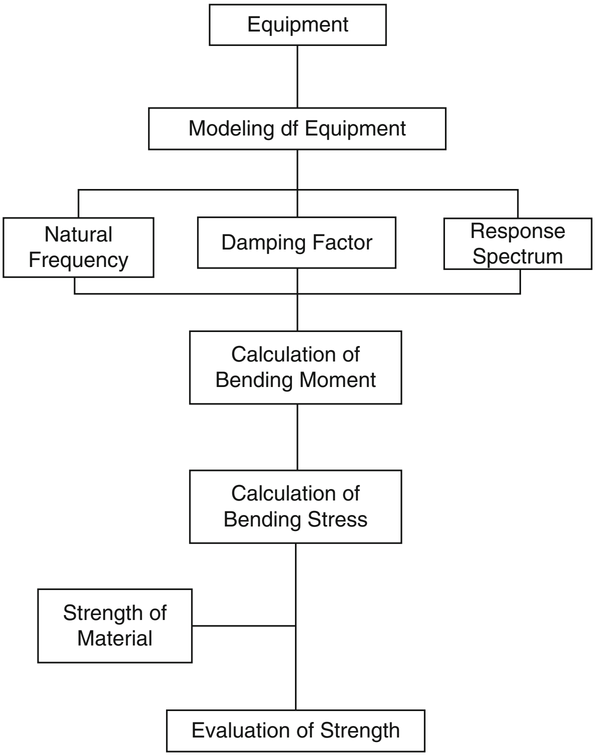



**Fig. 11.39** Flowchart of the evaluation procedure

The shake-table test is an option to confirm that the equipment satisfies the acceptable criteria directly. Figure 11.40 shows tested equipment on a shaking table for evaluation.

## 11.11.2 Practical Means to Enhance the Seismic Performance

If the stress calculated by the procedure in the previous subsections is higher than the permissible stress of the material used in the equipment with an appropriate margin, some kind of enhancement is necessary. The practical means to enhance the seismic performance of the equipment are described in this section.

### 11.11.2.1 Enhancement of Porcelain Insulators and Support Structures

Porcelain portions are usually the weakest part of the whole structure. Accordingly, the enhancement of porcelain is an effective means to improve the seismic performance of the equipment. This may be achieved by:

(a) Reduction of the equipment bending moment
- Reduction of the top weight
- Application of a polymer insulator (reduced weight)
- Reduction of the height of the equipment

**Fig. 11.40** Shake-table test

(b) Increasing the section modulus of porcelain insulators
(c) Application of high-strength insulators

#### 11.11.2.2 Enhancement by Bracing Porcelain

With regard to multiunit porcelain insulators, the stiffness of the bottom unit with the highest bending moment is strengthened by applying bracing porcelains in two or three directions from a connecting flange at the top or in the middle. An example applied to an air circuit breaker is given in Fig. 11.41.

#### 11.11.2.3 Strengthening of Supporting Frame

If the stiffness of the supporting frame of an equipment is not high enough for the equipment, the stiffness of the whole system is reduced.

The following countermeasures may be applicable:

- Increase the inertia of the supporting frame.
  - Add cross, horizontal, and vertical members.
  - Increase the section modulus of the members.
  - Increase the width of supporting frame.
- Decrease the height of the supporting frame.

#### 11.11.2.4 Increase in the Damping Factor

Rubber dampers or mechanical dampers are effective methods to absorb the vibration energy in earthquakes and reduce the response of the equipment.

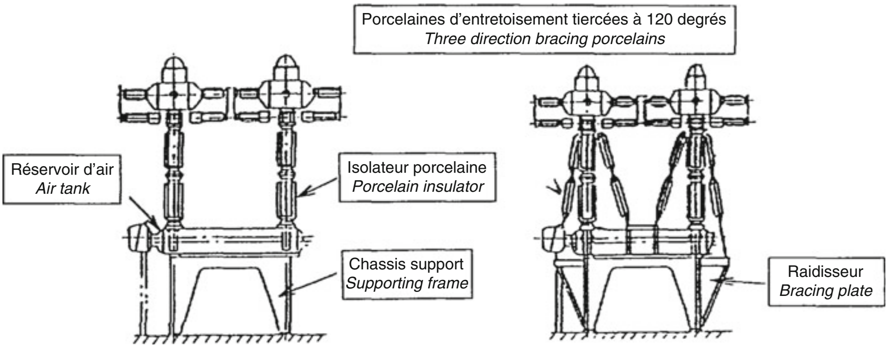



**Fig. 11.41** Example of adaption with bracing porcelains and bracing plates

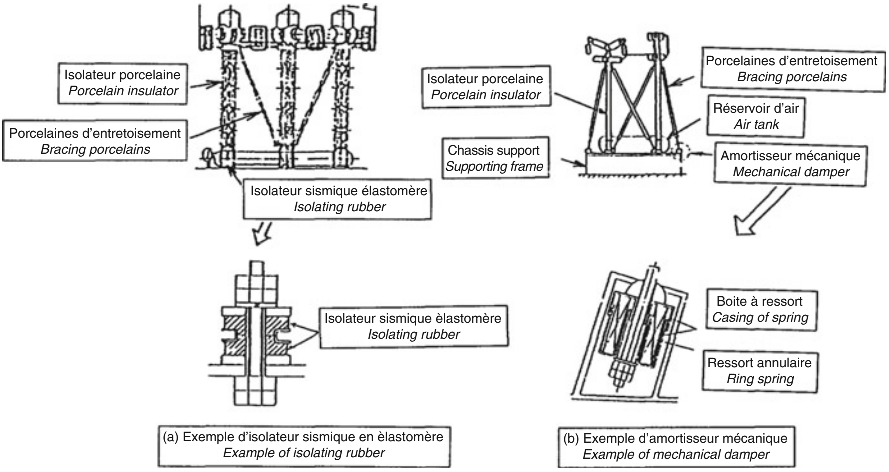



**Fig. 11.42** Example of isolating rubbers and mechanical dampers

Figure 11.42 shows examples in which rubber dampers are applied to a circuit breaker at the bottom of an air tank and mechanical dampers at the lower end of bracing porcelains.

It was proven that dampers worked effectively during the East Japan earthquake in March 2011 as illustrated in Fig. 11.43.

Isolating rubber has often been used for transformers to prevent the transfer of the electromagnetic vibration from the transformer to the floor (anti-vibration pads). When isolating rubber dampers are used for seismic protection, care must be taken for them not to be a cause of a rocking vibration (Miyachi et al. 1984). The rocking vibration is induced by the resonance of the vibration system of the transformer body and the isolating rubber. The rocking frequency may be close to the predominant

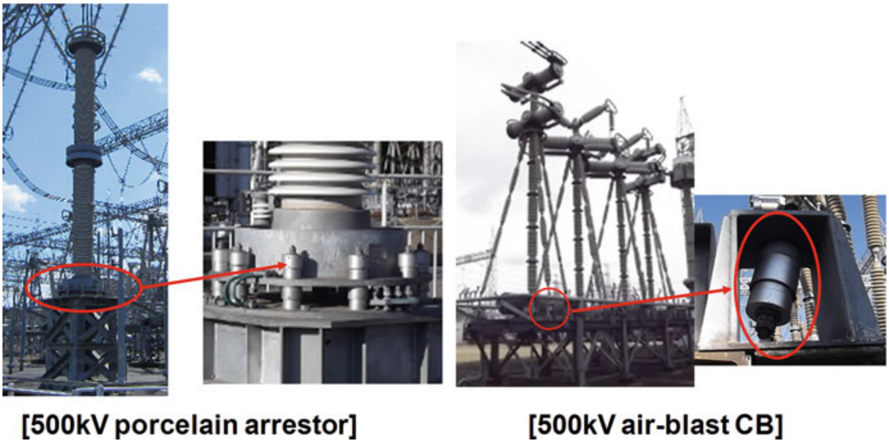



**Fig. 11.43** Actual effect of dampers at East Japan earthquake

frequency of earthquake waves and may amplify the earthquake force considerably. In that case, the manufacturer might change the rubber arrangement, size, and material or redesign the transformer.

#### 11.11.2.5 Other Countermeasures to be Taken into Consideration

Other countermeasures are also effective as follows:

- Removal of the wheels and sitting the transformer tank directly on the stringers of its foundation with firm abutments at each side.
- Fixing the wheel on the tracks by brackets.
- Stiffening the support of the bushing at the flange by brackets.
- Stiffening of the supporting frames for oil conservators and radiators.
- The piping and the control cable connections between the apparatus items to be as flexible as possible.
- The relays and the meters are liable to improper operation in earthquakes. To try to avoid this, they should be mounted with isolating rubber dampers or supported with soft cushion materials.
- The neighboring switchboards are better tightly connected to each other by rigid members and fixed by supporting members to the wall. An example of the countermeasures for switchboards is shown in Fig. 11.44.

#### 11.11.2.6 Influence of Lead Connections Between Two Pieces of Apparatus

When two neighboring pieces of apparatus are connected together by lead connections, tension may be produced by the difference in the vibration modes of the two apparatus items. This is particularly serious for rigid connections, but even for flexible connections, this could be a serious problem if the lead connections do not

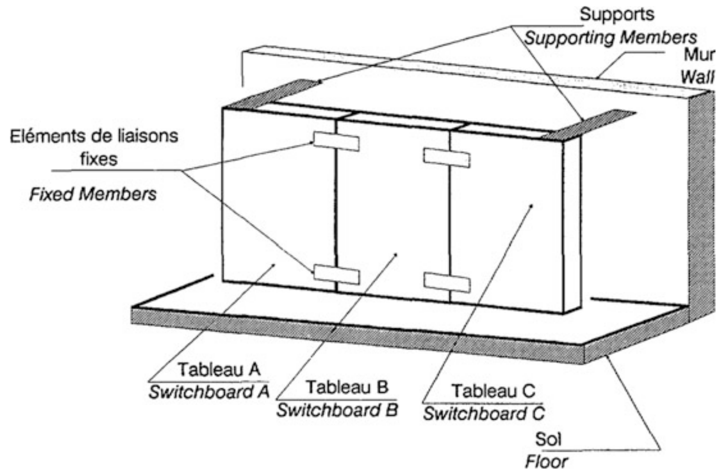



**Fig. 11.44** Example of countermeasures applied to switchboards

have sufficient slack. The stress caused by the tension of the lead connections is superimposed on the structure by the earthquake and may easily result in equipment damage.

Guidelines for the design of flexible connections include ensuring that the slack in the connection is:

(a) Specified to be at least 70 mm
(b) Greater than 5% of the connecting distance between the equipment items
(c) More than 1.5 times the maximum relative displacement under 0.3 g in three-cycle resonant frequency test analysis

### 11.11.3 Conclusion

A procedure and the practical means to enhance the seismic performance of the equipment in substations have been presented. When a countermeasure is applied on equipment, the solution has to be compatible with the service ability and the economy of the system. It is also important to see that the performance of the electric power system is balanced as a whole. The local features, particularly the level of an input acceleration considered to be possible in the area, have to be taken into consideration. Though it is not accurate in the strict sense, the method and the enhancements introduced in this document will give the simplest means to evaluate and improve the seismic performance of substations in various parts of the world.

## 11.12 Foundations, Buildings, Cable Trenches, Oil Containments, Etc.

### 11.12.1 Foundations

Installation of foundations for AIS equipment items forms a considerable proportion of the civil work cost for a substation, so some attention is justified to determine the most economic approach.

The foundations should be designed and calculated by a civil engineer in accordance with national or company standards and regulations to cater for the design loads and load combinations (see Sect. 11.5) provided by the substation designer. Some level of iteration between the two may be required to come up with the most economic design. A consistent design approach in relation to selection of the loads should be followed throughout the substation, e.g., design to match the rated loads of the individual equipment items used or design to meet loads based on the appropriate combination of design loads.

For each item one foundation could be used per phase, or alternatively a single foundation could be used to cater for all three phases.

Different approaches are available for the foundation designs, e.g., shallow raft foundations, block foundations, or deep foundations with pillars to mount the equipment. Selection could be based on ground conditions, installation cost for the different approaches, selected utility standard design approach, etc.

Depending upon the type of soil and the loads, foundation construction options could be:

- Poured concrete with or without steel reinforcement
- Prefabricated reinforced concrete
- Concrete slab (mostly used in indoor substations or for GIS)
- Drilled (suitable in hard soil)
- Auger-bored piles

In laying out the substation, the designer must consider what level the top of the foundation should be installed at, e.g., foundation below, at, or above finished ground level with the equipment support either directly on top of the foundation, a small distance above the foundation, or say 100 or 200 mm above the foundation.

If the equipment support is directly on the foundation, it is essential that the space between the two is grouted or sealed to prevent water lodging in the interface. If the support is above the top of the foundation, then grouting between the support base and the foundation or pouring a concrete cap around the base of the support may be needed for structural reasons. If a cap is used, then particular attention is required to the interface between the cap and the support structure to prevent water from lodging at this point which may promote corrosion of the structure.

There are two main possibilities of attaching the structure to the foundation:

- Drilled anchors
- Cast-in anchors

Usually the support structure is attached to the foundation by anchor bolts where two design approaches are used. Anchor bolts may be either cast-in to the foundation while it is being poured or drilled into the foundation after it has set. Two types of drilled anchor bolt are available, i.e., expansion anchors or chemical anchors. Chemical anchors have the advantage that the support structure can be located and the holes in the baseplate used as the drilling template. However extreme care is required that the supplier instructions are followed exactly to ensure proper adhesion as this is very dependent on the cleanliness of the drilled hole. It is a good practice to carry out a pullout test on a reasonable proportion of the installed quantity. Expansion anchors require the use of a separate drilling template as the hole diameter is normally larger than that of the bolt holes in the structure baseplate.

If cast-in bolts are being used, then considerable care is required during foundation installation to ensure that the anchor bolts are in the correct location as some structures, e.g., gantries require very tight coordination between the bolt positions on two or three foundations, while drilling the anchors into the poured foundations allows more tolerance in the foundation position. Some types of cast-in bolt do allow a degree of play in the position of the bolts which can then be grouted into place when the support structure is in place.

Similar to the cast-in anchor bolts, the steel structure itself can also be cast in. In this case the foundation itself is poured by leaving a pocket to insert the steel structure. Before pouring concrete, the structure has to be adjusted properly by some additional setting frames.

Comparing to this type, the anchor bolt fixing has an advantage, especially when the lead connections are made by tubular conductors. Here there is the possibility of adjusting the structure height to allow for any tolerance in the top of the foundation level.

In addition to the design of the structure fixing method, foundation design must also cater for the installation of earth conductors and control cables in so much as whether provision should be made for this during foundation installation or whether the provision, e.g., cut-outs, is made after the foundation is installed. There are advantages and disadvantages to both approaches. Making design provision during the foundation installation makes the foundation installation a bit slower and a bit more expensive but makes the subsequent earth conductor or control cable installation quicker and cheaper. However, if the design provision is not implemented correctly, then correcting this can be expensive and awkward.

The alternative approach of post-pouring provision makes foundation installation quicker and cheaper and the subsequent work more expensive, but this work will never be in the wrong position as it can be aligned with the installed equipment support structures.

In general, the presence of high voltages or large currents in the vicinity of the foundations does not have any impact on the design of the foundations, but there is one exception which is the design of the foundation for air-cored reactors which generate very strong magnetic fields. The design of the reinforcing for these foundations must ensure that it does not contain any closed loops of conductive material by using insulating material in the joints of conventional reinforcing bars or by using nonmetallic reinforcing material.

Civil works for transformers or oil-filled reactors must fulfill four different main purposes:

(a) To support the transformer during service and enable it to be moved in and out of its service position (rails may be needed depending upon transformer type).
(b) To retain any leakage of transformer oil. Additionally, by filling the oil containment area with gravel covered by an upper layer of broken stones or by connecting it to an underground tank, extinguishing of oil fires can be assisted.
(c) To reduce the risk of fire propagation (fire walls and fire stops in trenches arc recommended).
(d) Where necessary, to reduce the propagation of acoustic noise.

### 11.12.2 Buildings

The design of buildings must conform to national and company standards. Their main role is to contain and give shelter to switchgear, protection relays, SCADA equipment, auxiliaries, batteries, fire protection pumps, etc.

Whether a substation is manned or unmanned will determine the extent of the water, waste treatment, or accommodation facilities required locally for the operators.

Access conditions to the substations and the maintenance practices of the utility will determine whether or not to install a workshop or determine what size of workshop is required. The same approach is required in determining what amount of maintenance equipment, e.g., elevating platforms, $SF_6$ handling plants is stored permanently on-site as opposed to bringing them to site as required for particular tasks. In the ultimate case, there could, for example, be a case for installing a transformer un-tanking hall.

For economic reasons (reduction of control cable lengths and cross sections, lowering the voltage of the auxiliary supply, minimizing the first investment), several dispersed buildings rather than one central building can be built in a substation.

A wide variety of construction types are available for substation buildings, e.g., reinforced concrete, concrete block, brick or cladded steel, or steel plate. Roofs can be pitched or flat depending on construction costs or planning requirements. Planning requirements may also have an impact on the required surface finishes and color treatments.

The design of the buildings must also consider lifetime costs in particular in relation to protection against moisture ingress and in regard to protection against corrosion.

Buildings in a substation are important sources of energy consumption. For new buildings, compliance to the latest energy efficiency regulations could be easily achieved. Retrofits of existing buildings are more complex, and energy analyses should be conducted. Energy-saving opportunities include site and site planning, building orientation, wall/roof design, window design, solar heat gain, heating, ventilation and air-conditioning systems, electric lighting, and landscaping.

Another aspect of the building design is whether the building should be built on-site or should be prefabricated off-site and delivered to site fully equipped and lowered onto a prepared foundation. For small substations, this question could be considered as whether the building is to be thought of as a permanent or a temporary relocatable structure.

The on-site or off-site question is perhaps even more pertinent in the case of cabins, containers, or blockhouses used for decentralized control and protection equipment. Another decision here is whether a structure is required for each bay or whether each structure caters for a number of bays.

While initial and lifetime costs for the particular country or individual location are the main basis for the selected construction type, security concerns must also be taken into account which may result in requirements for minimal or no windows (or protected windows), reinforced non-flammable roofs, reinforced doors, etc.

In laying out a building, particular consideration should be given to protection against flooding, mainly in relation to prevention by the use of an appropriate floor level. A related issue is the design of the control and power cable access to a building. This needs particular care as it is quite difficult to successfully seal cable entries against water access.

Room design must cater for control cable access between equipment cabinets, between rooms, and between the building and the exterior. The options are overhead routing where the cables are run on cable tray or cable ladders suspended from the ceilings or alternatively where the cables are laid below floor level either in completely open sub-floor spaces beneath the floor tiles or in surface ducts set into the floor. Whichever system is used, it is essential that all locations where cables are routed between rooms are fire-sealed to minimize the spread of fire or smoke.

The local climate and the environmental requirements of the installed equipment will determine the degree of climate control required in substation buildings. While temporary provision can be made during construction work in a building, it is recommended that environmental conditions within a control building are such as to provide appropriate conditions for operational personnel. This may require the use of some level of climate control equipment. In addition to the requirements of the operational staff, some electronic equipment items have quite severe environmental requirements in relation to the permissible ranges of temperature and humidity. This also applies to batteries where some types have a minimum temperature requirement and others, e.g., valve-regulated lead acid lose much of their performance when the ambient temperature rises above 20 °C.

Such climatic requirements have an impact on the internal layout of buildings in that it may be appropriate to segregate equipment with particular climatic requirements to minimize the internal building volume which requires particular levels of climate control.

From another aspect, some equipment generates hazards which require them to be segregated. Lead-acid batteries are filled with sulfuric acid, some of which may be released as vapor which requires acid-resistant surfaces in the battery room. They also release hydrogen when they are being charged which means that battery rooms also require air circulation and extraction facilities.

Internal layout of buildings must consider the degree of access required for routine maintenance and also for replacement of control or protection equipment which may be required a number of times during the lifetime of the substation. The initial design of the building must either make appropriate allowance for future expansion requirements or be such as to allow for subsequent easy extension of the original building.

Building design must also consider appropriate provision for house supply transformers and/or diesel generators if these items are integrated into the buildings rather than being installed outside the building.

If dry-type transformers are used, then there are no particular requirements for the transformer room apart from provision of any necessary ventilation for cooling and appropriate clearances and access control if live terminals are accessible. If an oil-filled type is used, then fire-rated construction is required along with appropriate fire-suppression equipment and measures to retain any oil leakage.

A diesel generator room requires the same measures as on oil-filled transformer along with sizable ventilation openings needed for engine cooling which must be located so as to provide an appropriate airflow across the engine. The generator foundation will also need to be designed so that generator vibration is not transmitted to the remainder of the building.

Appropriate provision of water supply and of toilet facilities must also be considered. Decisions on the type of facilities to be provided must consider the likely degree of personnel presence in the substation and the lifetime maintenance cost of the different design approaches.

An appropriate-zoned fire alarm system should be provided which is connected to the SCADA system. A risk assessment must be carried out to determine what degree of fire suppression should be provided.

### 11.12.3 Cable Trenches

An important part of the design of an AIS switchyard is the design of the control cable installation between the individual items of HV equipment and the bay marshaling and control point and between the local control/marshaling point and the control building(s).

Three possible approaches to the cable route design are generally available. Each of them shows a contrast between initial installation cost and the ease or cost with which any changes can be made to the existing cables, e.g., installing additional cables.

These three options are:

1. Cables direct-buried (cheap installation/expensive changes).
2. Cables laid in pipe ducts (moderate installation costs with reasonable access for changes if pulling ropes are installed and care is taken with pipe joints to prevent the pipes from being blocked by silt and also to have enough spare pipes).

3. Surface ducts (expensive installation but easy access for any later changes). Two construction approaches are available, i.e., site constructed with walls of poured concrete or concrete blocks or prefabricated sections made from some form of glass-reinforced plastic which can be quickly clipped together on-site.
   The removable covers can be made from concrete, GRP, or even timber. Each of these has its own advantages and disadvantages (such as timber becoming slippery when wet or concrete covers requiring special lifting techniques) which need consideration. As these ducts will be used as pedestrian walkways, they should be designed to meet the required loads, e.g., concrete covers should include some level of reinforcement. The surface finish should also be roughened slightly to provide safe footing. Care should also be taken where a potentially buoyant material is used that they are fixed in place and will not be displaced during a flooding event.
   The design of cable routes must also consider the requirements for vehicle (sometimes heavy vehicle) access around the switchyard, so either the routes should be completely designed to meet the vehicle loads or alternatively designated vehicle crossing points should be provided and clearly indicated.
   The initial provision of cable routes must also make adequate provision for any additional cables which may be required to cater for any future extension to the substation as later installation of new additional cable routes to a control building is likely to be both difficult and expensive.

### 11.12.4 Oil Containment

The site should be chosen so as to avoid any damage to the natural drainage network, especially to permanent surface watercourses, avoiding their interruption, and to groundwater recharge areas, to avoid any damage to the underground network.

All noxious materials in the substation must be used and handled without leakage to groundwater or outside of the substation boundary. The vessels of power and instrument transformers, capacitors, coils, etc. must be, where possible, leakproof.

In most countries, additional measures against detrimental materials are required. Oil pits are designed to catch some or all of the oil (or other liquid) and also to prevent oil from burning. If a central underground tank is used, it must be large enough to contain the volume of the largest oil-filled equipment, any rainwater collected since the tank was last emptied and the volume of water resulting from operation of the water spray fire protection system (where used). When no oil leakage occurs, the rainwater may be drained off. Otherwise decontamination is necessary by such means as mechanical separation, filtering, or chemical cleaning.

While large power transformers are the obvious potential source of pollution from oil, all sources must be properly considered, e.g., diesel generator tanks, substation supply transformers, bulk-oil circuit breakers, etc.

The probability of an oil spill occurring in a substation is very low. However, certain substations, due to their proximity to groundwater resources, open water or designated wetlands, the quantity of oil on-site, surrounding topography, soil characteristics, etc., have or will have a higher potential for discharging harmful quantities of oil into the environment.

Increased awareness of the public to the environmental aspects related to substations as well as newer, more stringent environmental regulations force utilities to take measures to reduce the environmental impact of new substations generally but in particular the impact of these older substations. This section suggests some of the possible measures that can be taken to mitigate the environmental impact of oil spills that might occur in existing or new substations.

The solutions mentioned in this section are presented only in outline. Details of the solutions are not presented. It is up to each individual user to find solutions, which suit the national and regional laws and regulations in his/her own country.

(A) Evaluating the Need for a Spill Containment

Evaluation of the need for installation or retrofitting of oil-filled equipment with spill containments must be part of a well thought-out plan that should be developed by the substation owner. It is recommended that a high level of protection should be standard practice in new installations, but due to the high cost of retrofitting of spill containment, a risk assessment of all existing substations should be performed in order to decide which existing substations would need retrofit. Some of the criteria that a risk assessment should evaluate in the ranking of substations for retrofitting with spill containments are:

(a) Proximity of drinking water source or water mains
(b) Proximity of populated areas, navigable waters, and environmentally protected zones
(c) Potential contamination of groundwater
(d) Soil permeability in the vicinity of the station
(e) Potential contamination of storm runoff through existing drainage system
(f) Emergency response time if oil spill occurs
(g) Failure probability based on age, type, and operating history (spill records) of the considered oil-filled equipment
(h) Anticipated cost of implementing the containment relatively to the extent of environmental impact by oil spill

Such a ranking will allow the managers of a utility to identify the substations that are most likely to cause significant environmental impacts during a spill and to develop long-term plans that will address the spill containment retrofits in the most critical substations.

(B) Basic Design Concepts for Spill Containment Systems

Once the decision has been made that spill containment is needed, the engineer must weigh the advantages and disadvantages that each containment solution may have at a particular substation. This should consider the national, provincial, and municipal environmental requirements as well as integrating the solution with any fire or noise barrier requirements to minimize the cost.

The selected containment solution should balance the cost and sophistication of the system with the risk to the surrounding environment if oil were to escape into soil, groundwater, or even outside the boundaries of the substation. Some of the most important risks have been listed in the subsection (A) above.

Some containment systems are listed below, and these should be considered based on their relative merits and the circumstances related to the facility under the chosen retrofit solution; it should be kept in mind that most of the construction activities of the containment are likely to be performed within an energized environment. Furthermore, the containment system must also consider the access design for any power or control cables which are connected to the device which is being contained and suitable measures taken to avoid leakage at these points.

Some containment systems are listed below and these should be considered based on their relative merits and the circumstances related to the facility under consideration.

(C) Spill Containment Solutions

- Substation Ditching
  One of the simplest methods of collecting potential oil spills in a substation is the construction of a ditch around the outside perimeter of the substation.
- Collecting Pits with Separate Containment Pit Holding Tanks
  This containment solution is comprised of collection pits installed underneath the electrical equipment susceptible to leak/spill insulating oil, drains that connect these pits to a containment pit/holding tank and an oil trap/oil-water separator and the discharge drain. The collection pits surrounding the equipment can be filled with crushed stones for fire-quenching purposes and designed only deep enough to extinguish burning oil (usually 200–450 mm).
- Oil Containment Pits
  One of the most extensively used methods to ensure containment of oil leakages within the substation property is by placing containment pits around all major oil-filled equipment in the substation. These pits will confine the spilled oil to relatively small areas that in most cases will greatly reduce the cleanup costs. A sump with a pump (or a similar solution) is a required component in these containment pits in order to remove rainwater accumulated in the pit.

**Layout of a Spill Containment**

The basic principles of the design of spill containments are as follows:

(a) Spill containment should have a regular shape (rectangle, quadrant); irregularly shaped structures significantly increase cost of construction.
(b) Transformer and oil-filled equipment associated with transformer operation (coolers, oil conservator tanks, etc.) have to be included within the boundaries of the containment pit.
(c) The containment pit (internal face of the containment curb) has to extend to a reasonable distance from the face of any oil-filled piece of equipment included in the containment pit to collect oil that might gush out during a spill. However, the extent of containment in a retrofit situation may be limited by existing roads,

buildings, underground utilities, etc. Potential interferences, as well as the limitation of containment areas and proposed solutions, are discussed further below.
(d) Unless there is a reasonable clearance (indicated in relevant national and/or international standards and approved by local fire department) between adjacent transformers or transformers and buildings, a fire barrier should be installed.
(e) Two or more equipment containment pits could be interconnected in order to reduce the volume of each individual containment.

**Capacity of a Spill Containment Pit**

The volume of a spill containment pit must be selected based on the volume of oil in the largest oil-insulated equipment in the substation plus the quantity of rain that may fall during a given period of time during the spill. If two or more pits are interconnected, they should be constructed to contain a volume of oil equivalent to the largest piece of equipment located within the interconnected containment pits, as it is assumed that only one piece of oil-insulated equipment served by the pits will leak at one time. Therefore, it is reasonable to size interconnected pits to contain the volume of oil in the single largest transformer, plus any accumulated water as a result of rainfall and/or water spray discharge from a fire-protection system.

**Structural Integrity and Imperviousness**

Special attention has to be given to the design and installation of joints in the containment pits, as well as the joints within the existing foundations. The sealing performance of containment pits is largely dependent on the design and workmanship of these joints. Therefore, the number of joints should be kept to a minimum. Compacted granular fill and insulation slab will, respectively, provide a bearing capacity and prevent heaving effect. Thickness and extent of the insulation slab should be carefully determined to protect the soil down to the frost line from freezing.

It is very important to provide structural integrity to the spill containment by specifying concrete mix, reinforcing steel arrangement, and sequences of pouring.

A quality-control procedure during construction of the entire containment system will ensure that the containment will retain its sealing characteristics for a long time.

**Discharge-Control System**

Control of the discharge fluid from a spill containment pit is an important component of the system.

Water accumulation due to rainfall must be removed from the containment pit regularly to keep the entire volume of the pit available in the event of a major spill. Liquid discharged from a spill containment after rainfall may contain oil in concentrations exceeding normal due to chronic leaks of oil within spill containment area.

Some examples of frequently used discharge-control systems are as follows:

(a) Oil-Water Separator Systems

Oil-water separator systems rely on the difference in specific gravity between oil and water. Because of that difference, the oil will naturally float on top of the water, allowing the water to act as a barrier and block the discharge of the oil.

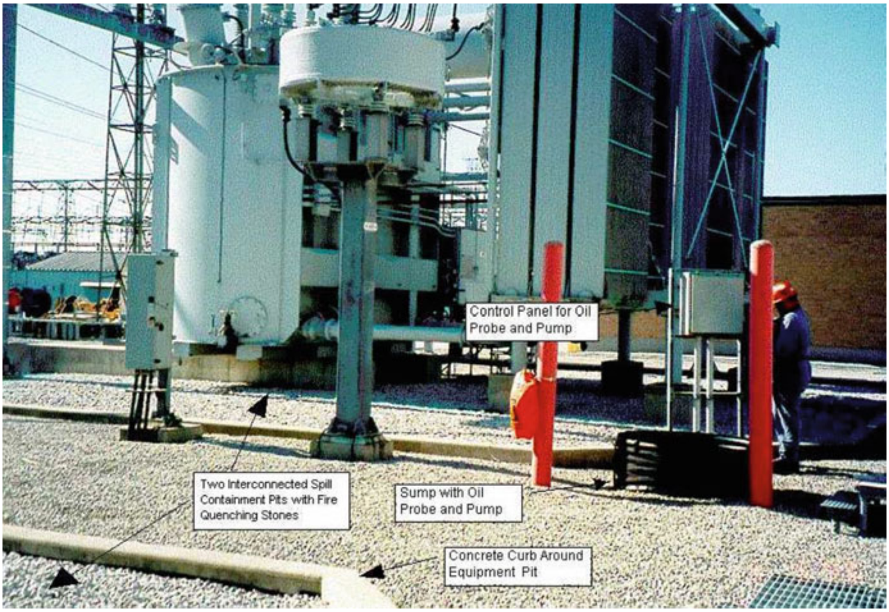



**Fig. 11.45** Example of two interconnected spill containment pits with fire-quenching stones (CIGRE WG B3.03 2003)

(b) Oil-Flow Blocking Systems

These systems detect the presence of oil and block all flow (both water and oil) through the discharge system.

Refer to TB 221 (CIGRE WG B3.03 2003) for more detailed information on this subject (Fig. 11.45).

(D) Synthetic Oils

Synthetic oils, e.g., askarels, or oils containing polychlorinated biphenyls (PCB) are poisonous, and special precautions are necessary to avoid contamination.

They are not likely to be deliberately used in new installations today but may still exist in old installations or in contaminated supplies of oil. Synthetic oils are used in a few countries for transformers but are more commonly used in capacitors. The quantities are usually small, and reasonable care may be sufficient to avoid pollution.

## 11.13 Fences, Gates, Security, and Animal Deterrents

### 11.13.1 Fencing

External fencing reduces the possibility of entry to the site by unauthorized persons. Special measures are usually defined in national standards.

Internal fencing is used mostly for defining areas where access is restricted, e.g., air-cored reactors or capacitor banks. Rails or wire fencing can be used for this purpose.

Fences or boundary walls can have considerable influence on the aesthetic impact of the substation on the environment. Special visual treatments are possible in particular for walls.

Power regulations and guidelines generally stipulate that power substations be protected by a chain-link or welded mesh fence or brick wall of a certain height. The perimeter fence should include high-voltage warning signs on all sides to warn non-substation workers against entering the site.

It is mandatory for substations to have one or more fences surrounding the entire site perimeter. In most cases, perimeter fencing is composed of reinforced galvanized steel chain-links. Alternatively, substations may be enclosed by concrete walls. The substation property boundary should also be marked by an appropriate fence which can be much lower than the substation security fence.

The advantage of using a chain-link fence is that it is almost transparent and hence may reduce the visual impact of the substation in more natural settings such as crop fields and farmlands. In addition, the average cost of a chain-link fence is generally less than that of a wall of any type. Furthermore, the use of a chain-link fence may encourage substation personnel to keep the interior tidy, as the content of the interior will be visible to the public.

However in other environments, the desired aesthetic objective may be to hide the substation equipment as far as possible behind high walls or to make visible structures more acceptable through the use of architectural treatments or appropriate use of color and different types of surface finish.

Case studies #12 and #13 in TB 221 (CIGRE WG B3.03 2003) provide examples of creative solutions to reduce the visual impact of the substation by modifying the perimeter fence (Figs. 11.46 and 11.47).

In some locations, much more substantial fences are required to prevent access by thieves. Examples of such types of fence are palisade fences with at least two palings embedded into the concrete to prevent the fence from being pulled off its posts (see Fig. 11.48).

Another problem requiring special fencing is that of vandalism. It is an unfortunate fact that in today's society there are a small number of individuals who take pleasure in causing damage by throwing objects at equipment to damage it. One of the most common targets is capacitor banks where the bushings projecting from the capacitor cans make an attractive target for such people. To protect against such attacks, one solution is to use "stone guard" fencing which has to be very high and with a dense mesh to protect against stones being thrown at it (see Fig. 11.49). A similar design of fence can be used also to provide a level of protection from firearms (see Fig. 11.50). The wind loading on such fences can be very high.

### 11.13.2 Gates

Metal gates are generally used in substations for vehicular access. A single-leaf gate is typically used for personnel access. From an earthing design viewpoint, it is better if the gates open inward.

**Fig. 11.46** The interior of the substation is visible through the chain-link fence

**Fig. 11.47** The chain-link fence is hardly noticeable

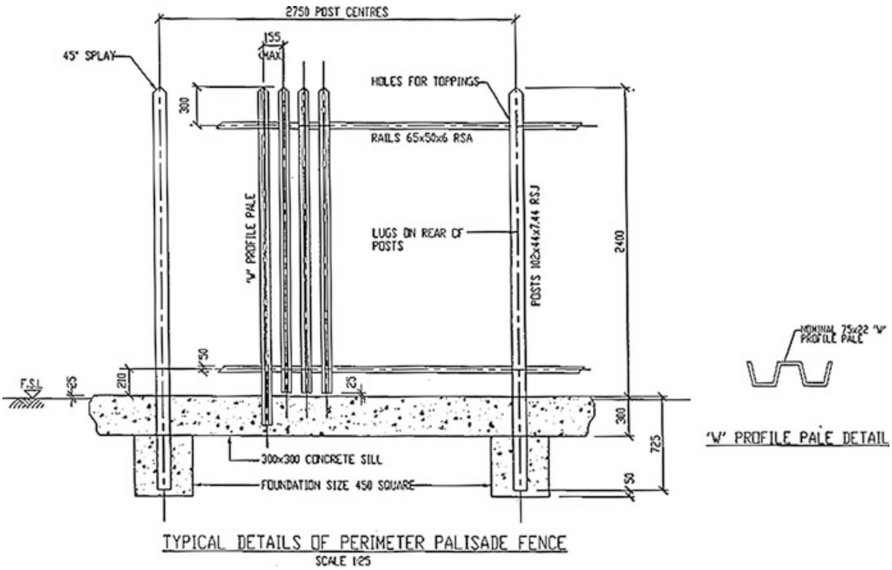



**Fig. 11.48** Example of typical palisade fence used for substation boundaries

**Fig. 11.49** Example of stone guard fencing to protect capacitor banks against vandalism

### 11.13.3 Substation Security

To control entry to a substation by unauthorized persons, the site should be equipped with suitable security measures. These measures serve two purposes: protection of public and personnel safety and protection of assets against loss and/or damage. Substations are a high-voltage environment which can present potential safety hazards to untrained and/or unaware people. Furthermore, the theft of copper grounding wires from perimeter fencing or from inside a substation could affect the integrity of the substation grounding system, thus potentially compromising the safety of the intruder as well as utility staff. Damage or loss of substation operating equipment could also result in the loss of supply to customers and material/property losses.

Substation security measures may include fences (in some cases with electrified wires), walls, entrance/equipment locks, physical obstacles against vehicle access such as ditches and entrance barriers, photoelectric motion sensing equipment, video surveillance systems, computer security systems, lighting, or landscaping. For each substation, an assessment should be made to determine which measure and/or combination of measures are most appropriate (Fig. 11.50).

For guidance on the effectiveness of substation security measures and criteria for security, refer to the IEEE Std.1402 "Guide for Electric Power Substation Physical and Electronic security" (IEEE 2000b).

### 11.13.4 Animal Deterrents

A considerable percentage of all outages on air-insulated installations, particularly at lower voltage levels, are due to direct contact with animals and birds or as a result of animal behavior, e.g., nests and bird waste. The impact can vary from momentary trips to major equipment damage. Unfortunately there is no single solution to deal with this problem.

The substation designer has to gather information both on the species which may cause problems and how they behave but also on those which are subject to special protection measures.

Considerable insight into the behavior of the relevant species and their interaction with installations and with other species is required to determine appropriate barrier or deterrent measures which require input from appropriate experts. This is particularly important to avoid adopting "obvious" measures which may result in unintended consequences, e.g., keeping snakes out of a substation may encourage an over-concentration of birds in the substation.

In many cases, again particularly at lower voltages, it may be possible to insulate live conductors to prevent animals from making contact with the conductors (see Fig. 11.51). Any such insulation must be designed for a high-voltage environment to ensure that an appropriate lifetime is obtained for the insulation.

**Fig. 11.50** Example from America of security fencing to provide some protection against vandalism from firearms

**Fig. 11.51** Shielding of HV connections from animals: example from Canada (CIGRE 2016)

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# Specification and Selection of Main Components for Air-Insulated Substations

# 12

John Nixon, Gerd Lingner, and Eugene Bergin

## Contents


12.1 General ........ 249
12.2 Circuit Breakers ........ 259
12.3 Disconnectors, Earthing or Grounding Switches, and Earthing or Grounding Poles ........ 264
12.4 Surge Arresters (or Lightning Arresters) ........ 267
12.5 Instrument Transformers ........ 279
12.6 High-Voltage Conductors and Connectors ........ 285
12.6.1 Purpose ........ 285
12.6.2 Conductor and Connector Material ........ 286
12.6.3 Selection of Conductors, Singular or Bundled ........ 286
12.6.4 Variation Caused by Temperature and Ice ........ 287
12.6.5 Movement Caused by Short-Circuit Forces and Wind ........ 287
12.6.6 Vibration ........ 287
12.6.7 Connector Types, E.g., Welded, Bolted, and Compression ........ 289
12.6.8 Fixed and Thermal Expansion Connectors ........ 289
12.6.9 Corona ........ 289
12.6.10 Jointing Methodology ........ 291
12.6.11 Joint Testing ........ 291
12.7 Solid-Core and Hollow Insulators ........ 292
12.7.1 Purpose of Insulators ........ 292
12.7.2 Insulator Material and Types ........ 295
12.7.3 Resistive Glaze ........ 299


J. Nixon (✉)
Global Project Engineering, GE Grid Solutions, Stafford, UK
e-mail: john.nixon1@ge.com

G. Lingner
DK CIGRE, Adelsdorf, Germany
e-mail: gerd.lingner@gmx.net

E. Bergin
Mott MacDonald, Dublin, Ireland
e-mail: Eugene.Bergin@mottmac.com

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12.7.4 Strength Selection Due to Static and Dynamic Forces ..... 299
12.7.5 Earthquake Ground Acceleration ..... 300
12.7.6 Bushings ..... 301
12.8 High-Voltage Cables ..... 302
12.8.1 Single-Core or Three-Core ..... 303
12.8.2 Cable Types ..... 303
12.8.3 Conductor ..... 303
12.8.4 Cable Insulation Materials ..... 304
12.8.5 Sheathing Material ..... 308
12.8.6 Outer Serving ..... 308
12.8.7 Bonding Design ..... 309
12.8.8 Current Ratings ..... 309
12.8.9 Cable Accessories ..... 310
12.8.10 Laying Arrangements ..... 310
12.8.11 Mechanical Considerations ..... 311
12.8.12 Jointing ..... 311
12.8.13 Testing ..... 312
12.8.14 Maintenance ..... 312
12.8.15 References ..... 312
12.9 Earthing or Grounding Grid ..... 313
12.9.1 General ..... 313
12.9.2 Materials Used in the Earthing or Grounding System ..... 313
12.9.3 Different Earth Rod Types ..... 313
12.9.4 Soil-Conditioning Agents ..... 314
12.10 Power Transformers and Compensation Equipment ..... 316
12.10.1 Impedance and Regulation ..... 316
12.10.2 Cooling Arrangements ..... 317
12.10.3 Winding Arrangements and Vector Groups ..... 317
12.10.4 Typical Transformer Arrangements ..... 318
12.10.5 Tertiary Winding Voltage and Rating ..... 318
12.10.6 Insulation Media ..... 320
12.10.7 Variation of Voltage ..... 321
12.10.8 Losses ..... 321
12.10.9 Noise ..... 322
12.10.10 Terminal Arrangements ..... 322
12.10.11 FACTS Devices ..... 322
12.10.12 Reactors ..... 323
12.10.13 Filters (Harmonic Filtering) ..... 324
12.10.14 Capacitors (Capacitor Banks) ..... 324
12.10.15 Static Var Compensator ..... 326
12.10.16 Voltage Source Converter Devices, E.g., STATCOMS ..... 326
12.11 Miscellaneous Equipment ..... 327
12.11.1 Purpose of Miscellaneous Equipment ..... 327
12.11.2 Line or Wave Traps ..... 327
12.11.3 Neutral Earthing or Grounding Resistors ..... 328
12.11.4 $SF_6$ Gas ..... 329
12.11.5 $SF_6$ Gas Analysis and Processing Equipment ..... 330
References ..... 332


There are many elements to be considered when specifying equipment for air-insulated substations. This chapter takes individual items of equipment and describes the requirements that will need to be considered when specifying the correct parameters for the particular installation.

## 12.1 General

Some parameters are applicable to all HV substation equipment. The following definitions are taken from IEC 62271-1. From the system parameters, equipment with the appropriate rating can be selected knowing:

**Rated Voltage ($U_r$)**
The rated voltage is equal to the maximum system voltage for which the equipment is designed. It indicates the maximum value of the "highest system voltage" of networks for which the equipment may be used. Standard values of rated voltages are given below.

- **Range I for Rated Voltages of 245 kV and Below**
  Series I: –3.6 kV – 7.2 kV – 12 kV – 17.5 kV – 24 kV – 36 kV – 52 kV – 72.5 kV – 100 kV – 123 kV – 145 kV – 170 kV – 245 kV.
  Series II (Voltages based on the current practice in some areas, like North America): – 4,76 kV – 8,25 kV – 15 kV – 15,5 kV – 25,8 kV – 27 kV – 38 kV – 48,3 kV – 72,5 kV – 123 kV – 145 kV – 170 kV – 245 kV.
- **Range II for Rated Voltages Above 245 kV**
  300 kV – 362 kV – 420 kV – 550 kV – 800 kV – 1,100 kV – 1,200 kV.

**Rated Normal Current ($I_r$)**
The rated normal current of switchgear and control gear is the RMS value of the current which switchgear and control gear should be able to carry continuously under specified conditions of use and behavior. The values of rated normal currents should be selected from the R10 series, specified in IEC 60059. The R10 series comprises the numbers 1 – 1.25 – 1.6 – 2 – 2.5 – 3.15 – 4 – 5 – 6.3 – 8 and their products by 10n. Rated currents for temporary or for intermittent duty are subject to agreement between manufacturer and user.

**Rated Short-Time Withstand Current ($I_k$)**
The RMS value of the current which the switchgear and control gear can carry in the closed position during a specified short time under prescribed conditions of use and behavior. The standard value of rated short-time withstand current should be selected from the R10 series specified in IEC 60059. The R10 series comprises the numbers 1 – 1.25 – 1.6 – 2 – 2.5 – 3.15 – 4 – 5 – 6.3 – 8 and their products by 10n.

**Rated Duration of Short Circuit ($t_k$)**
The interval of time for which switchgear and control gear can carry, in the closed position, a current equal to its rated short-time withstand current. The standard value of rated duration of short circuit is 1 s. If it is necessary, a value lower or higher than 1 s may be chosen. The recommended values are 0.5 s, 2 s, and 3 s.

**Rated Frequency ($f_r$)**
The standard values of the rated frequency are $16\frac{2}{3}$ Hz, 25 Hz, 50 Hz, and 60 Hz.

**Table 12.1** (1a) Rated insulation levels for rated voltages of range I, series I (not North America) from IEC 62271-1

| Rated voltage | Rated short-duration power-frequency withstand voltage | | Rated lightning impulse withstand voltage | |
|---|---|---|---|---|
| $U_r$ | $U_d$ | | $U_p$ | |
| | kV (rms value) | | kV (peak value) | |
| kV (rms value) | Common value | Across the isolating distance | Common value | Across the isolating distance |
| (1) | (2) | (3) | (4) | (5) |
| 3,6 | 10 | 12 | 20 | 23 |
| | | | 40 | 46 |
| 7,2 | 20 | 23 | 40 | 46 |
| | | | 60 | 70 |
| 12 | 28 | 32 | 60 | 70 |
| | | | 75 | 85 |
| 17,5 | 38 | 45 | 75 | 85 |
| | | | 95 | 110 |
| 24 | 50 | 60 | 95 | 110 |
| | | | 125 | 145 |
| 36 | 70 | 80 | 145 | 165 |
| | | | 170 | 195 |
| 52 | 95 | 110 | 250 | 290 |
| 72,5 | 140 | 160 | 325 | 375 |
| 100 | 150 | 175 | 380 | 440 |
| | 185 | 210 | 450 | 520 |
| 123 | 185 | 210 | 450 | 520 |
| | 230 | 265 | 550 | 630 |
| 145 | 230 | 265 | 550 | 630 |
| | 275 | 315 | 650 | 750 |
| 170 | 275 | 315 | 650 | 750 |
| | 325 | 375 | 750 | 860 |
| 245 | 360 | 415 | 850 | 950 |
| | 395 | 460 | 950 | 1,050 |
| | 460 | 530 | 1,050 | 1,200 |

**Rated Insulation Level {ELT045/2, 029/2, 039/2}**

The rated insulation level of switchgear and control gear shall be selected from the values given in Tables 12.1 and 12.2. In these tables, the withstand voltage applies at the standardized reference atmosphere (temperature (20 °C), pressure (101.3 kPa) and humidity (11 g/m$^3$)) specified in IEC 60071-1. These withstand voltages include the altitude correction to a maximum altitude of 1,000 m specified for the normal operating conditions.

**Table 12.2** (1b) Rated insulation levels for rated voltages of range I, series II (based on current practice in some areas, including North America)[a] from IEC 62271-1

| Rated voltage | Rated power-frequency withstand voltage | | | Rated lightning impulse withstand voltage | |
|---|---|---|---|---|---|
| $U_r$ | $U_d$ | | | $U_p$ | |
| | kV (rms value) | | | kV (peak value) | |
| | Common value | | Across the isolating distance | | |
| kV (rms value) | Dry | Wet[e] | Dry | Common value | Across isolating distance |
| | 1 min | 10 s | 1 min | | |
| (1) | (2) | (2a) | (3) | (4) | (5) |
| 4,76[c] | 19 | – | 21 | 60 | 66 |
| 8,25[c] | 36 | – | 40 | 95 | 105 |
| 8,25[d] | 38 | 30 | 42 | | |
| 15[c] | 36 | 30 | 40 | 95 | 105 |
| 15,5[d] | 50 | 45 | 55 | 110 | 121 |
| 25,8[c] | 60 | 50 | 66 | 125 | – |
| | | | | 150 | – |
| 27,0[c] | 60 | 50 | 66 | 125 | – |
| 27,0[c] | 70 | 60 | 77 | 150 | 165 |
| 38[c] | 70 | 60 | – | 150 | – |
| | 80 | 75 | – | 200 | – |
| 38[d] | 95 | 80 | 105 | 200 | 220 |
| 48,3[c] | 105 | 95 | – | 250 | – |
| 48,3[d] | 120 | 100 | 132 | 250 | 275 |
| 72,5[c] | 160 | 140 | – | 350 | – |
| 72,5[d] | 175 | 145 | 193 | 350 | 385 |
| 123[c] | 260 | 230 | – | 550 | – |
| 123[d] | 280 | 230 | 308 | 550 | 605 |
| 145[c] | 310 | 275 | – | 650 | – |
| 145[d] | 335 | 275 | 369 | 650 | 715 |
| 170[c] | 365 | 315 | – | 750 | – |
| 170[d] | 385 | 315 | 424 | 750 | 825 |
| 245[c] | 425 | 350 | – | 900 | – |
| 245[d] | 465 | 385 | 512 | 900 | 990 |

[a]For rated voltages higher than 72,5 kV up to and including 245 kV, the values in Table 12.1 (1a) are also applicable

[b]Isolation of indoor circuits is normally achieved by withdrawing the removable switching device. Refer to relevant equipment standards for testing methods and requirements where this method of isolation is applicable

[c]These ratings are generally applicable to switchgear equipment that is not used for isolation, for example, high-voltage circuit breakers and reclosers. Refer to relevant equipment standards

[d]These ratings are generally applicable to switchgear equipment that is used for circuit isolation, for example, high-voltage switches. Refer to relevant equipment standards

[e]The power-frequency withstand test under wet conditions is only required for outdoor switchgear

**Table 12.3** (2a) Rated insulation levels for rated voltages of range II from IEC 62271-1

| Rated voltage | Rated short-duration power-frequency withstand voltage | | Rated switching impulse withstand voltage | | | Rated lightning impulse withstand voltage | |
|---|---|---|---|---|---|---|---|
| $U_r$ | $U_d$ | | $U_s$ | | | $U_p$ | |
| (kV rms value) | kV (rms value) | | kV (peak value) | | | kV (peak value) | |
| | Phase-to-earth and between phases | Across open switching device and/or isolating distance | Phase-to-earth and across open switching device | Between phases | Across isolating distance | Phase-to-earth and between phases | Across open switching device and/or isolating distance |
| | (Note 2) | (Note 2) | | (Notes 2 and 3) | (Notes 1 and 2) | | (Notes 1 and 2) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
| 300 | 395 | 435 | 750 | 1,125 | 700(+245) | 950 | 950(+170) |
| | | | 850 | 1,275 | | 1,050 | 1 050(+170) |
| 362 | 450 | 520 | 850 | 1,275 | 800(+295) | 1,050 | 1 050(+205) |
| | | | 950 | 1,425 | | 1,175 | 1 175(+205) |
| 420 | 520 | 610 | 950 | 1,425 | 900(+345) | 1,300 | 1 300(+240) |
| | | | 1,050 | 1,575 | | 1,425 | 1 425(+240) |
| 550 | 620 | 800 | 1,050 | 1,680 | 900(+450) | 1,425 | 1 425(+315) |
| | | | 1,175 | 1,760 | | 1,550 | 1 550(+315) |
| 800 | 830 | 1150 | 1,425 | 2,420 | 1 175(+650) | 2,100 | 2 100(+455) |
| | | | 1,550 | 2,480 | | | |

Note 1: In column (6), values in brackets are the peak values of the power-frequency voltage $U_r \times \sqrt{2}/\sqrt{3}$ applied to the opposite terminal (combined voltage)
In column (8), values in brackets are the peak values of the power-frequency voltage 0,7 $U_r \times \sqrt{2}/\sqrt{3}$applied to the opposite terminal (combined voltage)
Note 2: Values of column (2) are applicable: (a) for type tests, phase-to-earth; (b) for routine tests, phase-to-earth, phase-to-phase, and across the open switching device
The values of columns (3), (5), (6), and (8) are applicable for type tests only
Note 3: These values are derived using the multiplying factors given in Table 3 of IEC 60071-1

**Table 12.4** (2b) Additional rated insulation levels for rated voltages of range II, series II (based on current practice in some areas, including North America)[a] from IEC 62271-1

| Rated voltage | Rated short-duration power-frequency withstand voltage | | Rated switching impulse withstand voltage | | Rated lightning impulse withstand voltage | |
|---|---|---|---|---|---|---|
| $U_r$ | $U_d$ | | $U_s$ | | $U_p$ | |
| | kV (rms value) | | kV (peak value) | | kV (peak value) | |
| kV (rms value) | Phase-to-earth and between phases (Note) | Across open switching device and/or isolating distance (Note) | Phase-to-earth switching device closed | Terminal to terminal, switching device open | Phase-to-earth and between phases | Across open switching device and/or isolating distance (Note) |
| (1) | (2) | (3) | (4) | (5) | (6) | (7) |
| 362[a] | 520 | 610 | 950 | 900 | 1,300 | 1,300 |
| 362[b] | 610 | 671 | – | – | 1,300 | 1,430 |
| 550[a] | 710 | 890 | 1,175 | 1,300 | 1,800 | 1,800 |
| 550[b] | 810 | 891 | – | – | 1,800 | 1,980 |
| 800[a] | 960 | 1,056 | 1,425 | 1,500 | 2,050 | 2,050 |
| 800[b] | 940 | 1,034 | – | – | 2,050 | 2,255 |

Note: Values of column (2) are applicable: (a) for type tests, phase-to-earth; (b) for routine tests, phase-to-earth, phase-to-phase, and across the open switching device
Values of columns (3), (5), (6), and (7) are applicable for type tests only
[a]These ratings are generally applicable to switchgear equipment that is not used for isolation, for example, high-voltage circuit breakers and reclosers. Refer to relevant equipment standards
[b]These ratings are generally applicable to switchgear equipment that is used for circuit isolation, for example, high-voltage switches. Refer to relevant equipment standards

The rated withstand voltage values for lightning impulse voltage ($U_p$), switching impulse voltage ($U_s$) (when applicable), and power-frequency voltage ($U_d$) shall be selected without crossing the horizontal marked lines. The rated insulation level is specified by the rated lightning impulse withstand voltage phase-to-earth.

For most of the rated voltages, several rated insulation levels exist to allow for application of different performance criteria or overvoltage patterns. The choice should be made considering the degree of exposure to fast-front and slow-front overvoltages, the type of neutral earthing or grounding of the system, and the type of overvoltage-limiting devices (see IEC 60071-2).

The “common values” used in Table 12.1 (1a) apply to phase-to-earth, between phases and across the open switching device, if not otherwise specified in this standard. The withstand voltage values “across the isolating distance” are valid only for the switching devices where the clearance between open contacts is designed to meet the functional requirements specified for disconnectors (Tables 12.3 and 12.4).

**Table 12.5** (A.1) Correlation between standard lightning impulse withstand voltages and minimum air clearances, IEC 62271-1

| Standard lightning impulse withstand voltage | Minimum clearance | |
|---|---|---|
| | mm | |
| kV | Rod structure | Conductor structure |
| 20 | 60 | |
| 40 | 60 | |
| 60 | 90 | |
| 75 | 120 | |
| 95 | 160 | |
| 125 | 220 | |
| 145 | 270 | |
| 170 | 320 | |
| 250 | 480 | |
| 325 | 630 | |
| 450 | 900 | |
| 550 | 1,100 | |
| 650 | 1,300 | |
| 750 | 1,500 | |
| 850 | 1,700 | 1,600 |
| 950 | 1,900 | 1,700 |
| 1,050 | 2,100 | 1,900 |
| 1,175 | 2,350 | 2,200 |
| 1,300 | 2,600 | 2,400 |
| 1,425 | 2,850 | 2,600 |
| 1,550 | 3,100 | 2,900 |
| 1,675 | 3,350 | 3,100 |
| 1,800 | 3,600 | 3,300 |
| 1,950 | 3,900 | 3,600 |
| 2,100 | 4,200 | 3,900 |

Note: The standard lightning impulse is applicable phase-to-phase and phase-to-earth
For phase-to-earth, the minimum clearance for conductor structure and rod structure is applicable
For phase-to-phase, the minimum clearance tor rod structure is applicable

## Electrical Clearance from IEC 60071-2: 1996

### A.1 Range I

The air clearance phase-to-earth and phase-to-phase is determined from Table 12.5 (A.1) for the rated lightning impulse withstand voltage. The standard short-duration power-frequency withstand voltage can be disregarded when the ratio of the standard lightning impulse to the standard short-duration power-frequency withstand voltage is higher than 1.7.

**Table 12.6** (A.2) Correlation between standard switching impulse withstand voltages and minimum phase-to-earth air clearances, IEC 60071-1

| Standard switching impulse withstand voltage | Minimum phase-to-earth | |
|---|---|---|
| | mm | |
| kV | Conductor structure | Rod structure |
| 750 | 1,600 | 1,900 |
| 850 | 1,800 | 2,400 |
| 950 | 2,200 | 2,900 |
| 1,050 | 2,600 | 3,400 |
| 1,175 | 3,100 | 4,100 |
| 1,300 | 3,600 | 4,800 |
| 1,425 | 4,200 | 5,600 |
| 1,550 | 4,900 | 6,400 |

**Table 12.7** (A.3) Correlation between standard switching impulse withstand voltages and minimum phase-to-phase air clearances, IEC 60071-1

| Standard switching impulse withstand voltage | | | Minimum phase-to-phase clearance mm | |
|---|---|---|---|---|
| Phase-to-earth | Phase-to-phase value | Phase-to-phase | | |
| kV | Phase-to-earth value | kV | Conductor-conductor parallel | Rod conductor |
| 750 | 1,5 | 1,125 | 2,300 | 2,600 |
| 850 | 1,5 | 1,275 | 2,600 | 3,100 |
| 850 | 1,6 | 1,360 | 2,900 | 3,400 |
| 950 | 1,5 | 1,425 | 3,100 | 3,600 |
| 950 | 1,7 | 1,615 | 3,700 | 4,300 |
| 1,050 | 1,5 | 1,575 | 3,600 | 4,200 |
| 1,050 | 1,6 | 1,680 | 3,900 | 4,600 |
| 1,175 | 1,5 | 1,763 | 4,200 | 5,000 |
| 1,300 | 1,7 | 2,210 | 6,100 | 7,400 |
| 1,425 | 1,7 | 2,423 | 7,200 | 9,000 |
| 1,550 | 1,6 | 2,480 | 7,600 | 9,400 |

### A.2 Range II

The phase-to-earth clearance is the higher value of the clearances determined for the rod structure configuration from Table 12.5 (A.1) for the standard lightning impulse and from Table 12.6 (A.2) for the standard switching impulse withstand voltages, respectively.

The phase-to-phase clearance is the higher value of the clearances determined for the rod structure configuration from Table 12.5 (A.1) for the standard lightning impulse and from Table 12.7 (A.3) for the standard switching impulse withstand voltages, respectively.

The values are valid for altitudes which have been taken into account in the determination of the required withstand voltages.

The clearances necessary to withstand the standard lightning impulse withstand voltage for the longitudinal insulation in range II can be obtained by adding 0.7 times the maximum operating voltage phase-to-earth peak to the value of the standard lightning impulse voltage and by dividing the sum by 500 kV/m.

The clearances necessary for the longitudinal standard switching impulse withstand voltage in range II are smaller than the corresponding phase-to-phase value. Such clearances usually exist only in type-tested apparatus, and minimum values are therefore not given in this guide.

**Utility Specified Safety Factors to Be Applied/Additional to "Standard"**

Throughout the world, utilities and manufacturers base their installations and equipment on international standards, e.g., IEEE, IEC, etc. These standards provide ranges and factors that would apply to the vast majority of applications. However, utilities often have their own additional requirements based on experience over many years of operating and maintaining their network. National standards too may be different to the international standards as they are specific to their particular country, e.g., Australian standards (AS), British standards (BS), Japanese standards (JS), Indian standards (IS), etc.

Based on experience and knowledge of their networks, utilities occasionally have additional requirements that push the international requirements to an even higher short-term extended limit. This could be ranges of temperature, voltage, current, ice, wind, earthquake, time duration, etc. Manufacturers need to take these into account in their product design and type-testing regime.

**Insulation Color**

Porcelain insulators have historically been used in the manufacture of HV electrical equipment and are used for supporting the associated busbars and overhead connections. Refer to Sect. 12.7 for further details. Porcelain insulators are generally coated in a smooth protective enamel glaze, either Brown to RAL 8017 or Munsell Grey ANSI 70. The finish color is down to preference, and generally the chosen color is applied consistently throughout the installation.

Polymeric (silicone polymer) insulator housings are directly vulcanized to the inner cores during compression molding with the polymer being the final visible color, which can be blue, brown, or gray.

**Environmental Considerations**

Any substation may be subjected to various environmental pollutants during the lifetime of the installation (Fig. 12.1):

- If located close to the sea, salt-laden air and rain can deposit salt on the insulation surface providing an ideal path for an electrical flashover.
- The same effect can be seen close by a road salted for the winter when spray from vehicles deposits salt on the insulators in the same way.

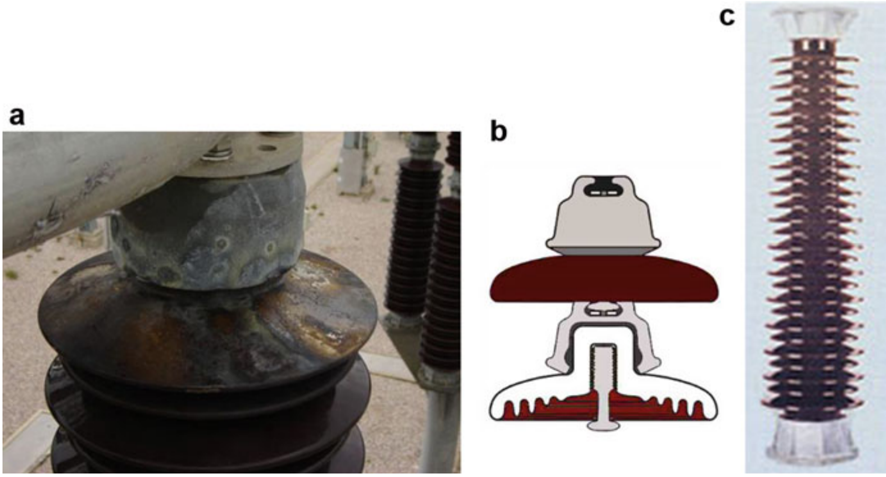



**Fig. 12.1** (**a**) Insulator showing signs of arcing. (**b**) Cutaway showing underside surface length extended. (**c**) Alternating long and short (ALS) shed shape

- If located in the vicinity of a polluting industrial unit, various products can be deposited onto the insulator surface.
- Moisture from fog can also cause flashover conditions.

**Methods of Dealing with Environmental Pollution**

In existing installations in a polluting environment, washing of insulators with deionized water will clear the deposits off the surface. This process will have to be repeated as required following regular monitoring of the contamination buildup. Washing can be carried out live using fixed spray equipment or by the use of mobile equipment.

**Building New Installations in Known Environments**

Choosing the correct shed shape is important. Providing a longer creepage or surface length will reduce the possibility of flashover. In the cutaway example above, the underside of the insulator has a much longer path than the smooth upper surface. The upper face will allow rainwater to wash the insulator, while in foggy conditions, the tracking length will prevent flashovers.

If the sheds are too close together, then dripping water can drop from one shed onto the next making the path much shorter. By using alternative long and short (ALS) sheds, then the water has much more of a gap to travel, thus breaking up the path length.

A creepage distance appropriate for the environmental conditions at the location should be chosen. Refer to Table 12.8 which provides a specific creepage distance (SCD) as used in the 1986 edition of IEC 60815 which was based on the system voltage. For a.c. systems, this is the phase-to-phase voltage. The unified specific creepage distance (USCD) refers to the voltage across the insulator, i.e., for a.c.

**Table 12.8** IEC 60815-1 (2008) [18], Table J.1: Correspondence between specific creepage distance (SCD) and unified specific creepage distance (USCD)

| Pollution level as IEC 60815:1986 | Specific creepage distance (SCD) for three-phase a.c. systems (mm/kV) | Unified specific creepage distance (USCD) (mm/kV) |
|---|---|---|
| – | 12.7 | 22.0 |
| I Light | 16 | 27.8 |
| II Medium | 20 | 34.7 |
| III Heavy | 25 | 43.3 |
| IV Very heavy | 31 | 53.7 |

**Table 12.9** Examples of how Table 12.8 is to be used

| | | | Insulator |
|---|---|---|---|
| Rated system voltage (kV) – $U_m$ | Previous pollution level | USCD (mm/kV) | Creepage distance (USCD x $U_m/\sqrt{3}$) |
| 420 | III (Heavy) | 43.3 | 10,500 mm (420 in.) |
| 225 | IV (Very heavy) | 53.7 | 6,975 mm (275 in.) |

systems the phase-to-earth voltage. Both SCD and USCD are specified as a minimum value, and the table gives the correspondence between commonly used values of SCD and USCD (Table 12.9).

For other extreme or severe environmental considerations, snow, ice thickness, wind, flooding, rain, cold, heat, etc., refer to CIGRE TB 614.

**Metallic Coatings and Paint Systems**

Utilities specify that the equipment for substations should have a minimum life of 25 years. Some utilities specify 40 years as experience has shown that with considered maintenance, usage within specification temperature limits and midlife refurbishment 50+ years are absolutely possible.

Unpainted metallic parts should be aluminum or galvanized steel. Fixings are particularly prone to rusting and galvanized steel or stainless steel should be used. Marine grade fixings may be required in coastal regions. Bimetallic connections should be considered when connecting mechanisms to structures, etc. Painted surfaces should have the paint removed in the location of the fixing to ensure a good connection. Any missing paint should be repainted after pretreatment to ensure all exposed steel surfaces are covered.

Inside surfaces of outdoor boxes and cabinets should be coated with anti-condensation paint. Appropriate measures to prevent water ingress into the low-voltage equipment are also required combined with appropriate ventilation.

**Earthquake Ground Acceleration**

Some regions of the world are affected by earthquakes. The equipment must be designed to withstand the ground accelerating very quickly, typically 0.2–0.5 g. Manufacturers carry out type tests on shaker tables to ensure that the equipment functions correctly under these specified conditions.

**Table 12.10** Normal air pressure related to altitudes above and below sea level

| Altitude m | | Air pressure kPa |
|---|---|---|
| 15,000 | | 12,0 |
| 10,000 | | 26,6 |
| 8,000 | | 35,6 |
| 6,000 | | 47,2 |
| 5,000 | | 54,0 |
| 4,000 | | 61,6 |
| 3,000 | | 70,1 |
| 2,000 | | 79,5 |
| 1,000 | | 89,9 |
| 0 | Sea level | 101,3 |
| −400 | | 106,2 |

**Altitude >1,000 m Above Sea Level**

International and national standards and the associated equipment are based on atmospheric pressure from sea level up to 1,000 m. Above 1,000 m, the atmospheric pressure reduces as altitude increases. For installations situated at an altitude higher than 1,000 m above sea level, the insulation level of external insulation under the standardized reference atmospheric conditions shall be determined by multiplying the insulation withstand voltages required at the service location by an altitude correction factor $K_a$ in accordance with IEC 60071-2:

$$K_a = e^{m\left(\frac{H}{8150}\right)}$$

where H is the altitude above sea level in meters and m is a factor equal to 1 or less which is derived from a graph in the IEC standard which relates m to the insulation coordination withstand voltage.

The correction factor $K_a$ is based on the dependence of the atmospheric pressure on the altitude as given in IEC 60721-2-3; see Table 12.10.

## 12.2 Circuit Breakers

**Purpose of Circuit Breakers**

Circuit breakers (CBs) are the key equipment in air-insulated (AIS) and gas-insulated (GIS) switchgear. High-voltage circuit breakers are mechanical switching devices which connect and break current circuits (operating currents and fault currents) and carry the nominal current in the closed position. These devices have no intelligence of their own; the detection of faults is done by the protection devices connected onto the HV system through instrument transformers. Protection devices, on detecting abnormal conditions, command the circuit breakers to open

**Fig. 12.2** Live tank circuit breakers

sending tripping signals to the circuit breakers mechanism trip coils. During maintenance periods, the circuit breakers must be opened to allow disconnectors to be opened in order to isolate sections of the substation. This operation can be done remotely or locally at the circuit breakers own local control cubicle (Fig. 12.2).

**Type of Circuit to Be Interrupted**

There are several types of circuit in which circuit breakers are connected, and the duty imposed on the circuit breakers varies depending on the type of circuit being controlled, e.g., overhead line circuit (OHL), power cable, power transformer, capacitor bank, series or shunt reactor (inductive/reactive), etc. When the current and voltage lag or lead each other, then the duty on the interrupter becomes more arduous. Interrupting at a current zero when the voltage is at a voltage zero is the best scenario. Interrupting at peak voltage or peak current is more difficult, and special tests, above and beyond the standard set of international tests, are performed to check if the interrupters are capable of this more difficult duty.

**Duty Required**

Depending on the duty, the circuit breakers may operate frequently, e.g., several times per day. For example, around the city of London, the HV network consists of mostly underground cables as overhead lines would not be visually acceptable. During the daytime working hours, the cables are heavily loaded, but at night time, they are lightly loaded. The capacitance of the cable becomes an issue during hours of light load, and therefore, reactance needs to be connected to compensate for the capacitance and to control the increased voltage. During heavy load, the opposite is true requiring capacitance to be added to compensate for the reactance, etc. This then requires not only the

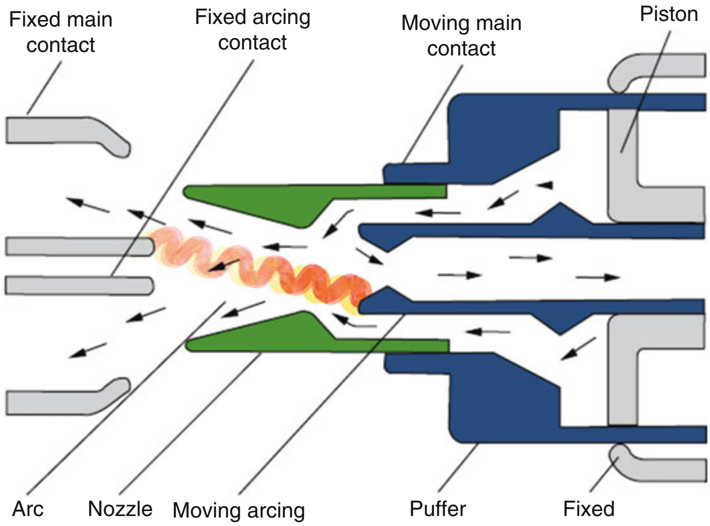



**Fig. 12.3** Interrupter principle

circuits to be switched but additional reactors and capacitors to be switched several times each day. However, circuit breakers in other parts of the network, not subject to load swings, free from lightning strikes, etc., may operate very rarely. To ensure they are available and ready to operate should they be commanded to do so, a regular "manual" trip test should be arranged to ensure everything is satisfactory (Fig. 12.3).

**Circuit Breakers Types**

Each circuit breakers has one or more interrupters today, normally surrounded by $SF_6$ insulating gas, which are the devices which break the HV normal and fault current. The interrupters consist of two parts, a fixed part and a moving part. When the interrupter is closed, then these two parts are connected together. The part which moves traps the $SF_6$ gas which on separation of the two parts is propelled through the created gap forcing the arc to be extinguished. The interrupters are physically linked to an operating mechanism, described later in this section.

There are several types of circuit breakers:

- Live tank
- Dead tank with integral instrument transformers
- Hybrid or mixed-technology switchgear
- GIS

Live tank or dead tank can be arranged as single-phase units or combined three-phase with a single mechanism (Fig. 12.4).

Live tank is where the interrupter chamber is located in, and separated from ground by, a porcelain or polymeric insulator.

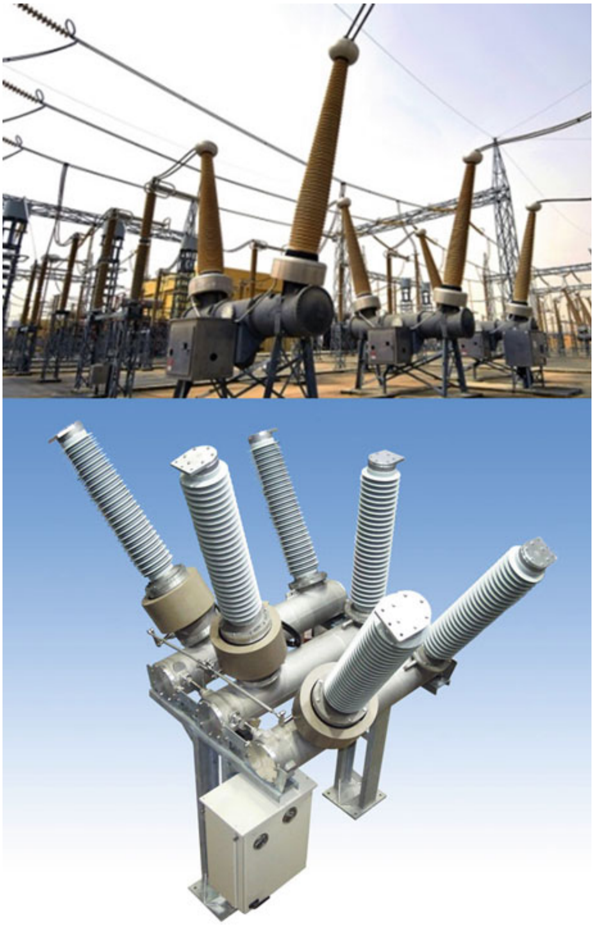


**Fig. 12.4** (Top) Dead tank and (below) hybrid or mixed-technology switchgear

Dead tank circuit breakers have their interrupting chambers located inside an earthed metallic enclosure part. These circuit breakers types are designed to also carry current transformers making them ideal replacements for older bulk oil-type circuit breakers.

Hybrid circuit breakers (also known as mixed-technology switchgear or MTS) are a combination of dead-tank circuit breakers but with additional disconnectors and earthing or grounding switches. These can also have nonconventional instrument transformers fitted if required. These are very compact units saving on foundations, structures, and installation time.

If only one interrupter is required for the switching duty, current, and voltage, then the maximum withstand voltage is applied across the single interrupter. Should a single interrupter be insufficient, then additional interrupters can be added in series. To ensure the voltage is shared across all of the interrupters evenly, grading capacitors can be fitted across each interrupter.

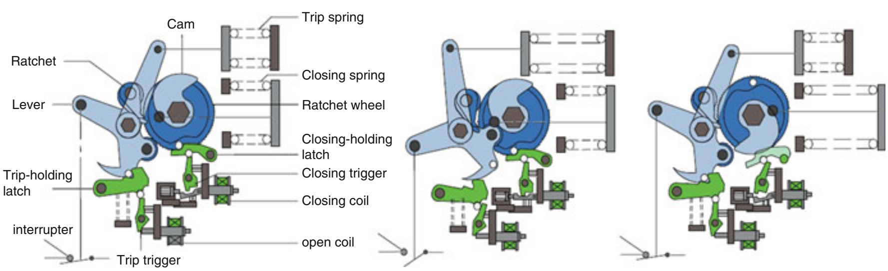



**Fig. 12.5** Spring mechanism – ready to open, close, and open

### Type of Mechanism

A number of different types of mechanism are available. The most common today is the spring type where the opening and closing strokes of the circuit breakers are performed by releasing charged springs. These types of mechanism, if auxiliary power is lost, are able to trip, close, and trip again should the need arise. Should a further close and trip cycle be required, then a hydraulic or pneumatic mechanism that has more stored energy will be required (Fig. 12.5).

### Switching

When the circuit breakers opens, the resultant effect depends upon whether the network is highly interconnected or not. When a fault occurs on the network, an arc from the energized circuit flashes to ground or to another of the energized phases. On detection of the fault, the circuit breakers is commanded to open. If the fault is transient, e.g., a lightning strike, then reclosing of the circuit would result in the circuit being permanently reinstated. Should the fault be permanent, e.g., a fallen tree across the circuit, then this reclosing would be followed by another trip of the circuit breakers.

OHL circuits are equipped with auto-reclose circuitry so that the HV circuit can be reinstated very quickly following a tripping incident. If the circuit breakers is three-phase gang operated, then all three-phase interrupters would open followed by a simultaneous close of all three phases. Should single-phase operated equipment be used, then only the faulted phase could be opened and then reclosed. As mentioned above, depending on the network configuration, opening and closing circuit breakers several times could cause the generators to become unstable. Delayed auto-reclose can be used to prevent this instability from occurring.

Switching on networks gives rise to other phenomena where the following standard solutions can be applied: Point On Wave (POW) switching devices operating on a specific point on either the voltage or current waveforms can be used to reduce the switching transients occurring on either closing or opening of certain types of circuit. An example is that when closing a capacitor circuit, the POW device ensures the circuit breakers interrupters operate on a voltage zero rather than on any other part of the waveform which reduces transient overvoltages and ensures longer service and less maintenance requirements. POW devices can be used based on current waveforms to reduce the risk of current chopping when switching shunt reactor circuits, and they can also be used to minimize the inrush current when energizing large power transformers.

Utility networks can have high overvoltages due to a sudden change in state. It has been common practice for many years to equip certain circuit breakers with closing resistors, as a means of controlling such system transient interactions during closing or reclosing operations. The closing resistors are inserted, for a short period of time, in series with the load circuit being switched, before closing the main contacts of the breaker thereby damping the transient overvoltages.

**Operation in Sub-zero Temperatures**

$SF_6$ gas-filled circuit breakers are designed for operation when the $SF_6$ is in a gaseous state. The gas provides the required insulation between the live internal components and the earthed enclosure. The gas also acts as the arc-quenching medium. At very low temperatures, the gas starts to turn into a liquid as $SF_6$ has a relatively high liquefaction temperature (−33 °C at 400 kPa).

To overcome this issue, a gas mixture can be provided. Early designs used $SF_6/N_2$, but the introduction of $N_2$ significantly reduced the arc interruption property of the gas and this required the equipment rating to be reduced. In recent years, a 50/50% mixture of $SF_6/CF_4$ (carbon tetrafluoride) has been found to have excellent arc-quenching properties and a much lower liquefaction temperature.

## 12.3 Disconnectors, Earthing or Grounding Switches, and Earthing or Grounding Poles

**Purpose of Disconnectors and Earthing or Grounding Switches**

Disconnectors consist of four main components: HV current-carrying parts (blade, jaws, contacts, etc.), fixed or rotating porcelain support insulators, metallic base frame, and operating mechanism(s). Disconnectors, known in the past as isolators, perform several key functions (Fig. 12.6).

When in the open position, they provide a visible gap in the high-voltage circuit. This is a visible isolating point and is necessary if the remaining part of the installation is going to remain energized at high voltage, while maintenance is to be undertaken. The insulating air gap, created by the open disconnector, is sufficient to meet international standards for insulation clearances. This functionality is proved by type test. When the disconnector is in the open position and the mechanism is physically locked preventing closure, then this becomes a reference point of isolation, part of the process of creating a safety zone.

(a) Disconnectors when closed act as a normal section of the high-voltage circuit or busbar. They are designed to carry rated current continuously within the specified temperature limits. They are also able to carry short-circuit current for a specified short duration, i.e., 1 or 3 s, all without detrimental effect on the future operation of the disconnector.

**Fig. 12.6** Typical disconnector

(b) Disconnectors can be used to change circuit arrangements, e.g., in a double-busbar configuration to change a feeder circuit initially connected on the main busbar to the reserve busbar. This operation must provide a parallel path controlled by a circuit breakers so that the disconnector is not required to interrupt the full-load current.
(c) Once disconnectors have been opened to disconnect all high-voltage infeeds to a specific point, e.g., a device to be maintained, then one or more earthing or grounding switches should be applied to the isolated section. These devices have no normal load duty as they are designed to carry short-circuit current only.
(d) Disconnectors are not designed to interrupt normal or short-circuit currents. This function is clearly the responsibility of the circuit breakers. However, they can be made to switch, make, and/or break small charging currents associated with short lengths of high-voltage busbar or circuit and can also have special additional contacts or interrupters fitted designed to make and/or break small inductive currents associated with transformers and reactors or capacitive currents associated with capacitor banks, long power cables and long overhead lines. Features such as sacrificial contacts and spring-loaded whip contact fingers are just a couple of examples that could be fitted.

There are many types of circuits or conditions to be earthed or discharged with earthing or grounding switches, e.g., OHL, cable, transformer, capacitive, inductive/reactive line charging, ferroresonance, and induced current switching capacitive and inductive. Earthing or grounding switches are used generally to ensure that a positive earth is applied to the high-voltage circuit prior to maintenance being carried out on the high-voltage equipment in the disconnected, isolated, and earthed zone. By applying the earthing or grounding switch, the isolated circuit will now be safe for maintenance staff to undertake their work:

(a) Earthing or grounding switches can also be designed and used to discharge the high-voltage busbar or circuit. Once the circuit is disconnected, a charge may still be present. Often with long, double-circuit OHL circuits, the disconnected line is coupled through the air to the parallel energized OHL circuit. At the substation, an earthing switch specially designed for induced current switching should be applied which will discharge the trapped charge and apply the earth simultaneously at the same time as making the associated capacitive current. The second earthing switch to be applied, if designed to be suitable for induced-current switching, will be capable of making and breaking the induced inductive current from the other circuit(s) on the same towers.

**Mounting Arrangement**

(a) Most disconnectors and earthing or grounding switches are mounted above the ground on tubular or lattice steel structures. The structure not only provides the support for the high-voltage part but also conveniently for the operating mechanism which generally is located at a level convenient for the operation and maintenance staff.
(b) Earthing or grounding switches may be free-standing or attached to a disconnector depending on the type of disconnector being used. If double-busbar disconnectors are being used, it can be convenient to fit additional earthing or grounding switches on one or both sides of the HV disconnecting gap.
(c) Both the disconnectors and/or earthing or grounding switches can also be mounted in a variety of positions and locations. They can be underhung from roofs and gantries or vertically mounted off walls and other support structures.

**Mechanisms**

Disconnectors and earthing or grounding switches can have any combination of mechanisms:

- Motor-operated with AC or DC motors in addition to manual operation for maintenance.
- Single-phase operation, i.e., one individual mechanism per phase.
- Three-phase or ganged operation, one mechanism per three-phase assembly with interconnecting rods between all phases.
- Manual operation only with crank handle or lift-up handle.
- Motor mechanisms may have local and remote selection for them to be operated locally (electrically) during maintenance and by the control room at the site or elsewhere.

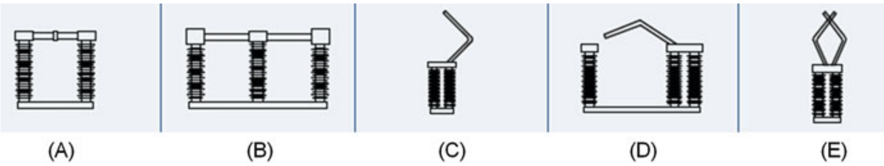



**Fig. 12.7** (**a**) Rotating end post or center break. (**b**) Center rotating post or double end break. (**c**) Vertical or semi-pantograph. (**d**) Horizontal semi-pantograph. (**e**) Full pantograph

**Fig. 12.8** Disconnector blade in closed position coated in heavy ice

**Types of Disconnector**

OHL and transformer circuits are generally located at 90° to the main busbar runs with the HV circuits passing either under or over the main busbars. Disconnectors (C) and (E) are specifically designed to connect onto the circuit passing above the disconnector creating a vertical isolation gap, whereas the other types create a horizontal isolation gap and require additional connections to make a connection between different levels (Fig. 12.7).

All disconnectors are designed to work in specified temperature ranges and seismic conditions and have the ability to open and close in heavy ice conditions (Fig. 12.8).

## 12.4 Surge Arresters (or Lightning Arresters)

Surge arresters are protective devices that limit overvoltages on a power system to protect important electrical equipment by bypassing surge current. They constitute an indispensable aid to the insulation coordination in substations and transmission lines. Their protective level may be selected to limit lightning overvoltages, or it may also conduct during switching surges. During normal, continuous operation, arresters should have virtually no effect on the power system. Surge arresters are used in different fields like AC and DC substations, transmission lines, railways, etc.

with different requirements. For substation applications, metal-oxide (MO, in particular Zinc Oxide (ZnO)) surge arresters without gaps have been state of the art since the late 1980s. New substations will usually be planned with MO arresters. However, large populations of gapped silicon-carbide (SiC) arresters, which represented the standard technology before gapless MO arresters were introduced, are still in service. For transmission lines, non-gapped line arresters (NGLA) and externally-gapped line arresters (EGLA) are used, where in either case the overvoltage-limiting components are MO resistors as in substation arresters.

The number of manufacturers of MO resistors and arresters has increased, as well as the application of MO arresters. Nowadays, MO arresters are installed in a.c. and d.c. power systems with very different voltage levels, from 660 V d.c. in traction systems up to 800 kV d.c. in HVDC systems and up to 1100 kV (China) and 1200 kV (India) a.c. in UHV systems, and they are used in air-insulated substations (AIS) and gas-insulated substations (GIS), in cable systems, as line arresters, etc., to give only some examples.

The continuous development and the field experience with the MO arresters have made it necessary to permanently review the actual state of the technology as well as the validity of the existing standards for testing MO resistors and arresters. An example is, for instance, the classification of MO arresters in line discharge classes. The line discharge classes for MO arresters are based on the energy (trapped charges) that may typically be stored in transmission lines of different system voltages. This classification works well as long as only three-phase transmission systems up to 550 kV system voltage are being considered. Various new applications in all electrical power systems, including UHV, FACTS, and HVDC, traction systems, distribution systems, etc. made it necessary to reconsider the classification according to line discharge classes. A critical review of the existing international standards was performed with emphasis on the energy-handling capability of MO resistors.

The new classification concept, charge transfer classes, and thermal energy ratings instead of line discharge classes were introduced in IEC 60099-4 Ed. 3.0 (2014-06) "Surge arresters – Part 4: Metal-oxide surge arresters without gaps for a.c. systems." Related IEC 60099-5 Ed. 2.0 (2013-05) "Surge arresters – Part 5: Selection and application recommendations" has been revised considering the changes in part 4 Ed. 3.0 and published in early 2018. Furthermore, the very first international standard on HVDC arresters was published in 2014 (IEC 60099-9, Ed. 1.0: "Surge arresters – Part 9: Metal-oxide surge arresters without gaps for HVDC converter stations").

MO surge arresters make use of nonlinear metal-oxide resistors connected in series and/or in parallel without any integrated series or parallel spark gaps. The term "surge arrester" is used in the HV and MV community and describes different designs of MO arresters. In the LV field, it is common to speak in general about "Surge Protective Devices (SPDs)," which covers different technologies and design types, e.g., spark gaps, metal-oxide varistors, and combinations of them including disconnecting devices, etc. In HV series capacitors, which are FACTS components, complete banks of HV surge arresters, containing hundreds or even thousands of MO resistors to protect the capacitors from overvoltages during line faults, are just named a "varistor."

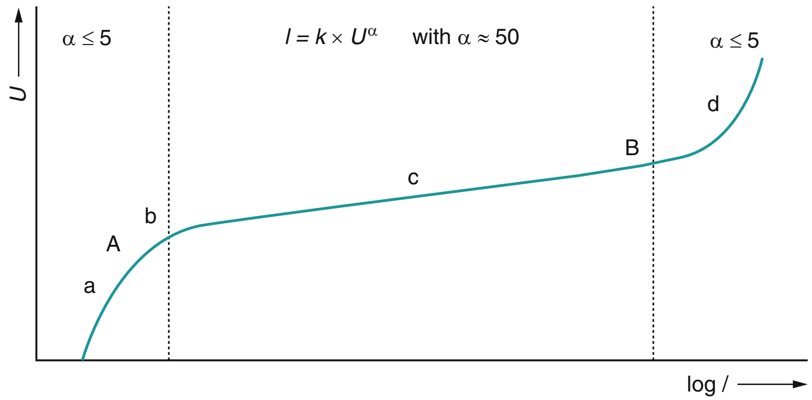



**Fig. 12.9** Voltage-current characteristic of a MO surge arrester. (*a*) Lower part (pre-breakdown region, mainly capacitive), (*b*) knee point, (*c*) strongly nonlinear part (breakdown region), (*d*) upper part ("turnup" area). (*A*) Operating point (below continuous operating voltage $U_c$), (*B*) protective level Up (at discharge current)

**Function**

The function of surge arresters with an active part consisting of a series connection of MO resistors is basically very simple. In the event of a voltage increase at the arrester's terminals, the current rises according to the characteristic curve, see Fig. 12.9, continually and virtually without delay, which means that there is no actual spark over but that the arrester reacts to the conducting condition. In case of an impressed current as is the case during a lightning strike to an overhead line, moderate residual voltages of only a few (1.6–3.6) per units (p.u.) of the system voltage will develop. After the surge subsides, the current becomes smaller according to the characteristic curve. A subsequent current, such as those that arise with spark gaps and spark-gapped arresters, does not exist; only the so-called almost pure capacitive leakage current $I_c$ of about 1 mA flows.

At the knee point b (Fig. 12.9), approximately corresponding to the arrester's rated voltage, $U_r$, and its reference voltage, $U_{ref}$, the arrester starts to conduct, and the resistive component of the current increases rapidly with a slight voltage increase. At $U_{ref}$ the current has a dominantly resistive component. Temporary overvoltages have to be considered in the voltage region between points b and c. In the low current region A up to point b power-frequency currents and voltages have to be considered (range of continuous operation). In the region above B, the protective characteristic of the MO arrester is of importance.

In Fig. 12.10, a more technical diagram is given, indicating the standardized definitions. It can be seen that differences do exist between a.c. and d.c. continuous operations as well as between different slopes of impulse currents in the protection level region. All this has to be considered in detail, e.g., in the insulation coordination process.

Surge arresters as a protection device have to be installed as close as possible to the object to be protected. So-called protective distances ("separation distances" in

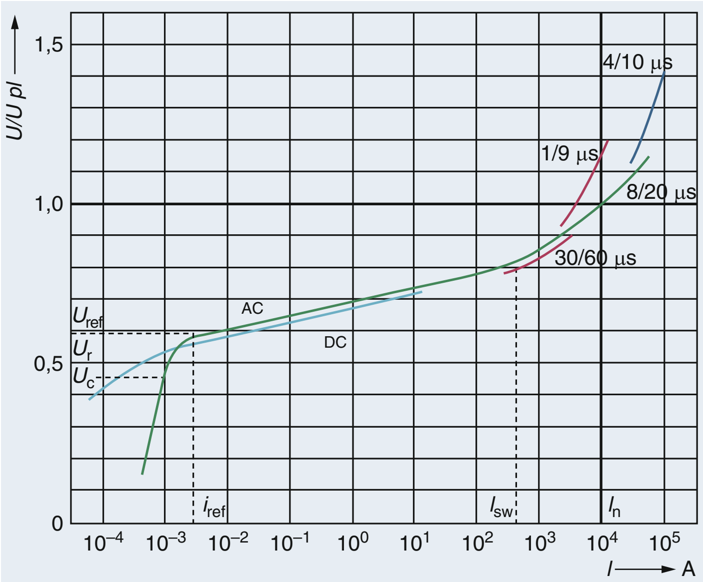



**Fig. 12.10** Voltage-current characteristic of a MO arrester with $I_n = 10$ kA, line discharge class 2. The voltage is normalized to the residual voltage of the arrester at $I_n$. The values are given as peak values for the voltage (linear scale) and the current (logarithmic scale). Shown are typical values

the IEEE standards) are quite small ranging from approximately less than 1 m in railway applications up to 50 m in EHV and UHV systems.

The development of MO resistors and arresters is ongoing with the goal of size and cost reduction but at the same time keeping the high quality and reliability. This leads to the development and use of MO resistors with increased field strength to reduce the size of the complete design, e.g., in GIS applications.

**Stresses on Surge Arresters**

As a protective device, the surge arrester has to withstand different electrical, thermal, and mechanical stresses. Electrical stresses on MO arresters can be divided into stresses at power frequency, which can have longtime durations, and transient stresses of short-time duration resulting from switching and lightning.

The different overvoltage stress types seen by MO arresters are:

**Temporary Overvoltages**

A temporary overvoltage (TOV) is an oscillatory phase-to-ground or phase-to-phase condition that is of relatively long duration and is undamped or only weakly damped. TOVs are one of the most crucial stresses on a MO arrester and are detrimental to the arrester. Temporary overvoltages cannot be limited by surge arresters. Quite to the contrary, the arresters have to be dimensioned to withstand this stress, under which high power-frequency currents may develop that impose high-energy stress to the arresters.

The following origins of TOV are typically considered:

- Earth fault temporary overvoltages occur in a large part dependent on the effectiveness of system earthing or grounding. Guidance for the determination of TOV amplitudes is given in IEC 60099-5 and IEC 60071-2.
  Within earthed neutral systems, the duration is generally less than 1 s. For resonant earthed neutral systems, with fault clearing, it is generally less than 10 s, and for systems without earth fault clearing, the duration may be several hours.
- Disconnection of a load will cause the voltage to rise at the source side of the operating circuit breakers. The amplitude of the overvoltage depends on the disconnected load and the short-circuit strength of the feeding substation. The amplitude of load rejection overvoltages is usually not constant during their duration. Accurate calculations have to consider many parameters.
- Voltage rise along long unloaded lines (Ferranti effect).
- Resonances, in particular ferroresonances.
- Overvoltages due to flashover between two systems of different system voltages installed on the same tower.

**Slow-Front Overvoltages**

Slow-front overvoltages, in most cases generated by switching or faults, are associated with load switching or fault clearing. Different switching cases have to be considered: line re-energization and switching of capacitive loads and inductive loads.

Random high-speed reclosing on transmission lines with trapped charges generates traveling waves on the phase conductors which may cause insulator flashover (s) to the tower(s) along the line if not controlled. Especially critical is the case at the remote end without terminal equipment (such as shunt reactors, transformers, or surge arresters) which may cause a doubling of the incident surge.

Capacitor bank energization can generate both voltage and current transients. Also, switches used for capacitive switching have been improved to reduce restrikes ,but these have not been totally eliminated. Therefore, some methods of reducing the severity of transients are often incorporated such as current-limiting resistors or reactors, point-on-wave switching, and surge arresters to minimize restrike possibilities and to also provide overvoltage protection.

Switching small inductive load currents is considered a challenge for circuit breakers designed for interrupting large fault currents. Very fast reignition and/or restrike transients can also damage “inductive” equipment like shunt reactors and transformers due to uneven winding voltage distribution.

**Fast-Front Overvoltages**

Fast-front overvoltages are in many cases caused by thunderstorms and occur all over the world. The heaviest thunderstorms with the most intensive lightning will normally be experienced in the equatorial region. Other sources are, for instance, current chopping of circuit breakers or back flashovers.

High-voltage (HV) systems in the range of 52 kV < $U_s$ ≤ 245 kV can be found in transmission and sub-transmission rural areas. Direct strokes, back flashovers, and induced overvoltages will statistically result in a higher stress for the installed arresters than in other voltage systems.

Transmission lines in extra-high-voltage (EHV) with 245 kV < $U_s$ ≤ 800 kV and ultra-high-voltage (UHV) systems above 800 kV have steel towers with shield wires and are well protected against direct lightning strokes to the phase wires in spite of their height above ground. Most of the lightning will hit the towers or the shield wires, and only shielding failures and back flashovers will cause a critical surge in the phase wire.

In general, in 90% of all cases, the lightning flashes are negative flashes from cloud to ground. However, some countries, such as Norway or Japan, often experience thunderstorms during winter. Typical weather conditions that create the winter thunderstorms are strong winds from the west, which transport warm air from the ocean to the mountains of the mainland. The typical positive lightning flashes of winter thunderstorms transfer higher charge than negative lightning flashes, which are typical for summer thunderstorms.

**Energy-Handling Capability of MO Resistors**

The energy-handling capability is a key property of MO arresters and has many different aspects, which are only partly or not at all reflected in the actual standards. Although this list may not be complete, they can be divided into:

- "Impulse" energy-handling capability
- "Thermal" energy-handling capability for the "impulse" energy-handling capability in response to single impulse stress, multiple impulse stress (without sufficient cooling between the impulses), and repeated impulse stress (with sufficient cooling between the stresses)

Thermal energy-handling capability, on the other hand, can only be considered for complete arresters, as it is mainly affected by the heat dissipation capability of the overall arrester design, in addition to the electrical properties of the MO resistors.

**Ambient Stresses**

MO arresters have to withstand the same stresses as do other HV devices in substations such as stresses arising from the environment and geographical location (pollution, altitude, wind, temperature, ice, and earthquake) and also from the installation situation inside of the substation (bending and short-circuit forces at HV terminals).

Ambient stresses can be divided into static and dynamic stresses and the severe case of seismic stresses, which is especially important for larger equipment with mechanically sensitive internal design like UHV arresters or $SF_6$ gas-insulated (GIS) arresters. Additionally, long-term stresses such as pollution and humidity, as well as very low temperatures and temperature cycles, must also be considered, particularly in the case of polymeric insulation.

**Parameters and Design**

The following subsections describe the relevant parameters which are necessary for the design and dimensioning of surge arresters.

**Voltages and Currents**

*Continuous operating voltage $U_c$*: Designated permissible RMS value of power-frequency voltage that may be applied continuously between the arrester terminals.

*Continuous current $I_c$*: Current flowing through the arrester when energized at the continuous operating voltage. The MO arrester behaves in an almost purely capacitive manner in the region of the continuous operating voltage. The current is around 1 mA, depending on the installation conditions, and almost 90° electrically shifted compared to the voltage. The resistive component in the overall current is in the range of 10–100 μA only. The power losses in this region can be neglected. The continuous current is also known as leakage current.

*Rated voltage $U_r$*: Maximum permissible RMS value of power-frequency voltage between the arrester terminals at which it is designed to operate correctly under temporary overvoltage conditions as established in the operating duty tests.

Briefly, the rated voltage $U_r$ is the voltage value, which is applied for $t = 10$ s in the operating duty test in order to simulate a temporary overvoltage in the system. The factor between the rated voltage $U_r$ and the continuous operating voltage $U_c$ is generally, with only few exceptions, taken as $U_r/U_c = 1.25$. This is understood as a given fact, but it is not defined anywhere. Other ratios of $U_r/U_c$ can be chosen by the manufacturer if all type tests can be passed under this condition. The rated voltage has no other importance although it is typically used when choosing an arrester. It represents, however, the arrester's capability to withstand TOV stress. If this value is not known and the arrester is only chosen by its $U_c$, resistance against TOV might not be achieved.

*Reference voltage $U_{ref}$*: Peak value of the power-frequency voltage divided by $\sqrt{2}$, which is applied to the arrester to obtain the reference current. This voltage is typically used by the manufacturer in the routine test in order to indirectly check the arrester's protection level.

*Reference current $I_{ref}$*: Peak value (the higher peak value of the two polarities if the current is asymmetrical) of the resistive component of a power-frequency current used to determine the reference voltage of an arrester. The reference current is chosen by the manufacturer in such a way that it lies above the knee point of the voltage-current characteristic and has a dominant ohmic component. Therefore, the influences of the stray capacitance of the arrester at the measurement of the reference voltage are not to be taken into account. The reference voltages, which are measured at single MO resistors, can be added to give the reference voltage of the entire arrester.

*Line discharge class – old; not in use any more for new arresters*: The line discharge class was the only possible way to specify the energy absorption capability of an arrester provided in IEC 60099-4 up to Edition 2.2. The line discharge classes 1–5 were defined with growing demands.

*Repetitive charge transfer rating $Q_{rs}$*: the maximum specified charge transfer capability of an arrester, in the form of a single event or group of surges that may be transferred through an arrester without causing mechanical failure or unacceptable electrical degradation to the MO resistors; it is calculated as the absolute value of current integrated over time; it may be accumulated in a single event or group of surges lasting for not more than 2 s and which may be followed by a subsequent event at a time interval not shorter than 60 s.

*The thermal energy rating* $W_{th}$: the maximum specified energy, given in kJ/kV of $U_r$ that may be injected into a substation arrester or arrester section within 3 minutes in a thermal recovery test without causing a thermal runaway.

*Thermal charge transfer rating* $Q_{th}$: the maximum specified charge (coulombs) that may be transferred through a distribution arrester or arrester section within 3 minutes in a thermal recovery test without causing a thermal runaway.

**Design of Surge Arresters**

For the design of surge arresters, the required MO resistor stacks have to be determined and also the housing where they are installed.

**MO Resistors**

Steady progress has been made over the last decades in MO resistor technology, their application in overvoltage surge protection devices, and the understanding of the basic mechanisms of nonlinear conduction, energy-handling capability, etc. Many new insights have been gained, new physical phenomena have been observed, improved and more consistent models have been developed, and much progress has been made in simulations related to materials and components.

The nonlinear conduction mechanism of the material can be traced back to individual grain boundaries in the ceramics, which show a typical value of the switching or breakdown voltage $U_B$ of approximately 3.2–3.4 V each. Combining many grain boundaries in series and in parallel within a MO element allows scaling of the voltage and current characteristic of a MO resistor. For a sufficiently large number of grain boundaries, the field strength E and current density J then describe the material characteristic more generally.

**Design of MO Arrester Housing**

Different basic design principles are used for high-voltage arresters and medium-voltage arresters. In the high-voltage field, mechanical requirements are much higher than in normal distribution applications. For this reason, porcelain housings are still used besides the growing number of composite hollow core insulators, so-called tube designs and directly molded designs. For distribution arresters in medium-voltage systems, porcelain housings have rapidly disappeared, and the directly molded design is used almost exclusively today (Fig. 12.11).

The stack of MO resistor elements is mechanically supported by an internal cage structure, for example, made from FRP (fiberglass-reinforced plastic) rods. This insert is clamped between the end flanges with the help of compression springs. Additional supporting elements (not shown in the figure) may be necessary to fix the insert in the radial direction. What is important is the fact that this arrester, due to its enclosed gas volume, needs a sealing and pressure relief system.

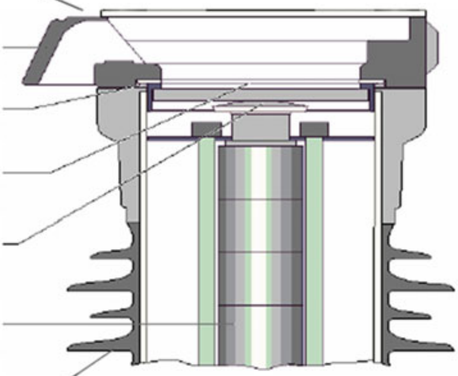



**Fig. 12.11** Polymer-housed arrester

**Grading and Corona Ring**

Depending on the voltage level, surge arresters can consist of either one single unit or alternatively several units. Typically, one unit is used for $U_C$ <150 kV, as long as creepage distance requirements are not higher than average. At all higher voltage levels, the arrester must consist of several units, for example, in a 420 kV system, it would have at least two parts. At the higher voltage levels or when there are extreme creepage distance requirements, it can also be made of more. In principle, there is no upper limit, as long as the arrester still proves to have sufficient mechanical properties. Starting from a certain length and usually for arresters made of several units, grading rings are absolutely essential. These serve to control the voltage distribution from the high-voltage end to the earth end, which is unfavorably influenced by the earth capacitances affecting the arrester. Without the appropriate countermeasures, the MO resistors at the high-voltage end of the arrester would be stressed considerably more than those at the earthed end, resulting in potentially excessive heating. Grading rings differentiate from each other in terms of their diameters and in the lengths of their fixing braces.

For EHV and UHV, the HV terminal has to be shielded by a corona ring (Fig. 12.12).

**Insulation Coordination and Selection of Surge Arresters**

Insulation coordination is the matching between the dielectric withstand ability of the electrical equipment, taking into consideration the ambient conditions, and the possible overvoltages in a system. In brief, it considers “stress versus strength.” For economic reasons, it is not possible to insulate electrical equipment against all overvoltages that may occur. That is why surge arresters are installed to limit the overvoltages to a value that is not critical for the electrical equipment. Therefore,

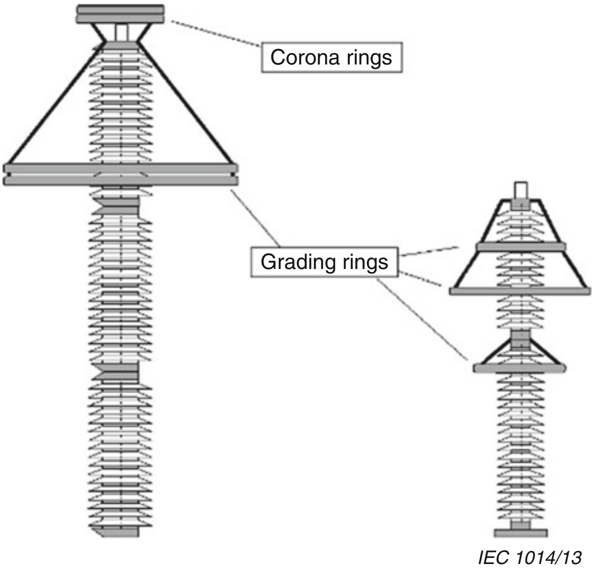



**Fig. 12.12** Examples of UHV and HV arresters with grading and corona rings

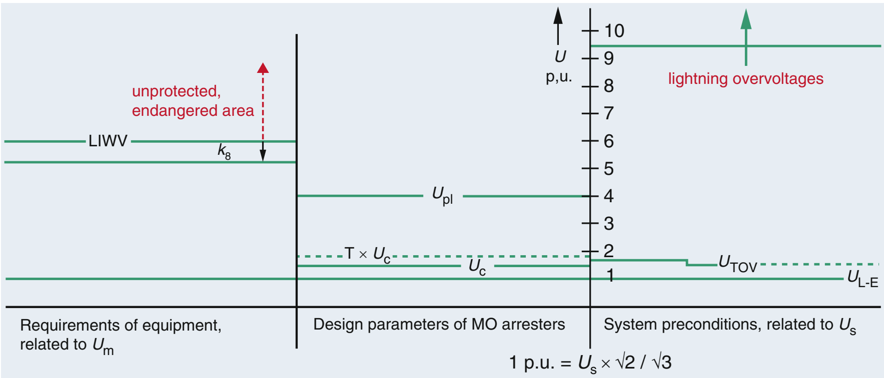



**Fig. 12.13** Comparison of the possible occurring voltages in the system, the withstand voltage of the electrical equipment, and the parameters of the MO arresters

a MO arrester ensures that the maximum voltage that appears at the electrical equipment always stays below the guaranteed withstand value of the insulation of an electrical device. More information on insulation coordination is given in ► Sect. 11.4.

In the following, some essential basics of insulation coordination are given; see also Fig. 12.13. An arrester has to fulfill two fundamental tasks:

- It has to limit the occurring overvoltage to a value that is not critical for the electrical equipment.
- It has to guarantee a safe and reliable service in the system.

The continuous operating voltage $U_c$ is chosen in such a way that the arrester can withstand all power-frequency voltages and also temporary overvoltages without being overloaded in any possible situation. This means the continuous operating voltage $T_c$ x $U_c$ shall be higher than or equal to the expected temporary overvoltage at the arrester terminals for the considered time duration ($T_c$ = TOV strength factor with reference to $U_c$).

Comment: Ferromagnetic resonances are the exception. The ferromagnetic resonances can become so high and exist so long that they may not be taken into consideration by the dimensioning of the continuous voltage if the arrester is still to be able to fulfill its protection function in a meaningful way. If ferromagnetic resonances appear, then this generally means that the arrester is overloaded. The system user should take the necessary measures to avoid ferromagnetic resonances.

The MO arrester can fulfill its function of protection properly if the lightning impulse protection level $U_{pl}$ lies clearly below the lightning impulse withstand voltage (LIWV) of the electrical equipment to be protected; the safety factor $K_s$ is also to be taken into consideration. The aim is to set the voltage-current characteristic of the arrester in a way that both requirements are met.

It makes sense to choose the continuous operating voltage $U_c$ a little bit higher than was calculated (for instance, by 10%). As a rule, there is enough distance between the maximum admissible voltage at the electrical equipment and the protection level of the arrester.

IEC 60099-5 “Surge arresters – Part 5: Selection and application recommendations” gives a lot of information for the selection of the right surge arrester and also describes the selection process.

**Installation Considerations**

Surge arresters as protection devices in substations will be installed at the entry of transmission lines and close to important (expensive) devices such as power transformers. Figure 12.14 shows the main installation possibilities: mounted on a pedestal (left), suspended from an earthed steel structure (middle), or suspended from a line conductor (right).

Figure 12.15 shows the typical arrangement beside an associated device. Surge arresters should be located as close as possible to the equipment to be protected in order to ensure effective overvoltage protection. Traveling wave phenomena will cause overvoltages at the equipment terminal much higher than the arrester’s terminal voltage, dependent on the steepness of the incoming surge and the distance between arrester and equipment. The length of HV and earth connection leads should be short and as straight as practical in order to minimize the loop inductance and ensure minimum inductive voltage drop across the leads. In lower-voltage systems, these voltage drops can superimpose and exceed the arresters’ residual voltage. The HV and earth leads, together with the connection points, should be rated to withstand both the high-magnitude surge currents and short-circuit current in the event of a flashover at the arrester or equipment location. A low-impedance earth electrode is required to dissipate the high-magnitude current safely into the earth.

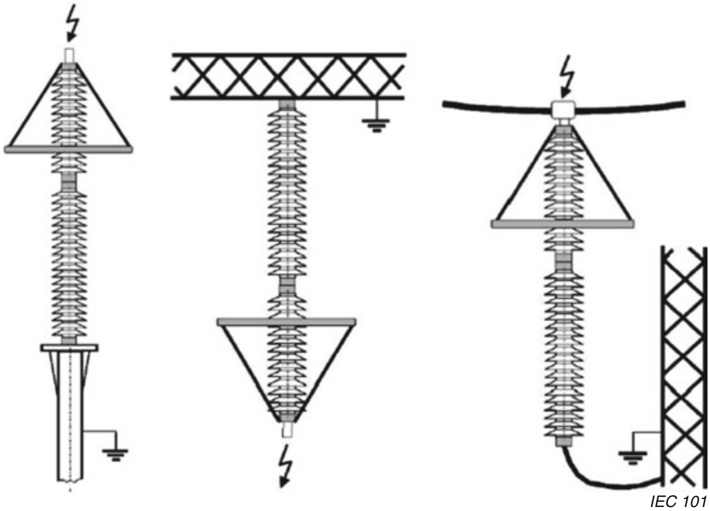



**Fig. 12.14** Types of arrester mounting

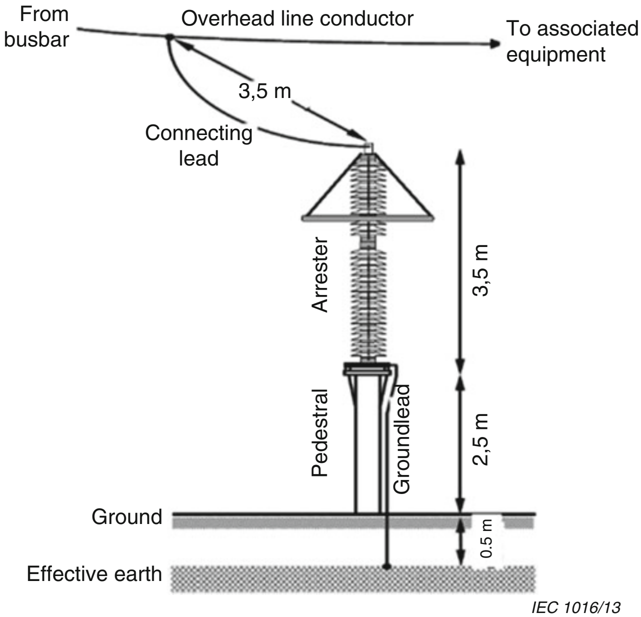



**Fig. 12.15** Typical arrangement

**Accessories**

Surge arresters function as overvoltage-limiting devices, normally behaving as an insulator with very low leakage current. The insulating properties are essential for the arrester life expectancy and for the power system operation reliability. Various diagnostic methods and indicators for revealing signs of deterioration or possible failure of the arrester have been used.

The diagnostic methods range from fault indicators, which indicate complete arrester failure, to instruments that are able to measure small changes in the resistive leakage current and/or power loss of gapless MO arresters.

It must be decided case by case if arrester monitoring is meaningful. The cost-value ratio is often critical, and only a few (expensive!) monitoring principles give really helpful information.

Surge counters operate at impulse currents above a certain amplitude or above certain combinations of current amplitude and duration.

Monitoring spark gaps are used to indicate the number and to estimate the amplitude and duration of discharge currents through the arrester. Special experience is necessary to interpret properly the marks on the gap. Spark gaps give no direct information about the actual condition of the arrester but may help to make decisions about continued operation.

Measurement of the arrester temperature can be carried out by means of thermal imaging methods. Advances in thermal imaging instruments have made this method of online arrester condition assessment very popular worldwide. The reason this method is effective is that during steady-state conditions, the arresters operate relatively close to ambient temperature, and the measurement is fast and accurate.

Leakage current monitor – Any deterioration of the properties of a MO arrester will cause an increase in the resistive leakage current or power loss at given values of voltage and temperature. The majority of diagnostic methods for determining the condition of gapless metal-oxide arresters are based on measurements of the leakage current. But because the leakage current is mainly capacitive, sophisticated methods have to be applied to detect an increase in the non-sinusoidal resistive component in the overall current. State-of-the art devices evaluate the third harmonic content of the leakage current and compensate for third harmonics that originate from third harmonics in the voltage.

Several of the diagnostic methods require an insulated earth terminal on the arrester. The earth terminal should have a sufficiently high withstand voltage level to account for the inductive voltage drop appearing between the terminal and the earthed structure during an impulse discharge.

## 12.5 Instrument Transformers

**Purpose of Instrument Transformers**

Instrument transformers are required to enable protection devices to perform their function of reacting to faults and providing measurements that reflect as accurately as possible which is present in the HV circuit, namely, current, voltage, and real and reactive power.

**Current Transformers**

Current transformers (CTs) are mounted in the HV conductor so the primary current can flow through the device.

Current transformers consist of five main components, in the top-core oil-insulated design:

- The primary head housing the required cores or ring transformers which are assembled from core rings of iron on which is wound a precise number of wire turns
- The primary conductor passing through the center of the head
- A secondary terminal or junction box where the wire tails from the ends of the winding tails of the CT cores are terminated and where the interface to the protection and control cabling is located
- The insulating housing which can be porcelain or polymeric and the base frame for mounting the CT on a support structure
- Insulating oil which fills the void between the core, tails, head, and support insulation

In Fig. 12.16, it can be seen that there are ring transformers mounted in the head of the instrument transformer. These have a specific transformation ratio, e.g., 2000:1, (2000 turns of wire around the magnetic core to 1 primary single turn conductor), so 2000 A flowing in the primary circuit would translate into 1 A flowing in the secondary output of the instrument transformer. This can then be used by protection and control equipment as required to monitor the safe operation of the substation equipment and associated network (Fig. 12.17).

There are a number of different basic designs of current transformer:

- Top core with the ring transformers mounted in the head of the instrument transformer. Different size heads are available from manufacturers containing from 1 to 7 ring CTs depending on their size.
- Hairpins are similar to top core except that the CT cores are located in the base of the instrument transformer and not in the head.
- Cable slipover ring CTs are provided when it is not possible or practical to connect in the HV circuit. The single-core cable can be inserted through the center of the ring where the cable is effectively the primary conductor.
- Ring types are used to slip over the end of a transformer bushing or wall bushing.
- Special CTs can be supplied for many other applications. Power transformer neutrals, for example, can be arranged to be solidly (directly) earthed or through a neutral earthing/grounding resistance or Petersen coil. Current can be measured in each of the phase neutrals before connecting them in a star configuration. Additional CTs can also be included in the "commoned" connection before finally connecting to the ground. So four or more CTs can be fitted in a special housing with the common star point included (Figs. 12.18, 12.19, and 12.20).

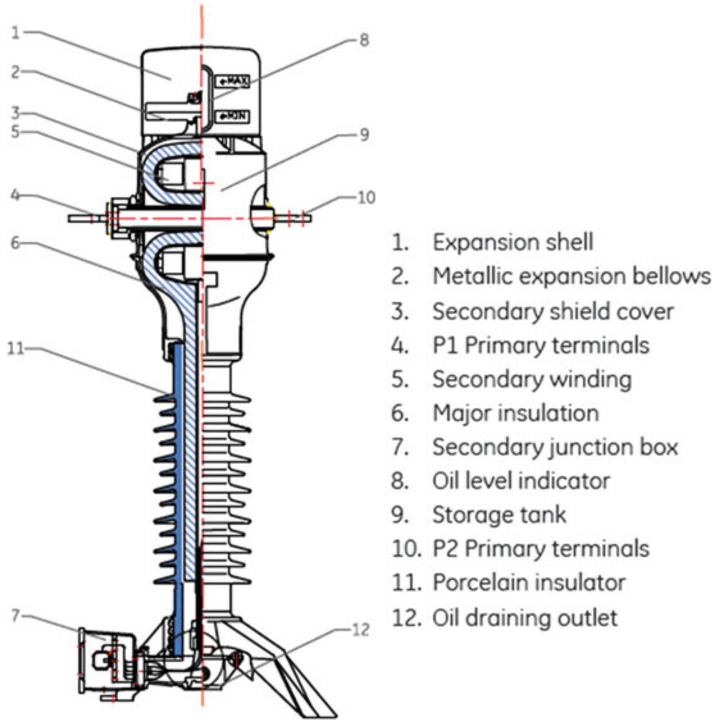



**Fig. 12.16** Typical top-core current transformer

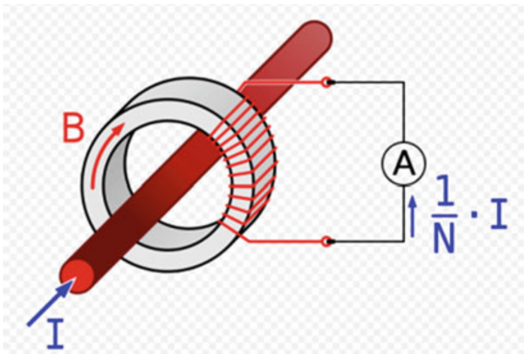



**Fig. 12.17** Principle of operation

Current transformers must be designed for the circuit which is to be protected or measured. Many parameters must be considered in the specification. Not only should the present design be considered but also the future requirements which may be required in the lifetime of the installation. Often cores may be included initially that may not be connected until sometime in the later life of the installation. Rather than having every conceivable variety of CTs, most utilities standardize on a smaller

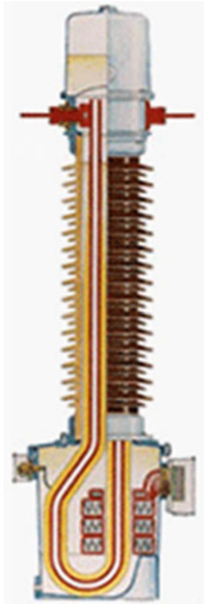


**Fig. 12.18** Typical hairpin design

**Fig. 12.19** Cable slipover current transformers and ring current transformer

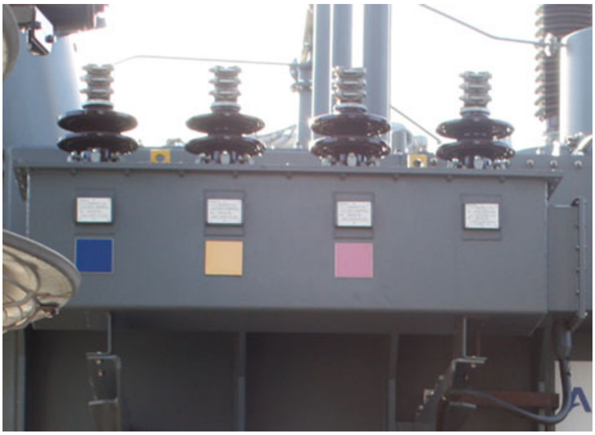


**Fig. 12.20** Neutral earthing or grounding current transformer

number of configurations to allow the holding of spare replacement units. This may introduce cores which may never be used, but these spare cores can be simply shorted out and earthed:

**Voltage Transformers**

Voltage transformers are connected to the HV conductors so that the primary voltage can be measured (Fig. 12.21).

Voltage transformers can be capacitive or inductive types. The most obvious type is inductive; however, for very high voltages, the large ratio required means that the transformation may require a number of transformers in series to achieve the transformation. This type of voltage transformer is often referred to as a cascade VT.

Such VTs are expensive, and so for transmission voltages, the capacitor voltage transformer is most commonly used. An oil-filled capacitor VT consists of six main components:

- The primary terminal used to connect the instrument to the HV conductor
- A capacitor divider
- A transformer in the base tank
- A secondary terminal or junction box where the wire tails from the ends of the transformer output are connected and where the interface to the protection and control cabling is located
- The insulating housing which can be porcelain or polymeric and a base frame/tank for mounting the VT on a support structure
- Insulating oil which fills the void

In the examples above, it can be seen that there are two methods of transforming the line or phase-to-earth voltage in the instrument transformer. They have a specific transformation ratio, e.g., for a 145 kV three-phase system, each of the phase-connected instruments needs to be designed for single-phase line to ground operation, i.e., 76,210:63.5 or 132 kV/√3: 110/√3. So when 132 kV system is energized, 63.5 V is present at the secondary output of the instrument transformer. This can then be used by protection and control equipment as required to monitor the safe operation of the substation equipment and associated network.

**Combined Current and Voltage Transformers**

Combined units containing current and voltage transformers are an economical and compact method of providing current and voltage measurement at a common location, particularly suited to providing high-accuracy metering at an interface where one utility provides power to another and there is a need to meter the distribution of energy. Being combined, this reduces the required land area and the quantity of foundations and associated support structures.

Generally, combined units are based on top-core current transformer technology, while the voltage transformer design is based on the inductive type, both as described earlier. Combined units are ideal at lower voltages as it becomes increasingly more difficult to combine them at 400 kV and above.

**Table 12.11** Current transformer application guidance notes

| | | |
|---|---|---|
| (a) | 1 A and 5 A secondaries | Protection relay manufacturers have standard solutions which require inputs of either 1 or 5 A. Therefore, the output from the CT needs to match the protection manufacturer's input requirements, particularly when extending or replacing an existing installation, then all CT outputs should match the individual device input, especially if older conventional protection is to be retained. With modern programmable protection working in isolation to existing systems, then this is less of an issue as the CT ratio can be programmed into the protection relay and the relay itself will adjust to the input being received from the CT |
| (b) | Ratios | These are dependent on the 1 or 5 A secondary output required and the maximum or rated current to be measured. Several ratios can be supplied on one core, e.g., 3000/2000/1000/1. This allows the lowest current to be used initially, i.e., 1000/1 A, and as the current demand grows as anticipated, then connections in the secondary terminal box can be moved to select the 2000/1 or 3000/1 A ratio and terminals |
| | | Standard CTs with multi-ratios can be defined by utilities which can be placed at any location in the network. For example, metering CTs, purchased in bulk for adding to existing installations, for metering between the TSO and DNO can have a ratio of 2000/1600/1200/800/600/500/400/1 A so as to be suitable for measuring any primary current between 2000 and 400 A |
| (c) | Multi-tap | Rather than having several single CTs, one CT with many taps can be provided to effectively provide the same function but only if the same response is to be provided, e.g., 2000/1/1/1/1 A. In this example, it is the same as having four separate cores, i.e., of 2000/1 A, each having exactly the same characteristics |
| (d) | Class and burden | For example, 5P10 class, 15 VA. More details on selecting class and burden are given in ▶ Sect. 37.1.2 |
| (e) | Insulating medium | Most high-voltage CTs are filled with insulating oil. $SF_6$ gas-filled designs can be an alternative solution to insulating oil. However, some utilities will no longer accept these for environmental reasons as $SF_6$ is a greenhouse gas. At medium and low voltages, solid epoxy cast resin is regularly used |
| (f) | Nonconventional current transformers | In conventional iron-cored CTs, the core itself is a source of inaccuracy, due to the need to magnetize it but not to over flux it. In the case of conventional CTs, achieving the low-level accuracy and dynamic range to satisfy both measurement and protection duties is a challenge |
| | | With nonconventional optical sensors instead of an iron core, the translation from primary to secondary measurement uses optical or Rogowski technology, with the optimal choice for AIS and GIS driven by the size of the respective digital measurement device, which allows footprint optimization for the substation |

(*continued*)

**Table 12.11** (continued)

| | | |
|---|---|---|
| | | Optical sensors use the Faraday effect. A fiberoptic loop sensor carrying a polarized light beam encircles the power conductor. This light will experience an angular deflection due to the magnetic field generated by the primary current flow. The sensors can then accurately determine the primary current based on the real-time optical measurement |
| | | Rogowski sensors dispense with the conventional CT core and instead implement windings as tracks on a multilayer printed circuit board. Four quadrants of the board are clamped together to form a toroid around the primary conductor. The sensor output becomes a low-level voltage measurement, which can be accurately correlated to the primary current |

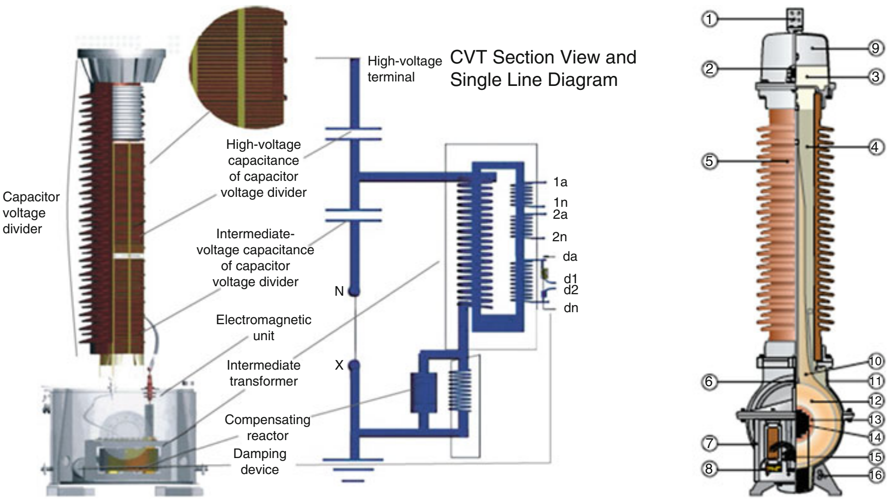



**Fig. 12.21** Typical voltage transformer types

## 12.6 High-Voltage Conductors and Connectors

### 12.6.1 Purpose

These are used to interconnect the terminals of all the various items of high-voltage equipment. Care must be exercised when specifying HV equipment and ultimately the conductor material used to interconnect them. Under short-circuit conditions, conductors will be rapidly forced together or apart putting strain on the equipment terminals, the conductor and connector materials, and the HV equipment itself. The whole substation's equipment and associated conductors must be designed holistically. Knowing the strength and capability of the equipment will determine how it is to be connected to the high-voltage circuit. For design considerations of busbar systems, please refer to ► Sect. 11.5.

### 12.6.2 Conductor and Connector Material

Conductors and connectors can be specified as either copper or aluminum. In high-voltage substations, aluminum is the preferred material today; see below for further information. However, care must be taken when connecting items which may have terminals of a dissimilar metal to that of the connectors. Terminals may possibly be made from brass, phosphor bronze, gunmetal, etc. A dedicated bimetallic connector or an additional sheet of tin sandwiched between the terminal and the connector will be required to prevent electrolytic action occurring between the two resulting in corrosion and degradation of the connection. It is also essential that moisture is prevented from entering the joint. Corrosion of the joint will lead to it becoming more resistive, creating overheating when carrying current and ultimately failure of the joint.

Copper was the material of choice in the past when currents were lower than used in today's substations and was particularly used, as now, for medium and low voltages. However, with increasing currents and higher voltages, increasing clearances and spans between circuits, lighter and stronger aluminum became the preferred material. Electrical-grade alloys were developed to provide the best electrical and mechanical performance.

### 12.6.3 Selection of Conductors, Singular or Bundled

To span large distances, rigid tubes or alternatively flexible stranded conductors in single or multiple formations may be used. Tubes can be extruded in long lengths of any inner and outer diameters and then cut to the required length. Standard sizes have been adopted and can be selected from tables from the manufacturer. Transportation becomes the limiting factor with long tubes. Stranded (flexible) conductors also come in a variety of standard sizes, stranding diameter, number of strands, etc. depending on the current to be carried.

Connectors at lower voltages and lower currents can be manufactured, cut, drilled, bent, shaped, etc. from flat bar or circular solid rod material. For high currents,, thicker material is required, and for higher voltages, corona-free connectors are essential, so these are made from cast aluminum to provide the profiles necessary for the connector types required.

Tubular busbar spans from one bay to another can be long, e.g., 400 kV circuits typically have a width of the order of 21 m. Being unsupported in the center inevitably allows the busbars to sag under their own weight. Busbar systems will have to operate over a wide temperature range, from very cold to very warm, creating even more sag due to ambient temperature further while carrying minimum and maximum currents. By selecting the tube with the correct outer diameter and wall thickness, the best strength can be provided which will allow the span to be made with allowable maximum sag under all operating conditions. Being rigidly supported on insulators or HV equipment, they are less susceptible to movement caused by wind or short-circuit forces.

Stranded conductors can be used to span even greater distances. A large diameter single conductor, though made from individual strands, may be difficult to handle or bend. Using two or more smaller stranded conductors may make it easier to control the change of direction. These conductors will be subject to the same forces and temperature conditions. Stranded conductors are particularly susceptible to swinging and clashing due to wind and short-circuit forces. These conditions need to be considered when selecting the appropriate conductors.

### 12.6.4 Variation Caused by Temperature and Ice

Busbars, be they stranded or tubular, and depending on the substation design, may be connected to the bay or circuit below through pantograph busbar disconnectors. Pantograph disconnectors reach up to the busbar above and grab the conductor or a dedicated trapeze contact hanging below the tube or overhead stranded conductor. It is essential that the trapeze contact always remains within the pantograph arm contact area defined by the manufacturer, so it is necessary for the substation designer to control the amount of sag and level of sag variation of the busbar conductor.

Once calculated, the correct conductor is selected. In extreme conditions, other additional features may be employed to assist in maintaining the sag between the required limits such as sag tension springs; see Fig. 12.22. These springs are installed between the gantry fixing point and the insulator string. Due to thermal expansion, the tension force decreases, and the spring deflection balances the elongation and the sag.

When busbars and connections, be they tubular or stranded, are coated with ice, they become heavier which naturally creates additional sag. Again, this must be taken into account when designing the busbar system (Fig. 12.23).

### 12.6.5 Movement Caused by Short-Circuit Forces and Wind

The open construction of AIS substations increases the risk of faults, e.g., by the ingress of foreign bodies into air gaps, and the risk of consequent damage is high due to their high normal operating currents and the amount of energy available. When adjacent conductors carrying a three-phase current suffer a short-circuit fault, the induced magnetic fields result in the conductors experiencing significant opposing forces. The conductors can be drawn together or forced apart. Stranded conductors can swing toward each other and drop causing forces on the conductors, their mounting arrangements, structures, and foundations. More information is included in ► Sect. 11.5.3.

### 12.6.6 Vibration

Vibration in conductors will in time fatigue the material causing catastrophic failure. Therefore, this must be considered when designing the busbar system and connections onto vibrating equipment.

**Table 12.12** Voltage transformer application guidance notes

| | | |
|---|---|---|
| (a) | Type | In addition, capacitive and inductive type voltage transformers can perform other functions and duties. As they are connected to the ground, they can be used to discharge capacitor banks and other charged circuits rather than applying earthing or grounding switches. In this case, a specially designed inductive VT is used where the winding construction is such that it can withstand the thermal heating as well as the electromagnetic forces associated with the discharge current |
| (b) | Ratios | Protection relay manufacturers have standard solutions which usually require inputs of, for example, 63.5 V or 110 V a.c. Therefore, the output from the VT needs to match the protection manufacturers' input requirements. Particular attention is required when extending or replacing an existing installation to ensure that VT outputs should match the input requirements of all connected devices, especially if older conventional protection is to be retained. With modern programmable protection working in isolation to existing systems, then this is less of an issue as the VT ratio can be programmed into the protection relay and the relay itself will adjust to the input being received from the VT |
| (c) | Multi-output secondary | A VT may be required to provide a voltage reference for a number of protection applications at the same time. One way of providing this is to incorporate several secondary output windings, and each winding can be specified and designed separately for the specific measuring and/or protection application. This is most common when the VT output is being used for tariff metering and usually a separate winding is specifically designated for the main metering |
| (d) | Class and burden | For example, 50 VA, class 1.0/3P. Details of how to select the class and burden are given in ► Sect. 37.1.3 |
| (e) | Secondary distribution | If a single VT output is provided, this output can be split at the VT secondary terminal box using MCBs or close by using a short protected cable to an additional MCB or fuse box. This box then contains a single-phase set of MCBs or fuse devices providing one device per protection circuit |
| (f) | Insulating medium [B57, 1990] | Most high-voltage VTs are filled with insulating oil. However, $SF_6$ gas-filled designs can be an alternative solution to insulating oil, although not preferred by some utilities for the same environmental reason as for CTs. At medium and low voltages, solid epoxy cast resin is regularly used |
| (g) | Nonconventional voltage transformers [B7, 1980] | Conventional VTs may experience ferroresonance phenomena resulting in thermal overstressing. Particular care is required when carrying out the step-by-step energization process during commissioning to ensure that the conditions likely to lead to inductive VT ferroresonance do not occur as this can destroy the VT. This is more likely to happen with GIS VTs |

(*continued*)

**Table 12.12** (continued)

| | | |
|---|---|---|
| | | With nonconventional optical sensors instead of an iron core, the translation from primary to secondary measurement uses capacitive technology, with the optimal choice for AIS and GIS driven by the size of the respective digital measurement device, which allows footprint optimization for the substation |
| | | Capacitive dividers dispense with the conventional VT core. Capacitors are built from slimline film stacks for AIS sensors or printed circuit board electrodes laid on the interior of the enclosure for GIS sensors |

Transformers and reactors, oil-filled or air-cored, create vibration when operating. The bushings of these pieces of equipment are the interface point which is connected to the HV circuit. The connections may be by flexible or tubular conductors.

Wind perpendicular to tubes can generate wind-induced vibration with vertical oscillation, known as Aeolian vibration. The measures to be taken to damp Aeolian vibrations are explained in ▶ Sect. 11.5.3 (Fig. 12.24).

### 12.6.7 Connector Types, E.g., Welded, Bolted, and Compression

There are different types of connectors available which provide the same function. These can be attached in a number of different ways.

### 12.6.8 Fixed and Thermal Expansion Connectors

As previously mentioned, a HV conductor system is subject to temperature change caused by ambient conditions and during operation when passing normal and short-circuit current. When expansion of tubular or solid conductors has not been considered, then damage to the high-voltage equipment is quite possible. To ensure the equipment operates correctly for its specified temperature range, the associated connectors are designed to continue operation and manage the temperature variation as per the examples in Fig. 12.25. For details of the design to allow for thermal expansion, refer to ▶ Sect. 11.5.3.

### 12.6.9 Corona

Corona is an electrical discharge brought on by the ionization of the air creating a region of plasma surrounding a conductor. More information on corona is given in ▶ Sect. 11.5.3.

Corona discharge usually forms at highly curved regions on electrodes, such as sharp corners, projecting points, edges of metal surfaces, or small diameter wires. The small radius causes a high potential gradient at these locations, so that the air

**Table 12.13** Combined CT/VT application guidance notes

| | | |
|---|---|---|
| (a) | Ratios | When used for metering purposes, they are located on the output side of power transformers and at the voltage being received by the receiving utility. As transformers vary in terms of voltage ratio and power output, the primary current on the HV-LV side can vary considerably from one transformer arrangement to another. If units are to be standardized to reduce spare holding, then a multi-ratio version is often the optimum solution, e.g., 1600/1200/1000/800/600/500/400/1A for each winding, which allows the best matching ratio to be selected |
| (b) | Multi-tap/output secondary | When used for metering purposes, dual redundancy is necessary to confirm or guarantee correct measurements. Metering often is arranged with main and check, regularly with different tariff meter manufacturers to ensure differing technology is used. Therefore, dual secondary windings are required for current and voltage to allow dual metering of real and reactive power transfer |
| (c) | Secondary distribution | A combined secondary terminal box can be supplied with integral MCB distribution. Often, at a convenient height for an operator, a separate distribution MCB or fused distribution box is provided. However, a separate sealed box may be required for the tariff metering connections |
| (d) | Insulating medium [B57, 1990] | Most high-voltage combined CT/VTs are filled with insulating oil. However, $SF_6$ gas-filled designs can be an alternative solution to insulating oil, with the same comment about environmental concerns |

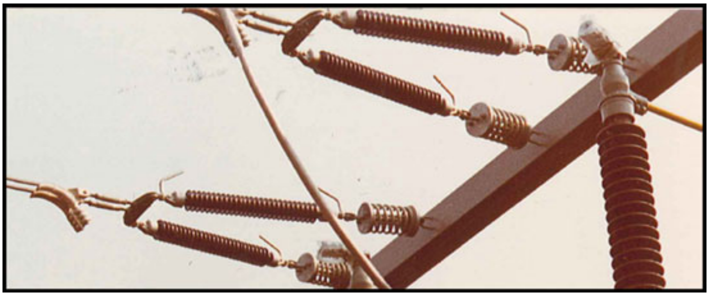


**Fig. 12.22** Compensating tension springs

breaks down and forms plasma there first. In order to suppress corona formation, terminals on high-voltage equipment are designed with smooth large diameter rounded shapes like balls, and corona rings are often added to insulators of high-voltage equipment to effectively remove any sharp corners.

To allow standard fixing materials to be used, the terminal castings are designed such that the sharp corners of the fixings are sunk below the top of the surrounding casting material preventing these from creating any corona discharge. As can be seen from the example in Figs. 26 and 27, all edges are rounded, and the threads and fixing heads are below the top of the smooth castings.

**Fig. 12.23** Equipment and conductors coated with snow and ice

**Fig. 12.24** Collapsed 400 kV busbar caused by vibration

### 12.6.10 Jointing Methodology

See table below (Table 12.15).

### 12.6.11 Joint Testing

A four-wire micro-ohm resistance measurement method should be used. A Ductor-type instrument should be used to check for low contact resistance joints.

The desired value is of the order of 10 μΩ resistance or less. Increased contact resistances of busbar joints may lead to damage when a fault current occurs in the system. Resistance measurements for all joints should be made between conductors and between conductors and equipment with the results kept as an installation record. The voltage leads should be placed either side of the joint in line with the connector arrangement under test. The two current leads are connected to the ends of the conductor. They remain connected there until the test is complete. With the leads in contact across the joint, a contact resistance reading is obtained.

Measurements are taken between individual test points (TP). The number of joints between the two TPs are counted and multiplied by 10 μΩ. Before carrying out an overall recorded measurement, each joint should be individually checked first. Where high values are found, the joint should be remade. When complete, move on to record measured values. If the measured value is less than the calculated value (acceptable), the value should be recorded. If the measured value is greater than the calculated value, measure each busbar joint to see which joint is reading higher than 10 μΩ. Remake the busbar joint and repeat the resistance measurement.

In the example above, seven joints are between the two test points, each joint should be $\leq$10 μΩ. The seven joints shown in Fig. 12.28 would be calculated as:

$$7 \text{ x } 10\ \mu\Omega. = 70\ \mu\Omega, \text{ therefore, measurement between TP1 and TP2} \leq 70\ \mu\Omega.$$

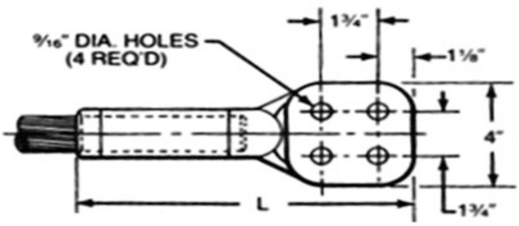
## 12.7 Solid-Core and Hollow Insulators

### 12.7.1 Purpose of Insulators

Solid-core post insulators are used in the assembly of disconnectors described in Sect. 12.3 above and for supporting HV electrical conductors in substations and incorporated in medium-voltage equipment. They are a simple product but extremely effective at performing such a function. Hollow insulators are used for supporting electrical equipment and to provide an internal chamber for connections, either electrical for items such as bushings, current transformers, voltage transformers, and power transformers or mechanical, typically for the drive rod of circuit breakers. Circuit breaker interrupters and drive rod assemblies can be wholly encapsulated in an insulator housing. There are many designs to cope with different applications, as described below. The fittings at each end of the insulator can be tailored by the manufacturer to suit equipment they are to be attached to, if necessary.

String insulators are an assembly of insulators which, when added together, form the required insulator. This type of insulator tends to be used in the support of stranded conductors spanning a bay or circuit. As they are not rigidly held together, simply pinned to the adjacent insulator, they are more flexible than the rigid post type insulator (Fig. 12.29).

**Table 12.14** Connector types application guidance notes

| | | |
|---|---|---|
| **Bolted**: | In this type, all the parts of the connector are bolted to each other and to the HV equipment. It requires cut lengths of tubes and/or stranded conductors to be assembled on site. Strict adherence must be paid to the manufacturers' bolt torque settings. These may be contained in the manufacturers' documentation or marked onto the connector itself. | |
| **Welded**: | In this type, the connector is physically welded to the busbar tube. This has to be prepared on site or welded in a factory and brought to site already fabricated. Any mistake in this type of connector will mean the complete replacement of the conductor and connector unlike the bolted type which could be undone and remade. |  |
| **Compression**: | This type of connector is used for compressing an end fitting onto stranded conductors. A hydraulic compression tool and dies, selected for the size of conductor and amount of compression required, are used to make several compressions to attach the fitting onto the conductor. | <br><br> |

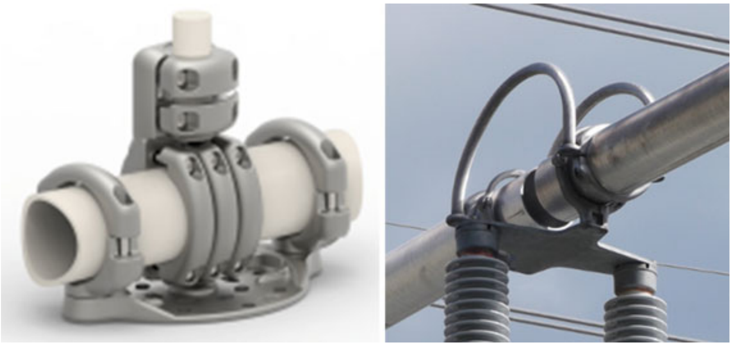


Fig. 12.25 Examples of fixed and expansion connectors

Fig. 12.26 Example of the use of anti-corona connectors

Fig. 12.27 Example of fixing with rounded edges to reduce corona discharge

**Table 12.15** Joint installation guidance notes

| | |
|---|---|
| **Bolted:** | Contact faces should be brushed vigorously with a dry clean stainless steel brush until both surfaces are bright indicating removal of any oxide film. For heavily oxidized faces, use a file instead of a brush. Spread a small quantity of a conductive grease thinly over the joint surface, ensuring that the joint surface is completely covered. This should be done immediately after the surfaces have been cleaned to prevent further oxidization. Scrape excess compound from the faces using the reverse side of a metal straightedge rule, so that all lumps are removed and a fine evenly distributed covering remains. Run nuts up bolts or studs to ensure that threads are not tight and that the threaded length of bolt or stud shank is adequate. Where blind or tapped holes are involved, bolts should be screwed in without washers initially to check that "bottoming" does not occur. Smear the threads of the bolts or studs with conductive. Grease and wipe off any excess so that only the threads are filled with compound and there is none projecting beyond the thread circumference. Bolt up the faces, securing all nuts or bolts with spreader, and lock washers in the correct positions, i.e., spreader washer below locking washer. Spreader washers should be of appropriate thickness and the bolts tightened with a torque wrench to the recommended torques. Wipe off any extruded compound from the periphery of the joint. Any slots or crevices capable of holding water should be filled with an appropriate grade of sealing mastic compound. For connections including a bimetal interface of either brass or cupal, the bimetallic joint must be sealed an appropriate grade of sealing mastic to prevent the ingress of moisture. It is always preferable to have the aluminum part of the joint above the copper/bronze portion. |
| **Welded:** | It is very important to remove all greases and oxides from the surfaces to be welded. This can be done by using a mild alkaline solution or standard degreasing solution. Then the same preparation indicated for bolted joints is required prior to welding. Contact faces should be brushed vigorously with a dry clean stainless steel brush until both surfaces are bright indicating removal of the oxide film. For heavily oxidized faces, use a file instead of a brush. The fittings can then be attached to the busbars using Tungsten arc inert gas (TIG) shielded welding or metallic arc inert gas (MIG) shielded welding. |
| **Compression:** | Compression or crimped connectors are another method of connecting and terminating high-voltage stranded conductors. To ensure a reliable connection or termination, both the conductor and the compression crimp should be cleaned down using cleaning wipes. The size, shape, and metal (copper or aluminum) must be correct for the stranded conductor. The correct crimp die set should be selected for the hydraulic compression head. The conductor must be fully inserted into the crimp connector. The correct compression or crimping sequence must be followed and the full compression pressure applied. |

## 12.7.2 Insulator Material and Types

### 12.7.2.1 Porcelain

This has been traditionally used in the insulation of bare electrical conductors since the discovery of electricity. Insulators are made from wet-processed porcelain which is machined to the desired specification. The insulators are coated with a hard weatherproof glaze before being kiln dried to give them high electrical and mechanical strength. The

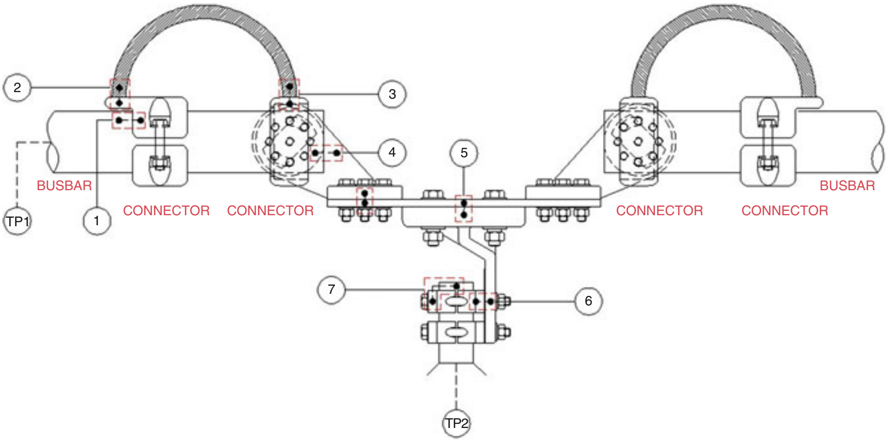



**Fig. 12.28** Example showing test point positions (TP1, TP2)

galvanized iron or cast aluminum fittings are attached to the insulator ends using Portland cement. The glaze which is applied can be the industry standard colors of brown or gray.

#### 12.7.2.2 Silicone Polymer Insulators

These are a modern alternative, in many situations, for traditional porcelain. Based on advanced chemical technology, these insulators boast some advantages over porcelain due to their lightness and compactness and are particularly advantageous for hollow gas-filled insulators because of their greatly reduced risk of exploding. However, both porcelain and polymeric are used extensively, and each has its own advantages and disadvantages over the other type. In the photograph (Fig. 12.30), the left insulator is porcelain and the right insulator is polymeric.

#### 12.7.2.3 Glass

Glass has been used for insulators since the invention of the telegraph. They have been used on overhead lines and in a.c. substations for the last 70 years with nearly 500 million glass insulators in service in more than 150 countries in all kinds of climate and contamination environments (Fig. 12.31).

#### 12.7.2.4 Post Insulators

Post insulators are used to support high-voltage conductors in compression, tension, or cantilevered arrangements.

They can be mounted vertically standing on top of a support structure or underhung from an overhead structure. These insulators can also be mounted horizontally, cantilevered off vertical walls or structures.


**Fig. 12.29** Substation with combination of porcelain post and glass cap and pin insulators

**Fig. 12.30** Example of porcelain and polymeric post insulators

**Fig. 12.31** Example of glass cap and pin insulator strings

Post insulators are of solid-core construction having the required shed profile to suit the environment in which they will operate, e.g., indoor and outdoor, contaminated by industrial pollution, salt-laden fog, clean air, etc. Depending on the voltage application, more than one insulator may be combined to achieve the required electrical rating.

As polymeric solid-core post insulators are more flexible than porcelain units, care is required when considering whether porcelain insulators can be replaced by polymeric insulators in a particular application.

**Fig. 12.32** Example of termination from overhead line

#### 12.7.2.5 Cap and Pin Insulators

Cap- and pin-type insulators are made from either glass or porcelain with galvanized iron fittings. They are generally used in high-voltage substations as strain sets for the substation connection onto the overhead line terminal tower, as shown in the photograph (Fig. 12.32), and for stranded busbar connections across the substation strung between gantry structures. They are also used as underhung support insulators to control the connection dropping from the overhead connection to the high-voltage equipment below, as can be seen in the glass example above (Fig. 12.32).

### 12.7.3 Resistive Glaze

Porcelain insulators can be prone to problems when pollution and moisture combine to form a highly conductive layer on their surfaces. When this happens, the insulator's surface resistance can decrease by up to 10,000 times compared to its dry and clean state. Surface discharges then occur and bridging dry bands are formed. Dry-band arcing can quickly develop into a complete flashover of the insulator. The principle behind the resistive glaze lies in the ability of the glaze to conduct low current (~1 mA), thereby promoting heating of the insulator surface to a few degrees above ambient temperature. Any existing pollution layer is kept dry, even under conditions of dew or fog. The glaze also acts as an alternative path for the leakage current flowing in the pollution layer as illustrated in Fig. 12.33. As such, dry-band arcing, formed when the surface of the insulator does not dry homogeneously, is prevented. This lowers the risk of flashover, and the layer of semiconducting glaze also stabilizes the voltage distribution along the insulator.

### 12.7.4 Strength Selection Due to Static and Dynamic Forces

The required strength of the insulator is determined by the insulator's position in the substation arrangement and also due to the combination of short-circuit, wind, and

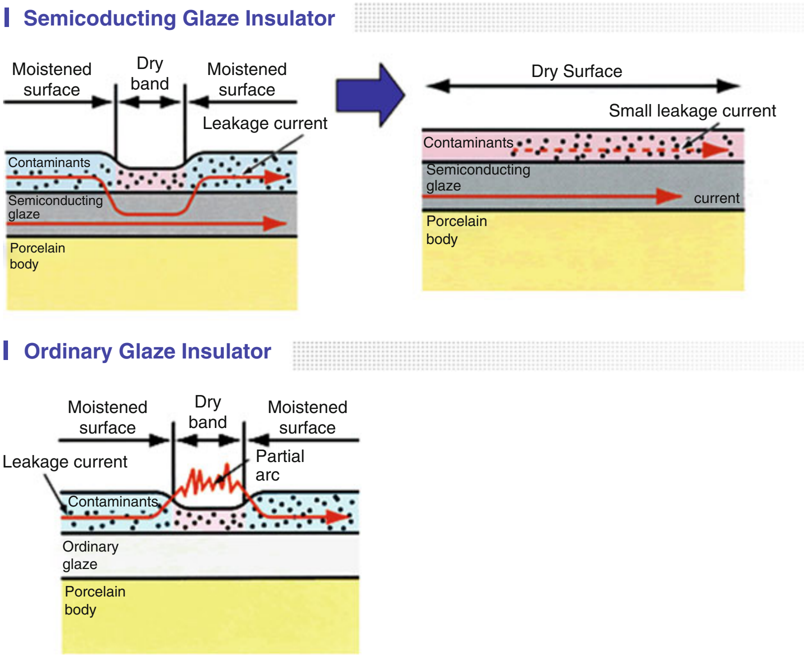



**Fig. 12.33** The use of semiconducting glaze to reduce the risk of flashover

ice forces that the insulator will be required to withstand. It is important to determine the correct strength and capability of the insulator, particularly when specifying equipment that must have the required level of insulator strength. Manufacturers will provide insulators to the minimum IEC requirements unless advised otherwise during the ordering process.

Insulators will have to cope with their own self-weight and supporting connections (static) plus any imposed dynamic forces as a result of a combination of short-circuit, wind, and ice.

## 12.7.5 Earthquake Ground Acceleration

Ground acceleration due to earthquake can cause damage to porcelain insulators. Allowing insulators to move under such conditions but in a controlled manner will ensure the insulator survives such events. Figure 12.34 shows a pair of underhung, multiple "long rod" insulators is used, supporting each suspended busbar. Flexible conductors, in triple formation, are used to connect the busbar to the high-voltage equipment terminals. In this way, the busbars and the connections have in-built flexibility to endure the specified earthquake ground acceleration requirements.

**Fig. 12.34** Underhung multiple "long rod" insulators supporting busbars for additional earthquake resilience

### 12.7.6 Bushings

Through-wall bushings or transformer/reactor bushings must be designed to withstand the electrical field strength produced in the insulation, when any earthed material is present. As the strength of the electrical field increases, leakage paths may develop within the insulation. If the energy of the leakage path overcomes the dielectric strength of the insulation, it may puncture the insulation and allow the electrical energy to conduct to the nearest earthed material causing burning and arcing.

Bushings are designed with a copper or aluminum conductor up the center surrounded by the hollow insulator, except for the terminal ends which are the interface points to the substation equipment.

Porcelain insulation has a small value of linear expansion which has to be accommodated by using flexible seals and substantial metal fittings, both of which present manufacturing and operational problems. The inside of a porcelain bushing is often filled with oil to provide additional insulation.

Where partial discharge is required to conform to IEC60137, paper- and resin-insulated conductors are used in conjunction with porcelain, for unheated indoor and outdoor applications.

The use of resin (polymer, polymeric, composite)-insulated bushings for high-voltage applications is common, although most high-voltage bushings are usually made of oil- or resin-impregnated paper insulation around the conductor with porcelain or polymer weather sheds.

Originally the housing was filled with insulating oil, and this type of oil impregnated paper is still in common use today. These days, it is also common to use resin-impregnated bushings.

Typically, paper insulation is impregnated with resin, and the paper is film-coated with a phenolic resin to become synthetic resin-bonded paper (SRBP) or impregnated after dry winding with epoxy resins, to become resin-impregnated paper or epoxy resin-impregnated paper (RIP, ERIP). To improve the performance of paper-insulated bushings, metallic foils can be inserted during the winding process. These act to stabilize the generated electrical fields, homogenizing the internal energy using the effect of capacitance. This feature results in the condenser/capacitor bushing.

The condenser bushing is made by inserting very fine layers of metallic foil into the paper during the winding process. The inserted conductive foils produce a capacitive effect which dissipates the electrical energy more evenly throughout the insulated paper and reduces the electric field stress between the energized conductor and any earthed material. These bushings produce electric stress fields which are significantly less potent around the fixing flange than designs without foils and, when used in conjunction with resin impregnation, produce bushings which can be used at service voltages over 1 MV with great success.

## 12.8 High-Voltage Cables

Cables intended for the transmission and distribution of electrical energy are mainly used in power plants, in distribution systems and substations of power supply utilities, and in industry. Standard cables are suitable for most applications. They are preferably used where overhead line connections are not suitable.

This section deals with the use of high-voltage cables inside substation sites. Substation cables are considered under the following headings:

- Single-Core or Three-Core
- Cable Types
- Conductor
- Cable Insulation Materials
- Sheathing Material
- Outer Serving
- Bonding Design
- Current Ratings
- Cable Accessories
- Laying Arrangements
- Mechanical Considerations
- Jointing
- Testing
- Maintenance

HV cables are used in substations under the following circumstances:

(i) As incoming or outgoing feeder circuits
(ii) To make cross-site connections, where it is not possible to use overhead connections due to space or clearance restrictions

**Fig. 12.35** HV cable drum

### 12.8.1 Single-Core or Three-Core

Depending on voltage and rating, cables may be single-core or three-core. Generally, in view of the rating required and due to size and handling difficulties, single-core cables are used at voltages from 220 kV upward.

### 12.8.2 Cable Types

There are many different types of high-voltage substation cables in existence today, and they may be categorized by their insulation type as follows:

(i) Low-pressure oil filled (LPOF)
(ii) High-pressure oil filled (HPOF)
(iii) Gas compression (GC)
(iv) Cross-linked polyethylene(XLPE)
(v) Gas-insulated line (GIL)
(vi) Superconducting

The cables are shown in the figures below (Figs. 12.36, 12.37, 12.38, 12.39, 12.40, and 12.41):

The cable constructions are described from the inner conductor to the outer serving in Sects. 12.8.3, 12.8.4, 12.8.5, and 12.8.6 below.

### 12.8.3 Conductor

The conductor for underground cable is made from either copper or aluminum. The choice of material and shape of conductor is determined by cost, current rating

**Fig. 12.36** Low-pressure oil filled (LPOF)

**Fig. 12.37** High-pressure oil filled (HPOF)

(under normal and short-circuit conditions), and the mechanical characteristics (bending radius, pulling tension, and thermomechanical expansion/force that can be exerted on the termination) required for the particular installation.

The different conductor shapes are as outlined below (Figs. 12.42 and 12.43):

### 12.8.4 Cable Insulation Materials

Many different designs of cable are possible at present including the following.

#### 12.8.4.1 Low-Pressure Oil-Filled (LPOF) Cables

In this case, the conductor is insulated with kraft paper impregnated with oil. The cable is kept under a positive oil pressure (0.5–5.25 bar) using an oil feed system,

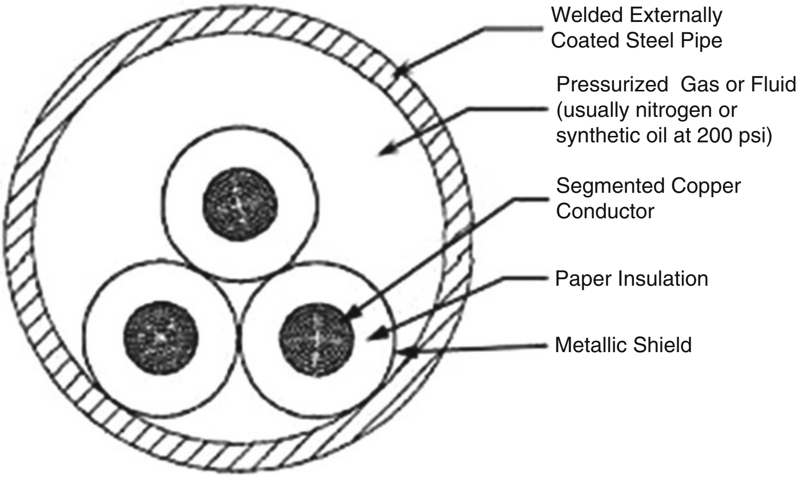



**Fig. 12.38** Gas compression (GC)

**Fig. 12.39** Cross-linked polyethylene (XLPE)


which usually incorporates oil tanks. The oil pressure must be monitored using oil pressure gauges and oil alarms. This design of cable has been used successfully from the 1930s, but has the disadvantage of using oil and the need to monitor the oil. Depending on the voltage and the rating, these cables may be three-core or single-core cables. The current voltage limit is 600 kV. A typical cable cross-section is shown above in Sect. 12.8.2, Fig. 12.36.

**Fig. 12.40** Superconducting

**Fig. 12.41** Gas-insulated line (GIL)

#### 12.8.4.2 High-Pressure Oil-Filled (HPOF) Cables

In this case, the conductor is insulated with kraft paper impregnated with oil. The cable is kept under a positive oil pressure (12 bar) using an oil feed system, incorporating an oil pumping system. The oil pressure must be monitored using oil pressure gauges and oil alarms. This design of cable has been used successfully from the 1930s but has the disadvantage of using oil and the need to monitor the oil. These cables are usually three-core cables, i.e., all three cores are in one steel pipe. The current voltage limit is 345 kV. A typical cable cross-section is shown above in Sect. 12.8.2, Fig. 12.37.

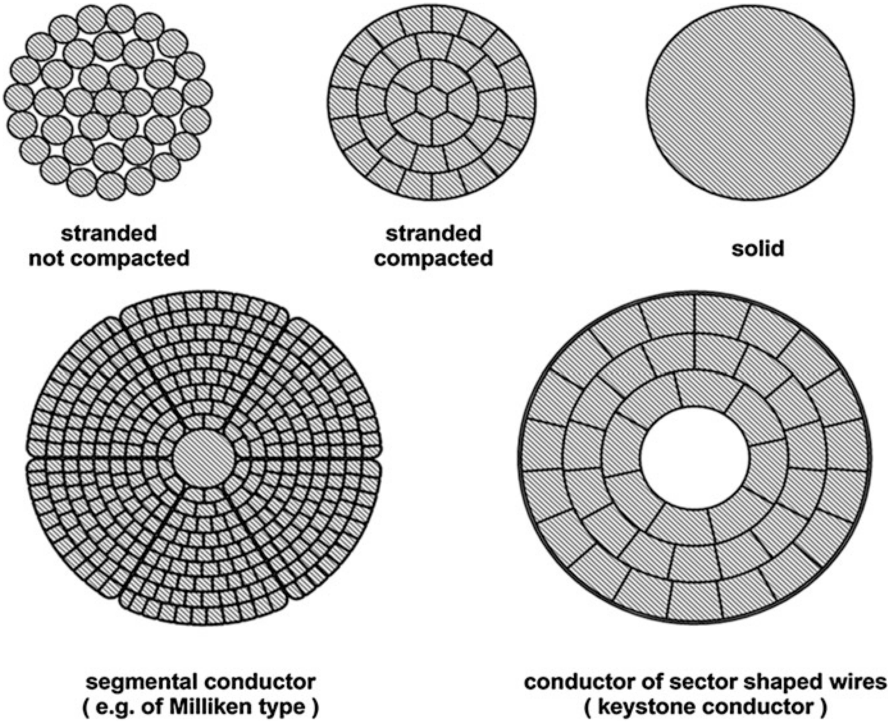



**Fig. 12.42** Construction of round conductor

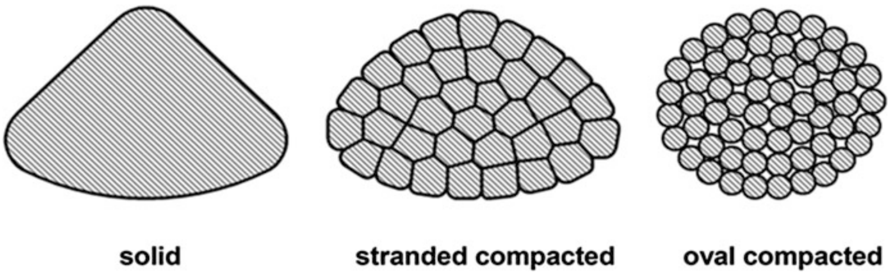



**Fig. 12.43** Construction for sector-shaped conductor

#### 12.8.4.3 Gas Compression Cable

In this case, the conductor is insulated with kraft paper. Gas compression cables are usually of three-core design with all three cores being located inside a steel pipe The cable is kept under a positive gas pressure (12 bar) using a pumping system. The gas pressure must be monitored using pressure gauges and alarms. This design of cable has been used successfully from the 1930s but has the disadvantage of using gas and the need to monitor the gas. These cables were mainly installed n Europe, and installation of this design for new circuits ceased in the 1970s. These cables are usually three-core in a single steel pipe. The current voltage limit is 132 kV. A typical cable cross-section is shown above in Sect. 12.8.2, Fig. 12.38.

#### 12.8.4.4 XLPE Cables

In this case, the conductor is insulated with cross-linked polyethylene (XLPE). This design of cable has been used successfully from the 1970s and is now the preferred design with most utilities as the design is relatively simple and there is no oil or gas to monitor. Depending on the voltage and the rating, these cables may be three-core or single-core cables. The current voltage limit is 600 kV a.c. A typical cable cross-section is shown above in Sect. 12.8.2, Fig. 12.39.

#### 12.8.4.5 Gas-Insulated Lines (GIL)

This design of cable has been developed for use in the last few years. Basically, it is the same technology that has been used successfully for gas-insulated switchgear and consists of an aluminum pipe with a conductor supported on epoxy supports, and the pipe is filled with a sulfur hexafluoride/nitrogen gas mixture. A typical cable cross section is shown above in Sect. 12.8.2, Fig. 12.41. As GIL is not really a cable, refer to ▶ Chap. 27 for more details.

#### 12.8.4.6 Superconducting Cable

Recent research has seen the development of cryogenic or superconducting cables, i.e., cables operating at very low temperatures, typically minus 250 °K or lower, and because of the low temperature, the cables are able to carry high currents. The design is based on single-core tubes. There is not much international operational experience with this design of cable. A typical cable cross section is shown above in Sect. 12.8.2, Fig. 12.40.

### 12.8.5 Sheathing Material

The cable core (conductor and insulation) is normally enclosed in a metallic sheathing material. This layer has a number of functions:

(i) It acts as a water barrier.
(ii) It protects the cable from mechanical abrasion.
(iii) It carries the short-circuit current when a fault occurs.
(iv) In the case of LPOF cables, it contains the oil. In this case. the sheath is also reinforced with bronze tapes to help contain the oil pressure.

### 12.8.6 Outer Serving

Cables are normally provided with an outer serving to insulate and protect the sheath from the surrounding ground. The serving is normally made from PVC or PE. Care must be exercised if PVC is used as it is more flammable than PE and it also liberates more smoke when it burns.

### 12.8.7 Bonding Design

In the case of three single-core cables, the magnetic unbalance caused by the three-phase currents in the conductors will induce a voltage in the sheaths of the three cables. If the sheaths are connected to earth at each end of the circuit (called solid bonding), circulating currents will flow in the sheaths. These will cause sheath losses and reduce the rating of the cables. There are three possible scenarios for bonding of the sheath:

(i) Solid bonding as described above.
(ii) Single-point bonding where the sheath is connected directly to earth at one end and is left floating at the other end. The floating end is connected to earth through a sheath voltage limiter (SVL), which diverts lightning impulses and switching surges should they arise. Under normal operating conditions, a voltage will be induced on the sheath at the floating end. The value of this voltage will depend on the magnetic imbalance, the current flowing in the circuit, and the circuit length. In some countries, limits are imposed on the permitted standing voltage.
(iii) Cross-bonding. This usually applies to long circuits with joints, and the circuit is divided into major sections. Each major section, in turn, is divided into three minor sections of equal length – each minor section is composed of one length of cable. With this arrangement, it is possible to arrange the cables in such a manner that magnetic balance can be achieved over the three lengths and there are no circulating currents.

### 12.8.8 Current Ratings

The current rating of a cable is a complex subject and is dependent on many factors including:

(i) The design of cable and in particular the conductor size, the conductor material, and the insulation thickness.
(ii) The bonding design. As stated above in Sect. 12.8.7, if the cable is solidly bonded, then there will be circulating currents and additional losses, thus reducing the rating.
(iii) The separation between phases. On the one hand, greater separation allows more heat to escape, but on the other hand, greater separation leads to a more expensive installation, uses more space, and causes more magnetic unbalance between the phases leading to higher circulating currents for solidly bonded cables. Greater separation also leads to higher standing voltages for single-point bonded or cross-bonded cables. The final design is a compromise between these factors.

(iv) The method of installation, i.e., whether the cable is installed in air, in the ground, in unfilled troughs, in filled troughs, in tunnels, in culverts, etc. as this will have a large impact on the dissipation of heat from the cables.
(v) The applicable ambient temperature for (iv). The higher the ambient temperature the lower the rating.
(vi) The thermal resistivity of the material surrounding the cable. The higher the thermal resistivity, the lower the rating.
(vii) One also needs to consider whether forced cooling is used as this will increase the rating.
(viii) One also needs to consider the impact of other heat sources like heating pipes or other cables.
(ix) It is not unusual, where high ratings are required, to use two or three cables per phase.

### 12.8.9 Cable Accessories

Substation cable circuits are generally terminated in sealing ends which may be air-insulated, $SF_6$ gas-insulated, or oil-immersed, depending on whether they are terminated in an outdoor substation, a gas-insulated station, or oil-immersed cable end boxes for transformers.

It is a normal practice to try to avoid using joints in substations, as they take up considerable space and are a potential source of failure.

In addition, for LPOF and HPOF cable, the oil-supply mechanism must be located in the substation, e.g., tanks for LPOF cables and pumps for HPOF cable. There is also a need to have pressure gauge panels and oil alarm systems to monitor the oil feeds.

LPOF and XLPE single-core cables require link boxes and SVLs as part of the bonding design. Single-point bonding may also require an earth continuity conductor (ECC) to help carry the fault current.

As GIL is a tube filled with $SF_6/N_2$ gas, it requires a gas monitoring system. GC cable requires a gas monitoring system for the $N_2$ gas system.

Superconducting cables require considerable accessories to maintain the cryogenic temperatures necessary.

### 12.8.10 Laying Arrangements

Depending on rating requirements and the space available, there are many possible installation arrangements for high-voltage cables in substations.

The cables may be installed on a tray over ground. In this case, one needs to take into account the cable being open to possible mechanical damage and the effect of solar radiation and the counter-effect of free air movement.

Cables may also be installed in the ground at a depth of about 1 m to try to avoid any mechanical damage effects. The backfill that is placed in the trench must be free of stones and have a suitable thermal resistivity. The trench must be open when the cables are being pulled in.

Cables may also be placed in preinstalled ducts in the ground – the ducts are normally placed at about 1 m depth and are surrounded by concrete. The ducts may be filled with bentonite after the cables are installed to improve the thermal behavior.

Cables may also be installed in filled or unfilled troughs. In the case of filled troughs, the troughs are usually filled with lean-mix concrete after the cables are installed.

Cables may also be installed in tunnels or culverts, which are routed across the site. This method, as it is very costly, is used where there are a lot of cables, and the site is very congested.

Of course, the choice of installation method is dependent on the ratings to be achieved and the cost and the difficulty of installing and maintaining the cables.

It is only the direct open trench method that requires the trench to be open at the same time as the cables are being installed. In all the other cases, the route can be established/constructed before the cables are delivered to site, and this may give some additional flexibility in the overall program. This may be of considerable importance on congested sites, where long outages could be required in the event of linearly programming the installation works.

### 12.8.11 Mechanical Considerations

The installation of high-voltage cables has to be treated with great care to ensure the cables are not damaged during the installation process and that their expected lifetime of 30–40 years is achieved. Cables must not be overbent and the pulling forces must not exceed permissible limits. Additional bending of the cable may be facilitated by using formers to hold the cable in place. Pulling tensions may be mitigated by ensuring the route is as straight as possible and also by using motorized caterpillars to push/pull the cable.

In addition to the above, one must also consider the forces exerted on sealing end support structures or cable end boxes by the cable during the normal loading cycle due to expansion and contraction. The design must also cater for the mechanical forces exerted during a short-circuit which cause the phases to separate. These forces depend on how the cables are restrained at the termination points, and the design is a compromise between the two requirements.

### 12.8.12 Jointing

Jointing or termination is one of the most important considerations in high-voltage cables. It is essential that fully proven accessories are used and that there is a full quality-control process with respect to cable/accessory manufacture, delivery, jointer training, site setup, and installation/jointing.

### 12.8.13 Testing

High-voltage cable and accessories should fully comply with the relevant IEC Standard and, if that does not exist, with the latest CIGRE Recommendation.

The tests to be performed may include the following:

(i) Prequalification tests – to prove the long-term life of the cable and accessory design – normally carried out on XLPE cables with an operating voltage in excess of 150 kV.
(ii) Type tests – to prove that the specific design of the cable and accessories being offered is adequate.
(iii) Sample tests – carried out on samples of cable and accessories as part of the quality-control process during manufacture.
(iv) Routine tests – carried out on all drums of cable and each accessory as part of the quality-control process on completion of manufacture and before delivery.
(v) Site tests – tests carried out on site as part of the commissioning process and before a cable circuit is energized. It may include the application of a test voltage, and in some cases, this may require the application of special test bushings to facilitate the application of that voltage.

### 12.8.14 Maintenance

The maintenance on any circuit will depend on a number of factors including:

(i) The importance of the circuit
(ii) The history of the circuit and its accessories
(iii) The potential repair time
(iv) The potential cost of the outage
(v) Potential cost of the damage
(vi) Effect on reputation
(vii) Potential damage from the failure
(viii) Effectiveness of the monitoring system adopted
(ix) Availability of monitoring tools and trained personnel
(x) Cost of monitoring

### 12.8.15 References

SC B1 covers high-voltage cables. The Customer Advisory Group of SC B1 has collated all of this information (Technical Brochures, Electra articles, Tutorials and Session Papers) and IEC Specifications into an Excel file “Information from CAG” on e-Cigre.

## 12.9 Earthing or Grounding Grid

### 12.9.1 General

Substations can be manned or unmanned throughout their operating life. When personnel are present at the substation for visiting, operation, maintenance, extension, or demolition, it must be safe at all times particularly during fault conditions, e.g., short-circuit, lightning, etc.

When personnel simply walk around the substation or touch or lean against equipment, it is important that there is no risk to human health.

In all substations, an equipotential plane is placed under the feet of everyone visiting the site, and the equipment is connected to this equipotential plane thus ensuring everything is at the same potential. ▶ Section 11.7 looks at the basic principles and design aspects, while this section looks at the specification and practical aspects of implementing the earthing system.

The ground, in which this equipotential plane is placed, can on occasion be aggressive to the earthing material. However, years of experience have enabled many issues to be overcome, as described below.

### 12.9.2 Materials Used in the Earthing or Grounding System

In the vast majority of countries, the preferred material for buried earthing is copper. Some countries use galvanized iron. Above ground the earth path can be steel, aluminum, or copper. The material chosen must be the correct size to carry the anticipated fault current for 1 s or 3 s as per the protection requirements. Not only the conductor itself but all the fittings need to be equally rated to carry the fault and withstand the associated heating effect. After the fault has passed, then the earthing system should be unaffected and return to normal.

The earthing plane below the ground, usually about 600 mm (2 ft) deep, is made of a lattice grid array. A buried sheet of copper would be far too costly, so a mesh made out of lengths of copper cable or copper rectangular strip, at a distance apart calculated to achieve personal safety, is used. IEEE 80 has become the international standard for calculating earthing systems and is used globally by utilities, consultants, and suppliers.

### 12.9.3 Different Earth Rod Types

Earth rods are used, if required, to connect the buried mesh to the best possible lower earthing resistance conditions found at greater depths. Where the mesh and rods are joined, an accessible inspection point can be provided to allow disconnection, inspection, and testing of the rod and earth grid system.

Rods are made of pure copper, stainless steel, or copper-coated (clad or bonded) steel. The latter earth rod is the most popular due to its corrosion resistance and cost-effectiveness.

As rods may have to be driven to considerable depth, all rods come in shorter sections, with threads at either end that allows them to be joined together with couplings, as they are driven into the ground. A spike is attached to the tip to ease the penetration into the earth, and a driving stud is attached to the top so as not to damage the thread to be coupled to the next section.

**Jointing Methodology**

The earthing mesh is made of rolled-out strips of copper or copper stranded cable. Where they cross or where a spur connection is made to a piece of electrical equipment, then a joint has to be made. A number of methods are available:

(i) For strip – Braised connection using heat, flux, and a filler rod made from alloy.
(ii) For cable – A compression "C"-shaped fitting compressing two cables together using manual or pneumatic compression tools.
(iii) For either – An exothermic weld which uses a mold to hold both pieces to be joined. A mixture is ignited which immediately melts and locally melts the conductors making a permanent weld.

When joining copper to ferrous metals or aluminum above ground, care must be taken to guard against electrolytic action. It is a common practice to tin the copper in the area to be joined prior to making the joint. This then eliminates the effect of electrolytic action. Once joined, a protective coat of bitumastic paint will seal the joint preventing ingress of water.

Earth conductor supports as seen in Fig. 12.45 above and clamps to connect earth rods to conductors are generally made of corrosion-resistant copper alloys, e.g., phosphor bronze or aluminum bronze.

### 12.9.4 Soil-Conditioning Agents

It is essential that earth rods, when driven into the ground, continue to provide an effective low-resistance path throughout the substation lifetime. When faced with difficult ground conditions, there are a number of solutions that can be provided to enhance the rods' ability to remain in contact with the surrounding soil:

- **Bentonite** is a moisture-retaining clay. This can be added locally around the rod reducing soil resistance and adding moisture. Bentonite has the ability to retain water for a considerable period of time and to absorb water from the surrounding ground moistened by rainfall.

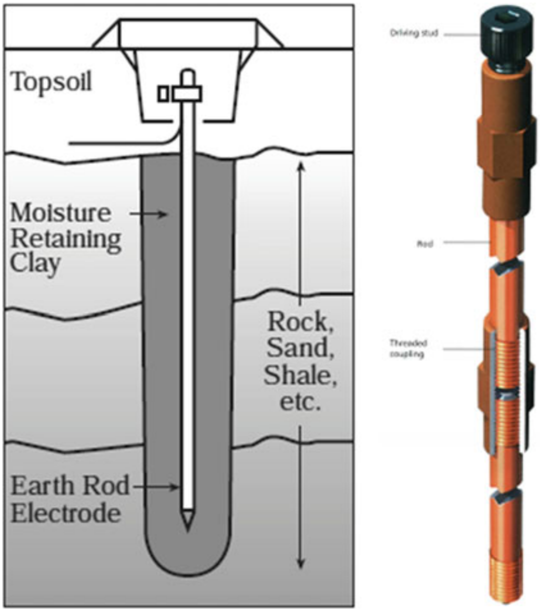



**Fig. 12.44** Shows rod surrounded with bentonite, marconite would be exactly the same arrangement

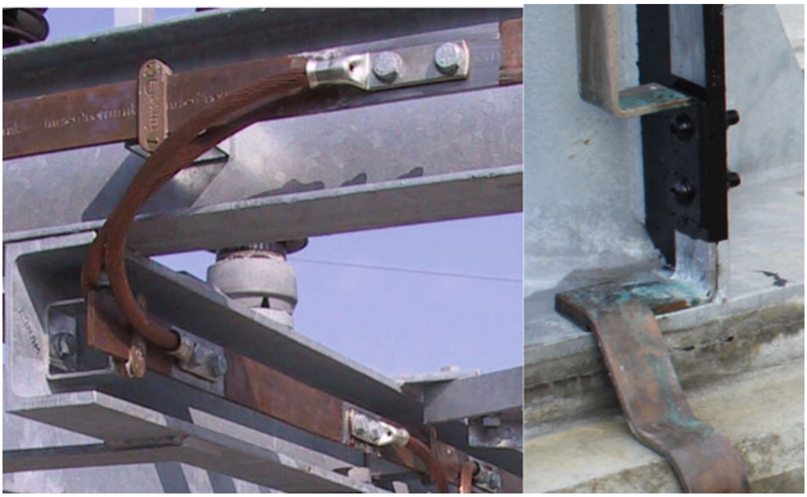


**Fig. 12.45** Outdoor earthing joints to galvanized steel structures

- **Marconite** is a conductive aggregate which, when replacing sand and aggregate with cement, creates conductive concrete. When used as a backfill surrounding an earth rod, it effectively increases the surface area of the rod thus lowering its resistance to earth (Fig. 12.44).

## 12.10 Power Transformers and Compensation Equipment

**Purpose of Power Transformers and Compensation Equipment**
Power transformers are used to interconnect two networks of different voltage levels. They can step down the voltage from a transmission operator's network to a utility network or step up the voltage from a generator operator to a distribution or transmission network operator. Transformers and compensation equipment are designed for specific duties:

- Generator step-up
- Intertie power transformers
- HVDC and transformers
- Phase-shifting transformers
- Shunt reactors and variable shunt reactors (VSR)
- Industrial transformers
- FACTS transformers
- Railway track feeder transformers
- Collector transformers for wind and solar plants
- Mobile transformers
- Poly-transformers
- Multi-voltage generator step-up transformers
- Environmentally safe and silent transformers (Fig. 12.46)

### 12.10.1 Impedance and Regulation

Transformers inherently have an impedance between the windings. With a two-winding transformer, there would be an impedance between the HV and the LV windings. This impedance is usually expressed as a percentage value on rating and is measured by short-circuiting the secondary winding and applying a variable voltage to the primary and increasing the value until the rated current flows in the transformer. The value of voltage necessary to achieve this is then expressed as a percentage of the rated primary voltage. This is quite important as the impedance of transformers provides a method of limiting the infeed of fault currents to a network and suitable impedance values can be designed into the transformer for this purpose. When there are more than two windings (e.g., when there is tertiary winding), then different impedances will exist between HV-LV, HV-TV, and LV-TV windings.

The existence of the impedance means that the per-unit voltages on the secondary side will be modified both in magnitude and in angle due to the flow of the load current through the impedance of the transformer which is largely reactive. This change in voltage across the transformer is called the regulation. The flow of the load current through the transformer will also give rise to a reactive power loss equal to the square of the load current multiplied by the reactance of the transformer.

**Fig. 12.46** Typical 400/132 kV transformer

### 12.10.2 Cooling Arrangements

All transformers generate heat when in use and the insulating medium, most commonly oil, heats up. Cooling the oil allows the transformer to work at a higher rating without exceeding the temperature limit. The transformer can be naturally cooled or forced cooled. Natural cooling is achieved by having tubes on the outer surface of the tank allowing natural air flowing past the transformer to cool the oil inside the tubes. This is suitable for relatively small transformers. Larger transformers generally require separate radiators, mounted on the tank or free-standing. The transformer can have a two-level design rating, i.e., natural cooling up to a specified rating and forced cooling to a higher rating (Fig. 12.47).

### 12.10.3 Winding Arrangements and Vector Groups

The rotational phase shift from one side to the other side of a transformer will depend on how the primary and secondary windings are actually wound. For more detail, see Fig. 12.48.

Vector groups are the IEC method of categorizing the primary and secondary winding configurations of three-phase transformers. Windings can be connected as delta, star, or interconnected star (zigzag). Winding polarity is important, since reversing the connections across a set of windings affects the phase shift between the primary and secondary. Vector groups identify the winding connections and polarities of the primary and secondary windings. From the vector group, one can determine the phase shift between primary and secondary.

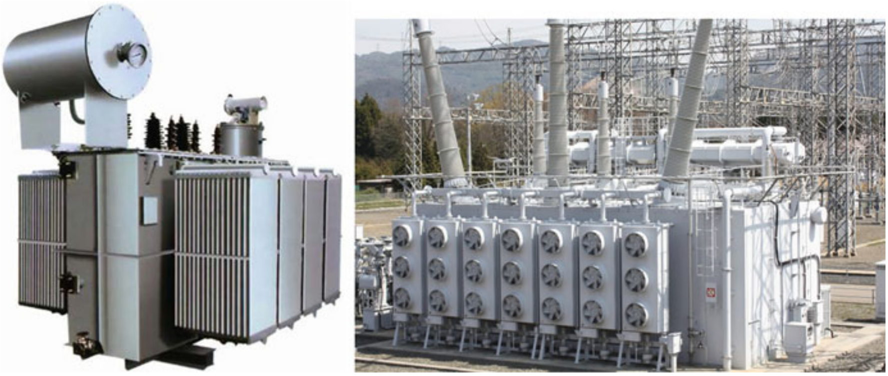


**Fig. 12.47** Natural- and forced-cooled transformers

The above discussion has been concerned with double-wound transformers having separate HV and LV windings. However, on transmission networks, the most common type of transformer used is an autotransformer. This transformer has effectively only one winding with the HV connected at the top of the winding and the LV tapped off part way down the winding (see Fig. 12.49).

This design of transformer has the advantage of having a significantly smaller frame size than a double-wound transformer of the same rating, which means that it is physically smaller, lighter, and easier to transport. The maximum ratio for an autotransformer is between 3 and 4/1, and it can only be used if the system earthing on the HV and the LV systems are the same (usually solid earthing) as the neutral connection of both windings is common.

### 12.10.4 Typical Transformer Arrangements

See table below (Table 12.16).

### 12.10.5 Tertiary Winding Voltage and Rating

Power transformers can have a third winding or tertiary winding which can be used for one of the following:

1. It reduces the degree of unbalance in the primary circuit due to unbalance in the secondary side.
2. It redistributes the flow of fault current.
3. Sometimes it is required to supply an auxiliary load at a different voltage level in addition to its main secondary load. This secondary load can be taken from the tertiary winding of a three-winding transformer. Also it can be used to connect compensation equipment which is at a different voltage level to the primary or secondary windings.

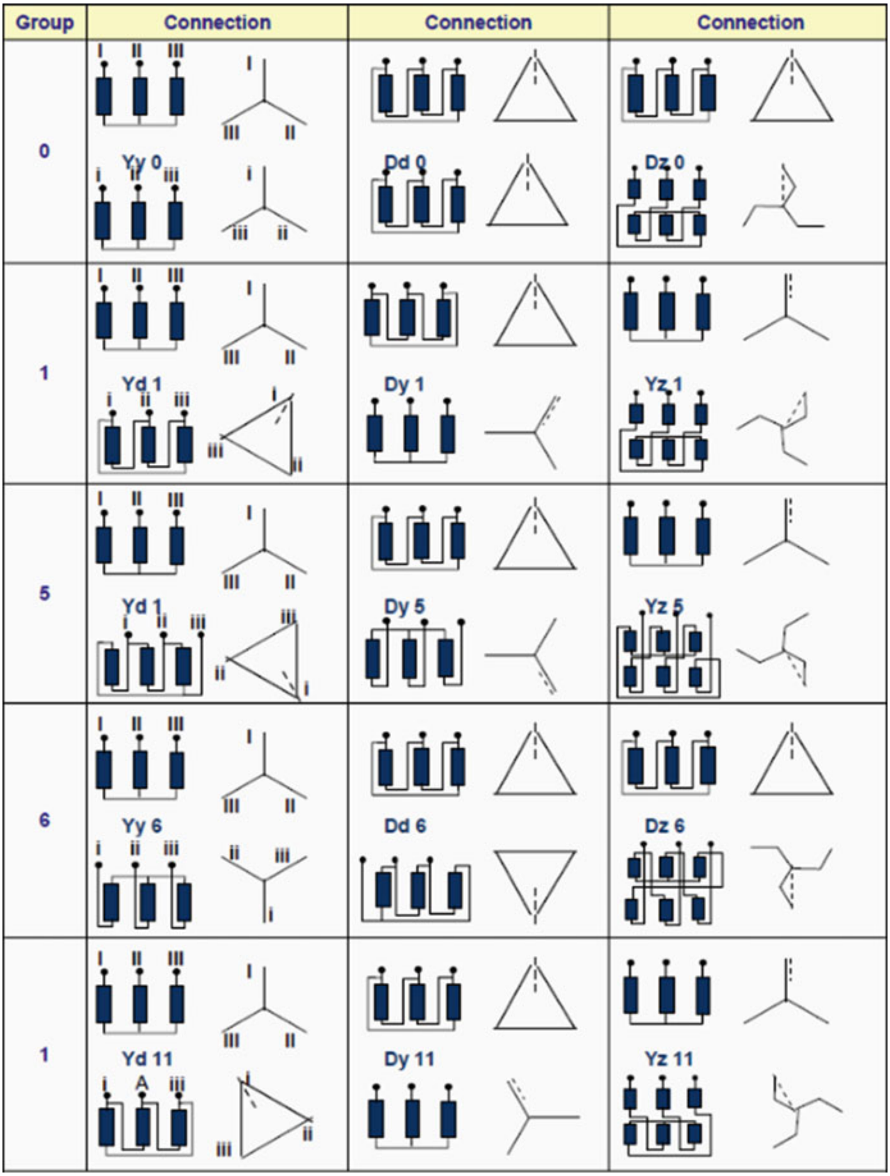



**Fig. 12.48** Transformer vector diagram based on IEC 60076-1

4. As the tertiary winding is connected in delta formation in a three-winding transformer, it assists in the limitation of fault current in the event of a short-circuit from line to neutral.
5. In a star/star connection, unbalanced load may result in neutral displacement, and third harmonic currents may circulate between lines and earth. These difficulties

**Fig. 12.49** Simple diagram of an autotransformer

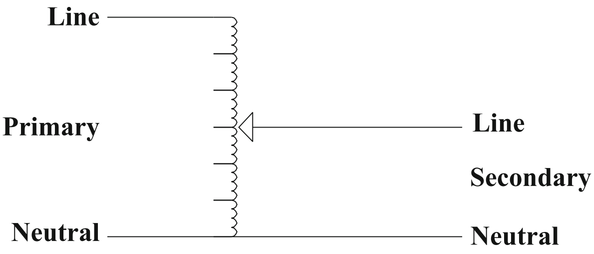



**Table 12.16** Typical transformer vector groups

| | |
|---|---|
| Step-up transformer: | Yd1 or Yd11 |
| Step-down transformer: | Dy1 or Dy11 |
| Grounding transformer: | Yz1 or Dz11 |
| Distribution transformer: | Vector group of Dzn0 which reduce 75% of the harmonics in the secondary side |
| Power transformer: | Vector group, depending on application, i.e., generating transformer, Dyn1, and furnace transformer, YNyn0 |
| Intertie power transformer: | Autotransformer with vector group YNa0d1 or d11 |

may be overcome by providing a delta-connected stabilizing (tertiary) winding with a rating sufficient to take short-circuit fault currents.

The voltage usually chosen for the tertiary winding is usually in the range 13–33 kV. The rating, if no external loads are connected, is decided by the zero-sequence fault currents it will experience. When external loads are connected, then the rating is chosen to suit the load connected. Frequently the type of load connected to a tertiary will be a reactive load so that this load does not add arithmetically to the load being carried between the HV and LV. In this case, typical values for the rating of tertiary windings are approximately one quarter of the HV to LV through rating.

## 12.10.6 Insulation Media

Power transformer windings and cores operate at high voltages and are mounted inside an earthed metal tank. The insulating medium between the windings and the tank can be:

1. No liquid insulating medium, i.e., air (small low-voltage transformers)
2. Dry type or solid insulation
3. Mineral oil
4. Silicone-based or fluorinated hydrocarbons

5. Pentaerythritol tetra fatty acid natural and synthetic esters
6. Vegetable-based oils
7. $SF_6$ gas

The type of medium used will depend on the location and its proximity to people and property. Transformers inside populated buildings will be considered differently to those to be mounted on offshore platforms or in substations located in the countryside.

### 12.10.7 Variation of Voltage

**On-Load Tap Changers**

The transmission network voltage varies constantly. This is due to the impact of switching different types of load in or out and energizing long capacitive lines and inductive-type loads, e.g., transformers, reactors, and heavy industrial processes such as aluminum smelting, steel production, etc. To deliver a nominal voltage with an acceptable tolerance to the utility customers, on-load tap changers can be provided. The internal transformer winding has a number of tappings which are brought out to a tap change mechanism. This is a motorized device which works in conjunction with voltage transformers on the secondary (utility side) and a tap-change control device which controls the tapping up and down to deliver a consistent voltage on the secondary side. For more details, please refer to ▶ Sect. 33.4.1.

**Off-Load Tap Changers**

These are more often used in distribution networks and probably set once during installation. The fixed tap is selected to provide the optimum voltage at the point in the network. If the network voltage profile changes over time, then a change in tap may be necessary. To do this, the supply will be removed while the change is made, during maintenance, for example.

### 12.10.8 Losses

Transformers are very efficient pieces of electrical plant, with a ratio of output over input between 95% and 98.5% at full load. The difference is due to losses in the transformer which are a combination of copper losses, iron losses, and auxiliary losses from fans and pumps. Losses manifest themselves in heat and noise.

Losses are a continuous cost during the lifetime of the transformer, and so it is usual to take account of this when selecting a transformer. This is done by the purchaser putting a capitalized cost per kW of loss against load losses (copper loss and auxiliary loss) and no-load losses (iron loss). The value will be much higher for no-load losses as these are always present whenever the transformer is energized, while load losses vary as the square of the load. When evaluating different transformers, the cost of the losses is obtained by multiplying the guaranteed loss figures by the relevant capitalized values.

These loss values are then added to the capital cost of the transformer in order to select the best buy (compromise between low initial cost and low cost of losses).

### 12.10.9 Noise

The transformer is at its noisiest when it is at full power with cooling fans operating. The noise is created from the vibration of the laminated core due to the alternating current in the windings. This phenomenon cannot be eliminated, but designers of transformers can reduce this noise to acceptable audible levels.

When engineering has produced the best achievable noise level design but the noise level is still above acceptable limits, then external means have to be employed to reduce the emitted sound even further. Acoustic noise enclosures can be fitted around the transformer tank; these are often manufactured from steel or of civil construction, e.g., brick, concrete, etc (Fig. 12.50).

Steel construction enclosures with integral sound-reducing panels can be added to transformers retrospectively if circumstances change in the locality.

### 12.10.10 Terminal Arrangements

Transformers can have the same or different connection arrangements for the HV, LV, and TV connections:

1. Porcelain or polymeric air-insulated bushings, oil/air
2. Gas-insulated bushing, oil/$SF_6$
3. Power cable, oil/cable box

With gas-insulated substations, the site area can be relatively compact, and therefore, it is often the case that when the transformers are immediately outside the GIS building, the optimum solution is to use GIS connections directly onto the transformer eliminating the air-insulated bushings. Medium-voltage connections can be through porcelain or polymeric bushings, but often cable boxes are provided to allow power cable, several per phase, to be connected to the transformer LV or TV connections. Standardization issues must also be considered when determining the “optimum” connection method.

### 12.10.11 FACTS Devices

FACTS devices are composed of static/electronic equipment used for enhancing controllability and for increasing voltage control and/or power transfer capability of the power grids.

There are two ways of connecting FACTS devices in power systems: in (i) shunt and in (ii) series-compensation modes. In shunt-compensation mode, it is connected

**Fig. 12.50** Acoustic enclosure under construction

in parallel to the power grid, working as a controllable current source to provide voltage control to the power grid. For series-compensation mode, the FACTS devices modify the line impedance, so as to control the transmittable active power. However, in this case, more reactive power must be provided for the FACTS performing this role as a series-connected apparatus.

### 12.10.12 Reactors

**Current Limiting (Series)**
Reactors placed in series with lines or cables in power systems play the role of fault current-limiting devices. They limit fault current due to the increased impedance of the circuit (inductive reactance) and the voltage drop across their terminals, which increases during the fault conditions. However, current-limiting reactors commonly also have a voltage drop under normal operating conditions and present a constant source of joule losses, if they are installed in feeders. When installed to split a busbar, these disadvantages may not happen, depending on the power flow division among circuits connected to the busbar. A current-limiting reactor is a passive fault current-limiting (FCL) device that requires only a fixed and easy-to-determine redefinition of protection settings after being installed in the network.

**Compensation for Capacitive Reactive Power Coming from Cable and/or OH Line Networks (Shunt Compensation)**
Frequently in power systems, a considerable number of transmission lines, or underground/undersea cables, can be used in the transmission grid to interconnect

different geographical regions or to integrate power generation located far from the main load centers. Especially during lower active power transmission (light load periods), the use of many and long transmission lines or underground/undersea cables generates significant capacitive load (line charging due to the Ferranti effect) that has to be compensated, since this transmission configuration increases the voltage profile of the system beyond the acceptable or desired levels. Shunt reactors are applied to perform this role.

A shunt reactor is a device that absorbs reactive power and helps voltage regulation by lowering the voltage profile. It can be either a three-phase unit or a set of single-phase ones, depending on planning design criteria, on the voltage of the system to which it is intended to be installed, and on its rated reactive power. The shunt reactor can be permanently connected (fixed shunt reactor) or switched via a circuit breakers and could be installed on a substation busbar to perform the role of helping the steady-state voltage profile control of the system or at the ends of transmission lines/cables, mostly to perform control of transient overvoltages due to switching or load rejection.

Variable shunt reactors with tap changer can be used for precise and slow voltage variation regulation. Another possibility for voltage regulation is to use more than one switched shunt reactor at the same location. At higher voltage levels (extra-high voltage or above) and for large rated reactive power, shunt reactors will be of gapped core and oil-immersed type to minimize losses, sound, and vibration. At lower voltages and for small rated reactive power, the shunt reactor could be of dry type (including alternatives with no iron core to lower equipment costs).

### 12.10.13 Filters (Harmonic Filtering)

The flow of harmonic currents in power systems creates a distortion of the sinusoidal wave of the power current and voltage. This behavior is undesirable since it can cause heating or damage to equipment and interference with communication/control/protection systems. If this harmonic injection is relevant enough to distort the voltage beyond the accepted levels, some measures should be taken, as, for instance, installing harmonic filtering devices. Harmonic injection into power systems will typically be generated by power electronics related to the use of rectifiers and/or inverters with loads from distribution networks or power system equipment, such as HVDC converter stations. Therefore, harmonic filtering can be used to mitigate harmonic distortion on the transmission system. The use of harmonic filtering can also help the voltage regulation of the power system, since in steady-state operation at the power frequency, they act as a capacitor bank (increasing the voltage profile).

### 12.10.14 Capacitors (Capacitor Banks)

Capacitor banks produce reactive power that compensates for the inductive reactive power consumption of transformers, highly loaded lines, inductive loads, etc. A

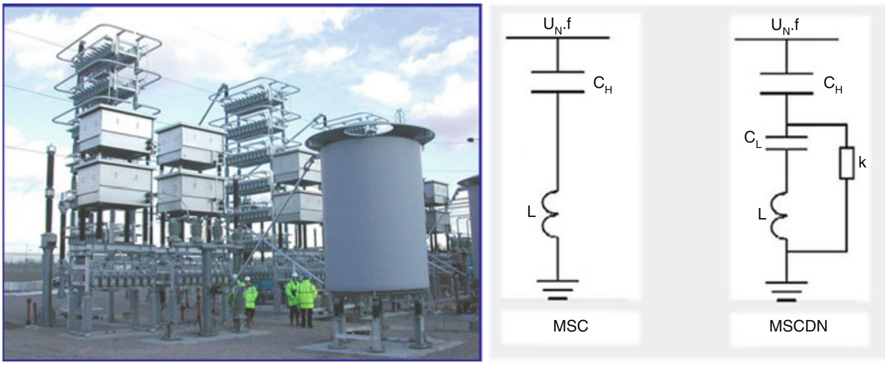



**Fig. 12.51** MSCDN – capacitor, reactor, and resistor combination

capacitor bank is a group of several capacitor units of the same rating that are connected in series and/or parallel arrangements with each other to store electrical energy. A capacitor itself consists of two conductors (or metal terminals) that are separated by an insulating material called a dielectric. When current passes through the capacitor terminals, a static electric field develops in the dielectric, which creates the stored energy (in terms of electric field). The use of capacitor banks results in increased transmission capacity and reduced losses leading to higher-power factors, higher-voltage profiles, and higher transmission capacity of the grid. Capacitor banks may help voltage regulation (by increasing the voltage) and can be helpful in meeting voltage regulation, power quality, and stability conditions coming from grid requirements.

**Mechanically Switched Capacitor with or Without Damping Networks**
These are a combination of, per phase (Fig. 12.51):

- Capacitors
- Reactor
- Resistor

Mechanically switched devices are the most economical reactive power compensation devices. They are strategically placed in the network; they are a simple, low-cost, but low-speed solution for voltage control and network stabilization under heavy load conditions. Their use has almost no effect on the short-circuit power, but they support the voltage at the point of connection.

**MSC: Mechanically Switched Capacitor**
The effectiveness of voltage stabilization depends on the distance from the fault location. The MSC does not create any harmonics but may amplify pre-existing system harmonics.

**MSCDN: Mechanically Switched Capacitor with Damping Network**
A more highly developed form of mechanically switched capacitor, the MSCDN, is a "C" filter tuned to a frequency usually approximately the third harmonic which, in addition to providing voltage support, provides damping of pre-existing system harmonics.

The MSC/MSCDN can be operated in a controlled or manual mode. For more details, refer to ▶ Sect. 33.4.2.

### 12.10.15 Static Var Compensator

A static var compensator (SVC) is a set of electrical and power electronic devices that provides fast reactive power control on high-voltage or medium-voltage transmission/distribution networks. They are used as well for industrial purposes, such as controlling flicker of arc furnaces, for instance. SVCs are intended to regulate/control voltage profile and power factor and to stabilize the system. Unlike a synchronous condenser which is a rotating electrical machine, a static var compensator has no significant moving parts. The SVC normally includes a thyristor-controlled reactor (TCR), thyristor-switched capacitors (TSCs), and harmonic filters. It might also include mechanically switched shunt capacitors (MSCs), and then the term "static var system" is used. As the TCR produces harmonics, there normally is the need to use harmonic filters (conjugated with the SVC). At fundamental frequency, the filters produce capacitive reactive power and therefore also play a role of a capacitor bank in the SVC system. The TCR is typically larger than the capacitor blocks so that continuous control is realized. Other possibilities are fixed capacitors (FCs) and thyristor-switched reactors (TSRs), a SVC solution with lower investment cost. The rating of an SVC can be optimized to meet the required demand for reactive power supply and voltage control. The rating can be symmetric or asymmetric with respect to inductive and capacitive reactive power limits. Usually a dedicated transformer is used, having a tailor-made reactance for the SVC project, with the reactive compensation equipment at medium voltage for cost-saving reasons. The transmission side voltage is controlled, and the Mvar ratings are referred to the transmission side (high-voltage side of the SVC transformer). The ratings will depend on the requirements of each solution for the power system requirements.

### 12.10.16 Voltage Source Converter Devices, E.g., STATCOMS

The STATCOM is a very useful dynamic reactive power source to suit the most severe power system requirements for voltage control, voltage unbalances and flicker control, power factor correction, and system stabilization while at the same time avoiding harmonic pollution, due to its totally electronically controlled behavior, and can even be used to solve resonance or power quality issues. STATCOM is an acronym for "Static Synchronous Compensator," and it is a power electronic device comprised of power inverters used to inject reactive current into a power system for the purpose of smooth and fast control of the system voltage or power factor. The voltage source converter (VSC) is the basic electronic part of a STATCOM, which converts d.c. voltage into a three-phase set of output voltages with desired amplitude, frequency, and phase.

The VSC-based device has the voltage source behind a reactor. The voltage source is created from a d.c. capacitor, and therefore a STATCOM has very little active power capability. However, its active power capability can be increased/ improved if a suitable energy storage device is connected across the d.c. capacitor. The reactive power at the terminals of the STATCOM depends on the amplitude of the voltage source. If the terminal voltage of the VSC is higher than the a.c. voltage at the point of connection, the STATCOM generates capacitive reactive power, acting as a capacitance; on the contrary, when the amplitude of the voltage source is lower than the a.c. voltage, it absorbs capacitive reactive power, acting as an inductance. The response time of a STATCOM is shorter than that of a SVC, mainly due to the fast switching times provided by the IGBTs of the voltage source converter. The STATCOM also provides better reactive power support at low a.c. voltages than an SVC, since the reactive power from a STATCOM decreases linearly and smoothly with the a.c. voltage.

**Reference**

1. Three Phase Transformer Winding Configurations and Differential Relay Compensation Paper by Larry Lawhead, Randy Hamilton, John Horak, Basler Electric Company

## 12.11 Miscellaneous Equipment

### 12.11.1 Purpose of Miscellaneous Equipment

Miscellaneous equipment is required to support the main equipment. Main items of equipment, as described previously, may require other equipment to allow them to operate correctly and to fulfill their function.

### 12.11.2 Line or Wave Traps

Line traps, sometimes referred to as wave traps, are used in power line carrier (PLC) systems. Particularly for substations with long distances between them, these devices enable communications to be carried over the utility HV connections between substations. Remote control signals, voice communication, and control between substations are made possible by the introduction of one or two wave traps at each end of the overhead line.

They are effectively a low-pass filter which has virtually no impedance to power current and a very high-impedance to high-frequency current which can be maximized at the chosen communication frequency. They are generally located outdoors. They can be mounted in a number of ways:

- Underhung or suspended from line entry gantries.
- Mounted on insulators on separate structures; see, example, Fig. 12.52.
- Mounted on top of OHL circuit capacitor VTs.

Mounted inside the line trap are a number of components the main item being the tuning device. This is for single frequency, double frequency, or wideband tuning and is selected for the range of frequencies to be communicated over the network.

The protective device is a surge arrester connected across the coil terminals to protect the line trap against transient overvoltages.

To prevent birds entering or nesting in the line trap, bird barriers can be fitted as shown in Fig 12.53. They are designed to ensure that the line trap has adequate cooling.

### 12.11.3 Neutral Earthing or Grounding Resistors

Neutral earthing resistors (NERs), also called neutral grounding resistors, are employed in medium-voltage a.c. distribution networks to limit the current that would flow through the neutral point of a transformer or generator in the event of an earth fault. Earthing resistors limit fault currents to a value that does not cause any further damage to switchgear, generators, or transformers beyond what has already been caused by the fault itself.

There are two types of NER:

**Fig. 12.52** Example of line traps mounted on insulators on separate structures

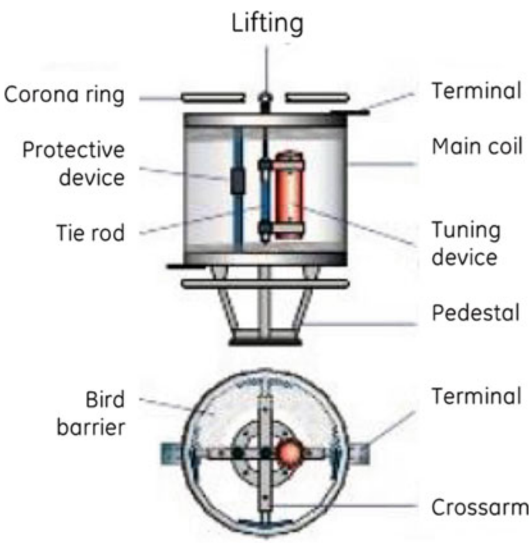



**Fig. 12.53** Line trap components

(a) Liquid filled which are filled with a custom sodium carbonate (soda ash) electrolyte solution. This has to be accurately calibrated and must be recalibrated, offline, every 2–4 years.
(b) Wound fixed resistors mounted in air-cooled enclosures (Fig. 12.54).

### 12.11.4 $SF_6$ Gas

Circuit breakers, GIS, gas-filled transformers, gas-filled instrument transformers, etc. all require sulfur hexafluoride ($SF_6$) gas to operate to specification. $SF_6$ is an excellent insulating and arc-quenching medium and has been used in switchgear applications since the 1960s.

At normal atmospheric pressure and temperature, $SF_6$ is a colorless gas. When supplied to site, it is delivered in steel cylinders in a pressurized liquid form, at approximately 22 bar at 20 °C. When used in substation equipment, it must remain in gaseous form; however, as the ambient temperature drops, then liquefaction occurs, i.e., it changes from gas to liquid form.

The atmosphere inside the switchgear must be that of pure $SF_6$ (Table 12.17).

Prior to introducing the gas into the equipment, the inside space of any equipment must first be dried out by removing any moisture. The gas too must have a low moisture content, the condensation of moisture as liquid (droplets = dew) or solid (ice) occurs when the moisture partial pressure reaches a critical dew-point value [°C].

For equipment located in severe cold climates, jacket heaters can be fitted to maintain a minimum temperature inside the switchgear above the liquefaction point (Fig. 12.55).

**Fig. 12.54** Examples of (left) liquid and (right) enclosed wound resistor NERs

**Table 12.17** Maximum acceptable impurity levels for new gas (IEC 60376 ed. 1)

| Impurity | Specification |
|---|---|
| Air | 0.05% w |
| $CF_4$ | 0.05% w |
| $H_2O$ | 15 ppmw |
| Mineral oil | See note |
| Total acidity expressed in HF | 0.3 ppmw |
| Hydrolysable fluorides, expressed as HF | 1.0 ppmw |

Note: $SF_6$ shall be substantially free from oil. The maximum permitted concentration of oil and the method of measurement are under consideration

## 12.11.5 $SF_6$ Gas Analysis and Processing Equipment

The $SF_6$ gas to be introduced from the gas cylinder to the equipment must be handled carefully so as not to introduce any contaminants. The equipment must be evacuated for a defined number of hours, often overnight, and then filled with the pure gas of the required dew-point temperature. To ensure this is done correctly, gas handling specialist equipment is used to evacuate and fill in a single process (Fig. 12.56).

Temperature and pressure are critical to the operation of the equipment, and these must be measured and recorded at the time of filling. To ensure that the correct volume of gas is installed in the equipment, the manufacturer normally specifies a weight of gas per equipment, pole, or compartment. Scales are employed to measure the gas cylinders before and after filling to ensure the correct quantity of gas has been installed.

**Fig. 12.55** Jacket or blanket heating on circuit breaker

**Fig. 12.56** On-site $SF_6$ gas handling equipment

**Table 12.18** On-site $SF_6$ measuring devices

| Device | Quantity | Range | Minimum accuracy |
|---|---|---|---|
| $SF_6$ pressure gauge | Pressure | 0–1 MPa | ±10 kPa |
| Thermometer | Temperature | −25 to 50 °C | ±1 °C |
| Dew point meter | Moisture | Dew point, −50 to 0 °C | ±2 °C |
| $SF_6$ content measuring device | $SF_6/N_2$, $SF_6$/air | 0–100% by vol. | ±1% vol. |
| Reaction tubes for impurity detection | $SO_2$ oil mist | 1–25 ppmv | ±15% |
| | | 0.16–1.6 ppmv | |

Table 12.18 shows measuring equipment used when processing the $SF_6$ gas. Other equipment include weighing scales, as mentioned above, and once the gas has been installed, a tightness check can be undertaken using a handheld leak detector device. This will make sure all gas joints are suitably tight and leak-free.

## References

CIGRÉ TB 544: MO surge arresters-stresses and test procedures (2013)

ICLP-435: Overview of IEC Standards' recommendations for lightning protection of electrical high-voltage power systems using surge arresters (2014)

IEC 60099-4, Ed 3.0: Surge arresters – part 4: metal-oxide surge arresters without gaps for a.c. systems (2014–06)

IEC 60099-5, Ed. 2.0: Surge arresters – part 5: selection and application recommendations (2010–05)

# Construction of Air-Insulated Substations 13

Akira Okada

## Contents

13.1 Construction Method ........ 334
13.2 Site Logistics and Transportation ........ 339
13.3 Construction Quality Control ........ 340
13.4 Outage Management ........ 341

After selection of materials and equipment, the next step is to physically construct the substation. The construction process is the process of using the engineering drawings and specified material and equipment to physically construct a new substation or add to an existing substation as required.

Where new substations are required, the construction process involves the physical transformation of a plot of land into a substation site. Refurbishment and upgrading projects are more complicated and require methodical planning and sequencing during the construction process.

Due to the complex nature of substations, the construction process is usually affected by variable and differing conditions for each project, constrained by the specific circumstances and actual condition of the substation site. As AIS is fully composed of air-insulated components, one of the main issues to contend with during the engineering and construction process is the insulation distance required for the different equipment such as insulators and/or bushings, circuit breakers, disconnecting switches, surge arrestors, instrument transformers, power transformers, capacitors, bus bars, conductors, and so on.

This chapter will describe some of the key principles and requirements to manage the construction process successfully by completing the substation within the allocated budget and time schedule. The client will need to evaluate carefully the

A. Okada (✉)
Global Business Division, Hitachi, Tokyo, Japan
e-mail: akira.okada.on@hitachi.com

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strengths and weaknesses of its organization before deciding on the suitable options to employ for the construction process.

## 13.1 Construction Method

The construction process brings together the activities of design engineering, procurement, and construction. A client has several construction methods or contracting options to choose from when embarking on a substation project. These are:

(a) Turnkey
(b) In-house engineering/procurement/construction
(c) In-house engineering/procurement and giving out construction to a contractor
(d) In-house engineering and giving out procurement and construction to a contractor

The main benefits and risks for the different construction options are summarized in the table below. The client has to evaluate carefully the strengths and weaknesses of its organization and of the available contractors, the project needs, and the commercial requirements to select the suitable construction method for the substation project.

CIGRE brochure #354 provides more detailed information (Table 13.1).

Most utilities tend to adopt Option (c) above, i.e., in-house engineering/procurement and giving out construction to contractor, especially for expansion and replacement projects. As each substation project is unique, utilities may choose to adopt a

**Table 13.1** Allocation of responsibilities by type of contract

| | Engineering | Procurement | Construction | Remarks |
|---|---|---|---|---|
| **Turnkey** | By contractor | By contractor | By contractor | Less coordination for utility<br>Less risk for utility<br>Project time is normally shorter |
| **In-house eng, procurement, and construction** | By utility | By utility | By utility | Higher risk for utility<br>Utility should be experienced<br>Utility should be resourceful |
| **In-house eng and procurement and giving out construction** | By utility | By utility | By contractor | Utility has control of equipment selection and cost |
| **In-house eng and giving out procurement and construction** | By utility | By contractor | By contractor | Suitable for upgrading/ replacement projects |

different type of construction method depending on the specific nature and circumstances of each project.

CIGRE's research as documented in brochure #354 shows that most utilities agree that in the current socioeconomic climate, the main constraints for a substation project are:

(a) Land construction increases, driving costs up
(b) Shorter civil construction period to build a new substation
(c) Restrictions on transportation of equipment
(d) Requirement for a short installation period

Therefore, it is very likely that similar constraints will be faced by any substation project as well. Generally, the approach to cost reduction of AIS should concentrate on minimizing construction time and eliminating mis-sequencing of construction activities. This could be achieved by standardization of design, construction process, and methods. Or some utilities may prefer to use turnkey construction method instead of the other traditional construction methods due to these constraints.

Irrespective of the construction method chosen, construction processes have to be methodically planned and sequenced in order to optimize construction costs. Integral to this is having a proper project management plan and project schedule. One of the most important aspects of the project management plan is achieving a balanced critical path management with the following key points in the project execution:

- Flow of work should not be reversed (Fig. 13.1).
- Work execution should be matching with time schedule (Fig. 13.2).
- Complete compliance with required interface engineering (Fig. 13.3).

The project execution flow in Fig. 13.1 illustrates the flow of work that should be done after the contract is awarded to the service provider in a turnkey project.

This flowchart is an actual example that was used in a real turnkey project. The visual presentation of using a flowchart is important as it allows all parties to easily understand the workflow of the project. The use of a flowchart will also encourage all parties to adopt a common and systematic approach to the execution of the project. A good flowchart will also identify all the key activities that are contained in a substation project.

One of the most important tools of a project management plan is to have a project time schedule that identifies the key milestones in the project. As an example, Fig. 13.2 shows the typical time schedule of construction work for different types of substation project:

- AIS
- MTS
- GIS
- Removal of existing substation if required

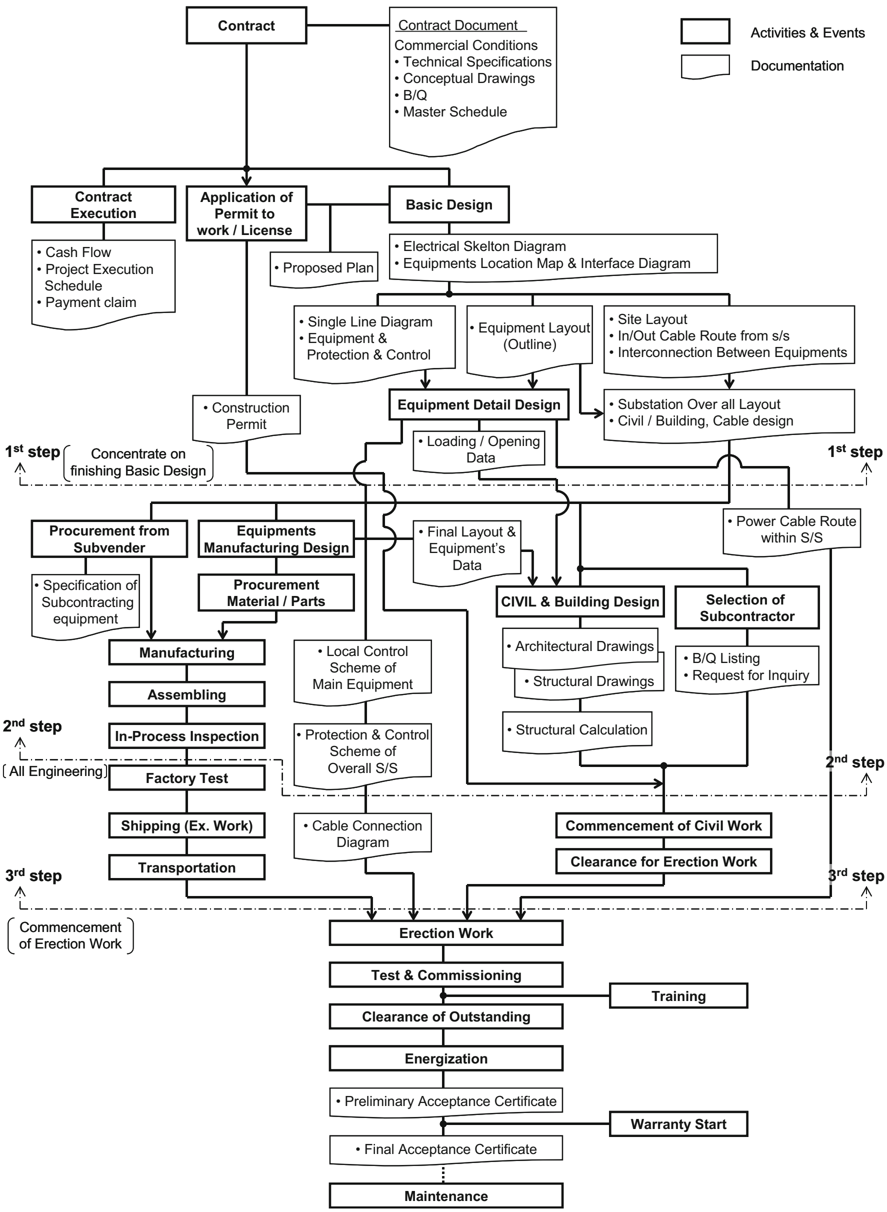


**Fig. 13.1** Example of project execution flow

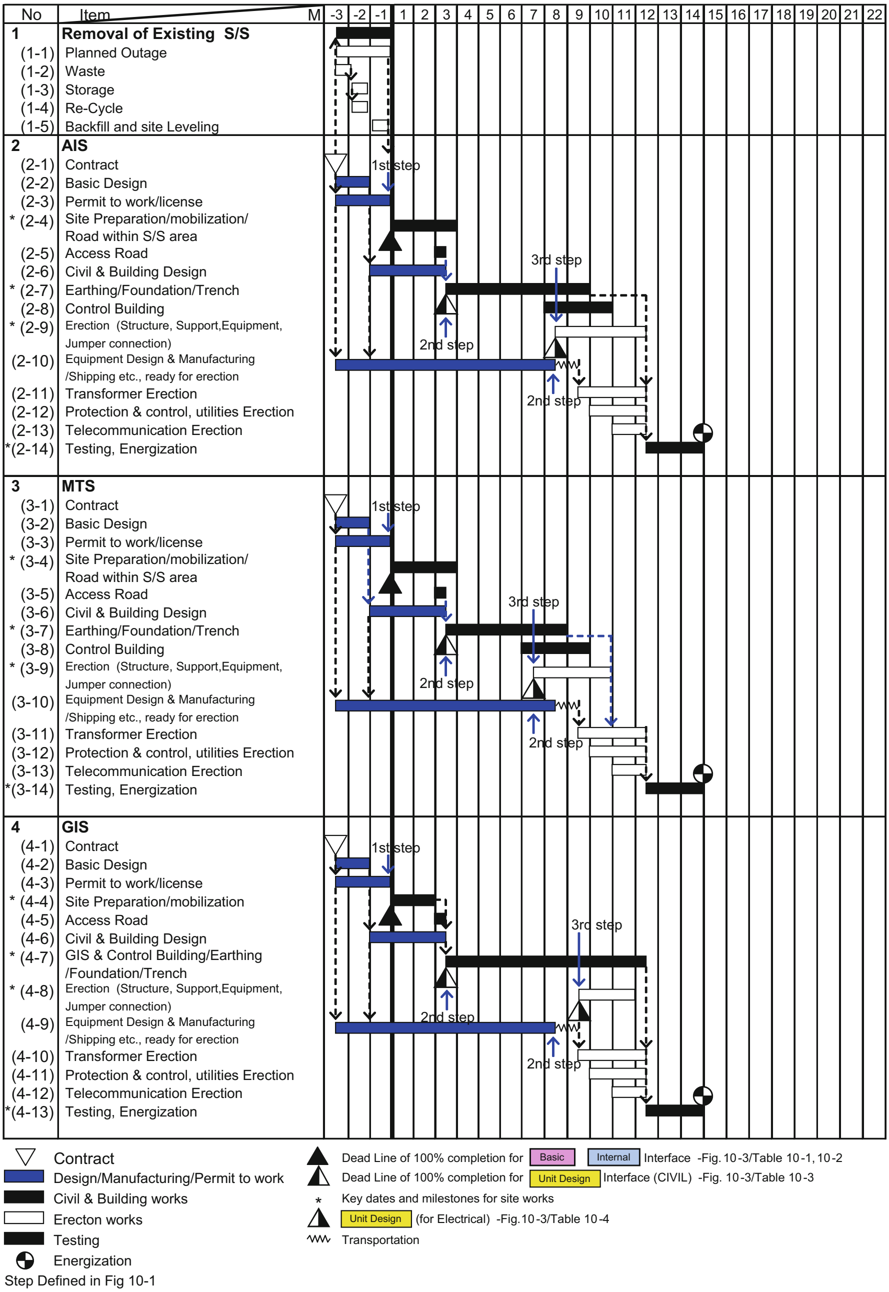


**Fig. 13.2** Example of time schedule

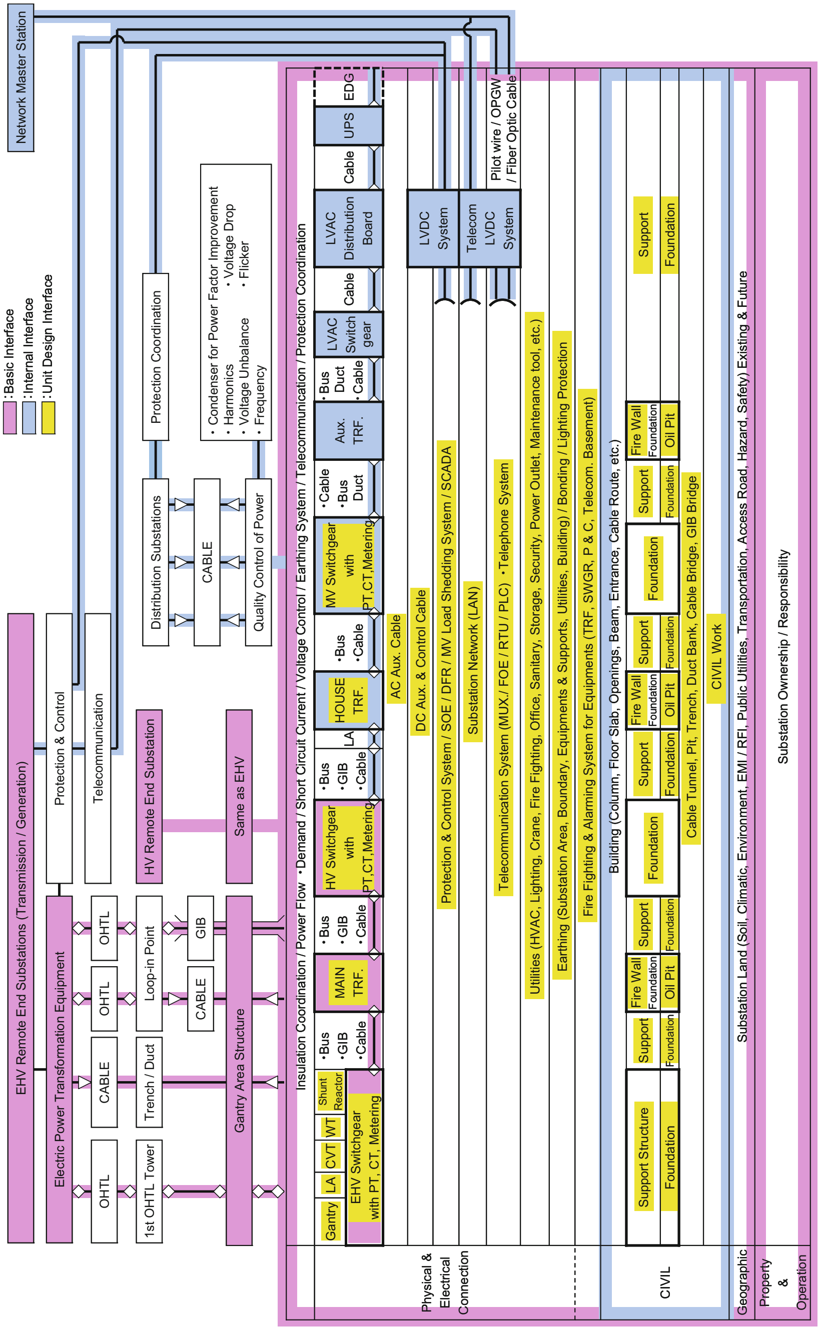


**Fig. 13.3** Example of engineering interface for a typical substation project

In a typical schedule, there are generally four key dates and milestones for construction works:

- Commencement of site preparation/mobilization
- Commencement of civil building/foundation works
- Commencement of erection (installation of structures and equipment)
- Energization

The three steps listed in Fig. 13.1 must be performed in sequence according to the time schedule shown in Fig. 13.2

- 1st step – Concentrate on finishing basic design which enables the two major teams (the equipment/civil and erection) to start their own activities in parallel
- 2nd step – Prepare all engineering for commencement of civil works including permission for construction and all engineering for manufacturing equipment and delivery to site
- 3rd step – Commencement of erection work

After the 3rd step, the next target is energization. But it is important to recognize that the 1st step and 2nd step are the most important for overall coordination and management.

Figure 13.3 shows the necessary engineering works for a typical example of a turnkey substation project. Complying with project execution flow and time schedule requirements described earlier, the priority of the engineering works can be classified as:

- Basic interface
- Internal interface
- Unit design interface

By observing the project execution flow, time schedule, and engineering interface, substation projects can be managed successfully. More information about these strategies can be found in brochure #439.

## 13.2 Site Logistics and Transportation

AIS equipment can be fragile and normally requires delicate handling during transportation and installation. The delivery and storage of materials and equipment require detailed coordination to ensure that they are delivered on time, handled, and stored properly on the substation site.

The most suitable delivery options for the major equipment and material for the project must also be considered. The delivery options could be:

(a) On-time delivery
(b) Storage at the manufacturer's site
(c) Storage by the utility/client

Effective management of the site construction logistics is one of the factors which affects the cost of substation project. For prudent planning, it is advisable to ensure that a suitable temporary storage facility is provided at the substation site for storing equipment and material prior to installation. As each substation site is physically unique, the challenges for logistics and transportation are different. It is essential that a transportation and logistics plan is prepared specifically for each project, addressing the constraints for the substation site and the transportation route.

A project transportation plan should include, as a minimum, the following components:

(a) Freight instructions/specifications (this could include instructions when a certain item must be transported in a particular orientation to avoid damage)
(b) Pro forma packing lists
(c) Nominated freighting and forwarding companies
(d) Procedures for shipping release
(e) Route of land transportation
(f) Unloading procedures
(g) Heavy lifting plan for bulky consignments/cargo
(h) Timing of freight and delivery

Most of the substation equipment is bulky and requires special consideration during transportation. As part of the transportation process, it is important to ensure that the transportation company conducts a predelivery road survey to identify the following items:

(a) Entire route of transportation
(b) Any traffic restrictions for movement of large trailers
(c) Obstacles such as gantries, overhead lines, and bridges
(d) Limitation of road and bridge widths
(e) Limitation of allowable axle load on bridges
(f) Temporary roads at construction site (required or not)

While the transportation company usually conducts such a survey, it is important that this is included as part of the checklist in the project management plan to minimize any unforeseen difficulties during transportation of major equipment. This would play an important part in ensuring that equipment is delivered to the construction site safely and on time.

## 13.3 Construction Quality Control

Quality control is one of the most important aspects in substation projects and is also one of the key areas where cost can be reduced by minimizing construction errors and deviations. Most utilities, suppliers, and contractors will have their own quality control manuals and procedures. Contractors should be required to submit a quality control plan that documents all the necessary procedures and steps for construction work.

While it is important to ensure that quality standards are adhered to, it should be noted that overzealous quality control measures and unnecessary requirements will add to the overall project cost. Therefore, a balance between critical quality control and cost should be achieved.

To prevent accidental equipment damage, it is recommended that heavy steelwork be installed first; equipment can next be installed and tested and bus work will follow.

One of the cost-effective methods used to reduce the cost of the substation control, metering, and protection equipment is to fabricate, install, wire, and interconnect this equipment locally in the factory.

In any project, it is inevitable that claims or variances will arise in the course of the project. Variances may arise due to many reasons; however in most instances variances arise due to a combination of the following:

- Incomplete specification
- Inaccurate scope of work
- Missing scope of work
- Delays caused by other reasons (such as regulatory approval) or other contractors
- Changes in substation layout
- Changes in technical requirement of equipment

Variances and claims must be kept up-to-date and regularly reviewed as this affects the overall budget for the project. In order to minimize potential problems caused by engineering, the project engineering should be planned in a systematic manner. Most utilities have a standard practice/procedure to evaluate construction deviations from the design. In general, any construction deviation has to be reported by site inspection teams and approved by design engineering teams. This ensures that all deviations are properly recorded and evaluated before the deviation is approved. During construction, the construction quality can be controlled by diligent site supervision, adherence to ISO requirements, material quality, and so on.

## 13.4 Outage Management

During construction of the substation, there may be a need for outages in projects that involve existing "live" substations such as extensions, upgrading or replacement of transformers, switchgear feeder bays, and bus sections. The most popular choice is to provide a partial shutdown; very few utilities adopt a full shutdown approach.

Even if it is a new substation project, an outage may be required at an existing remote-end substation for feeder connection and testing of the related control and protection system between the substations.

Normally, utilities will try to minimize the outages during the construction period. Outage schedules are usually coordinated with transmission or network regulators to minimize the outage period. In some countries, outages are associated with network performance indicators, which could be subject to financial penalties by the network regulator.

Where outages are not permitted, other alternatives to maintain the network supply will have to be considered, such as providing temporary supply by using mobile substations.

# Instruction Manuals and Training for Air-Insulated Substations

# 14

Mark McVey

## Contents

14.1 Instruction Manuals ... 343
14.2 General Training ... 345
14.3 Operations, Installation, and Maintenance Training ... 346
14.3.1 Installation Training ... 346
14.3.2 Maintenance Policy ... 347
14.4 Safety Training ... 348
14.5 Safety Procedure for On-Site Work ... 350
14.5.1 Work Planning ... 350
14.5.2 Awareness ... 353
14.5.3 Verification ... 353
14.6 Design for Safety and Human Protection ... 355

## 14.1 Instruction Manuals

Manuals and documentation are an important part of substation design standards. IEEE, IEC, and CIGRE brochures are uniquely referenced by manuals as each electric utility or asset owner drafts manuals based on experience and lessons learned. Instruction manuals include many of the chapters contained in this book. An example of standard design topics may include the following:

- General location and detail of symbols used for drawings
- Substation designs, current utility design practice
- Substation single-line diagrams and drawing standards
- Busbar scheme
- Fault current levels and calculation of mechanical forces

M. McVey (✉)
Operations Engineering, Dominion Energy, Richmond, Virginia, USA
e-mail: mark.mcvey@dominionenergy.com

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- Neutral point earthing or grounding standards
- Electrical equipment design standards and operation instructions and ratings
- Switching guidelines and operator instructions for loop splitting and line dropping
- Control design standards and general practice
- System protection and relay standards and general practice
- LV AC/DC calculation
- Electrical equipment standards and ratings
- Equipment loading guidelines
- Preliminary engineering and estimating guide
- Permitting and regulatory guidelines
- Environmental procedures, process, and regulatory requirements for design and construction
- Utility safety manual
- Foundation drawing
- Architectural, civil drawings, and calculations
- Earthing drawings and calculations
- Power cable layout
- Insulation coordination study document
- Assembly drawings for steelwork

Wherever possible, instruction manuals should be requested and provided for each and every piece of equipment or material in a substation. Manuals should not only include all primary and secondary substation equipment but also include auxiliary devices that are not related to the substation equipment but form a part of the overall substation asset and are important to document. Examples of some of these auxiliary items includes:

- Water pumps for firefighting system
- Fire alarm panel
- Substation security systems such as CCTV equipment, intruder alarm system, remote/electrically operated gates and doors
- Control building assets such as air-conditioning or heater systems

In addition to instruction manuals, other documentation such as as-built drawings and test reports related to the substation equipment must be properly maintained. These items include:

- Substation plan drawing and layout drawing
- Foundation drawing
- Architectural, civil drawings, and calculations
- Earthing drawings and calculations
- Equipment layout
- Power cable layout
- SCADA/relay panel layout, manual
- Equipment instruction manual
- AC power supply single-line diagram

- DC power supply single-line diagram
- Control cable connection drawing
- LV AC/DC calculation
- Power cable current calculation
- Insulation coordination study document
- Assembly drawings for steelwork
- Equipment detail drawings
- Protection and control schematic drawings
- Relay protection and control settings
- Ground grid readings
- Test reports of all equipment

As-built documentation is extremely useful for reference and important for future modification. Accurate as-built records are essential to ensure that future modification or extension schemes are correctly interfaced between existing and new equipment. Updated accurate documentation will reduce potential errors and incorrect engineering during modification and extension work.

As-built drawings must be checked and revised by site project staff before completion of the project or before staff are transferred to another project. Every point of checking must be completed by that time. A process should be established to ensure accuracy.

CIGRE brochure #354 provides additional detail and information and can be reviewed for reference and additional detail.

## 14.2 General Training

Depending on a utility's or asset manager's organization structure and philosophy, different training types or levels for different classes of employees may be necessary.

General training may be provided for nontechnical employees that are not involved in day-to-day operation of the substation. For example, this could be general training for new employees.

These kinds of training should cover basic understanding of electrical network and substation operation. Some of the suggested topics to include in the training material are:

- Information about the electrical transmission and distribution network of the utility
- Function of major equipment
- Process of electric transmission and distribution from generation to end user
- Process of substation construction and installation
- Process of equipment testing and commissioning
- Simple step-by-step illustration of daily substation operation and maintenance activities
- Safety aspects while visiting/working in a substation environment

It is advisable that diagrams should be used as much as possible to illustrate the above, as the audience may not be technically knowledgeable. With today's access to digital cameras, it is possible to film a training session to refresh knowledge or train new employees at a later time. Documenting training by recording is a new tool that is effective at reaching a large number of employees in any utility organization.

## 14.3 Operations, Installation, and Maintenance Training

It is common for utilities and asset owners to have an in-house operation and maintenance (O&M) team for AIS substation equipment. In order that maintenance and repairs can be performed quickly and effectively, it is often important that the utility staff (or staff of the utility's maintenance contractor) are familiar with the specific utility equipment within the substation. Routine training may have to be provided to ensure that necessary skills and experience are retained throughout the life cycle of the substation.

Employees will require technical support and advice as needed. Continuity of core knowledge and procedures should be ensured either from the original manufacturer or from another source (such as utility's central engineering group). Contractor or consultant training is also an alternative with careful evaluation.

Depending on the structure and policy of the organization, it is essential that regular training is provided for the O&M group, particularly when a new type or model of equipment is to be installed in a project. An example would be a new or nonstandard technology.

In general, O&M training must include step-by-step guides for operation and troubleshooting of the equipment, including all specific safety precautions pertaining to the equipment. It is advisable to include a hands-on session during the O&M training. Development of evaluation tools such as implementing a test or scoring system to ensure trainees have attained sufficient knowledge is a good method. It is important to evaluate the effectiveness of training and gauge the overall knowledge of employees. In some countries the training is a formal process, and certificates or badges are required to perform maintenance tasks. Each asset owner must become familiar with local compliance standards.

### 14.3.1 Installation Training

Many utilities employ contractors and consultants for everyday engineering and for large projects. These projects are referred to as (EPC) Engineering, Procurement, and Construction and are delivered to the utility as turnkey. After completion of a substation installation project, a substation is handed over to the operation staff who will operate and maintain the substation. As part of the operation procedures for the substation and its equipment, it is essential to provide instruction manuals and training to the operating staff.

For every substation project, it is a common contractual requirement that the equipment manufacturer, installer, or contractor provides instruction manuals and training at the conclusion of each project. Documentation and training must be a requirement written into the turnkey contract agreement.

As the owner and operator of the substation, specifying the standard or contents of the instruction manuals according to the utilities document preference or standard is necessary. Items to include might be the format of the drawings, maintenance requirements, spare parts, safety bulletins, and vendor instruction manuals.

It is also advisable to specify the expectations of training that is required for the owner operator. In most cases, utilities will specify the number of training days to be provided. All training must include a session or chapter on safety procedures for working in a substation. Both classroom and hands-on field training are typical as a deliverable.

Proper instruction manuals coupled with effective training will lead to more efficient maintenance of the substation by operation maintenance staff. Properly identified scopes and instructions allow the asset owner to optimize the strategic maintenance plan which will result in a significant cost reduction impact and improve the total cost of ownership. It is important to allocate sufficient time and resources for mutual discussions between owner and contractor about future planned maintenance, as instruction manuals are useful only for normal maintenance, not for strategic maintenance.

### 14.3.2 Maintenance Policy

Each utility or asset owner will have its own standard maintenance policy or required set of safety instructions. If an organization does not have a maintenance policy established, consider developing a maintenance policy that is suitable based on the organization's needs, compliance, and available resources.

Figure 14.1 provides a generic type of maintenance philosophy or structure. There are different options to perform maintenance. All steps are included under preventive maintenance, and these terms refer to any activity that is designed to:

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

Preventive maintenance frequencies can be varied according to the deterioration and failure rates, the operating strategy, the cost of performing the activity, and the penalty associated with asset failure. Decision models for timing of inspection, repair, and replacement based on asset failure data can be useful. It is possible to distinguish two features, an activity to be performed and a frequency at which the activity is performed. Maintenance policy is not a one-size-fits-all strategy. Each utility or asset owner should develop a combination of policies

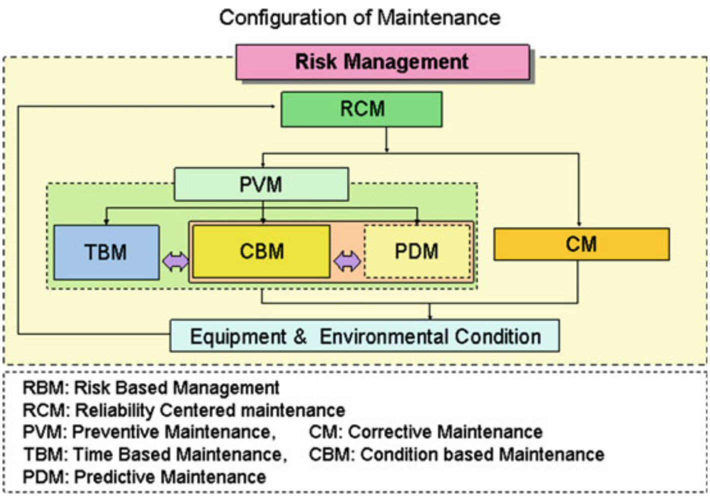



**Fig. 14.1** Configuration of maintenance

based on an individual business model and or compliance to a specific reliability requirement.

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

Some utilities complain about the increasing pressure of cost savings; therefore they have to set priorities and invest in replacement/refurbishment of the most critical equipment. For this type of maintenance driver, the asset owner evaluates the substation physical and operating condition and then decides what to do. Only severe failure on certain type of equipment will influence the procedure. Each asset owner has to evaluate the business driver for maintenance.

In a corrective maintenance strategy, the expenditure on operation and maintenance will be low, but if a failure occurs the expenditure on operation could be very high.

Asset owners may refer to CIGRE brochure #300 for more detailed information on maintenance policies and tools for assessment and asset evaluation.

## 14.4 Safety Training

Each utility and country has specific safety requirements and rules to be followed on which training must be provided to all employees. These requirements or rules safeguard the employee and the public from electrical and physical hazards.

(a) **Proper use of personal protective equipment (PPE)**
Each employee needs to be instructed in the proper use of personal protective equipment. This equipment is the minimum protective equipment to be worn at a

**Fig. 14.2** Example of PPE

substation or work site to prevent electrical shock or physical harm to personnel. An example of equipment can be hard hats, eye protection, leather gloves, steel toed-steel shank electrical hazard-rated boots, fire retardant clothing, and reflective vests. The proper use of shields or clothing must be identified at a job site and clothing of the proper rating supplied for work in an arc flash area. An example of PPE is shown below: (Fig 14.2)

(b) **Proper work area clearance and minimum approach distance from energized conductors and magnetic fields**
In North America and many other countries, there are electrical standards and government agencies that specify how close employees or the public can approach energized electrical facilities. Approach distances are different from minimum acceptable clearances for fixed installed electrical equipment. The substation design must be designed for qualified workers to be able to operate and maintain an energized substation. Each utility and contracting company must comply with regulatory rules and should supply training and supervision for work around or in proximity to energized conductors and equipment. To develop a standard the calculation of minimum approach distance (MAD) is covered in ► Chap. 5 of this book. Examples of standards that cover MAD in the USA are IEEE 516 and the US National Electric Code (NEC). The codes or

work rules are determined to help keep public and employees safe by dividing the distances into qualified (trained) and unqualified personnel. An example of these distances for the USA is shown below: (Fig 14.3)

(c) **Certifications or qualifications required to design electrical substation or to perform work such as switching, use of tools for energized work, live line work, gloving, and bare handing.** Each country has specific requirements or certifications necessary for employees. Many government and utility employees are required to demonstrate and pass a professional certification test. There are wide varieties of requirements and standards from country to country that govern employee qualifications to design and work at an electrical facility. Each locality or utility must adopt or develop a program for qualified electrical workers. A Professional Examination (PE) process requires an engineer to display knowledge and experience of physics, mathematics, and engineering to design electrical facilities. Most programs require an internship or apprentice program to meet the requirements necessary for final certification. An example of programs for electrical workers, in North America, is an electrical union like the International Brotherhood of Electrical Workers (IBEW). The IBEW provides training and certification for work from apprentice to line worker or substation electrician. In the UK a similar program exists where electrical workers pass steps of certification and earn badges to be able to perform specific types of work. In the UK before a contractor is allowed to perform a specific task of construction or maintenance, the worker must provide proof of qualification by displaying appropriate badges.

## 14.5 Safety Procedure for On-Site Work

There are three areas of focus for safety procedure necessary to protect personnel and substation equipment and prevent accidental or forced outages of customers. The sections are “Work Planning” Sect. 14.5.1, “Awareness” Sect. 14.5.2, and “Verification” Sect. 14.5.3.

### 14.5.1 Work Planning

**Prejob Briefing** – Before each task prior to or upon entering a substation or work site, a review of work and responsibilities is to be performed. Each individual entering the station needs to have a clear understanding of how their work or presence in the work zone impacts other individuals or workers. A clear understanding of emergency procedures for injuries or accidents should be discussed and documented. An example is shown below: (Fig 14.4)

**Operating Experience and Quality Alerts** – Utilities should and often do document equipment problems, accidents, and injuries to personnel from work experience. A database of human performance events should be designed and documented to prevent repetition of performance events. Prior to start of work, the

| SAFE ELECTRICAL WORKING CLEARANCE TO LIVE PARTS | | | |
|---|---|---|---|
| MINIMUM APPROACH DISTANCE (MAD) | | | |
| | Dominion Qualified Electrical Worker | | Non-Qualified Electrical Worker |
| Voltage (P-P) | MAD (P-G) | MAD (P-P) | MAD (P-G) |
| 0 V to 300 V | Avoid contact | Avoid contact | Avoid contact |
| 301 V to 750 V | 1'-2" | 1'-2" | 10' |
| 751 V to 15,000 V | 2'-2" | 2'-3" | 10' |
| 15,001 V to 36,000 V | 2'-7" | 3' 0" | 10' |
| 36,001 V to 46,000 V | 2'-10" | 3'-3" | 10' |
| 46,001 V to 72,500 V | 3'-4" | 4'-0" | 10'-9" |
| **72,600 V to 121,000 V[3,4,5]** | **3'-3"** | **4'-0"** | **12'-5"** |
| **121,001 V to 145,000 V[3,4,5]** | **3'-8"** | **4'-8"** | **13'-2"** |
| **169,001 V to 242,000 V[3,4,5]** | **5'-3"** | **7'-5"** | **16'-5"** |
| **362,001 V to 550,000 V[3,4,5]** | **10'-6"** | **16'-2"** | **26'-8"** |

Note 1: MAD also applies to work platforms and reach with hand tools.

Note 2: MAD for voltages equal to and less than 72.5 kV reflect the OSHA 1910.269 values (April, 2014)

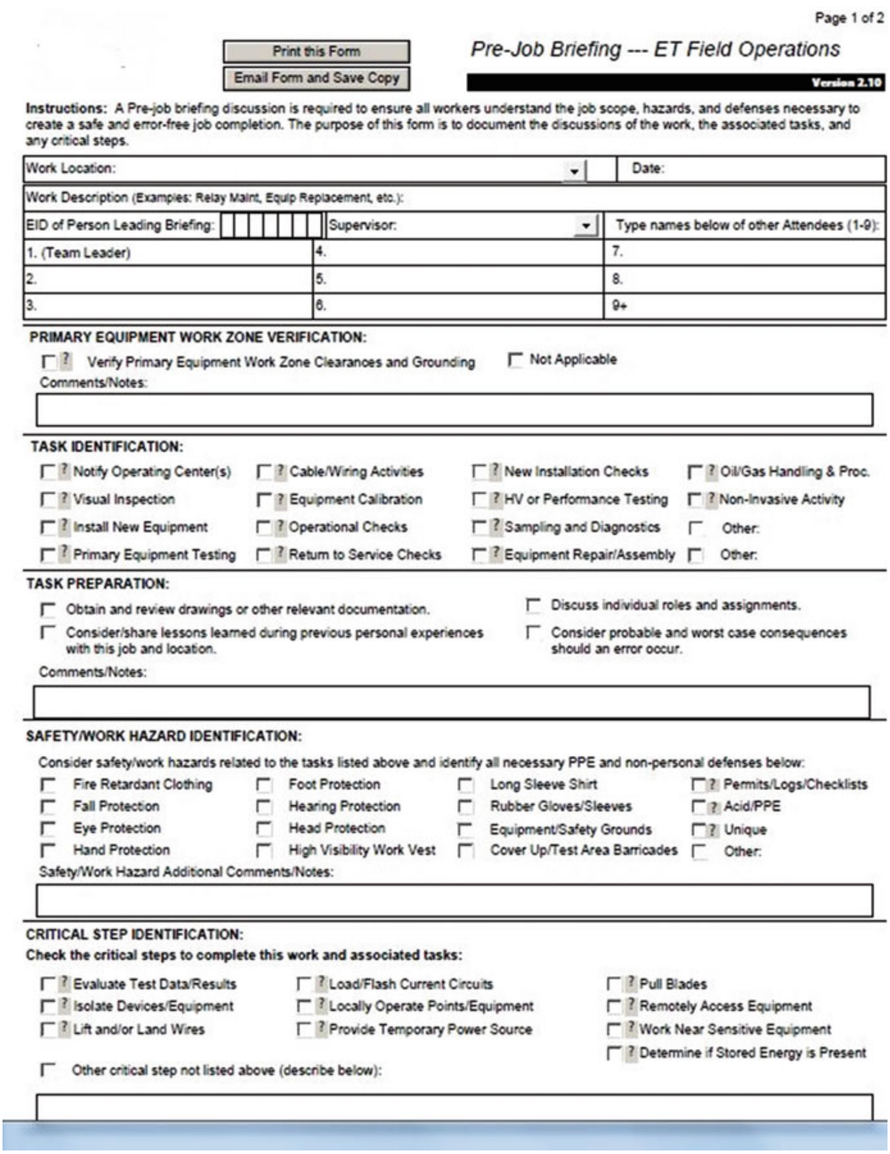
**Note 3: The distances specified for voltages greater than 72.5kV are the air, bare-hand, and live-line tool distances.**

**Note 4: MAD for voltages greater than 72.5kV are based on an engineering study of the Dominion system and maximum TOV values as calculated according to 29 CFR 1910.269 and IEEE 516 (2009)**

**Note 5: To utilize calculated approach distances above 72.5kV reclosing, switching surge, terminal arresters, and weather must be considered**

Note 6: Multipy MAD by a 1.05 correction factor for a working altitude between 3001'-5000'.

**Fig. 14.3** Example of safe working clearances


Page 1 of 2

Print this Form

Email Form and Save Copy

Pre-Job Briefing --- ET Field Operations

Version 2.10

Instructions: A Pre-job briefing discussion is required to ensure all workers understand the job scope, hazards, and defenses necessary to create a safe and error-free job completion. The purpose of this form is to document the discussions of the work, the associated tasks, and any critical steps.

| Work Location: | | Date: |
|---|---|---|
| Work Description (Examples: Relay Maint, Equip Replacement, etc.): | | |
| EID of Person Leading Briefing: | Supervisor: | Type names below of other Attendees (1-9): |
| 1. (Team Leader) | 4. | 7. |
| 2. | 5. | 8. |
| 3. | 6. | 9+ |

PRIMARY EQUIPMENT WORK ZONE VERIFICATION:

- ? Verify Primary Equipment Work Zone Clearances and Grounding
- Not Applicable

Comments/Notes:

TASK IDENTIFICATION:

- ? Notify Operating Center(s)
- ? Cable/Wiring Activities
- ? New Installation Checks
- ? Oil/Gas Handling & Proc.
- ? Visual Inspection
- ? Equipment Calibration
- ? HV or Performance Testing
- ? Non-Invasive Activity
- ? Install New Equipment
- ? Operational Checks
- ? Sampling and Diagnostics
- Other:
- ? Primary Equipment Testing
- ? Return to Service Checks
- ? Equipment Repair/Assembly
- Other:

TASK PREPARATION:

- Obtain and review drawings or other relevant documentation.
- Discuss individual roles and assignments.
- Consider/share lessons learned during previous personal experiences with this job and location.
- Consider probable and worst case consequences should an error occur.

Comments/Notes:

SAFETY/WORK HAZARD IDENTIFICATION:

Consider safety/work hazards related to the tasks listed above and identify all necessary PPE and non-personal defenses below:

- Fire Retardant Clothing
- Foot Protection
- Long Sleeve Shirt
- ? Permits/Logs/Checklists
- Fall Protection
- Hearing Protection
- Rubber Gloves/Sleeves
- ? Acid/PPE
- Eye Protection
- Head Protection
- Equipment/Safety Grounds
- ? Unique
- Hand Protection
- High Visibility Work Vest
- Cover Up/Test Area Barricades
- Other:

Safety/Work Hazard Additional Comments/Notes:

CRITICAL STEP IDENTIFICATION:

Check the critical steps to complete this work and associated tasks:

- ? Evaluate Test Data/Results
- ? Load/Flash Current Circuits
- ? Pull Blades
- ? Isolate Devices/Equipment
- ? Locally Operate Points/Equipment
- ? Remotely Access Equipment
- ? Lift and/or Land Wires
- ? Provide Temporary Power Source
- ? Work Near Sensitive Equipment
- ? Determine if Stored Energy is Present
- Other critical step not listed above (describe below):

**Fig. 14.4** Example of work planning form

leader or person responsible for work should perform a review of the database for similar work types or work to be performed. The ability to learn and prevent danger to equipment or personnel is the purpose of database trending.

**Confirm Terminology** – Often workers have different understandings of work to be performed, and words and descriptions used can be confused based on worker culture or language translation. Workers should repeat back to leader or supervisor emergency process and work expectations. This tool is known as three-way communications where the communication is repeated back and forth to make sure there is consistent understanding between leaders and employees.

**After-Action Review** – After each workday or when employees or individuals complete tasks and exit the work zone, a summary of positive or negative job experiences should be documented. To clearly document the success of a work performance tool, each tool or new method of construction needs to be documented in the prejob briefing database for trending future analytics. The key is to develop work methods and routines that are effective, safe, and trouble-free.

### 14.5.2 Awareness

**Situational Awareness** – Often workers become complacent or fatigued and forget the dangers of their surroundings. All personnel inside the fence and especially inside a work zone should routinely assess their location relative to other workers and work hazards. Throughout the day many construction sites have multiple crews and contractors constantly changing types of work and locations in the station. Situational awareness is a tool that should be taught and learned. Several times during the day employees should stop and look for change.

**Questioning Attitude** – A helpful job skill is to always question if the work method or job requirements are proceeding as planned or have critical people or tasks changed. Always be sure employees have the correct skill, correct tool, and correct supervision to complete the objective task. There should never be an issue making frequent stop points using a questioning attitude toward safety.

**Tactical Work Zone** – Whenever possible it is important to clearly mark the work zone to instruct all workers of hazards. Shown below is an example of work zone marking to prevent the potential human error of working on the wrong panel. Clear marking and cover-up can prevent danger to employees and accidental equipment operations (Fig 14.5).

**Self-Check –** Each employee when working by themselves needs the ability and experience to perform a self-assessment. Employees should be taught to periodically stop and assess the work zone for changes such as new hazards or new people entering the station or work zone. In the case of significant exposure to cold or heat, it is important to recognize exposure to hypothermia, frostbite, or dehydration. Self-check is a learned safety habit and an attitude to be learned by all employees to detect danger to themselves or others.

### 14.5.3 Verification

**Peer Check –** Each employee should not only be responsible for themselves but should also to watch out for each other. Making sure personnel have proper PPE or MAD or communication is a prime example of a safe attitude. Teams and work


**Fig. 14.5** Example of work zone identification marking

crews must be encouraged to assess and check on each other to prevent exposure or mistakes. Most industrial accidents are not caused by one person making one big error. Most incidents are caused by several people making relatively small errors. These mistakes multiply or cascade together to cause a catastrophic accident. Employees who are checking each other on a crew and a team prevent accidents.

**Coaching –** A foreman or supervisor is immediately responsible for instructing or directing employees. Coaching is a learned behavior that all experienced employees should be encouraged and taught. Coaching and peer check are behaviors to be considered and assessed before and after any job or task. Coaching can help prevent lack of clear instruction and inexperience which can be contributing factors for any accident.

**Three-Way Communication –** Three-way communication is a technique used to ensure that each employee understands or properly conveys an instruction. One employee provides a verbal instruction to another employee. The employee receiving the instruction is now required to repeat the instruction back to the original instructor. Often this communication tool is used when communicating instructions over the phone such as a switching order. Three-way communication is a useful tool during the prejob briefing to ensure all workers are aware of on-site hazards and work expectations.

**Checklists –** Checklists were originally developed by airplane pilots to prevent errors before take-off or landing. Checklists are an essential tool to identify work hazards, coordinate work activities during construction, and identify job scope and expectations. It is too easy to skip safety steps for a complicated job or procedure. Checklists prevent errors, compensate for lack of experience, and mitigate problems with fatigue. Repetition of safe procedure not only improves productivity, but predictable performance teaches the right attitude at work. The prejob briefing form above is an example of a checklist for utility work in an energized station. The form can also be used as a way to flag progress for each day's work.

**Flagging or Pointing –** Much of communication is nonverbal. Pointing or identifying a work zone is a key component for error prevention. The use of barriers or markers to identify where to work can prevent mistakes of employees working on the wrong controls or equipment. Examples are shown below.


**Fig. 14.6** Example of work zone identification marking

**Stop When Unsure –** A key attitude for the safe performance of any job or work is the approval to and willingness to stop whenever there is a doubt on how to proceed. Accidents frequently occur when employees overreach or rush. Accidents often occur because there is a lack of communication, time pressure, lack of work knowledge or experience, and fatigue. Supervision should develop a culture allowing employees to stop and question any time they are unsure of a task or the proper way to proceed on a job site (Fig 14.6).

## 14.6 Design for Safety and Human Protection

Engineering for safety and human performance is a real and powerful concept. Effective design can be an important part of any safe work environment as often accidents can be prevented or eliminated.

**Ingress and Egress –** The ability to safely operate inside a substation is of great importance to operating and maintenance personnel. At some point mechanical or electrical equipment may operate incorrectly or fail. Workers need a clear path to safely leave the work location. A rally point should be established at each location during the prejob briefing to ensure all employees are accounted for should an accident occur. Busbar layout and switch handle orientation must be considered to allow a quick exit path in emergencies. The orientation of doors on circuit breakers and control panels must be considered to prevent them creating a trap by impeding

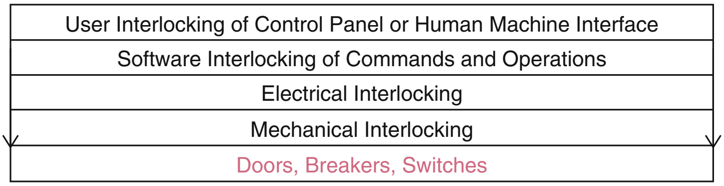



**Fig. 14.7** Types and locations of interlocking systems

**Fig. 14.8** Example of key interlocking system

escape routes. Additional doors or gates must be considered for installation to allow exit from the control house or substation if a fire or accident blocks an exit. The points of exit should be identified in any safety briefing.

**Interlocking Design –** FACTS devices or substation switchgear assemblies or switchyards can be complicated and difficult devices to operate and switch. Engineers can design interlock systems to prevent mistakes or to control access to areas of the substation until work zones have been made safe for personnel (Fig 14.7).

Interlocking key designs allow discrete control of switching and access. A worker can only go to the next operational step or gain access to a work area by working in a specific order. For example, a key to an energized area can only be obtained once a ground switch has been closed (Fig 14.8).

**Design for Human Performance –** Design of systems to prevent a single point of failure is not just a reliability practice but is a safety practice. Redundant protection and control panels allow employees to maintain or repair equipment by separating relay panels and control from different sources and communications. A relay or control panel can be de-energized so that work for maintenance and restoration can be performed. If an electrician drops a tool by mistake, the tool will not cause a short-circuit or an unintended operation of a circuit breaker or other devices. However the interactions between the redundant or duplicated systems must be carefully considered to prevent the creation of unintended scenarios.

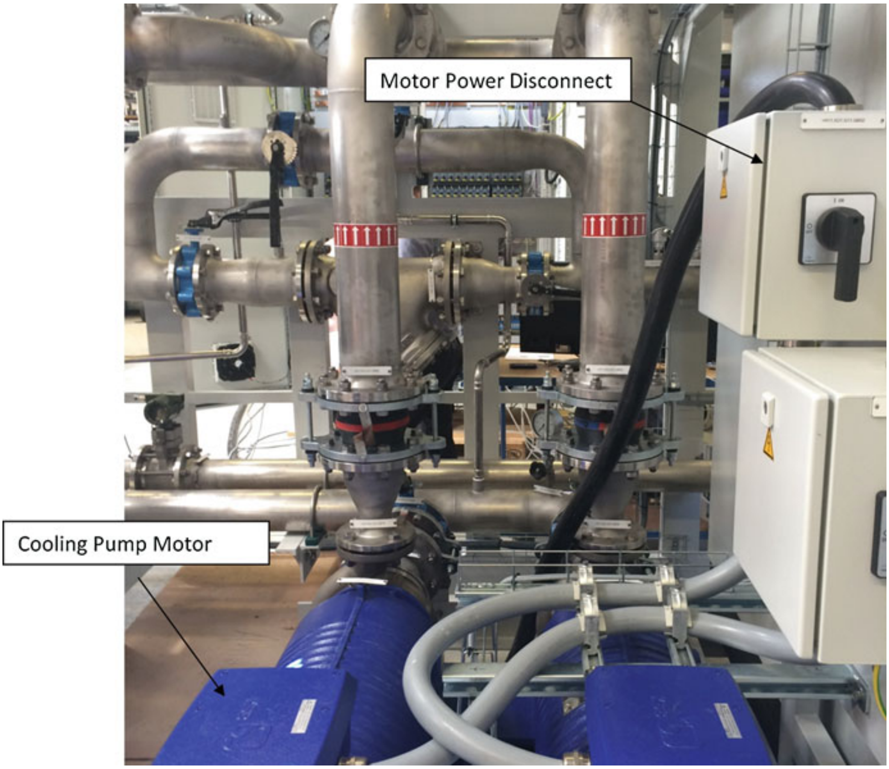



**Fig. 14.9** Location of isolation point relative to the isolated device

Employees that take personal clearance when performing maintenance need the ability to control open connection points by locking or visible control. The installation of red tags for personal clearance is essential. Shown below is an example of installing isolation points in clear sight of employees performing work. The clearance man has physical and visual control of the point of energization. Shown below is an example of a motor disconnect mounted above a cooling system motor (Fig 14.9).

Safety and training varies from utility to utility largely from regulator guidance and experience. A safety manual provides a list of minimum guidelines. Good utility practice advises that workers go beyond the minimum. Safety and human performance is guided by a culture that is developed in a workplace. Each worker has the ability to be the difference and protect their fellow employee and themselves.

# Part C

# Gas-Insulated Substations

*Peter Glaubitz*

# Why Choose GIS?

15

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

15.1 Benefits of GIS ........ 361
15.2 Impact of Environmental Conditions on Switchgear ........ 363
15.3 Switchgear Impact on Environment ........ 365
15.4 Quality Assurance/Reliability ........ 365
15.5 Safety ........ 367
15.6 Life Cycle Costs ........ 368
15.7 Conclusion ........ 368

## 15.1 Benefits of GIS

The main advantage of gas-insulated switchgear (GIS) over AIS or MTS is its compactness which has a direct influence on land requirement, land cost, visual impact, and possible technical applications. The compact size offers high variety in design which in turn allows indoor, outdoor, underground, hybrid, and containerized installations (even for temporary operation). A modular design of GIS in connection with its compactness allows specific site requirements to be met to an extent higher than it is possible for AIS.

The land area required for a GIS substation is generally in the region of 10–20% of that required for an equivalent AIS substation, considering the switchgear only.

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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The saving in overall land area depends very much upon the specific voltage level and the connection to transformers, reactors, and incoming/outgoing lines. Maximum saving is achieved by cable connections and short-length GIS trunking. If the substation is connected to overhead lines, then space will have to be allocated for towers and down droppers which might reduce the total land saving. In Figs. 15.1 and 15.2, GIS both kinds of connections are shown. In Fig. 15.1 it is connected to an OHL (overhead line); in Fig. 15.2 it is connected to a cable.

In most cases, the compactness and therefore reduced area requirement allows the optimum choice of location for new planned gas-insulated substations, based on

**Fig. 15.1** 420 kV GIS with overhead line


**Fig. 15.2** 145 kV GIS with cable connection

network requirements. For indoor or underground GIS, this is possible even in urban or highly populated areas. Quite often this will allow building of the substation at the point of consumption in urban or industrial areas which will bring significant cost savings in the distribution network.

At power stations, GIS can be erected close to turbines and generators which allows significant savings in cabling or bus duct connections and cost benefits for the civil works are also possible. The possibility of erecting the substation as close as possible to the step up transformers enhances the reliability of the whole plant.

GIS with higher ratings can be used for replacement of AIS in the event of growing power demand or for a higher transmission voltage without additional space requirements. The same applies if the need to extend AIS comes about. Two examples of replacing AIS by GIS are shown in Fig. 15.3. Figure 15.3 shows the replacement of an indoor AIS with a GIS, and Fig. 15.4 shows the replacement of an outdoor 300 kV AIS with an outdoor GIS with rated current increased from 4 kA to 6/8 kA and short circuit breaking current from 50 kA to 63 kA.

## 15.2 Impact of Environmental Conditions on Switchgear

At severe environmental conditions, for example, at coastal sites with heavy saline pollution or in industrial locations with other strong pollution deposits, the cleaning of post insulators and OHL bushings can be required at very regular, also short-term intervals. Similarly, corrosion of metallic components, flanges, electrical joints, etc. can show severe effects. Such facts can lead to very high maintenance costs for outdoor installations. A GIS enclosed within a building is immune from these effects – a major justification for the application of GIS.

**Fig. 15.3** Replacement of a former indoor 6-bays-AIS substation (150 kV) by a 5-bay-GIS substation (145 kV)

**Fig. 15.4** Replacement of a former outdoor 14-bay-AIS substation (300 kV–50 kA) by a 14-bay-GIS substation. (300 kV–63 kA) (Chubu Electric Power Company, Higashi-Nagoya S/S)

The site pollution severity (SPS) has to be evaluated during the first stages in the project. IEC/TS 60815-1 "Selection and dimensioning of high-voltage insulators intended for use in polluted conditions" describes two types of deposition of the insulators (Type A and Type B) and five types of pollution (desert, dissolving salts, solid deposits, chemical or industrial pollution, agriculture).

Similarly, where a substation has to be installed at very high altitudes, the effects of air pressure need only be considered relative to the $SF_6$/air bushings of a GIS installation (whereas for AIS these considerations could require the provision of additional costly insulation).

In case of extremely low temperatures, snow or ice, again additional measures need only be considered for the bushings and GIS parts outside the building.

In order to meet the specified requirements for seismic conditions, extensive mechanical support and bracing of an AIS may be required. The physical design of GIS allows seismic criteria to be more readily achieved at a lower overall cost. These considerations may further lead to a hybrid arrangement of GIS/AIS called mixed technology switchgear (MTS) where circuit breakers, disconnectors, CTs, and VTs may be metalenclosed per circuit with terminating bushings connecting outgoing overhead lines and an overhead busbar arrangement (see also Part D).

## 15.3 Switchgear Impact on Environment

Due to the reduced space demands of GIS compared to AIS, the impact on the environment is minimized (e.g., clearing of forests or civil works in mountainous areas). The visual impact of an AIS and associated overhead lines may not be acceptable in areas of exceptional natural or architectural beauty and places with a high frequency of population (like in a city center). The compactness of GIS allows (in a relatively uncomplicated way) a substation to be hidden from the public eye. Two examples are shown in Figs. 15.5 and 15.6.

Noise emission from a substation can also be significant, particularly where the substation is situated close to areas of habitation. The operational noise emitted from a GIS substation, particularly if it is an indoor installation, is likely to be significantly less than that of an equivalent AIS. The emission of electromagnetic fields can also be significantly lower than in the case of AIS, depending on the design of the GIS and the earthing system.

## 15.4 Quality Assurance/Reliability

Most manufacturers have installed a quality management system according to international standards. The highest-quality standard is ensured by the fact that all the equipment are developed, type tested produced, routine-tested, installed, and site-tested by one manufacturer. Parts/bays of the GIS are preassembled in the factory to the highest possible level of completeness (limited only by transport and handling restrictions, i.e., transport of pressurized vessels, measurements). The complete transport units are routine-tested (mechanical, dielectric, and tightness tests) which ensures maximum quality. In addition, the assembly steps and erection time are shortened (see also ▶ Chap. 22).

In the case of integrated or prefabricated control cubicles and cabling, all circuits and functions may be factory-tested, which significantly reduces the failure probability on site and the time for commissioning.

The final step of quality control is the on-site commissioning testing of the whole GIS assembly which includes dielectric tests.

The decrease of failure frequency of GIS has already been proven by higher reliability data. Questionnaires among users have shown that GIS commissioned so far are working satisfactorily.

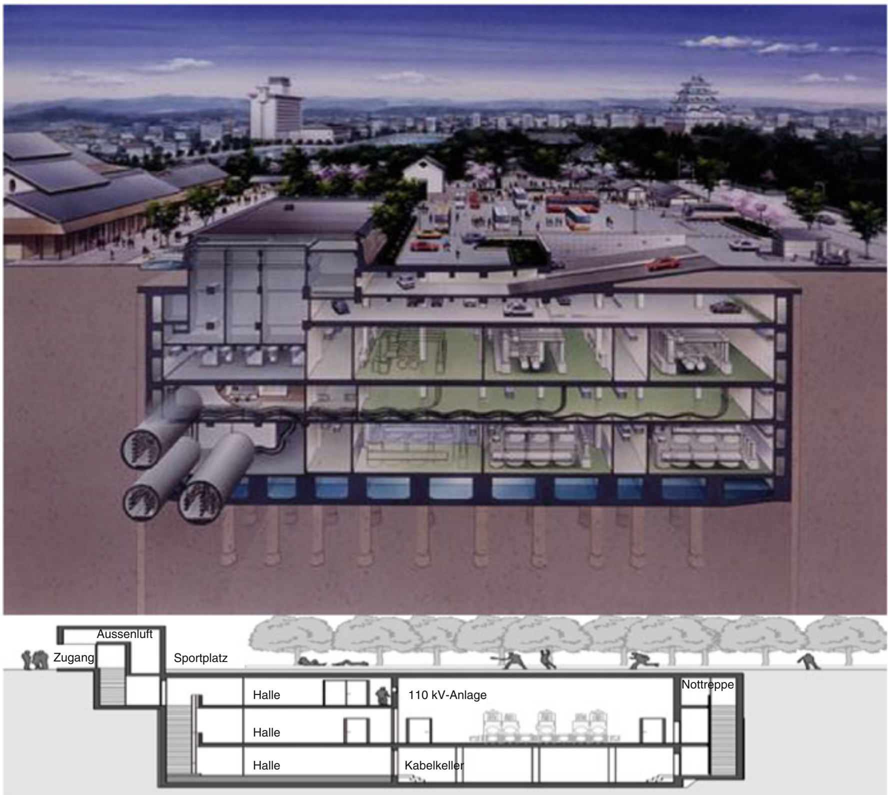



**Fig. 15.5** Underground substation with 300 kV and 168 kV GIS (Chubu Electric Power Company, Meijyo S/S)

The improvement of the reliability of GIS reduced the frequency of maintenance intervals during the last decades, giving benefits in terms of life cycle costs among others. The dependability of GIS is generally very high; normally the major inspection is recommended after 25 years of operation, whereby the first visual inspection is recommended after approx. 9 years. The reliability of a GIS can be demonstrated by the mean time between failures (MTBF). It describes the period between erection of the GIS and the first major failure. Also outage times of bay-wise sections have been perceptibly reduced, not only due to the high technology standard but also to the optimization of the maintenance intervals, by consideration of the best possible relationship between design and material. However, opening of gas compartments cannot be avoided in any case after a certain lifetime of GIS. For further information on GIS failure rates and information about MTBF, see also references in the "Report on the 2nd international survey on high voltage gas-insulated substations (GIS) service experience" brochure No. 150 (year 1967–1995) and "Final Report of the 2004–2007 International Enquiry on Reliability of High Voltage Equipment – Part 5 – Gas Insulated Switchgear" brochure No. 513. Failure frequencies versus voltage class of GIS taken from these questionnaires are given in Table.15.1.

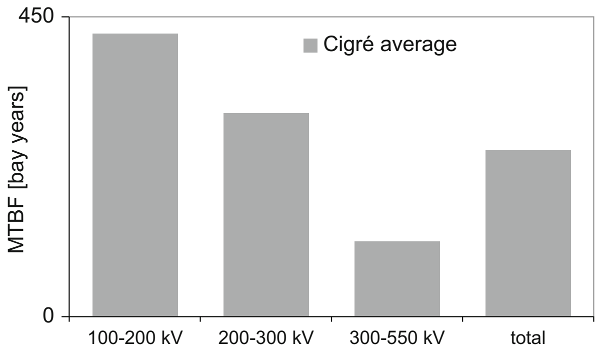
## 15.5 Safety

The encapsulation of high voltage components in GIS provides a high degree of safety for operators and other personnel due to the fact that it is impossible to touch any live part of the switchgear inadvertently, i.e., without the use of tools or extreme force. Protection against vermin or vandalism is also provided.

The consequences of an internal arc are normally contained within the enclosure through rapid operation of the protection. Even under worst case conditions, it is

**Fig. 15.6** 23 bays of 145 kV GIS and 4 bays of 362 kV GIS and transformer hidden in a shopping complex

**Table 15.1** Mean time between failures by voltage class



limited to the operation of a pressure-relief device or a burn-through after a certain time IEC 62271-203 – 5.102.2 “External effects of the arc.” No GIS part will explode, and the damaged region is limited by the gas compartmentalization. Metal vessels are routinely pressure tested up to twice the construction pressure.

## 15.6 Life Cycle Costs

Modern GIS can be expected to perform satisfactorily in service for many years with minimal or even no maintenance. Some GIS are still operating since almost 50 years. This is particularly true for indoor GIS where deterioration due to weathering is eliminated. Unless the GIS is subjected to regular and onerous switching duties, maintenance of circuit breakers, disconnectors, and earthing switches is unlikely to be required for many years, and indeed with GIS, we are continually getting closer to the maintenance-free concept of “fit and forget.” A lifetime-cost approach is essential when comparing equivalent AIS or GIS installations and it may well be found that this aspect alone can justify the initial equipment costs of GIS at the installation stage.

## 15.7 Conclusion

The assessments described must be made by the user before the enquiry specification is produced which must indicate a clear requirement for either AIS or GIS. The evaluation must be performed as a technical-economic analysis. The economical part may be difficult, because the user is often unable to obtain realistic budgetary prices for equipment arrangements at the design stage. Manufacturers are often reluctant to quote realistic budgetary prices due to the inadequate information available at such a stage and in view of their potential competitors. However, in future, users and manufacturers should endeavor to be more cooperative in assisting each other in this part of the decision-making process at the design stage.

# GIS Configuration

# 16

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

16.1 Establishing a Preliminary Configuration for the GIS ... 370
16.2 Further Studies ... 370
16.3 Detailed Design and Design Approval ... 370
16.4 Manufacturing Period ... 371
16.5 Selection of GIS Type ... 371
16.6 Type of Construction ... 372
16.6.1 Extent of $SF_6$-Insulated Modules ... 373
16.6.2 Hybrid Installation: Mixed Technology Systems ... 373
16.6.3 Service Conditions ... 374
16.7 Single-Line Diagram Design ... 377
16.8 Layout Design ... 379
16.9 Information to be Given by the User and the Manufacturer ... 380
16.9.1 Basic User Input Data ... 380
16.9.2 Basic Manufacturer Input Data ... 381
16.9.3 Optimization ... 381
References ... 381

System-design considerations dictate the requirements for the substation basic configuration as well as its location within the system. Consequently, they also include the basic selection between GIS and AIS. After making the decision for an $SF_6$ gas-insulated system, it is necessary to consider GIS design as described in the following sections.

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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## 16.1 Establishing a Preliminary Configuration for the GIS

The first study to be performed is a detailed study for a more definitive single-line diagram (SLD). This should include special demands linked with GIS technology, e.g., the use and position of earthing switches, instrument transformers, surge arresters, etc.

Based upon this SLD, it will be possible to make sketches of different GIS designs and layouts which are available, most reasonable and space saving to see how these may be used in the actual project, including the relation to site and civil requirements (e.g., indoor, outdoor, hybrid).

It is normal and useful for the customer at this time to contact manufacturers for pretendering discussions and to obtain preliminary technical proposals with budgetary prices. However, at this stage a check should be made to ensure that the users' basic layout does not exclude a certain manufacturer.

Close and continued contacts to several manufacturers (at events like trade fairs, customer day workshops, and conferences) will also give good information regarding the experience and design concepts of each.

An important item to study is the connections between the GIS and other components of the network, such as overhead lines, transformers, cables, etc. These connections will have a major impact on the overall layout.

The SLD, the draft basic technical data, and the layout drafts will be fundamental for a later enquiry for a tender.

In this chapter essential information for the planning and determining of the basic data and configuration are given. Further information can be found in IEC 62271-203 "Gas-insulated metal-enclosed switchgear for rated voltages above 52 kV."

## 16.2 Further Studies

When the preliminary configuration and the main data are determined, further studies have to be performed. These should cover (Table 16.1):

## 16.3 Detailed Design and Design Approval

When the order is placed, the manufacturer starts the detailed engineering of the installation.

Before this activity commences, the two parties should in cooperation perform a "Design Review," to ensure that all items are covered and taken care of according to the original project requirements.

The final design and all other agreed specifications between the customer and the manufacturer have to be approved by the user. The user should ensure continuity of technical agreements reached before and during contract negotiations.

**Table 16.1** Overview content for further studies

| Title | References |
|---|---|
| Overvoltages, insulation coordination studies | ▶ Chap. 17 |
| Secondary equipment, such as control, protection, diagnostics, and monitoring equipment | ▶ Chap. 19 |
| Electromagnetic compatibility | ▶ Sect. 19.5 |
| Earthing of the GIS and the secondary equipment | ▶ Chaps. 19 and ▶ 21 |
| Civil engineering aspects | ▶ Chap. 20 |
| Quality assurance, testing procedures during manufacture and especially on-site testing | ▶ Chap. 22 |
| Transport, storage, and erection facilities | ▶ Chap. 23 |
| Demands imposed by the service and maintenance of the GIS and possible future extensions | ▶ Chap. 25 |

So as not to delay the progress of the project, it is important to establish efficient routines for the approval procedures – including firm deadlines for submission and approval of information subject to acceptance by the user.

Where multiple contractors are employed, it is important to define interface responsibilities and to ensure that these are agreed and confirmed with the GIS manufacturer, e.g., transportation, civil works, transformers, cables, etc. The design work concerning arrangement of equipment and earthing systems should be completed before the commencement of civil works.

## 16.4 Manufacturing Period

During the manufacturing period, a lot of activities are going on in parallel. As the GIS is manufactured in the workshops, the civil works are performed at site and subsuppliers are manufacturing their parts.

All the time checks and tests of various parts are performed on the GIS in the manufacturer's factory according to a quality assurance plan which should be agreed upon by the user.

A condition for execution of the GIS project as planned is a rigid and mutually agreed time schedule covering all information to be submitted by the manufacturer and accepted by the user.

## 16.5 Selection of GIS Type

Having decided on GIS, the user faces the matter of GIS type selection. The following basic classification depends on type of construction, on service conditions, and on the extent of $SF_6$-insulated parts (Table 16.2):

**Table 16.2** Overview types of GIS installation

| Type of construction – 16.6 | Extent of $SF_6$ insulated modules – 16.6.1 | Service conditions – 16.6.3 |
|---|---|---|
| GIS for new substation | Fully encapsulated GIS installation | Indoor GIS |
| GIS for reconstruction or extension of existing GIS | Hybrid installation | Outdoor GIS |
| GIS for reconstruction or extension of existing AIS | | Special applications |

**Fig. 16.1** Extension of 420 kV GIS with single-phase busbar

## 16.6 Type of Construction

At the early stage of any substation design, the system requirements determine the main type of construction, i.e., whether it will be a new construction or a reconstruction of an existing GIS or AIS. The type of construction together with the place and the character of the installation site affects that basic configuration (extent of $SF_6$-insulated parts) and those service conditions which GIS will have to meet (see Sect. 16.6.3). An extension of existing GIS is possible. However, in some cases the designs of different manufacturers and/or of different GIS generations require special interfaces (Figs. 16.1 and 16.2).


**Fig. 16.2** Extension of a GIS with three-phase busbar

## 16.6.1 Extent of $SF_6$-Insulated Modules

### 16.6.1.1 Fully Encapsulated GIS Installation

Fully encapsulated GIS installations include only metalenclosed $SF_6$-insulated components in their primary circuits. Owing to investment costs or technical reasons (see ► Chap. 18), a few components may be excluded from this rule, e.g., surge arresters, voltage transformers, or high voltage-high frequency coupling (HV-HF) equipment in outgoing lines.

Fully encapsulated GIS can be designed for an indoor or outdoor application. With these types, all key GIS advantages described in Chap. 16 can be achieved in full scope.

## 16.6.2 Hybrid Installation: Mixed Technology Systems

Hybrid installations represent combinations of GIS and AIS components. The basic two different concepts can be described either:

- Combination of GIS and AIS simultaneously installed in common configuration (so called “classic” hybrid)
- Combination of more or less separated and complete GIS and AIS parts mutually interconnected

The first case is usually represented by the following two alternative combinations:

- Gas-insulated switchgear with conventional air-insulated busbars and/or busbar disconnector
- $SF_6$-insulated busbars including disconnectors with conventional air-insulated switchgear

Other combinations are possible. The “classic” hybrid arrangements are usually used at such installations where there are stringent requirements for quick or simple isolation of a bay in case of a serious major failure and for restoration of the part remaining in service or in such installations where it is necessary to interconnect GIS bays which are located quite far away from one another and where the $SF_6$ bus duct interconnection would become more expensive than in an air-insulated design. They can also help effectively when it is necessary to change the original SLD of AIS, during AIS upgrading as a result of space reduction.

The second case is usually represented by the use of only $SF_6$-insulated bus duct for interconnection between two AIS parts or by connection of an AIS part with a fully encapsulated GIS part.

In general, hybrid installations (namely, the “classic” type) usually require outdoor or containerized/mobile GIS components and can be used for new constructions as well as (especially and preferably) for extension, reconstruction, refurbishment, or upgrading of an existing substation. Figure 16.3a shows a newly built 420 kV hybrid and Fig. 16.3b shows an upgraded 550 kV hybrid.

## 16.6.3 Service Conditions

### 16.6.3.1 Indoor

GIS assigned for indoor service conditions is defined as indoor GIS type. The main advantage of an indoor GIS is that it is, with the exception of $SF_6$/air bushings or outdoor interconnecting bus ducts, fully independent of the outdoor environment and also that its impact on the environment is minimized. It can be installed in a new building, an existing building, an underground cavern, a dam, or a simple hall. A major advantage is the independence of indoor GIS from weather conditions during maintenance activities. The disadvantage is additional civil work costs. The use of indoor GIS is therefore necessary in the following cases:

- Urban area, places of natural beauty or difficult topography, or in other substations which have to be landscaped
- Polluted or coastal site areas, or areas of high altitude, or severe/extreme climatic conditions, or severe seismic area
- Strategic locations

### 16.6.3.2 Outdoor

GIS assigned for outdoor service conditions is defined as outdoor GIS type. In very hot or cold ambient conditions, the insulating gas ($SF_6$ mixture) inside the GIS may

**Fig. 16.3** (**a**) 420 kV hybrid installation with GIS and air-insulated busbar. (**b**) 550 kV hybrid installation with GIS and air-insulated busbar

need to be matched with the given circumstances and can lead to a higher price than for indoor GIS. But generally due to very simple civil works, the total installed costs of outdoor GIS are about 90% those for indoor GIS. Maintenance costs are a little higher for the GIS equipment for an outdoor GIS compared to an indoor GIS, but this may be offset by lack of any need for building maintenance. The outdoor design allows building of hybrid installations for new substations, as well as for extension and upgrading of existing AIS. In most cases this is the factor that determines whether outdoor GIS needs to be used.

Special precautions must be taken in material selection (long-term resistance capability, corrosion and weatherproofing protection for metallic parts, $SF_6$ seals, joints, mechanisms and their housings, control cubicles, cables, and $SF_6$ monitoring devices). Measures must likewise be taken to ensure correct operation at low temperatures.

**Fig. 16.4** First containerized substation 145 kV in 1985 with machine transformer

#### 16.6.3.3 Special Applications

(a) **Containerized**

In containerized GIS as shown in Fig. 16.4, a standard metal container includes all active components of one or two encapsulated circuit breaker bays, a control box, thermal insulation, lighting, air conditioning, ventilation, and access doors, and it is fully factory-tested before shipment. Usually containerized GIS in a standard ISO container is applicable for lower-rated voltages. Using the containerized GIS type, it is possible to utilize advantages of both indoor and outdoor GIS types. This design is appropriate for hybrid installations for temporary or permanent service and for GIS of smaller extent.

In permanent service, a containerized GIS unit is installed on site on simple concrete foundations. These units can also be connected in series. The building and erection times for such installations are very short. Minimal on-site assembly work preserves the effectiveness of factory quality control and results in service reliability.

(b) **Mobile**

In temporary service, a simple GIS bay may be installed on a truck as shown in Fig. 16.5 and serves for temporary operation, while existing substation parts have for various reasons to be de-energized. Thus, the power supply of the reconstructed AIS bay can be moved through a temporary GIS bay and is not discontinued.

**Fig. 16.5** 245 kV mobile GIS

## 16.7 Single-Line Diagram Design

The main aspects which influence GIS SLD selection, i.e., busbar scheme switching arrangement and individual components used, are generally valid for GIS as well as for AIS and are described in detail in ▶ Chap. 4 of this book.

(a) Operational flexibility (impact of system requirements and/or faults on substation service)
(b) System security (impact of substation maintenance requirements and/or failures and their repairs on system service, strategic importance of substation)
(c) Availability (expected planned and unplanned outages of individual substation components and their impact on the substation extent which has to be de-energized, impact of further substation extension)
(d) Substation control (simple and efficient performance of operational duties)
(e) Secondary equipment
(f) Substation security (impact of primary and secondary equipment on substation protection systems)
(g) Costs (optimized in technical/economical terms)
(h) Other considerations, such as:
   - Future development of supply system
   - Facilitating future extensions
   - National regulations and user's standardization policy
   - Level of skill and experience of operating staff

As has already been mentioned above, the basic rules are the same for both GIS and AIS. Nevertheless, GIS has its obvious technical advantages on the one hand but, on the other hand, has a bearing on equipment costs. It is not usually effective to simply take over schemes from former AIS projects and directly convert them into a GIS project. Generally the following special features of GIS and their consequences should be considered:

- The higher reliability and availability of GIS (low failure frequency rate and long maintenance intervals).
- Independence of insulation coordination of atmospheric and geographic conditions
  Less stringent GIS redundancy requirements are acceptable in HV circuits, i.e., simpler GIS SLD. These diagrams can have fewer main bus bars and switching devices and the installation of transfer bus bars for maintenance purposes seems in most cases unnecessary.
- Easier crossings in GIS
  The flexibility of GIS arrangements allows, for instance, crossings of incoming overhead lines or bypassing of circuit breakers. This can increase the reliability and/or availability.
- Greater compactness, enclosed gas compartments, earthing system, and different repair requirements.
  Even if the reliability (availability) of GIS is higher than that of AIS, the aspects mentioned can lead to a higher number of switches (e.g., busbar sectionalizers) and to a greater number of secondary device requirements (e.g., another location of instrument transformers, gas leakage sensors, overpressure protection, signaling, and diagnostic/monitoring sensors – like partial discharge sensors).
- Number and location of earthing switches.
- GIS can be matched according to the given space at location in various forms (installation in L-, U-, or ring-shape) even “multilevel” extending to different floors in the building. As GIS is enclosed and the high-voltage conductor is not accessible, each section has to be provided with an earthing switch (isolated or non-isolated).
- Compactness and wide variety of GIS with different designs, dimensions, and interfaces typical for different manufacturers or different generations of GIS. This can cause some difficulties for further GIS extension (CIGRE Technical Brochure 2009). Incorporating certain measures into the first stage of construction will reduce future constraints. Such measures affect not only building/site area reserves but also single-line diagram, gas compartmentalization, and layout. Their extent depends on the lapse of time in the further extension stages, on the importance of the GIS, on the number of new bays, and on the connection types of old and new bays. The single-line diagram design must allow for the assumed final GIS extent from a network viewpoint (busbar and switching schemes) as well as from a configuration-related viewpoint (the order and connection type of all bays). In some cases it is useful to accept

early investment (e.g., busbar disconnectors and earthing switches, simple removable joints, extension tubes, or busbars) to facilitate change at a future stage, providing advantages in
  - Project's performance
  - Substation availability (e.g., service continuity)
  - Cost reduction in further extension, modification and maintenance purpose
- Bay designations.
- Type of each bay (line, transformer, reactor, auxiliary bay).
- Type of each bay connection – GIS offers several connection possibilities, i.e.:
  - $SF_6$/air bushings
  - $SF_6$/cable boxes
  - $SF_6$/oil or other insulation medium transformer bushings
  - Encapsulated $SF_6$-insulated lines (bus ducts)

Note: The single-line diagram should also show all air-insulated HV devices (i.e., surge arresters, VTs, or HV-HF equipment) which will be directly connected to individual bays.

## 16.8 Layout Design

The modular system of GIS components allows the creation of any SLD (circuit configurations/busbar schemes) in an effective way corresponding to the specific conditions of each individual construction. Regarding layout, the GIS-earthed modular system with its compactness and minimal dimensions offers, in comparison with AIS layouts, a much wider range of different combinations. These may be, depending on a manufacturer's design and specific conditions, characterized by the following:

- Three- or single-phase encapsulation or a combination of both
- Mixed, separated, or coupled phases of busbars and/or bay arrangements
- Single-, two-, or more-line arrangement of circuit breakers
- Horizontal or vertical ("U" or "Z") circuit breaker designs
- Vertical, horizontal, triangle, or upper or lower flange connected busbar arrangements

Arranging GIS bays similar to AIS arrangements may result in a substantial cost increase and unnecessary bus duct length, which can reduce GIS reliability. Nevertheless, in order to enable a manufacturer to design an optimized solution, it is necessary for a user to provide a manufacturer with a detailed description of input conditions in the technical specification of an enquiry. Simultaneously a user should avoid over determination and should be ready to cooperate with the manufacturer and/or be prepared to think about the manufacturer's proposals for changes, so that the optimization process will be effective.

## 16.9 Information to be Given by the User and the Manufacturer

### 16.9.1 Basic User Input Data

The user input conditions, which influence GIS layout design, must include at least the following:

- Local environmental and ambient conditions for GIS
- Single-line diagram with major ratings
- Service requirements, e.g., type of circuit breaker auto reclosing (three-phase, single-phase, or without AR), special switching conditions (reactors, generators, filters, long lines, etc.), use of earthing switches with short-circuit switching capacity
- Shape and dimensions of space availability (in case of an existing building, extension or reconstruction of existing equipment, also the overall layout and technical description of this equipment)
- Arrangement of relevant power equipment in the station:
  - Direction and width of line corridors
  - Location of power transformers
  - Location of interface connections
- Specification of connection principles:
  - $SF_6$/air bushing connection: Required minimum air clearances (phase-to-phase of one system, phase-to-phase of different systems, phase-to-earth), assumed layout of towers or conductor anchoring (e.g., directly to wall)
  - Cable connection: Type of cable, number of cables and number of their cores, assumed cable routes
  - $SF_6$/transformer bushing connection: Type of transformer (reactor) and its bushing arrangement
  - $SF_6$ bus ducts or gas-insulated lines (GIL): Distance and specification of interface connection
- Arrangement of other equipment in station:
  - Conventional HV equipment (e.g., surge arresters, instrument transformers, air-insulated equipment in hybrid installations, etc.)
  - Medium-voltage equipment (primary or secondary)
  - Protective and control system, control room, auxiliary equipment, etc.
- Special requirements, if any, e.g.:
  - Special requirements for assembly: Access roads, impact on remaining operational equipment, namely, when GIS is used for extension or reconstruction of existing equipment
  - Requirements for GIS operation during its further extension
  - Special requirements for gas compartment division considering maintenance and repair aspects
  - Seismic requirements

### 16.9.2 Basic Manufacturer Input Data

The basic manufacturer's proposal is the response to the user's inquiry and the provided input data. Consequently the quality and completeness depend on the input data.

The basic manufacturer's design should include:

- GIS type including all major ratings
- Single-line diagram
- Overall layout (area and height required)
- Weight of GIS and average loads on floors
- Any specific shock loads from circuit breaker operation
- Requirements for crane, if necessary
- Location and space for control cubicles
- Solution for connections to other equipment ($SF_6$/air bushings, cables, bus ducts, transformers)
- Limitations of scope of supply, with clear identification of interface responsibilities
- Methods of achievement of special requirements

Deviations from the user input data or specifications should be mentioned and alternatives indicated.

### 16.9.3 Optimization

The user's specification is usually a collection of requirements of different weighting. Some of them are essential for the user; others indicate only a preference. However, for the manufacturer it is impossible to identify the difference. Moreover, during the tendering stage, users tend to postpone clarification or alternatives due to reasons concerned with evaluation. In consequence, high costs are sometimes involved in the manufacturer's attempt to meet the specification of which the user may be unaware.

The optimization process is therefore an essential step on the way to achieving the best technical and economical solution. The manufacturer should clearly indicate which requirements increase costs and put forward alternatives. On the other hand, the user should be ready to check the necessity of their requirements.

## References

CIGRE Technical brochure 389 - Combining innovation and standardisation (2009)

# Insulation Coordination

# 17

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

17.1 General ........ 383
17.2 $SF_6$ Breakdown Characteristic ........ 384
17.3 Insulation Coordination Procedure ........ 385
17.4 Determination of Withstand Voltages ........ 387
17.5 Actions Which May Be Taken to Achieve Insulation Coordination ........ 387
17.6 Information to Be Given by the User and the Manufacturer ........ 388

## 17.1 General

The coordination of the insulation within GIS depends upon the overvoltages generated in the associated system and the GIS itself. These may consist of:

- External overvoltage
  - Lightning overvoltages
  - Switching overvoltages
  - Temporary overvoltages
  - AC overvoltages generated by circuit resonance conditions
- Specific for GIS

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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- DC stressing
- DC plus AC stressing
- Very-fast-front overvoltages

Coordination is generally achieved against externally generated overvoltages by the application of overvoltage limiting devices and against internally generated overvoltages by means of other precautions. The overvoltage stresses have to be taken into account in such a way that the probability of a fault at the insulation will be reduced to an economically and operationally acceptable value.

Insulation coordination is a complex subject and only general considerations are given below. For a more detailed explanation, the reader is recommended to refer to IEC 60071-1, IEC 60071-2, and IEC 62271-1.

The main task is to coordinate the values of the overvoltage stress in the GIS and the insulation strength of the GIS.

Two methods are in use for the coordination:

- The deterministic method is applied if no statistical information about these values is available. In this case a set of values is assumed as most critical and deterministic. They are coordinated in such a way that no breakdown will occur under this assumption. The real statistical scatter is covered by a safety factor.
- The statistical method is applied if the risk of failure is fixed at an acceptable value and calculated out of the overvoltage probability distribution and the breakdown probability of the insulation.

## 17.2 $SF_6$ Breakdown Characteristic

The breakdown characteristics of $SF_6$ when subject to various rates of rise of transient overvoltages are very flat compared with air breakdown characteristics (see Fig. 17.1), and consequently air coordinating gaps cannot give adequate protection against steep fronted waves. This effect is intensified by typical electrical field configurations in AIS and GIS. Inhomogeneous fields in AIS cause a stronger

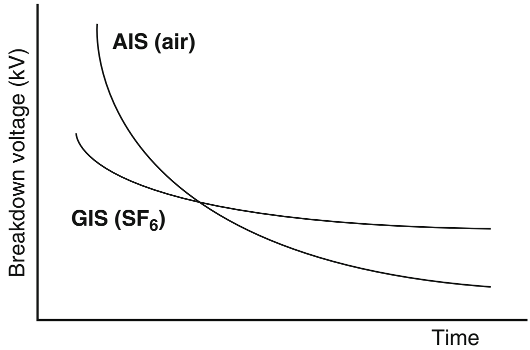


**Fig. 17.1** Different breakdown characteristic between AIS and GIS

variation of the breakdown voltage depending on the voltage rise time compared with homogeneous fields in GIS. A surge protection device should match more closely the $SF_6$ breakdown characteristic in GIS.

## 17.3 Insulation Coordination Procedure

The insulation coordination procedure has to be performed according to IEC 60071-1 "Insulation co-ordination – Part 1: Definitions, principles and rules" and the IEC 60071-2 "Insulation co-ordination – Part 2: Application guide" for the different types of voltages. The principle procedure is given in Fig. 1 – "Flow chart for the determination of rated or standard insulation level" of IEC 60071-1.

The abbreviations used below are those defined in IEC 60071-1 as follows (The relationships between the specified voltages are illustrated in Fig. 17.2):

| | |
|---|---|
| $U_r$: | Rated voltage [IEC 62271-1 "high-voltage switchgear and control gear – Part 1: Common specifications"] |
| $U_{rp}$: | Representative overvoltages – these consist of defined overvoltages of standard shape and class |
| $U_{cw}$ | Coordination withstand voltage – the value of withstand voltage that meets the performance criteria |
| $K_c$: | Coordination factor – the value by which $U_{rp}$ must be multiplied to obtain $U_{cw}$ |
| $U_{rw}$: | Required withstand voltage – the required withstand voltage is the test voltage which the insulation must withstand in a specific test |
| $K_s$: | Safety factor – the factor to be applied to $U_{cw}$ to obtain $U_{rw}$ |
| $U_w$: | Rated withstand voltage according to IEC |

External overvoltages typically should be treated in the same way as for AIS:

For the continuous power-frequency voltage, the coordination factor $K_c$ is 1.0 and the coordination withstand voltage $U_{cw}$ is equal to the rated voltage $U_r$ divided by $\sqrt{3}$ (Tables 1 and 2 in IEC 62271-1). In any case the deterministic method is applied.

- For the power-frequency short-duration voltage, the coordination factor $K_c$ is 1.0 and the coordination withstand voltage $U_{cw}$ equals the assumed maximum of the

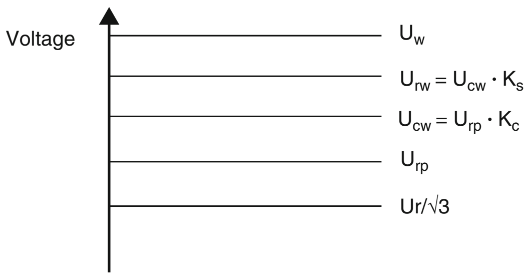


**Fig. 17.2** Definitions of insulation coordination

temporary overvoltage divided by $\sqrt{2}$ for the deterministic method. The statistical method is seldom applied to GIS.
The representative voltage $U_{rp}$ for slow-front overvoltages is equal to the switching impulse protective level of the arrester. Depending on the ratio of the prospective overvoltages and the protection level of the arrester, a deterministic coordination factor between 1 and 1.1 has to be chosen for the determination of $U_{cw}$. The statistical method is not usually applied to GIS.

- For the determination of fast-front overvoltages, the deterministic coordination factor $K_c$ is 1.0. In the case of the deterministic method, a few different lighting strokes with the most critical current shape at the assumed most critical locations under the most critical switching conditions have to be considered. Considerable experience is necessary to ensure that the most critical case with the expected lifetime of the GIS is taken into account. Therefore, the statistical method or simplified statistical method is proposed in any event according to Annex E of IEC 60072-2.

The following internal overvoltages are specific for GIS:

- For very-fast-front overvoltages, the systems analysis is very elaborate. These overvoltages are caused by switching operations within GIS. The maximum values of these overvoltages depend on the voltage drop at the switch just before striking. The amplitudes of $U_{rp}$ are scattered around a mean value of 1.5 p.u. related to the rated voltage $U_r$ multiplied by $\sqrt{2}$ and divided by $\sqrt{3}$. Higher values have to be considered for fast moving disconnectors and in the case of out-of-phase switching with a multiple-break circuit breaker in series. When a section of GIS is de-energized, a DC trapped charge is left on the de-energized section of busbar. This may have a value of typically up to 1.2 p.u. If an associated circuit breaker has grading capacitors across its interrupters, an AC voltage will be superimposed on the DC voltage. This AC voltage may have a value typically up to 0.8 p.u. When the associated switching device is reclosed, this trapped charge voltage is dissipated which in turn creates a very steep fronted pulse. Usually maximum values of 1.7 p.u. and 2.5 p.u. are assumed.

A representative overvoltage has not been established since very-fast-front overvoltages have no influence on the selection of the rated withstand voltages for peak values up to 2.5 p.u. It is generally accepted that the standard lightning impulse withstand test adequately covers this condition. In the extraordinary cases where the very-fast-front overvoltage may exceed 2.5 pu, it may be necessary to apply special precautions for rated voltages of 550 kV and above.

To prevent the breakdown to ground of the arc of an operating disconnector caused by simultaneous very-fast-front overvoltages, special requirements for switching of bus-transfer currents are specified in IEC 62271-102 for disconnectors for rated voltages of 72.5 kV and above. Tests are generally not necessary for rated voltages below 300 kV.

## 17.4 Determination of Withstand Voltages

In the next step the standard test conditions of the type or the routine test have to be taken into account by a safety factor $K_s$ for the determination of the required withstand voltage $U_{rw.}$

$$U_{rw} = K_s \cdot U_{cw}$$

Further factors have influence, mainly the respective size of the total GIS and the testing unit and the dispersion in the insulation quality, and are compensated by $K_s$. For GIS $K_s$ is usually 1.25.

In a final step, the adequate and most economical set of rated withstand voltages $U_w$ according to Tables 1 and 2 in IEC 62271-1 has to be chosen by which all the required withstand voltages are covered.

## 17.5 Actions Which May Be Taken to Achieve Insulation Coordination

The process of insulation coordination will usually result in the use of metal-oxide surge arresters at overhead line or cable entry points and at GIS/transformer and GIS/reactor interfaces. For small compact GIS stations with voltages up to 300 kV, surge arresters on the entry points are normally sufficient for protecting the GIS station and adjacent high-voltage equipment. For geometrically large GIS stations and arrangements with long bus ducts and for GIS stations for voltages higher than 300 kV, extra surge arresters are often required in the GIS station or mounted close to the transformers or reactors.

The selection of a surge arrester is a compromise between temporary overvoltage capability, protective level, and energy capability of the surge arrester. The surge arrester must be stable under system conditions and under short-duration power-frequency overvoltages. When these conditions are not known, a sufficient safety margin must be selected. On the other hand, the protection level should be selected as low as possible in order to achieve a sufficient margin between the protection level of the surge arrester and the insulation level of the equipment. The energy capability of the surge arrester must match the stress the surge arrester will endure during switching and lightning overvoltages. Simplified calculations are normally sufficient to select the correct temporary overvoltage capability, protective level, and energy capability of surge arresters.

The overvoltage protection of a substation is not only a question of which arrester to choose. For protection against lightning surges close to the station, it is even more important to install the arrester in the most efficient way. The surge arrester should always be placed as close as possible to the equipment to be protected. For line entry points in GIS, this implies that an air insulated surge arrester should be placed within a few meters of the $SF_6$/air bushing. Also the length and inductance of the earth connection between the enclosure of the GIS and the earthing point of the surge arrester should be minimized. For GIS cable entry points, surge arresters are normally required at the line/cable interface. Within the GIS, attention should be paid to arrangements with long bus ducts and cable/GIS interfaces, due to possible reflections at open disconnectors. For transformers and reactors, the surge arrester (air-insulated or metal-enclosed surge arrester) should be placed as close as possible to the transformer and reactor bushing. An example of direct GIS/transformer connection with metal-enclosed surge arresters is shown in ▶ Fig. 18.8. Normally, the positioning of surge arresters can be decided upon by simple calculations based on the experience of the manufacturer and users.

In exceptional cases, a detailed insulation coordination study may be needed to confirm arrester locations and ratings. If the GIS configuration is expected to require metal-enclosed surge arresters, the GIS manufacturer should provide the additional cost per arrester for evaluation from the start of planning.

## 17.6 Information to Be Given by the User and the Manufacturer

The user has the responsibility for adequate insulation coordination as they are the only ones who can describe the actual network conditions. In many cases this task is given to a manufacturer or a third party. In any event it has to be emphasized that the quality of the result depends on the completeness of input data. Special attention should be paid to ferroresonance phenomena and very-fast-front overvoltages.

The fundamental data given by the manufacturer are:

- Surge impedance of GIS
- Configuration of GIS
- Value of grading capacitors, capacitances to earth, inductances
- Residual voltage of surge arresters

# GIS Primary Components

# 18

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents


18.1 Conductors ........ 390
18.2 Enclosures ........ 390
  18.2.1 Three-Phase or Single-Phase-Enclosed ........ 391
  18.2.2 Segregation of Gas Zones ........ 393
  18.2.3 Insulating Spacers/Parts: Bushings ........ 394
  18.2.4 Pressure Relief Devices: Rupture Disks ........ 394
18.3 Switching Devices ........ 396
  18.3.1 Circuit Breakers ........ 396
  18.3.2 Other Switches ........ 397
18.4 Current Transformers (CTs)/ Core-in-Air CT ........ 398
18.5 Voltage Transformers (VTs) ........ 400
18.6 Nonconventional VTs and CTs ........ 400
18.7 Surge Arresters ........ 402
18.8 GIS Cable Connection ........ 403
18.9 Air Bushings ........ 405
18.10 Connection to Transformers and Reactors ........ 405
  18.10.1 Direct Connection via $SF_6$-Insulated Bus Ducts ........ 405
  18.10.2 Connection via Cable ........ 406
  18.10.3 Connection with Short Overhead Lines ........ 406


P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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18.11 Connection Elements Within GIS .... 407
18.11.1 Compensators .... 407
18.11.2 Coupling Element .... 407
18.11.3 X-, T-, and Angle-Type Enclosures .... 407
18.12 Nameplates/Labeling .... 407
18.13 Online Monitoring and Diagnostics .... 408
18.14 Integration of Protection and Control Devices into GIS .... 409
18.15 Information to Be Given by the User and the Manufacturer .... 409

## 18.1 Conductors

The design of conductors, connections, and supports should ensure that thermal and mechanical interaction due to normal currents or short-circuit currents do not worsen the current conduction and dielectric performance of the GIS. Basic criteria and suitable tests are specified in the relevant international standards.

The material normally used is aluminum or copper. Conductors are either supported directly by single- or three-phase composite insulators or are connected to live components or switching equipment. Generally these connections can be of spring-loaded or bolted type. With bolted-type connections, the inner structure in the enclosures is fixed, whereas spring-loaded contacts are used to compensate for thermal expansion of the conductors and also for installation and manufacturing tolerances. The connections should be designed in such a way that due to transportation and during installation and operation, the dielectric strength cannot deteriorate (prevention of particle generation).

Certain GIS designs include removable conductor pieces which facilitate testing, maintenance, and repair work and allow later extension. Especially in the case of the on-site dielectric tests of GIS, the primary devices like cables, transformers, and surge arresters have to be disconnected. A removable conductor is also useful on bus bars to limit the impact during testing, maintenance repair work, and extension.

## 18.2 Enclosures

Gas enclosures are usually made of aluminum or steel alloy chosen for a desirable combination of mechanical strength, good electrical conductivity, resistance to atmospheric corrosion, and reasonable price. They are required to meet certain pressure design criteria generally covered by international standards. In some countries, however, statutory legal criteria still apply, and the requirements (e.g., gas tightness, transportation restrictions for pressurized components) prevailing in a specific country should first be ascertained. Cast, extruded, and wrought production methods are used depending on the application. For example, a complex switch enclosure may be cast aluminum, and a bus enclosure may be extruded. Enclosure parts may be welded together.

The method of bolting adjacent enclosures should ensure long-term electrical conductivity and gas tightness over years to allow the flow of sheath-induced currents and should ensure continuous impedance for transient switching overvoltages. In order to compensate for thermal expansion, bellows or similar devices are required. If electrical segregation is necessary for any reason, special precautions (e.g., varistor shunting) will need to be taken into account to avoid sparking across the flanges.

To prevent or reduce the flow of induced current in the earthing system, enclosures of each phase should be linked by bonding circuits designed to withstand circulating currents. These circuits, connected to the earthing system, are best located near the connection of GIS with other items (bushing, cables, and transformer connections) and at the ends of the bus bars.

Gas compartments and their flange connections shall reach the leakage rate prescribed in the valid standards (0.5% acc. to IEC 62271-1). Nevertheless some manufacturers reach a maximum $SF_6$ leakage rate of 0.1% per year per gas compartment. Design of the enclosure must be such as to limit gas leakage within the anticipated equipment life span to very low levels. The lifetime of the gas-tight sealings should be at least equal to the anticipated lifetime of the whole switchgear.

All gas zones are normally provided with means of safely releasing the overpressure (like bursting disks) which might be generated in the event of an internal fault, gas overfilling, or other causes of overpressure. Pressure coordination philosophy should ideally allow a first-stage protection to clear a fault before pressure relief device operation, in order to prevent $SF_6$-emission.

### 18.2.1 Three-Phase or Single-Phase-Enclosed

The main components may be either three-phase-enclosed or phase-segregated. The complete substation is often a mixture of both types. Generally, for higher-voltage levels, switchgear tends to be single-phase-enclosed. From a user's point of view, the consequences of the three-phase to-earth fault, as may occur in three-phase-enclosed GIS, must be considered. Transient stability problems of the associated circuits and/or the system itself may be an overriding consideration.

The advantages of gas-insulated switchgear are its compact design and modular system. The standardized modular structure is designed to match the various customers' specifications and allows almost all substation configurations to be realized in compliance with them. Three-phase design requires relatively large aluminum enclosures because it must house all three conductors. At higher-voltage levels, the isolation distances between the phases and between the phases to ground enclosures are getting larger. The cast aluminum technology limits the max. size of enclosures on an economical basis. Over the last few years, the casting technology has improved, and with this the voltage levels for three-phase insulated enclosures have increased. At first, only voltages up to 123 kV were of a three-phase encapsulation design; today the levels are at 170 kV and approaching 245 kV. A three-phase encapsulation has fewer parts, less insulating gas, and less enclosure material than its single-phase counterpart.

The single-phase encapsulated GIS has a high level of standardized enclosures. Each module is basically used for only one function, for example, switching, measuring, and connecting, with the main modules being circuit breakers, disconnectors, ground/earthing switches, current and voltage transformers, bus bars, extension modules with different angles, surge arresters, thermal expansion joints, cable and transformer connections, and outdoor connections to overhead lines or transformers.

The modular system of GIS components allows the creation of any SLD in a most effective way corresponding to the specific conditions of each individual construction. In a short time, a new three-position type of integrated disconnecting and earthing switch with a common moving contact and a common drive was also introduced among the single-phase-enclosed constructions.

(a) If three-phase encapsulated bus bar with switching elements (active BB), then bay-wise gas-tight sectionalization is required.
(b) If three-phase encapsulated bus bar without switching elements (passive BB), then bay-wise gas-tight sectionalization is **not** required, but additional modules for bus bar disconnectors are necessary.

If single-phase encapsulation is not required, three-phase encapsulation should be used to obtain the below mentioned advantages (Figs. 18.1 and 18.2).

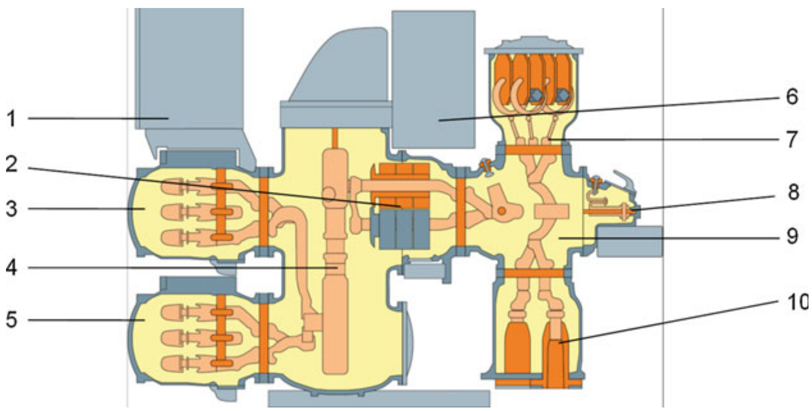



**Fig. 18.1** 145 kV high-voltage switchgear. (*1*) Integrated local control cubicle. (*2*) Current transformer. (*3*) Bus bar I with disconnecting and earthing switch. (*4*) Circuit breaker interrupter unit. (*5*) Bus bar II with disconnecting and earthing switch. (*6*) Spring-stored-energy operating mechanism with CB control unit (common or single drive). (*7*) Voltage transformer. (*8*) Make-proof earthing switch (high speed). (*9*) Outgoing module with disconnecting and earthing switch. (*10*) Cable sealing end

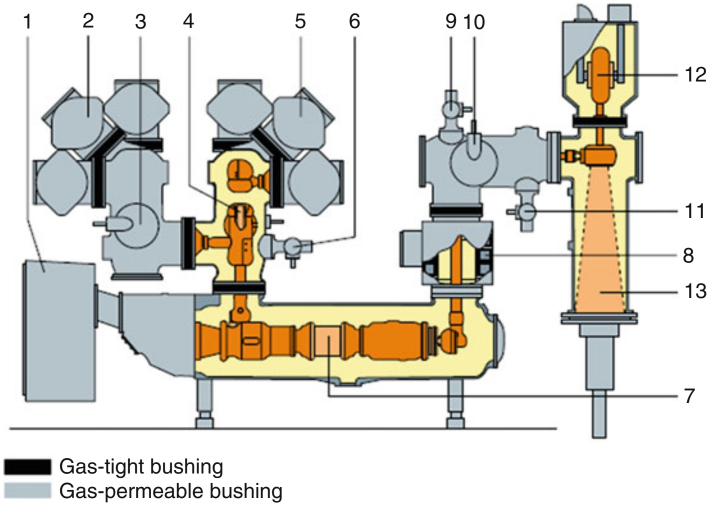



**Fig. 18.2** 420 kV high-voltage switchgear. (*1*) Circuit breaker control unit with spring operating mechanism. (*2*) Bus bar I. (3) Bus bar disconnector I. (*4*) Bus bar disconnector II. (*5*) Bus bar II. (*6*) Earthing switch. (*7*) Circuit breaker. (*8*) Current transformer. (*9*) Earthing switch. (*10*) Outgoing disconnector. (*11*) High-speed earthing switch. (*12*) Voltage transformer. (*13*) Cable sealing end

| Three-phase encapsulation | Single-phase encapsulation |
|---|---|
| Less compartments, less quantity of sealings, less moving parts | High degree in flexibility to adopt customer layouts, e.g., transformer connection, cable connection, OHL |
| Less connection pieces | Small compartments |
| 1/3 of number of compartment of a single encapsulated design | High degree in flexibility of design of the feeders by using of less compartments |
| Less volume of $SF_6$ | High variety and small room requirements |
| Erection work is fast and easy | Entrance of cable single phase |
| In case of internal fault: pressure rise is less due to bigger volume of gas compartment | Only phase to ground faults are possible |
| Maximum reduction of size and weight is possible | In case of failure, remaining phases are not affected, reduced repair efforts required |
| Building size can be reduced to a minimum | Easy access for erection and maintenance |

### 18.2.2 Segregation of Gas Zones

Equipment should be segregated into sufficient independent gas zones to allow the required degree of operational flexibility. The segregation of gas zones should consider the rules described in ▶ Sect. 24.5.2.1.

In general, easy access to gauges and gas filling points should be provided. On the other hand from the tightness point of view piping, work should be reduced – to minimize the number of interfaces and risk of leakages. The final solution has to be agreed between user and manufacturer.

It is now general practice for each gas zone where a switching arc can occur to be fitted with desiccant material to assist in the absorption of water vapor and gaseous breakdown products. With regard to the absorption of water vapor, this might be done for each gas zone. Exception can be the voltage transformer connected to its adjacent compartment via bypass.

Gas service connections should be of a uniform type throughout the substation, and many users prefer the self-sealing type of connection. The diameter of gas connections between different enclosures should be big enough to ensure a fast evacuation.

### 18.2.3 Insulating Spacers/Parts: Bushings

Throughout the GIS, insulating spacers are used to support the inner conductor and hold it central under normal operating and fault conditions and to provide separation between two gas compartments. In principle, two types are used: gas-tight and gas-permeable bushings. The design of gas zone barriers (only with gas-tight bushings) should be such as to withstand the effects of the following pressure differentials which may result during operation, depending on the GIS design:

- Rated filling density on one side and vacuum on the other
- Rated pressure on one side and controlled overpressure on the other
- Maximum pressure rise resulting from an internal arc on one side and atmospheric air on the other side

Gas zone barriers should be capable of withstanding these pressure differentials in both directions of stressing. This pressure requirement is tested as a routine test with each insulator reaching the levels according to the pressure standard BS EN 50089 (1992) for cast resin insulators. If repair and maintenance work in an adjacent zone of a pressurized bushing might be necessary, then this should be taken into consideration in the gas zone barrier design. For maintenance aspects including safety requirements, see ► Sect. 24.4.

### 18.2.4 Pressure Relief Devices: Rupture Disks

Pressure relief devices should ensure the protection of the enclosure against inadmissible overpressure. It is advisable to install such a device in every gas zone. In some countries, statutory legal criteria still apply, and the requirements prevailing in a specific country should first be ascertained.

Usually two different kinds of relief devices are applied: non-self-closing types (Fig. 18.3 or bolt type) and self-closing types (Fig. 18.4). In the case of a non-self-closing type, the disk can be made of metal (cast iron) or graphite.

In order to avoid endangering persons in the unlikely event of the pressure relief device operation, the device aperture must be located at a non-critical point, and/or the released jet of gas must be diverted in a non-critical direction with the help of diverters.

A general philosophy is to limit any operation of a pressure relief device prior to the operations of control or protection, thus limiting the possibility of substation pollution and contamination of associated equipment with decomposition products in the unlikely event of an internal fault. This philosophy can generally be achieved with state-of-the-art gas monitoring. Density monitors for gas compartments filled with $SF_6$ are designed with two or three threshold values (filling pressure, minimum operating pressure, and maximum operating pressure) (Fig. 18.5).

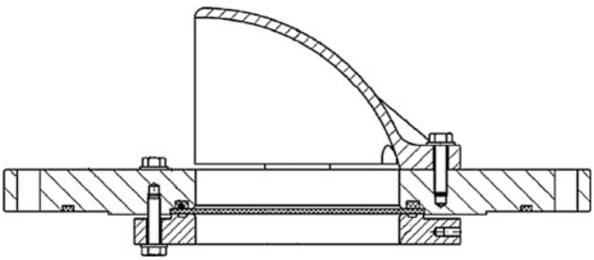


**Fig. 18.3** Non-self-closing-type pressure relief device

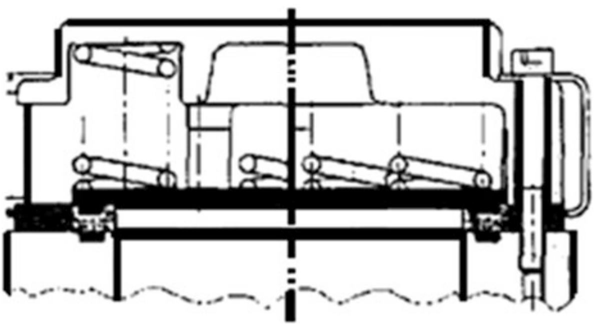


**Fig. 18.4** Self-closing-type pressure relief device

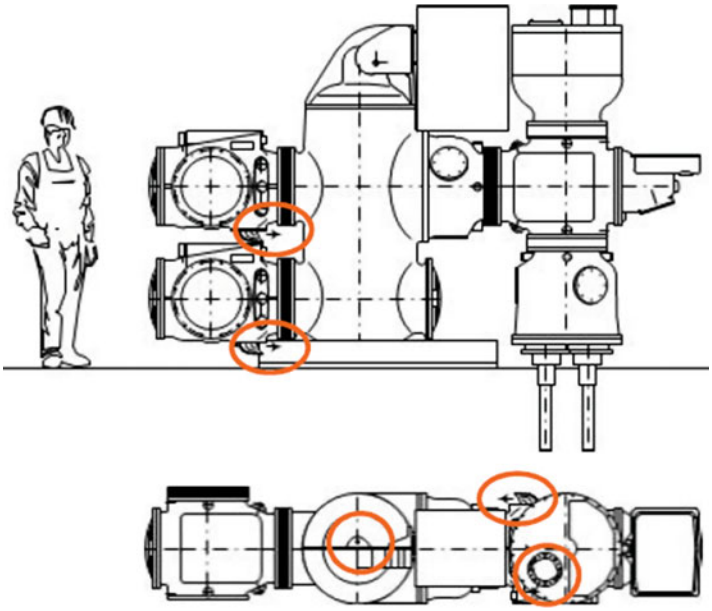


**Fig. 18.5** Diverter directions to ensure personnel safety

## 18.3 Switching Devices

All GIS are equipped with various operational switching devices. The switches may be fitted with one operating mechanism driving all three phases (common pole drive), or alternatively they may have individual operating mechanisms per phase (single-pole drive).

### 18.3.1 Circuit Breakers

The circuit breaker (CB) is usually in a separate enclosure because of the higher gas pressure requirement for its arc extinguishing capability. The module may be horizontally or vertically oriented and is the base module of a bay. Other modules are connected to it. The compartment usually has a higher operational pressure (0.5–0.8 MPa) than the other modules (0.4–0.6 MPa, except the voltage transformer which normally has the same pressure as the CB) because of the need to extinguish the switching arc for interruption of rated currents (typically 2000–5000 A) or in case of short circuits (typically 25–80 kA).

Operating mechanisms of circuit breakers may be of the hydraulic, pneumatic, or spring-operated type. In general, considerations concerning monitoring and control circuits are the same as for conventional $SF_6$-circuit breakers. If the circuit breaker is equipped with an individual operating mechanism for each phase, single-phase auto-reclose operation is possible.

Where multibreak circuit breakers are used, capacitors are installed across the breaks for voltage control purposes. These capacitors have to be taken into account in combination with inductive voltage transformers for ferroresonance phenomena and for other overvoltage considerations.

The circuit breaker is also the largest and heaviest physical part of the GIS and is often the main physical attachment and fixed point in relation to environmental and GIS thermal expansion forces. In this role, the CB is designed to have strong tanks, nozzles, and support structures.

### 18.3.2 Other Switches

GIS switches are generally motor-driven, and the user may also require facilities for locking the switches to make them both electrically and/or mechanically inoperative.

#### 18.3.2.1 Disconnectors

The main purpose of a disconnector is to provide a safe isolation distance between two parts of a circuit at all times. Any normal switching operation which the disconnector may be required to perform should not cause reduction of the dielectric integrity of the isolation distance. This is particularly pertinent, for example, when load transfer currents are switched or when earthing switches might be incorporated in the disconnecting chamber. Disconnectors must also be capable of switching the bus bar capacitive currents, of withstanding the induced very fast transient switching overvoltages, and of withstanding the DC trapped charge (with superimposed AC) which may be left on the bus bars. Where disconnectors are associated with generator circuits, they may be required to switch asynchronous no-load voltage conditions.

In a double bus bar arrangement, a disconnector having a breaking and making capability is required for bus-transfer currents depending upon the magnitude of the load transferred and the size of the loop between the location of the bus coupling and the disconnector to be operated.

Tests for many of the switching conditions described have now been incorporated into international standards.

In some countries, devices to check directly the operating position of the disconnector contacts, namely, inspection windows, are required. Many users nowadays accept the principle of external position indication provided that it always truly represents the state of the internal contacts (via a kinematic chain). In case of missing accessibility between the bays, also the position indication can be located in front of the bay (LCC – local control cubicle) via push-pull cable. Even camera systems for inspection windows are available. The integrity of such external indication is covered by IEC standards, and many users accept this philosophy.

#### 18.3.2.2 Load Break Switches

Switch disconnectors were used in the past mainly in AIS substations and were considered uneconomical for GIS. However, with modern interrupting techniques, they are again becoming more economically feasible and can perform switching duties located between those of a disconnector and a circuit breaker operating nominal current. Protection triggered commands and opening of short-circuit currents have to be operated by a series connected circuit breaker.

#### 18.3.2.3 Earthing Switches

Due to the encapsulated main conductor, the number of recommended earthing switches is higher in the case of GIS. The principles for GIS earthing for maintenance are described in ► Sect. 24.5.1.1 and may reflect three basic concepts:

- Permanently fixed power-driven or manual slow-operation-type devices
- Permanently fixed power-driven or manual (stored-energy) fast-operation types capable of safely making onto a live circuit, of withstanding the associated fault current, and of being opened satisfactorily afterward with no internal damage to the GIS
- Portable earthing devices as an additional tool for inspection and maintenance purpose

Short circuit making earthing switches are mainly used for earthing of incoming lines or capacitive charged equipment. The permanently installed earthing switches must be capable of switching on and off all no-load service conditions valid for the specific installation, e.g., line-induced capacitive and inductive currents when parallel lines are in service (see IEC 662271-102).

Insulated earthing switches are used for maintenance purposes or in order to allow primary circuit access for testing. With removed earthing link, they generally need to be insulated to withstand voltages in the order of 1–10 kV between the earthing switch contact and the enclosure. Dirt layer at the external located insulation may reduce the withstand capability. Prior to testing, cleaning of the earthing switch's insulation is recommended. Under normal substation operation, the earthing link has to be installed to avoid hazards to the equipment and operator's health and safety.

## 18.4 Current Transformers (CTs)/ Core-in-Air CT

Toroidal-ring-type current transformers are generally used in GIS where the conductor forms the primary winding. Such CTs may be housed internally inside the GIS enclosure (Fig. 18.6), in which case, a stress control sleeve is generally fitted between the conductor and the CT secondary winding assembly. Such CTs may also be fitted with an additional heavy current winding comprising a few turns, which provides a facility for CT and protection testing.

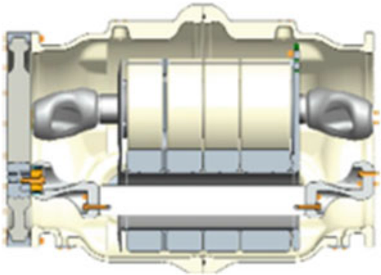


**Fig. 18.6** Current transformer internally fixed in the GIS enclosure

**Fig. 18.7** Current transformer fixed externally to the GIS enclosure

Alternatively in the case of single-phase-encapsulated GIS, the CTs may be fitted externally to the GIS enclosure (Fig. 18.7), and there it is necessary for a discontinuity (insulating ring) to be incorporated into the GIS enclosure to avoid a CT short-circuit turn. However, such a discontinuity forms high surge impedance to VFT voltages which may cause flashover of the insulation at this point. Varistor shunting may be fitted to alleviate such breakdown. A further option is for external current shunts to be provided, but these may not always limit very fast transients (VFT) flashover of the insulated flange.

Depending on the requirements for metering and protection, the CTs may incorporate a variable number of cores (up to 5) which may have one or more current ratios (taps). The number of cores, their arrangement, and their location may influence the layout of the GIS because the size of the enclosure is variable.

Modern digital protection equipment requires much less input power. This enables the use of alternative current transducers which will be more available in the future (see Sect. 18.6). These transducers are covered by the standard IEC 61869.

They are divided into two different groups depending on the interfaces between protection equipment and transducers:

- Transducers with a low power analog output signal

The user should check the output power and the number of transducers in order to be able to fit the CT to modern secondary equipment.

- Transducers with a serial digital data bus output signal

The bus system requirements will be covered by IEC 61850. The user should check the compatibility of secondary equipment, bus system, and transducer.

## 18.5 Voltage Transformers (VTs)

Voltage transformers used in GIS are generally of the electromagnetic type. Transformers of the capacitive type were used in early GIS but are rare today. The HV winding of the electromagnetic voltage transformer comprises many kilometers of wire which must be mechanically and thermally robust as well as being appropriately dielectrically graded. Advantages of the electromagnetic voltage transformers are the relatively large outputs and high measuring accuracies. In principle the secondary winding can be directly connected to protection or metering devices. If the electromagnetic voltage transformer is on a line termination, DC trapped charges left on a disconnected line will be dissipated. Thus transient switching overvoltages can be reduced, particularly for rapid auto-reclosing.

The inductance of the primary winding may be such as to cause resonance with grading capacitors and/or with the capacitance of the associated GIS bus bar. Under such conditions, high overvoltages may occur and thermal damage may result. Measures to prevent resonance should be taken by the manufacturer based on information given by the user about components connected to the GIS and the intended burden. Appropriate measures can be the application of specially designed voltage transformers or of additional burdens, e.g., ohmic resistors or inductances and/or by proper switching sequence instructions.

The design of modern electromagnetic voltage transformers incorporates internal shielding to limit the coupling of very fast transients into secondary (control) systems to the value specified in IEC 61869.

As in the case of current transformers, voltage transformers used together with modern microprocessor-based control and protection devices likewise need much less input power and can be classified in the same way (see Sect. 18.4). Therefore, more simple and economic voltage transducers (e.g., capacitive dividers or optical systems) are likely to replace conventional transformers (see Sect. 18.6) and is covered by the standard IEC 61850.

## 18.6 Nonconventional VTs and CTs

Transformers more compact and lightweight than those used in GIS today should become practicable shortly. In power engineering, these so-called sensors or transducers depend on different fundamental principles. The following table gives an overview of principles used and worked on today.

**Table 18.1** Principles of sensors and transducers for current and voltage measurement

| Technology | VTs | CTs |
|---|---|---|
| Semi-conventional | Resistive (R) – dividers | Miniature iron core |
| | Capacitor (C) – dividers | Rogowski-type air core |
| | Mixed (RC) – dividers | |
| Optical | Pockels effect sensor | Faraday effect – parametric sensor |
| | Inverse piezo effect | |
| | Interferometric sensor | Faraday effect – interferometric sensor (Sagnac type) |

In the beginning, transducers on semi-conventional principles (see Table 18.1) have been developed and utilized. For voltage measurements, the well-known divider principles have been used in GIS for more than 20 years. This technology never became an economic success due to expensive power amplifiers required for supporting the standard 100 V interface and high burdens. However, nowadays digital secondary equipment with small power demands have led to new activities in the standardization of low power interfaces (IEC 60044, IEC 61869). This makes semi-conventional transducers again promising candidates for simple and efficient voltage measurement.

For current measurement, it is possible to miniaturize CTs with iron cores, if there is no need for high burdens. These miniaturized CTs offer excellent accuracy and standard transient response for protection applications. The miniaturization process is limited due to saturation effects, or if there are very strong requirements for transient response, it may not be applicable.

Rogowski coil-type transducers are free of saturation effects for current measurement. However, this type of sensor requires sophisticated integration circuits and compensation for effects of the electrical field component. If high accuracy is required, temperature effects also need to be compensated.

Transient phenomena (e.g., very fast transients) have significant impact on the response of all semi-conventional transducers. Therefore such systems often require precautions against transients.

Because of recent notable advances in optical technologies, optical sensors now appear so attractive that optical fiber instrument transformers using optical fiber current or voltage sensors have been developed and utilized. Optical measurements have the following merits:

- Insulation is easy.
- Signals are free of electromagnetic noise.
- Measurements are possible over a wide frequency range.
- Signals can be transmitted over long distances.

Optical current transducers are mainly based on the principle by which the Faraday effect converts the strength of the magnetic field generated around a conductor into an optical variation. If this measuring principle is applied to electric power systems, it is advantageous for ensuring insulation integrity because there are no electric circuits in the high-voltage components of the sensor. In the signal transmission system, light can be used effectively for noise reduction. On the other hand, where such optical fiber current sensors are put to practical use to measure currents in electric power systems, some problems arise, including the effects of the magnetic fields of other phases; variations in the light source (at the light emission side); thermal characteristics of the photoelectric conversion circuit, noise, etc. (at the receiver side); and particularly thermal characteristics and sensitivity of Faraday elements. To compensate for these effects, sensor assemblies based on the Sagnac interferometer may be used.

The voltage detection sensor (optical VT) mainly utilizes the Pockels effect to measure the strength of the electric field applied to the Pockels element by converting it into an optical variation. Several structures have been designed depending on the modulation methods and the types of Pockels elements. For optical fiber voltage sensors, like current sensors, the sensitivity of Pockels elements and thermal characteristics are also important. Another optical voltage sensor type uses the inverse piezoelectric effect. The change of the geometry (thickness) of a piezoelectric crystal due to the electrical field is sensed by fiber optics.

Research into and development of optical measuring techniques have made positive advances, centering on the development of optical fiber sensors with higher sensitivity and better thermal characteristics, so as to achieve a higher level of reliability. Following field performance proof tests, they are expected to find wider applications in GIS.

The wide application of new sensors and transducers for current and voltage measurement in GIS depends also on the success of the standardization activities in IEC 61850.

## 18.7 Surge Arresters

Surge arresters used to protect GIS can be either of the air-insulated type or alternatively can be of the metal-enclosed type. Gapless metal-oxide surge arresters are used in either case. Metal-enclosed surge arresters tend to be expensive; air-insulated surge arresters are used to give protection at line entries. Such arresters, however, may in some cases be inadequate for protecting the whole GIS. It is relatively common practice for metal-enclosed arresters to be installed to protect transformers or reactors (Fig. 18.8); they may also be required to protect open points in a GIS substation where voltage doubling may occur.

**Fig. 18.8** GIS surge arrester with direct connection to the transformer via $SF_6$ insulated bus duct

In the case of very fast transient overvoltages, their effect is limited due to the very fast rising wave front. The transformer manufacturer's and surge arrester manufacturer's guidance should be sought in such cases.

## 18.8 GIS Cable Connection

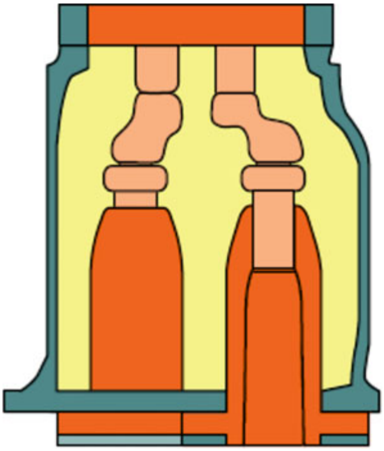
Cables represent a suitable possibility for connecting GIS to other power transmission systems (in a very compact arrangement difficult to achieve with overhead lines). They enable a variety of arrangements, e.g., underground installation or crossings.

GIS cable connections must be designed such that the insulation medium of the cable and the $SF_6$ gas of the GIS are separated and do not influence each other. In order to ensure compatibility of GIS and cable systems from different manufacturers, not only the cable sealing end is standardized, but also the limits of scope of supply of both manufacturers for the different portions of the cable connection are defined in IEC 62271-209. The limits of responsibility are comprised in the scope of the commercial contract.

In addition, GIS enclosures have to be designed to take account of movement, vibration, and expansion variations and of some aspects concerning on-site cable testing. To allow testing of the cable separated from the GIS, the cable box and/or the GIS itself shall be provided with an isolating link and a termination for a test power supply if required by the user. If GIS parts are subjected to this test voltage, the user and manufacturer shall agree upon the specific voltage to be used for cable tests. An example for a GIS cable connection is shown in Fig. 18.9.

A separation between GIS and cable can be achieved also by a plug-in connection providing independent handling of GIS and cable in its installation, commissioning,

**Fig. 18.9** GIS cable connection



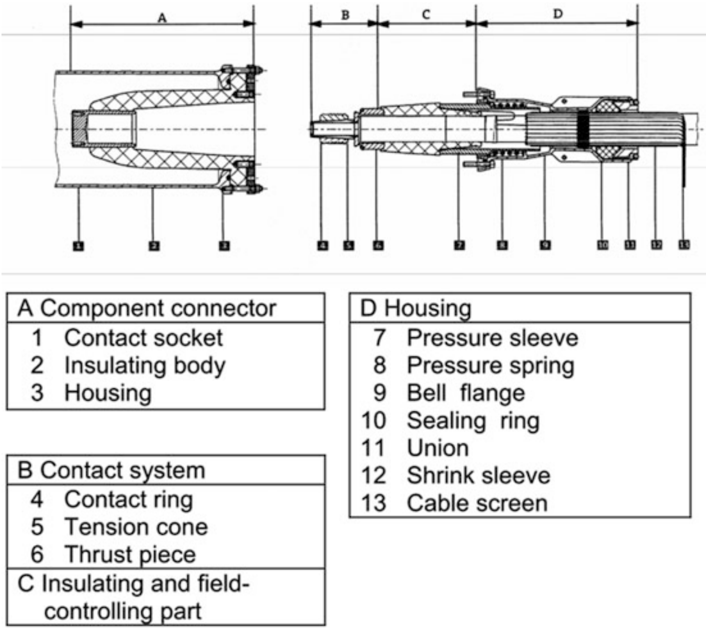



**Fig. 18.10** GIS cable plug system connection

and servicing (Fig. 18.10). As the contact socket is included at the GIS manufacturing and routine tests, also the volume of $SF_6$ gas works is reduced, and no site precautions for cleanness at cable compartment are required.

The earthing systems of GIS and the connected cable must in some cases be isolated from each other. In this case, the open connection must be protected against overvoltages with nonlinear resistor/varistor.

## 18.9 Air Bushings

Air bushings are provided to connect the overhead line to the GIS. They are supplied by the GIS manufacturer. They form the only GIS component with insulation to ground exposed to prevailing environmental conditions. Consequently, the creepage distance must conform to the atmospheric conditions. Values of the nominal specific creepage distance are specified in IEC 60815.

The insulator housing of the air bushings may be of porcelain or of composite insulation (fiber-reinforced resin tube with silicone rubber sheds). The latter is virtually rupture proof and safer for personnel and equipment in case of internal (i.e., internal fault) or external influence.

The insulation between the inner conductor and the housing can consist of compressed $SF_6$ gas or resin-impregnated paper (RIP body). The space between the RIP body and the housing can be filled with compressed $SF_6$ gas or an insulating foam compound.

Attention should be paid to the influence of atmospheric conditions and pollution in particular if the bushings are mounted at an angle beyond 30° from vertical. The forces from the line connection must not exceed the specified values.

## 18.10 Connection to Transformers and Reactors

Connection to transformers and reactors can be divided into three major categories. In special cases, a combination of these categories is possible.

### 18.10.1 Direct Connection via $SF_6$-Insulated Bus Ducts

The direct connection via bus duct has the advantage that no equipment is exposed to environmental stress. In addition, the space requirements are minimized due to the encapsulated system. In Fig. 18.11 such a connection to transformers via $SF_6$-insulated bus duct is shown. Special care has to be taken for direct connection of GIS to transformers and reactors. The following points must be considered:

- Settlement of transformer platform
- Vibration of transformer
- Greater changes in length due to higher temperature of transformer
- Forces acting on GIS in case of an earthquake

The abovementioned points normally require additional expansion joints/bellows close to the transformer and very careful coordination between the user and the manufacturer of GIS and transformer, respectively. The $SF_6$/oil bushing should be supplied by the transformer manufacturer. It should be clearly indicated who is responsible for coordinating the connection flanges between GIS and $SF_6$/oil

**Fig. 18.11** GIS with direct connection to the transformer via $SF_6$-insulated bus duct

bushing. Standards determine the limits of scope of supply and the interface arrangement in order to assure electrical and mechanical interchangeability (IEC 62271-211).

The earthing systems of GIS and the transformer must in some cases be isolated from each other. In this case, the open connection must be protected against overvoltages.

### 18.10.2 Connection via Cable

The connection via cable covers the advantages of direct connection as described above but ensures mechanical decoupling of GIS and transformer due to its flexibility. For more details about GIS cable connections, see Sect. 18.8.

### 18.10.3 Connection with Short Overhead Lines

The GIS/transformer connection via short overhead lines has the advantage of complete independence from transformer manufacturer and design. The use of conventional surge arresters as well as of spare transformers is consequently facilitated.

On the other hand, the bushings are exposed to environmental stress. In addition, the required clearance between the phases has to be ensured (requirement for additional space).

## 18.11 Connection Elements Within GIS

### 18.11.1 Compensators

Compensators balance axial, lateral, and angular forces due to thermal expansion, earthquake recommendations, or manufacturing tolerances. Compensators are also often necessary to enable the dismantling of the GIS for maintenance or repair work.

### 18.11.2 Coupling Element

The coupling element is a component of the bus bar. It usually telescopes and enables dismantling and insertion of bus sections without removal of other GIS components for assembly, maintenance, repair, and extensions.

### 18.11.3 X-, T-, and Angle-Type Enclosures

With X-, T-, and angle-type enclosures and straight parts (bus ducts), the GIS termination can be led to any spatial point necessary for connection to other components. Such parts allow very versatile and complex arrangements. Sometimes they are used as branch-off points or for attaching connection components, e.g., bushings.

## 18.12 Nameplates/Labeling

In view of the complexities of GIS and so as to minimize the possibilities of operational errors, it is important that primary components are adequately identified. The following indications are normal practice:

- Nameplates are provided on at least each GIS bay and the instrument transformers.
- Each mechanical switching device has attached to it, in a noticeable position, a label identifying the user's operational reference.
- Phases of each GIS bay (and bus bars) are identified with appropriate phase referencing.
- Each partition between gas zones is clearly marked.

- Each density monitor is provided with a label identifying the parameter it is reading.
- Each valve carries a label identifying its gas zone.
- Each point of LV isolation is provided with a label identifying its function.
- Each cabinet, cubicle, or marshaling kiosk carries a label identifying its corresponding primary equipment.
- The language and content of the labels must be agreed between user and manufacturer.

In addition, a permanent gas schematic diagram showing all primary functional devices within their $SF_6$ gas compartments may be provided. This diagram should be made to conform (as closely as possible) to the physical layout of the equipment and should show all gas barriers, gas valves, piping, and/or gas monitoring locations. The gas schematic diagram should be permanent and mounted in a convenient place for the use of operating and maintenance personnel.

## 18.13 Online Monitoring and Diagnostics

It has been shown that GIS is very reliable and major faults are rare. Nevertheless, it is the aim of development to further increase its dependability. In order to detect incipient faults, detailed information about the operating condition of the GIS is necessary. Intensive development has led to various possibilities in monitoring and diagnostic systems. Online monitoring systems are able to obtain continuous information about equipment conditions while it is in operation. Diagnostic systems permit the location, identification, and evaluation of a fault which has already occurred or a potential fault which has been detected. The application of such techniques offers the user many advantages such as increased functionality and performance enhancement. They can be used to indicate anomalies within GIS offering the opportunity of planning and taking necessary measures while ensuring continuing operation.

The monitoring systems can also be used to develop new maintenance philosophies like condition-based or reliability-centered maintenance. In these events, maintenance is not performed on a periodic basis but depending on operating conditions including number of operations, amount of power flow, age, etc. The information can support an end of life assessment of the GIS. This is of special interest because experience has shown that the condition of the GIS is in most cases better than predicted after several years in service, and an extended life time can be expected. Most of the possibilities mentioned above have significant influence on the reduction of the life cycle cost justifying in many cases a higher initial installed cost for the GIS.

The choice of the parameters to be monitored and sensors to be used depends first of all on the aim of the monitoring system application.

## 18.14 Integration of Protection and Control Devices into GIS

Recent advances in electronics have enabled substation protection and control systems to incorporate functions equivalent to or higher than conventional systems using central processor unit (CPU)-equipped programmable modules, and such systems are likely to be put into wider use. The size of such systems can be sufficiently reduced to make it feasible to mount them individually in GIS cubicles. Between the GIS and the substation control room, the use of electronics permits signal transmission via a small number of optical fiber cables or electrical (serial) cables eliminating the need for the large number of conventional multi-core cables, which needed a lot of on-site labor to install. The use of electronics in the control and protection of GIS will continue to expand along with the developments of various sensors.

## 18.15 Information to Be Given by the User and the Manufacturer

Basic information necessary for specifying the primary components of GIS can be drawn from ► Sect. 16.8. Detailed information which has to be exchanged between user and manufacturer is described in the relevant standards of the individual components. The application of the standards is similar to that in the case of AIS design. Special attention should be paid to detailed specifications of all GIS interface requirements.

# GIS Secondary Equipment

# 19

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents


19.1 Interlocking ........ 412
19.2 Gas Monitoring ........ 412
19.3 GIS Condition Monitoring ........ 413
19.3.1 Partial Discharge (PD) Detection ........ 413
19.3.2 Fault Location ........ 414
19.4 Special GIS Demands on Protection System ........ 414
19.4.1 Protection System Timing ........ 414
19.4.2 Auto-Reclosing ........ 414
19.4.3 Busbar and Bay Protection ........ 415
19.4.4 Intertripping ........ 415
19.4.5 Earth Fault Protection ........ 415
19.5 Electromagnetic Compatibility ........ 415
19.6 Information to Be Given by the User and the Manufacturer ........ 416
19.6.1 Basic Users Input Data ........ 416
19.6.2 Basic Manufacturers Input Data ........ 417


The definition of secondary equipment generally covers all individual components which form part of the switchgear protection, control, and monitoring systems.

These items of equipment which include all the devices needed to operate, supervise, protect, control, and monitor the primary equipment are in many cases


P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de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similar to those used on AIS. However, in some areas specific considerations have to be given to the secondary equipment because of the nature of GIS. Traditionally the local bay cubicles of GIS are equipped with:

- Local control facilities
- Hard wired bay interlocks
- Visual/audible alarm indicators
- Interface to remote control

The trend toward introducing digital control and protection systems and the move toward so called “integrated systems” are bringing major changes and benefits to the architecture of secondary systems in HV substations and in particular GIS. Modern digital devices dispense with the need for discrete devices for each function, therefore allowing multiple functions to be handled on the same hardware platform but using specific software modules. This allows the opportunity to locate all the GIS bay-related functions at the local bay cubicle close to the GIS bay. This affords considerable advantages in terms of the drastic reduction in volume of wiring necessary as well as a reduction in the quantity of secondary equipment required. The introduction of these new technologies also provides an opportunity for the introduction of enhanced monitoring and diagnostic facilities.

## 19.1 Interlocking

The interlocking requirements and facilities for GIS are the same as for AIS in that most users require a positive and reliable means of protection against potentially harmful maloperation of the switchgear. While GIS is inherently safer than equivalent AIS, its construction can necessitate some different operational philosophies. Most users specify a purely electrical/electronic interlocking scheme with mechanical safeguards to ensure safe emergency manual or maintenance operation of equipment.

The disconnector and work-in-progress earthing switch module is designed as a three-position device with a common drive. Both functions are always mutually interlocked as a result of its design as a three-position unit with a common drive.

## 19.2 Gas Monitoring

The gas monitoring system has the task of checking that the specified $SF_6$ density levels are maintained in each individual gas zone. This function is of major importance in GIS because the dielectric-withstand strength to earth and across open contacts of a switching device is determined by the $SF_6$ density. A variety of monitoring devices are used on GIS:

- Temperature-compensated pressure gauge or switch with alarm contacts
- Pressure gauge with separate density switches

- Pressure transducer with separate temperature compensation
- Density transducer independent of temperature

Normally two gas leakage alarm stages are provided for all GIS gas compartments. The first alarm stage occurs at a gas pressure slightly higher than the minimum functional pressure. At this stage the user should check and refill the gas compartment within an appropriate time. The second alarm stage at circuit breakers, sometimes at disconnectors or at other switching devices as well, includes lockout of their operation (similar to the procedure with conventional SFs circuit breakers). If this second alarm occurs, the staff must check the secondary system condition immediately and, if no malfunction is discovered, remove the relevant GIS part from service. It is of course possible, but not advisable, to connect the circuit breaker lockout alarm with a forced trip signal. Under such conditions the user must be aware that a forced trip signal might cause a maloperation due to the lesser reliability of secondary equipment.

If the circuit breaker is operated with a rated $SF_6$ pressure higher than in adjacent compartments, it is sometimes recommended that adjacent compartments be provided with a third alarm indicating overpressure (increased density) conditions in case of internal leakage at the partition.

As $SF_6$ gas leaks can be one of the causes of switchgear unavailability, the monitoring of $SF_6$ is an important part of the GIS secondary system (also see the CIGRE $SF_6$ tightness guide no. 430).

## 19.3 GIS Condition Monitoring

Condition monitoring covers both periodic and continuous monitoring systems where the sensors, monitoring equipment, and opportunities for integration can differ greatly. As digital control and protection become integrated, including monitoring functions, the emphasis will shift toward more continuous monitoring which will in turn influence the type of sensors used on GIS equipment. For further information see ► Sect. 18.13.

Monitoring systems which are specific for GIS and commonly used today are as follows:

### 19.3.1 Partial Discharge (PD) Detection

Techniques have been developed, based on UHF (ultrahigh frequency) electrical or acoustic methods of partial discharge detection. It is likely that such condition monitoring is an increasingly common part of GIS secondary equipment. Electrical techniques with the highest sensitivity necessitate the introduction of sensors inside the gas compartments, whereas acoustic methods, and some electrical methods, have sensors outside the enclosure. These have less sensitivity for some PD causes (e.g., defects in the epoxy resin). Also CIGRE Guide no. 525 "Risk Assessment on Defects in GIS based on PD Diagnostics" can be very helpful.

The selection for installation of sensors and monitoring system shall consider also the economic factors such as:

- Importance of installation/substation within service network operation
- Service voltage level (higher-rated voltage level are more affected by PD effects)
- Permanent installed sensors and mobile detection system to be used on request or maintenance action)
- Online monitoring

### 19.3.2 Fault Location

If a flashover to earth occurs in GIS, the insulation is unlikely to be self-restoring and its precise location may not be immediately apparent. Although such faults on GIS are infrequent, some users and manufacturers equip GIS with fault location devices (also called arc detection device) to assist in the identification of the precise location of the fault. Such devices can utilize optical, electromagnetic, overpressure, acoustic and chemical sensors, or temperature-sensitive paint.

## 19.4 Special GIS Demands on Protection System

The basic design aspects of protection systems within AIS and GIS are the same. Nevertheless, there are some special GIS features which must be considered. The most important are the following:

### 19.4.1 Protection System Timing

A rapid fault clearance should be obtained in order to minimize the damage of the equipment and the risk of release of contaminated $SF_6$ into the atmosphere in the unlikely case of an internal fault. The insulation in GIS is not self-restoring and the longer a fault persists, the higher the damage will be, and consequently longer outage duration is probable. Permissible maximum times for fault clearance and corresponding specifications for design and testing of GIS with respect to internal faults are included in IEC 62271-203.

### 19.4.2 Auto-Reclosing

In addition to clearing faults of external circuits, the protection used on GIS must ensure that automatic reclosure does not occur in the event of an internal GIS fault.

Clearly any such fault reclosure may entail a danger to personnel and would almost certainly result in greater fault damage and longer outage and repair times.

### 19.4.3 Busbar and Bay Protection

Busbar protection should be applied. In order to minimize the fault clearing time, it should be designed in such a way that only the faulted section is cleared, leaving the maximum number of circuits still energized. This may entail the use of more CT cores and locations than might be the case in an AIS substation.

### 19.4.4 Intertripping

For faults on GIS connections to external circuits, protection must be coordinated with the circuit remote end protection, and rapid fault clearance should be obtained by the use of intertripping circuits.

### 19.4.5 Earth Fault Protection

In GIS with single phase enclosures used on grid systems without a solidly earthed neutral, conventional protection systems might be unsuitable for detecting an earth fault. Therefore protection systems that are able to detect the earth current are required.

## 19.5 Electromagnetic Compatibility

It is well known that high-frequency transients are generated within GIS which differ in generation, transmission, and attenuation from those in AIS; this can impose more demanding requirements on the secondary equipment associated with GIS.

High-frequency transients, generated by operation of circuit breakers, disconnectors, and earthing switches or by fault conditions, are generally confined inside the shielding provided by the GIS enclosures. However, all GIS include discontinuities which allow the high-frequency effects to be transferred to the exterior of the GIS. As a result of these disturbances generated within the substation, the secondary equipment associated with the GIS is exposed to two types of electromagnetic origin:

- Radiated electromagnetic fields
- Conduction in the conductors associated with the equipment (common mode or differential mode voltage)

The fundamental difference between GIS and AIS consists essentially in the spectrum of the frequencies involved. Provided that measures are implemented in the design of the GIS and its associated secondary equipment, the difficulties of electromagnetic compatibility can be overcome. IEC 60694 provides specific guidelines for users in how to treat secondary equipment.

As more electronic equipment is introduced into the GIS substation environment for integrated control, protection and monitoring applications, the higher might be the potential risks for EMC occurrence.

- The design of the GIS earthing system
- The shielding and termination of secondary cabling
- The shielding of local control cubicles containing sensitive electronic equipment directly mounted on the GIS
- The shielding and protection of individual items of secondary equipment where appropriate
- The increased use of inherently immune communication methods such as optical fibers

## 19.6 Information to Be Given by the User and the Manufacturer

In AIS and GIS, primary equipment and secondary equipment may be supplied by different manufacturers. In this case it is important that user and manufacturer describe the borderlines and coordinate the transfer of data between the various functions. Early adjustments allow minimization of cabling and placing of some or all devices in the bay control cubicle, thereby saving on costs and space. The complex structure of GIS requires early fixing of the technical data of current and voltage measurement devices. Subsequent changes may lead to a fundamental redesign of the GIS layout.

### 19.6.1 Basic Users Input Data

- Ratings of current and voltage transformers
- Number and place of current and voltage transformers
- Requirements for transient performance of CT and VT
- Required type and number of input/output signals, especially if they do not follow international rules
- Links from bay to bay, especially if extensions are planned
- Links from bay:
  - To station control
  - To protection systems
  - To metering systems
  - To monitoring systems
- Design of the earthing system

### 19.6.2 Basic Manufacturers Input Data

- Operating times of circuit breaker, disconnector, and earthing switches
- Bursting pressure
- Opening characteristic of pressure release device
- Alarm steps of gas density monitoring devices
- CT magnetizing curve and transient performance characteristics if requested
- Quality and number of links from the primary equipment to the bay control unit
- Shielding concept of cabling
- Output signals, especially if they do not follow international rules
- Special requirements on the earthing system
- Burn-through time

# Interfaces: Civil Works, Building, Structures, Cables, OHL, Transformers, and Reactors 20

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents


20.1 Training of Operation Personnel ... 420
20.2 Building/Civil Works ... 420
 20.2.1 Construction ... 420
 20.2.2 Space Requirements ... 421
 20.2.3 Handling Equipment ... 423
 20.2.4 Load, Walls and Ceilings ... 423
 20.2.5 Windows/Doors ... 424
 20.2.6 GIS Mounting Points ... 424
 20.2.7 Cooling/Heating and Ventilation ... 425
 20.2.8 Fire Protection ... 425
 20.2.9 Noise Abatement ... 425
 20.2.10 Cables ... 425
 20.2.11 Lighting and Socket Outlets ... 425
 20.2.12 Earthing ... 426
20.3 Support Structures and Accessibility ... 426
20.4 Information to Be Given by the User and the Manufacturer ... 426
 20.4.1 Basic Users Input Data ... 427
 20.4.2 Basic Manufacturers Input Data ... 427



P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de



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## 20.1 Training of Operation Personnel

Prior to commissioning and formal acceptance, the users' appropriate personnel should be trained by the manufacturer in the operation and maintenance of the GIS equipment.

If possible key personnel may benefit from taking part in factory acceptance testing and in onsite installation, tests, and commissioning; ref. ▶ Sect. 24.8.

## 20.2 Building/Civil Works

Switchgear (high-voltage and, if applicable, medium-voltage), auxiliary systems (e.g., station service equipment, control systems, protective gear), transformers, cables, and overhead lines form a functional unit. The special layout of the system components must therefore be well coordinated by the customer, architects, and electrical engineers. Possible subsequent expansions must be taken into account as early as the building planning stage.

The manufacturer of the GIS provides the user or building planner with construction specification plans, which contain all information for performance of the civil works (room internal dimensions, loads, wall and ceiling penetrations, etc.) relevant for GIS. These construction specifications form the planner's (or construction firm's) basis for the structural drawings. Before construction starts, the structural drawings must be submitted to the manufacturer of the GIS, who will examine the relevant aspects. Local construction site management is responsible for implementation of the approved structural drawings in construction of the site.

The civil works range from outdoor foundations and steel framework structures in outdoor substations to architecturally complex edifices or complicated underground caverns. Three examples are given in Figs. 20.1, 20.2, and 20.3. In general, building requirements and fire regulations for buildings are regulated on national or regional levels. The following requirements, planning principles, and recommendations should be followed for areas and locations around high-voltage switchgear assemblies in acc. with IEEE C37.122 and IEC 62271-203.

### 20.2.1 Construction

Rooms for electrical installations must be designed such that no water can penetrate and such that condensation is kept to a minimum. Pipes and other facilities must not endanger the electrical system if they suffer damage. Joints within the building should be avoided. In other respects the user must define possible movements and the manufacturer shall take measures to accommodate this movement. In any event, structural columns and joints should be arranged such that they harmonize with the pole/bay spacing of the GIS. The design of structures (e.g., building, foundations, containers, etc.) must be able to withstand the expected mechanical stressing (static and dynamic) imposed by the installation and operation of GIS and its associated connections including auxiliary equipment, e.g., cranes.

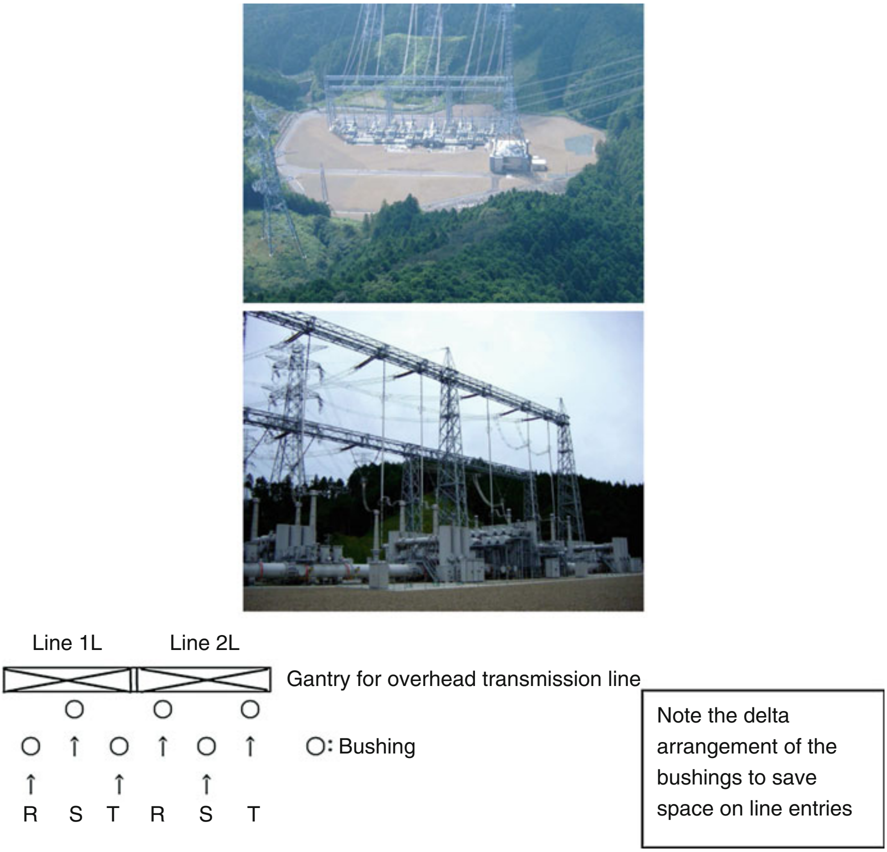


**Fig. 20.1** 500 kV Shizuoka Substation (Chubu Electric Power Company)

### 20.2.2 Space Requirements

Corridors and access ways must be of adequate dimensions for switchgear operation and maintenance and for any necessary work to be done for transportation and installation.

**Indoor and Underground Mixed Substation**

This indoor and underground mixed substation comprises two buildings of which one part is indoor and the other part is underground. This is located in business and commercial area near a station. Originally this was built as 154/33 kV indoor substation. In order to supply the increasing electricity demand along with the large-scale redevelopment of the area around the station, this substation was refurbished to two buildings (indoor part and underground part) and the primary voltage of the power transformer uprated from 154 kV to 275 kV. In addition, 275/77 kV power transformer was installed to provide a stable for the long term in this area.

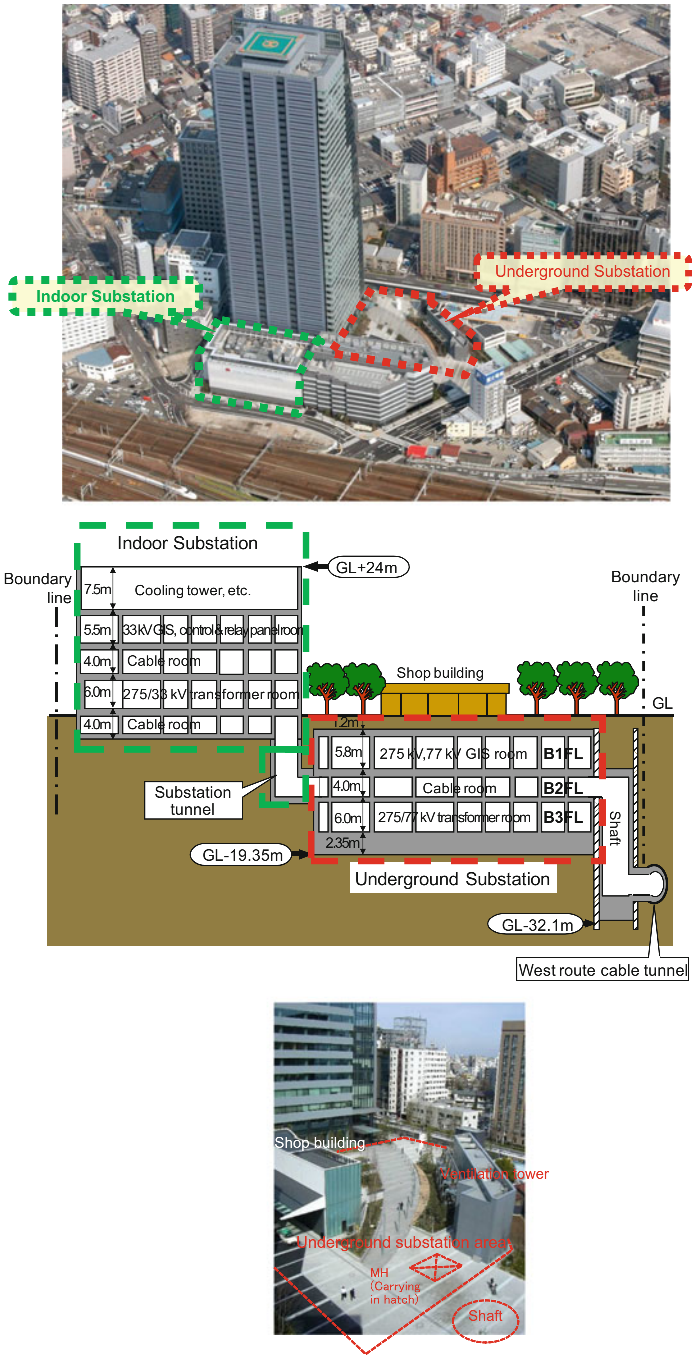


**Fig. 20.2** Indoor and underground mixed substation (Chubu Electricity Company, Inc. Ushijima-Cho S/S)

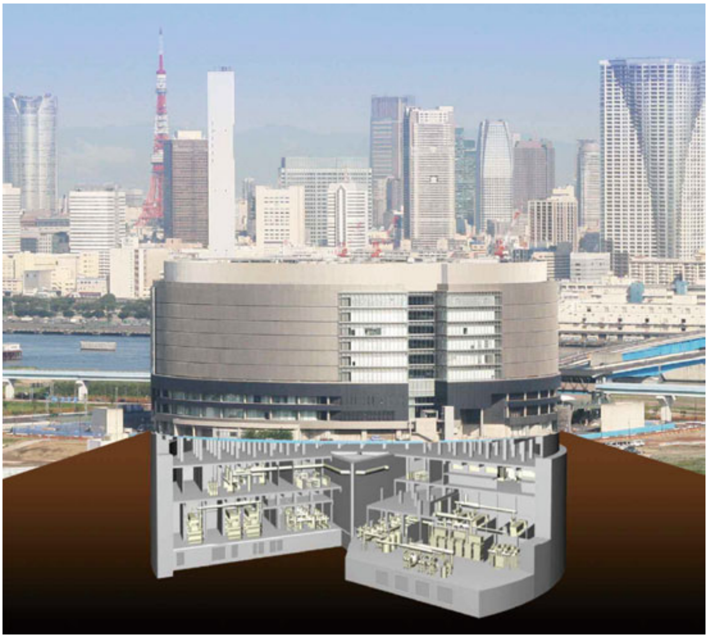

**Fig. 20.3** 500 kV circular form underground substation – Shin-Toyosu (TEPCO)

Data center and offices are arranged in the upper building purposes. Local regulations must be complied with concerning minimum gangway widths and length of escape routes. In addition to the spaces required for the system and equipment, adequate space for performing commissioning work (e.g., work on the gas system, high-voltage test) and inspection work (e.g., dismantling of an interrupter unit) must be provided.

### 20.2.3 Handling Equipment

If installation, operation, or repair work requires a crane, adequate crane hook height and approach route dimensions must be assured. In switchgear systems with many bus bars crossing aisles, remote control of the crane system would be appropriate.

### 20.2.4 Load, Walls and Ceilings

Modern designs of GIS are delivered in large units (typical for the voltage levels of up to 145 kV). In any case, weights in excess of some hundred kilograms or even some tons need to be moved on site in the building. Therefore, the ceilings and structure need to be strong enough to carry the load. Also the floor finish must be capable of withstanding the forces coming from fork lifters or air lift devices carrying the GIS bays. The weights need to be given by the manufacturer.

In general, dust production should be minimized. Additionally, dust deposits must be avoided; walls and ceilings must therefore be smooth and easy to clean. Openings for $SF_6$ bus bars must be sealed to provide protection against the weather and constructed to accommodate the mechanical and thermal movement.

The walk passages that connect the indoor GIS to outdoor equipment should not affect the stability of the walls. If metal parts are used for wall passes, they have to be grounded. Any panels or parts accessible from the outside by a public area need to be fixed in such a way that they cannot be removed.

In the case of an internal arc within the GIS, the pressure inside the enclosure could increase to a point where a disk ruptures, resulting in the bursting disk falling into the building room. The wall, ceilings, and floors should be strong enough to adequately withstand the increase in pressure. The pressure load depends on the enclosure gas volume and the short-circuit rating of the equipment and can be calculated by the manufacturer.

### 20.2.5 Windows/Doors

All high-voltage switchgear installations must be set up as locked electrical service locations. Windows must be of a design to prevent entry from outside. Therefore, the windows should be located more than 1.8 m above the ground, acc. to IEC 61936. The glass may be comprised of unbreakable material or the window is protected with an iron curtain.

Larger access ways are required for the delivery of GIS. Such access way shall be kept free during operation in case of problems and if required for future extension. Access doors must be fitted with safety locks and safety legend plates. Doors must open outwards. It must be possible to open emergency exit doors from inside without the need for a key. Additional security provisions might have to be considered.

### 20.2.6 GIS Mounting Points

The floors and levels have to be durable and suitable for bearing all static and dynamic loads and have to lie within the tolerances. The tolerances have to be agreed between user and manufacturer. The floor covering must have adequate pressure-withstand capability to bear the loads occurring when switchgear system components are transported.

The following fixing measures are used:

- Drill anchor
- Embedded anchor
- Anchor rail
- Steel rail for welding

### 20.2.7 Cooling/Heating and Ventilation

The permissible ambient temperatures have to be assured by means of adequate ventilation taking into account the heat dissipation of GIS (if necessary, air conditioning or heating). Natural ventilation is preferred. Rooms containing $SF_6$ switchgear must be adequately ventilated. This also applies to rooms, ducts, etc. located below rooms containing GIS equipment. Locally applicable regulations must be complied with. A fixed or mobile fume extraction unit may be provided to assist in the removal of $SF_6$ decomposition products.

Water condensation due to temperature change, mainly when the building is air-conditioned, should be avoided to prevent corrosion. If this cannot be obtained, precautions should be taken to prevent the consequences of water leaking or condensation affecting operating safety. Handrails or slippery-save walkways may be necessary.

Information is given in IEC 62271-4 for gauging the potential effects on health in the event of release of $SF_6$ into the atmosphere.

### 20.2.8 Fire Protection

GIS itself does not require any specific fire precautions. However, adequate fire protection measures must be taken between switchgear rooms and transformers and also between switchgear rooms and cable basements. After installation, ceiling and wall penetrations must be sealed in such a way that the fire prevention specifications applying to the building are fully complied with. In the event of a fire, escape routes, rescue routes, and emergency exits must be usable and unobstructed.

### 20.2.9 Noise Abatement

Depending on the location, noise abatement for the GIS (due to switching operation) and transformers may require additional measures for the building.

### 20.2.10 Cables

Cable racks or screen-covered ducts have proved suitable for installation of control cables. In the case of power cables, the permissible bending radius and the space required for fitting the sealing ends must be taken into account. The danger of fire spreading and subsequent gas contamination must be minimized by selection of suitable cables and segregation zones.

### 20.2.11 Lighting and Socket Outlets

The level of light shall be sufficient for normal operation. For specific work, removable lights may be used. Socket outlets must be installed for power supply to special tools (like handling plant for $SF_6$) as well as for the supply for test equipment.

### 20.2.12 Earthing

All earthing, overvoltage protection, and EMC measures must be coordinated. An EMC protection zone concept must be borne in mind when the earthing and overvoltage protection measures are devised. A well-designed earthing system and potential grading are essential for this purpose. A direct connection with the building reinforcement might also be used.

The specific grounding or earthing requirement of the GIS is related to the high transient voltages when any switch in the GIS is operated and the very compact design of the GIS. The very fast transients of a high-frequency nature need a low impedance to ground/earth. Such is reached by having multiple connections made between the concrete reinforcement steel grid and the earthing system of the building at various points in the GIS floor.

At the building wall, a multiple connection for the GIS to air bushing is needed between the GIS enclosure and the building wall. To achieve good conductivity in the building wall, steel panels are usually integrated with multiple connections to ground/earthing of the building. Secondary equipment used with the GIS should be adequately designed and tested for their immunity against transient overvoltages of the secondary circuits.

## 20.3 Support Structures and Accessibility

Many GIS components are self-supporting. If steel structures are required as support elements or due to seismic specifications, the planning and approval should be performed by the GIS manufacturer. This will avoid interference and matching problems during installation.

Some users question whether it is appropriate for operators to require high-level access for normal operational functions; the argument generally depends on whether or not inspection windows are considered necessary.

It may also be necessary to provide transportable platforms to allow better access, and even then it may still be necessary for operators to climb across the switchgear to gain access to all parts. Access may also be required to certain specific equipment in order to fit safety padlocking facilities, and additionally gas filling points may also require high-level access.

## 20.4 Information to Be Given by the User and the Manufacturer

On condition that the user or a third party is responsible for all civil and steel structure works, manufacturer and user should exchange at least the following information:

### 20.4.1 Basic Users Input Data

- Structural drawings of the building
- Tolerances of floor level, structural columns and openings for cabling, bushings, etc.
- Possible floor movements
- Boundary conditions for transportation and installation
- Climatic condition in the building, especially during installation
- Limits of supply
- Limits of accessibility
- Availability of socket outlets
- Drawings of the earthing system

### 20.4.2 Basic Manufacturers Input Data

- Basic characteristics of the layout including detailed dimensions of the GIS
- Dimensions and weight of the largest and heaviest shipping units
- Locations and dimensions of support structures
- If necessary, requirements for further structures which are not part of the scope of supply
- Dynamic and static forces at the locations of the supports
- Civil works tolerances, especially tolerances in the elevations of the places of installation of the GIS
- Requirements for the cable ducts and the earthing system
- Requirements for a lifting device
- Space requirement for on-site assembly and testing and $SF_6$ handling equipment
- Requirements for cleanliness during installation
- Required climatic conditions in the building
- Limits of supply

# GIS Earthing

# 21

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

21.1 Effect of GIS on Design of Earthing Systems ... 430
21.1.1 General ... 430
21.1.2 Physical Size ... 430
21.1.3 Transient Enclosure Voltage (TEV) ... 430
21.1.4 Discontinuities ... 431
21.1.5 Screening ... 431
21.1.6 Effects on Personnel ... 432
21.2 Design of GIS Earthing System ... 432
21.2.1 Design of Earth Grid ... 432
21.2.2 Connections to the Earth Grid ... 433
21.2.3 Discontinuities ... 434
21.2.4 Effects on Control Circuit ... 437
21.2.5 Treatment of Sensitive Control Equipment ... 438
21.2.6 Instrument Transformers ... 438
21.3 Testing and Maintenance of Earthing Installations ... 438
21.3.1 Power Frequency Compatibility ... 438
21.3.2 High-Frequency Compatibility ... 439

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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## 21.1 Effect of GIS on Design of Earthing Systems

### 21.1.1 General

While the physical characteristics of the GIS will have a profound effect on a number of aspects of the design, the basic requirements of an earthing system for a GIS installation are not different to those for an air insulated site, i.e., to protect operating staff against any hazard and to protect equipment against electromagnetic interference and damage.
The design of an earthing system at a high voltage is based on following key aspects:

- Capability to withstand all mechanical forces caused by fault currents
- Ability to carry the thermal effects of highest level of fault current
- Avoidance of damage to operational equipment and goods
- Ensuring of safety condition to persons at all operations

Additional demands on the earthing system are given by the requirements in:

- Overvoltage protection
- Potential equilibration
- Lightning protection
- EMC measures

Basic international standard are given by IEC 61936-1 (2014) “Power installations exceeding 1 kV a.c.,” EN 50522 (2011) “Earthing of power installations exceeding 1 kV a.c.,” and IEEE Std. 80-2000 “Guide for Safety in AC Substation Grounding.“

### 21.1.2 Physical Size

As the area occupied by a GIS substation is typically only 10–25% of that of the equivalent air installed installation, then clearly achieving the required level of earth electrode resistance is going to be more difficult. In addition, the individual items of equipment are closer together requiring a “high density” grid, i.e., more ground conductor in a given area. This latter feature helps to reduce the earth electrode resistance but not in a very cost effective way because increasing the ground area is far more effective than increasing the amount of earth electrode surface in a given area.

### 21.1.3 Transient Enclosure Voltage (TEV)

Transient enclosure voltage is caused by high-frequency current, not by currents flowing at service frequency. TEV can be set up by lightning strokes, operation of lighting arresters, phase to earth faults, and discharges between contacts during switching, mainly disconnector operations. The TEV is set up by the currents fed into the earthing system and capacitance of the GIS installation and can have rise times as low as 3–20 nsec but only sustained for 20–30 msec at the most.

The high-frequency currents cause local transient potential rise because of the relatively high reactance of conventional earth connections, e.g., a 1 m length of straight copper can have reactance of approximately 60 Ohms at 10 MHz, whereas at 50 Hz it would be approximately 0.003 Ohms. Thus connections must be as short and direct as possible because bends in copper conductors also cause high reactance at high frequencies.

### 21.1.4 Discontinuities

High-frequency transients are generally confined to the inside of the screening provided by the GIS enclosures and as such cause no problems. However all GIS includes discontinuities in the enclosures which allows the high-frequency effects to be transferred to the exterior of the GIS.

Discontinuities exist at:

- $SF_6$ to air terminations
- $SF_6$ to transformer or reactor bushings
- $SF_6$ to HV cable bushings
- Insulated flanges employed in externally mounted current transformers, i.e., CT's mounted around the metal enclosure
- Exposed insulation at enclosure flange joints
- Windows at disconnectors
- Monitoring devices
- Instrument transformers, terminals of secondary windings

The $SF_6$ to air termination gives the most significant enclosure discontinuity and is therefore the largest potential source of high-frequency effects. The magnitude of the high-frequency transient coupled from $SF_6$/air termination is dependent on the arrangement of the termination itself. The propagation of the transient back into the GIS is influenced by bushing supports, earth connections, and any shields which may be installed.

Other enclosure discontinuities are also sources of high-frequency effects, but these are generally much smaller than those which appear due to the $SF_6$/air bushings.

On some designs of GIS enclosures, the main flange joints are made using a sandwich of metal flanges and the insulating spacer. Special measures therefore have to be introduced to prevent sparking across the discontinuity which can cause alarm to operational staff and, in extreme cases, may cause damage to the insulation of the discontinuity.

### 21.1.5 Screening

Transient enclosure voltages interfere with protection, control, and communication circuits by electromagnetic coupling. If the earthing is not efficient, high-frequency transients as high as 50 kV may be reached on the GIS enclosure making it necessary to screen control, protection, and communication cables attached to the GIS enclosure and to separate them from the enclosure whenever possible.

### 21.1.6 Effects on Personnel

The presence of TEV in GIS has often raised questions concerning the safety of personnel having access to such a substation. TEV, however, is a low energy, short duration phenomenon, and there is no recorded evidence to suggest that it is directly dangerous to personnel performing their normal duties within GIS installations.

The appearance of sparking at insulated discontinuities during switching operations may, however, startle operators and cause them harm, e.g., if standing on a ladder at the same time. Consequently it may be appropriate to introduce warnings limiting access during switching operations. However, the introduction of measures described in the next section should provide a safe working environment for operation and maintenance personnel.

## 21.2 Design of GIS Earthing System

### 21.2.1 Design of Earth Grid

The purpose of the earth grid is to provide a low impedance path for the earth fault current and also the high-frequency current arising from TEV. The service frequency criteria are the most significant factors.

Before designing the grid, it is necessary to know the maximum earth fault current that the earth grid will have to carry, the soil resistivity, and, consequently, the maximum allowable potential rise; it is a simple matter to calculate the required overall earth electrode resistance, e.g., if the maximum allowable potential rise is 650 V and the current 10 kA, the earth electrode resistance should be less than 0.065 ohms. Various standards give guidance on this matter (see Sect. 21.1.1).

Normally with an AIS (which will be larger in area compared to the equivalent GIS), a single uninsulated copper loop laid around the perimeter of the site with cross connections to pick up the individual items of equipment will provide a sufficiently low resistance electrode. However, the smaller area occupied by a GIS means that the size of the main earth loop will be smaller, and therefore the total amount of conducting path will also be smaller and additional measures may be necessary.

#### 21.2.1.1 Effect of Different Mesh Arrangements

Increasing the length of conductors laid within a single loop will reduce the resistance of the mesh but not in direct proportion to the additional length laid, e.g., see Fig. 21.1.

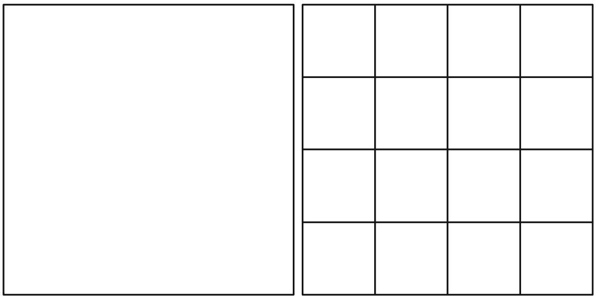



**Fig. 21.1** Different mesh arrangements

However, the desirability of providing frequent and short connections for the closely spaced individual items of equipment does provide an incentive to lay a "high density" grid.

#### 21.2.1.2 Effect of Connecting to Reinforced Concrete Mat

If a continuous reinforced concrete floor slab is being used, then connecting the reinforcing steel mesh and structural steel to the earthing grid will certainly serve to reduce the total earth electrode resistance and also provide more even potentials within the floor area and at the surface. Preferably the reinforcing steel rods should be welded together for continuity. However this brings with it a number of practical difficulties, e.g., the need to bring the earth connections through the concrete slab at frequent intervals and the need to avoid undesirable "loops" of high current which could damage concrete locally. It is of course possible to lay the grid over the concrete mat, but this increases its earth electrode resistance because it is not laid in the ground.

#### 21.2.1.3 Use of Deep Driven Ground Rods

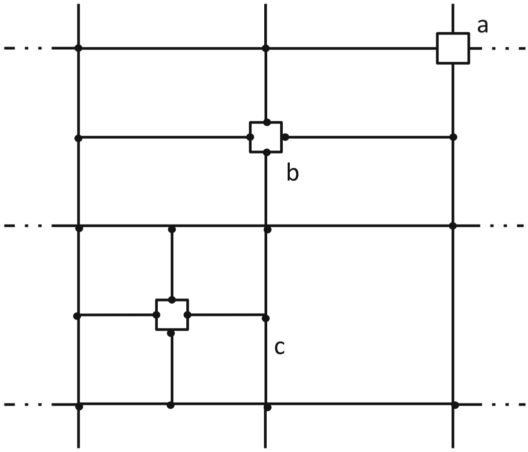
If it is found to be impossible to reduce the earth electrode resistance to a sufficiently low value using the methods described above, then deep driven ground rods or chemical treatment of the soil, to reduce resistivity, may be beneficial.

The value of the designed earth electrode resistance can be calculated using empirical formula quoted in various standards, but it is recommended that means be provided in the design to measure the resistance on completion so that additional measures can be taken if necessary.

### 21.2.2 Connections to the Earth Grid

Frequent connection of the GIS enclosure to the earth grid and the fact that the phase enclosures are also bonded together will minimize hazardous "step" and "touch"

**Fig. 21.2** Connection of equipment to the earthing grid




voltages within the GIS area. In addition, connections should be as short and straight as possible to reduce the impedance at the higher frequencies (see Fig. 21.2).

The need to make connections to earth as short and direct as possible also suggests strongly that GIS enclosures should be as near to ground level as possible though this should not be the overriding consideration when the GIS installation itself is being designed.

### 21.2.3 Discontinuities

As described in Sect. 21.1.4, high-frequency potentials can occur at discontinuities in the GIS enclosure, and special measures have to be taken to alleviate the condition.

#### 21.2.3.1 At Cable Entries

The use of insulated flanges at cable entries produces a discontinuity at the flange, but a simple and economic remedy is available by means of nonlinear resistors, connected symmetrically around the flange with short connections (see Fig. 21.3). Coupling capacitors may also be used in place of the nonlinear resistors.

#### 21.2.3.2 Transformer or Reactor Bushings

Similarly, where the GIS equipment is connected to a transformer, reactor, etc. via bushings, the need to keep the metal work of the two metal masses separate necessitates insulation between the flanges and, in consequence, a discontinuity in the enclosure. The high-frequency potential difference across the discontinuity can be kept to a safe level by means of nonlinear resistors (see Fig. 21.4).

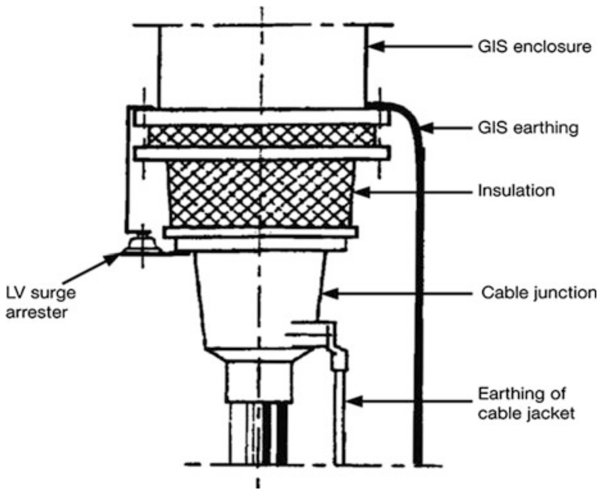



**Fig. 21.3** Shunting of the insulation between the metal enclosure of a GIS and the metal part of the cable by means of nonlinear resistors

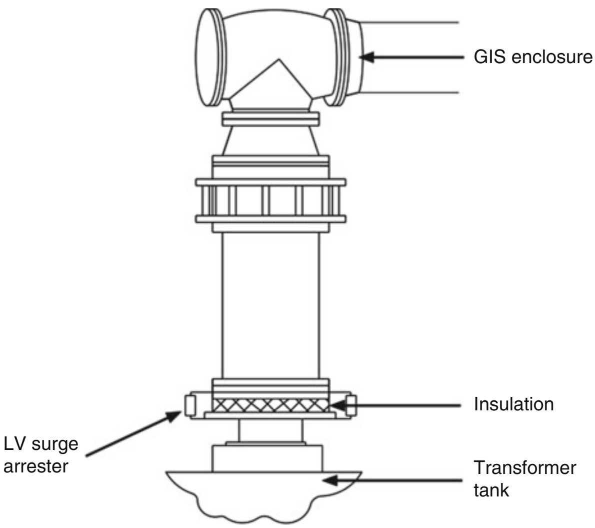



**Fig. 21.4** Shunting of the insulation between the metal enclosure of a GIS and a transformer tank by nonlinear resistors

In some cases the metal masses are deliberately bonded together, but, even so, care will need to be taken because of the change in surge impedance.

#### 21.2.3.3 CT's Fitted External to the Enclosures

When current transformers are fitted to the outside of enclosures, it is clearly necessary to avoid power frequency currents flowing in the enclosures in the opposite direction to the main fault current in the primary conductor. Insulated flanges have to be fitted at those points at the inner tube. The continuity in the metal enclosure is provided at the external tube (see Fig. 21.5).

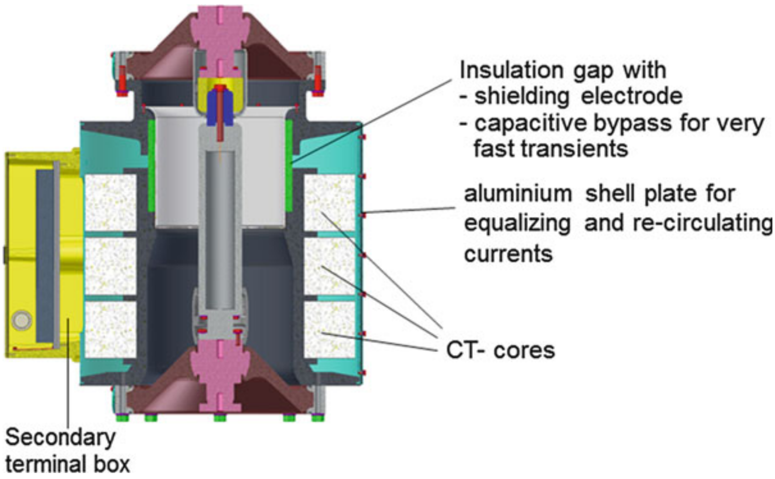



**Fig. 21.5** External current transformer “core-in-air” with continuity of metal enclosure

#### 21.2.3.4 $SF_6$/Air Bushings

While insulated flanges do not feature in $SF_6$/air bushings nevertheless, due to the different surge impedances of the internal busbars and the bushings, there is a “discontinuity” in the enclosure, and it is important to keep the high-frequency impedance of the earthing connections at the bushings to a minimum, e.g., if the design allows, every effort should be made to keep the bushing close to the ground so that the earth connection to the main grid is as short and straight as possible.

#### 21.2.3.5 Indoor Substation Entrance Points

The point at which a GIS enclosure enters a building provides an excellent opportunity for improving the earth connections, particularly if the GIS terminates at an $SF_6$/air bushing outside the buildings. Under such circumstances there will be a need to provide a low impedance path for the refracted wave.

An arrangement shown in Fig. 21.6 provides an ideal method for preventing the refracted wave from reentering the building. To be most effective, the GIS enclosure must be well bonded to the surrounding metallic portion of the surrounding wall, e.g., the reinforcing bars which, in turn, must be connected to the earth grid by at least two, preferably more connections, made entirely of metal which, of course, must be closely bonded to the GIS enclosure.

#### 21.2.3.6 Nonlinear Resistors

Nonlinear resistors designed for the explicit purpose of protecting GIS discontinuities have not always been readily available.

When a single point earthing system was widely adopted in the early years of GIS application, a large number of nonlinear resistors were connected between GIS-insulated

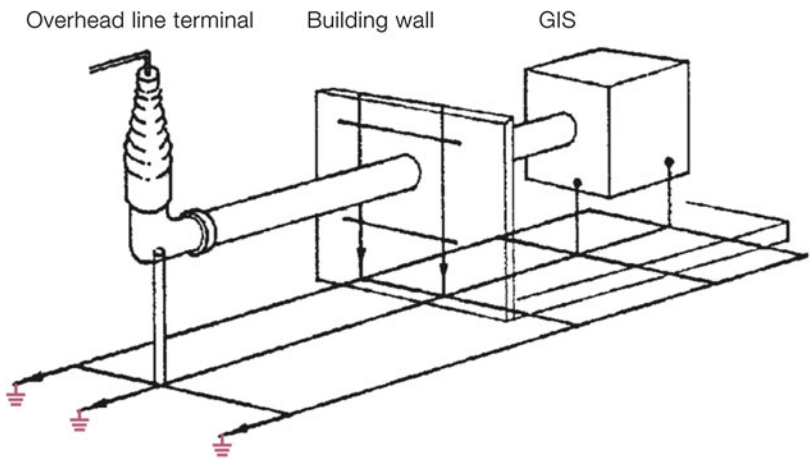



**Fig. 21.6** Method of screening GIS termination into building

flanges at the discontinuities in Japan and other countries. However, at present multipoint earthing systems have become more common, so the number of discontinuities is quite limited and consequently the use of these nonlinear resistors has reduced.

When nonlinear resistors are used, then the earthing designer should use a resistor designed taking into account high-frequency response, voltage rating, and energy absorption characteristics. In addition great care must be taken to reduce stray inductances by careful design of the connecting leads.

### 21.2.4 Effects on Control Circuit

It will be obvious to the designer of the earthing system that owing to the distance between the ends of control cables in a GIS system and the comparatively large "high-frequency" impedance of the earth connection that, unless special measures are taken, there could be a high potential difference set up between the ends of different control cables (tens of kilovolts). This can affect the performance of control equipment, e.g., printed circuit boards connected to the GIS equipment even through remote from it.

This condition can be alleviated by:

(a) Careful choice of control cable routes

The "coupling" between the enclosure and the control cables can be reduced if the latter are placed as far away as possible from the enclosure. Thus, unscreened control cables should not be fixed to the enclosure for any distance and should be led away from the enclosure as quickly as possible after leaving the "entry point," e.g., CT terminal box, etc.

(b) Screening of control cables

In general, conditions in a GIS installation, particularly the range of frequencies experienced, makes it necessary to use "continuous" screens; "braided" screens are of limited use because of their high impedance at high frequencies. Effective screening, however, can be produced by enclosing the individual cables in their own screens or by enclosing a group of cables in metallic conduits or totally enclosed cable trays. This screen should be bonded to the cabinet or housing containing the equipment, e.g., gas density relays and earthed at the remote end by short direct connections. The cabinet or housing should be bonded to the main earth.

### 21.2.5 Treatment of Sensitive Control Equipment

If some of the control, protection, or telecommunication equipment associated with the GIS have a very low transient immunity level, or if the relay room is within the GIS building, it may be necessary to provide complete shielding (Faraday cage) of the rooms or cabinets containing the equipment. In instances when a Faraday cage is used, cables from the control cabinet at the GIS should still be completely screened and the screens bonded to the shield of the Faraday cage as directly as possible. For cable runs in excess of 60 m, either between the GIS and the control kiosks or between the control kiosk and the control/relay room, it may be necessary to use isolation transformers or interposing relays.

With the increasing tendency to mount control equipment next to the switchgear, the possibility of interference increases in importance though, conversely, latest EMC directives should lead to design of control equipment more immune to transients.

### 21.2.6 Instrument Transformers

Transient voltages transmitted via instrument transformers to the secondary circuits can be reduced by carefully placed earth connections within the transformer and by internal screening of the secondary windings.

## 21.3 Testing and Maintenance of Earthing Installations

### 21.3.1 Power Frequency Compatibility

The main reason for making measurements of an earthing installation is to verify the adequacy of a new earthing installation and to ascertain those additional measures, if any, that are necessary to protect personnel and control/communications equipment. Measurements are also recommended after major changes affecting the basic requirements and at regular intervals (5–10 years) to check the condition of the earthing installation.

Measurements although somewhat difficult will usually give more reliable results than calculations and in any case are always advisable to check the latter.

A suitable method based on the use of current injection via an auxiliary electrode is incorporated in several commercially available instruments which gives a direct reading of the earthing resistance.

For large sites where the distance to the auxiliary electrode is long, induction effects in the long-measuring leads can introduce appreciable errors. These can be mitigated by increasing the value of the injection current.

Inspection and testing of the aboveground earthing and bonding connections should be made before commissioning the installation to ensure that all joints and connections are sound and secure. When measuring joint resistance of conductors of the same size, the measuring probes should be located approximately 25 mm on either side of the joint. The joint resistance should not exceed that of an equivalent length of a similar conductor. Where conductors of dissimilar size are jointed, the resistance should not exceed 75% of equivalent length of smaller conductor.

The above checks and tests should be repeated at the maintenance intervals when any wear, damage, or corrosion to flexible bonding braids or lamination should be rectified.

### 21.3.2 High-Frequency Compatibility

The tests and checks outlined in Sect. 21.3.1 should be adequate to preserve the integrity of the earthing installation in respect of power frequency currents, but additional measures may be necessary in respect of the high-frequency earthing and bonding circuits.

Since the high-frequency phenomena preponderantly arise from the switching of disconnectors, the integrity of the earthing installation against high-frequency transient effects can probably be best checked out by strategic disconnector switching at the substation commissioning stage.

During such switching operations, checks should be made for sparking at flanges and spurious or maloperations of protection and/or control systems.

It is assumed that all secondary equipment will have been previously type and routine tested for electromagnetic compatibility in the factory and that the purpose of the test at site is limited to checking that the equipment has been correctly transported to and reinstalled at site together with the connections originating at site. The tests should also reveal if the GIS has, in any way, inadvertently overstressed the secondary equipment.

# GIS Testing

# 22

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents


22.1 Type Tests ........ 442
22.2 Routine Tests ........ 442
22.3 Tests After Installation On-Site ........ 443
22.4 Installation, On-Site Test, Commissioning, and Formal Acceptance ........ 443
22.5 Site Preparation ........ 445
22.6 Work Crew Preparation ........ 445
22.7 Installation of New GIS ........ 446
22.8 Installation of GIS Extensions ........ 446
22.9 Service Continuity ........ 447
22.10 Commissioning ........ 447
22.10.1 Commissioning of Primary Equipment ........ 448
22.10.2 Commissioning of Secondary Equipment ........ 448
22.10.3 Commissioning of the $SF_6$ Insulation Medium ........ 448
22.11 Information to be Given by the Manufacturer and the User ........ 449
22.11.1 Basic Users Input Data ........ 449
22.11.2 Basic Manufacturers Input Data ........ 449


International standards specify requirements and define ratings and tests for gas-insulated metalenclosed switchgear and its individual components. The applicable IEC standards are those defined in the table in ► Sect. 25.9. (Many of these standards are under revision. The reader is encouraged to use the most recent editions):


P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de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IEC 62271-203 states rules for the dimensioning of the enclosures, but also pressurized equipment regulations, existing in various countries, must be taken into account if they have the force of law. The standards define for gas-insulated switchgear three types of tests:

- Type tests
- Routine tests (to be performed, whenever practicable, at the manufacturer's works)
- Tests after installation on site (considered part of routine tests by IEC standards)

## 22.1 Type Tests

The type tests are for the purpose of proving the characteristics of switchgear and control gear, of their operating devices, and of their auxiliary equipment. They must be carried out on a given design, to prove compliance with a standard.

The manufacturer must be able to demonstrate, with test reports or test certificates, that all the type tests have been performed on subassemblies of the same design supplied to the customer. Type tests are not part of a quality assurance system applicable to each supply consignment and should be performed only once for a given design. Type tests involve at least:

- Dielectric tests
- Measurement of the resistance of the main circuits
- Temperature rise tests
- Short-time withstand currents and peak withstand current tests
- Verification of the degree of protection of the enclosure
- Tightness tests
- Electromagnetic compatibility (EMC) test
- Verification of making and breaking capacities
- Low and high temperature tests
- Proof tests for enclosures
- Pressure test on partitions
- Tests to prove performance under thermal cycling and gas tightness tests on insulators
- Circuit breaker design tests
- Fault-making capability of high speed earthing switch
- Switch operating mechanical life tests

## 22.2 Routine Tests

Routine tests are an integral part of the quality assurance process. They are carried out during manufacture on each item of equipment, with the purpose of revealing faults in material or construction. Acceptance tests, if requested by the customer, should be a part of routine tests. Since the acceptance tests are not defined by standards, acceptance criteria with tolerances should be stated by the manufacturer prior to routine tests in order that they can be witnessed by the customer. Tests included in routine tests are:

- Dielectric tests
- Tests on auxiliary and control circuits
- Tightness tests
- Measurement of the resistance of the main circuits
- Pressure tests of enclosures
- Mechanical operation tests
- Tests on auxiliary circuits, equipment, and interlocks in the control mechanism
- Pressure tests on partitions

## 22.3 Tests After Installation On-Site

Tests after installation on-site are carried out in order to detect possible damage suffered during transportation, storage, exposure to the environment, or final assembly. Typically, a gas-insulated switchgear is mostly partially assembled in the factory. It is important to point out that on-site testing is a repetition neither of type tests nor of routine tests. The aim is to prove the integrity of the system before it is energized. It is the final step in the process of quality control and quality assurance.

Recommendations as well as technical and practical considerations of site testing are given in ► Chap. 20 and annex C of IEC 62271-203. Particular attention must be paid to dielectric tests. While all other tests can be performed quite easily and do not require expensive test equipment, dielectric tests may pose problems concerning:

- The optimal test procedure to be chosen
- The actual possibility of performing the tests
- The cost of the tests

Examples for different test setups are given in Figs. 22.1 and 22.2. Figure 22.1 shows a resonance test circuit where the voltage is applied to the GIS with an air bushing. Figure 22.2 shows a gas-insulated test transformer directly connected to the GIS with attached coupling capacity for conventional PD measurement. Today, IEC standards recommend mainly voltage tests (AC or impulse voltage tests). New methods, using partial discharge detection with nonconventional detecting systems (e.g., acoustical or UHF), have been developed. In this respect many users and manufacturers apply test procedures (which should be agreed in advance) based on their own experience.

## 22.4 Installation, On-Site Test, Commissioning, and Formal Acceptance

Special conditions apply during the installation of GIS. All civil works have to be completed before the start of the installation.

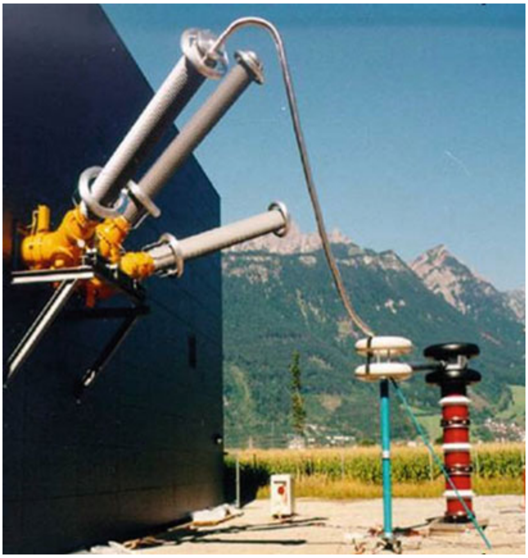

**Fig. 22.1** Resonance test circuit connected to the GIS via $SF_6$/air bushing

**Fig. 22.2** Gas-insulated test transformer and coupling capacitor for PD measurement directly connected to the GIS

The installation work requires special skills and should preferably be done by the manufacturer. The manufacturer should at least supervise the work and ensure that appropriate site qualities prevail.

## 22.5 Site Preparation

Regardless of indoor or outdoor installation, the GIS platform or building must be complete and all preparations in place prior to the start of installation. Project scheduling should ensure that inappropriate tasks (e.g., civil works modifications) are not planned for the same installation period. The keyword is “cleanliness.” The long-term reliability of the final product depends greatly on the level of cleanliness maintained during the installation process. This can be achieved by the provision of a defined clean working area. Additional preparation measures to be taken include the following:

- The manufacturer should specify any local working condition limitations which should be imposed on the installation of the GIS to avoid contamination by particles, dust, water, or ice. Temporary measures in the form of shelters, barriers, or heaters may be necessary to achieve this condition, especially during outdoor installation.
- The party responsible for the on-site installation of the GIS must ensure the availability of the contractually agreed installation tools and accessories (e.g., lifting equipment, tools, and power supply) throughout the full installation period.
- The manufacturer should specify the number and qualifications of the personnel needed to complete the installation.
- The foundation (floor) should be cleared to allow for the layout of the GIS and the concrete sealing preventing unnecessary dust pollution.
- The unpacking and if necessary general cleaning of the components should be performed away from the final clean assembly area.

## 22.6 Work Crew Preparation

It is strongly recommended that GIS be installed under the supervision of the manufacturer. If the actual installation is performed by a third party, it is essential that this party possesses the basic knowledge regarding the assembly procedures and quality standards and has to hold every certificate to fulfill the manufacturing standard. This can be achieved by the following:

- Prior to the installation start, the installation crew is given adequate training in the quality standards applicable to the tasks to be performed. This training should be “refreshed” at regular intervals during the installation process.
- Clear instructions are given, especially if a second language is used.
- The relevant installation documentation should be available.

- The correct tools, accessories, and special clothing are available and their proper use is understood.
- All installation activities which require direct supervision are firmly established between all parties.

## 22.7 Installation of New GIS

The overall installation process for GIS may encompass many months, during which time other activities associated with the project must continue. Coordination of activities among all the project's responsible parties is a necessity, especially with regard to the interface with the HV transformer and HV cable connections.

Time spent in these coordination processes will help to ensure the minimum number of disruptions during the installation process. Disruptions will nevertheless occur and a certain degree of flexibility on the part of all parties is essential.

Specific installation procedures are tailored for each manufacturer's GIS requirements. However, a typical sequence for the installation of new GIS could be as follows:

- The anchoring/support system is installed and leveled to accommodate civil works tolerances.
- Complete bays and single- or three-phase bay components are erected on their respective supports.
- Inter-bay connecting elements are installed and busbars coupled.
- Installation of secondary control panels and interconnecting cables.
- Commencement of $SF_6$ gas vacuum-filling process.
- Voltage transformers and busducts, including $SF_6$ air bushings to outgoing transformers or line positions, are installed.
- Interface components are installed (e.g., GIS to HV cable or power transformers), but busbar links remain uncoupled.
- Site commissioning tests are completed, including local control.
- GIS is subjected to the high-voltage withstand tests (ref. Chap. 22).
- Ancillary GIS devices (e.g., surge arresters and monitoring/signaling equipment) are installed and busbar links to high-voltage cables and/or transformers coupled.

To accelerate the overall program, some tasks can be done in parallel if the overall standard of the assembly practices is not compromised.

## 22.8 Installation of GIS Extensions

The installation of an extension to an existing GIS substation imposes special conditions on both the manufacturer and plant operator that do not normally apply for the installation of new GIS. These special conditions or limitations can be related but not limited to:

- Provisions provided in the existing substation for future extensions like space availability (ref. ► Sect. 16.5)
- The need to keep in operation all or portions of the existing plant (ref. ► Sect. 24.3 ongoing)
- Safety concerns with operational equipment, both primary and secondary
- High-voltage withstand testing of the completed extension (ref. Chap. 22)

There is no standard installation sequence related to an extension of a GIS substation. Each case must be looked at separately by the manufacturer who can say what must be done, and the user will have to say how it can be achieved with minimum disruption of the existing operational plant. The following specific terms can apply (acc. to IEEE C37.122.6-2013 "Recommended practice for the interface of new gas-insulated equipment in existing gas-insulated substations rated above 52 kV"):

- Manufacturer A: The supplier of the existing or initial GIS
- Manufacturer B: The supplier of the new extension GIS
- User: Current owner of the existing or initial GIS and of the new extension GIS

It should be recognized that manufacturer B will be the same as manufacturer A in those situations where the extension is of the same make but of different design.

During the extension process, the end user and plant operator will have to play an active role in order to assure that the working practices of the installation contractor meet the minimum safety standards applicable to their operating practices.

## 22.9 Service Continuity

When performing an extension, prime consideration should be made to keep the max number of existing feeders in service. Some outages of feeders may be required to make the connection to the existing equipment and to perform the high-voltage tests. This is dependent on the bus configuration and on the layout of the GIS.

Therefore, it is important to anticipate this requirement during the early stages of GIS design, as it can impact the SLD arrangement, the layout, and the number of components to be supplied in the initial stage.

The outage implications can be different during installation of the extension equipment and during site testing. They should be assessed by the user and manufacturer B during the design of the extension and should cover both site installation and site testing. More additional guidance about service continuity is also given in IEEE C37.122.6 and in Annex F of the IEC 62271-203.

## 22.10 Commissioning

The commissioning of GIS, including the performance of all applicable tests, represents the final stage of the manufacturer's quality assurance program prior to the GIS being connected into the user's network. The procedures specified in this stage are intended to be complementary to the manufacturer's overall quality assurance program and should not replace or duplicate controls which have been acted upon in prior stages.

### 22.10.1 Commissioning of Primary Equipment

The procedures and tests recommended by the manufacturer for primary components are intended to confirm that the interfaces between factory-assembled components have been assembled on-site without error or introduction of defects.

Special attention should be paid to the high-voltage AC dielectric test. Recommendations given in IEC 62271-203 should be used as a basis for discussions between the user and manufacturer for establishing the dielectric site test procedures to be applied to the completed GIS. For information concerning commissioning and on-site tests, see also Chap. 22.

### 22.10.2 Commissioning of Secondary Equipment

As the secondary control and protection equipment associated with a complete substation is normally only integrated into the GIS during the on-site assembly, it is necessary to confirm that:

- The interconnecting wiring and cabling between GIS and panels has been accurately and securely installed.
- All operational and annunciation functions in both remote and local mode are correct.
- The bay-by-bay control philosophy pretested in the manufacturer's works reflects the user's complete substation operation control and logic requirements.

### 22.10.3 Commissioning of the $SF_6$ Insulation Medium

In most cases the processing of the GIS gas compartment prior to the filling of $SF_6$ gas is performed after completion of the installation of the GIS. Exceptions to this rule may be factory-assembled gas compartments, which can be shipped in their entirety and require no additional intervention during the on-site assembly process (e.g., voltage transformers and circuit breakers). The controls and checks of this on-site processing should include:

- Confirmation of the tightness of each gas compartment during the vacuum cycle and after final $SF_6$ gas filling
- Confirming that the final moisture content of the $SF_6$ is within recommended limits (e.g., values can be found in the operation manual or IEC 60376)

## 22.11 Information to be Given by the Manufacturer and the User

### 22.11.1 Basic Users Input Data

- Access limitations to the local site
- Local working conditions and any restrictions that may apply (e.g., safety equipment, normal working hours, union requirements for supervisor, manufacturer's and local installation crew, etc.)
- Availability and capacity of lifting and handling equipment
- Availability, number, and experience of local personnel
- Specific pressure vessel rules and procedures that may apply during installation and commissioning tests
- Interface requirements for high-voltage cables and transformers
- In the case of extensions to existing GIS:
  - Provisions for the extension available within existing primary and secondary equipment
  - In-service conditions or operating restrictions that must be respected.
  - Safety regulations that must be adhered too

### 22.11.2 Basic Manufacturers Input Data

- Space necessary for installation and assembly
- Size and weight of GIS components and testing equipment
- Site conditions regarding cleanliness and temperature for clean installation and preparation area
- Number and experience of local personnel required for installation
- Time and activity schedules for installation and commissioning
- Electric power, lighting, water, and other needs for installation and commissioning
- Proposed training of installation and service personnel
- In case of extension to existing GIS:
  - Out-of-service requirements of existing components related to the installation schedule
- Safety precautions

# $SF_6$, Its Handling Procedures and Regulations

# 23

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

23.1 The EU-F-Gas-Regulation (EU) 517/2014 .......... 453
23.1.1 Leakage Detection Systems .......... 454
23.1.2 Handling and Repair .......... 454
23.1.3 Training and Certification .......... 455
23.1.4 Labeling .......... 455
23.2 $SF_6$ Handling During Installation and Commissioning .......... 455
23.3 Storage and Transportation of $SF_6$ Bottles .......... 456
23.4 Reuse of $SF_6$ .......... 456
23.5 Handling of $SF_6$ Decomposition Products .......... 458
23.6 Information to Be Given by the Users and the Manufactures .......... 459
23.6.1 Basic Users Input Data .......... 459
23.6.2 Basic Manufacturers Input Data .......... 459
References .......... 460

$SF_6$ and its handling are subject to a number of publications, especially from CIGRE. However, the most familiar ones for GIS project execution are the IEC standards IEC 60376 (2005–06) (for technical grade gas), IEC 60480 (2004–10) (for used gas), and IEC 62271-4 (2013–08) (for handling of $SF_6$ in high-voltage switchgear).

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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Official national and international documents give excellent information on all items related to $SF_6$ and its handling procedures and to ensure to keep the $SF_6$ in a closed cycle. These are summarized in Table 23.1.

$SF_6$ is a colorless, odorless, chemically neutral, and inert gas, noninflammable and five times heavier than air, nontoxic, and not ozone depleting. Because of its excellent electrical, physical, and chemical properties enabling significant benefits for the electricity supply network: $SF_6$ is strongly electronegative; it has a unique combination of physical properties, like the dielectric strength, which is about three times that of air. It has over 100 times better arc-quenching capability than air ($N_2$) and better heat dissipation, about twice that of air. For more information see IEC 62271-4, Annex E.4 "Electrical properties."

$SF_6$ electric power equipment is used worldwide with an increasing tendency. Today it is estimated that an average of about 80–90% of HV equipment, manufactured and installed, contains $SF_6$. $SF_6$ is permitted in the electric power industry without restrictions.

**Table 23.1** Summary of documents related to $SF_6$

| | |
|---|---|
| **Standards and basics** | IEC 60376 "Specification of technical grade sulfur hexafluoride ($SF_6$) for use in electrical equipment"<br>IEC 60480 "Guidelines for the checking and treatment of sulfur hexafluoride ($SF_6$) taken from electrical equipment and specification for its re-use"<br>IEC 62271-4 "Handling procedures for sulphur hexafluoride $SF_6$ and its mixtures"<br>IEEE Std. C37.122.3-2011 "IEEE Guide for Sulphur Hexafluoride ($SF_6$) handling for high-voltage (over 1000Vac) equipment" (IEEE Std C37.122.3™ 2012–01)<br>CIGRE brochure No. 276, 2005 ($SF_6$ handling guide) "Guide for the preparation of customized "practical $SF_6$ handling instructions" (CIGRE 2005)<br>ELECTRA Magazine No. 274, "CIGRE $SF_6$ position paper," 2014 (ELECTRA 2014) |
| **Focus on design and manufacturing** | CIGRE brochure No. 594, 2014 "Guide to minimize the use of $SF_6$ during routine testing of electrical equipment" (CIGRE 2014a) |
| **Focus on installation, erection, commissioning, end of life, recycling** | IEC 62271-4<br>IEEE C37.122.3-2011<br>CIGRE brochure No. 276, 2005<br>CIGRE brochure No. 594, 2014<br>CIGRE brochure No. 234, 2003 "$SF_6$ recycling guide" (CIGRE 2003) |
| **Avoid leakage in service** | CIGRE brochure No. 430, 2010 "$SF_6$ tightness guide" (CIGRE 2010) |
| **Repair work and maintenance** | IEC 62271-4<br>IEEE C37.122.3-2011<br>CIGRE brochure No. 276, 2005<br>CIGRE brochure No. 163, 2000 "Guide for $SF_6$ gas mixtures" (CIGRE 2000) |

However, certain regulations have to be considered which are all implemented in processes and products.

The application of $SF_6$ as one of 28 fluorinated substances is well described in the EU-F-Gas-Regulation (EU) 517/2014 (Regulation (EU) 2014), Annex I “Fluorinated greenhouse gases referred to in point 1 of article 2.”

Pure $SF_6$ is nontoxic and is physiologically completely harmless for humans and animals; it is even used in medical diagnostics. Due to its weight, it might displace the oxygen in the air; large quantities can concentrate in deeper and non-ventilated places and can lead to danger of suffocation. For the same reason, additional care has to be taken, when evacuating a $SF_6$ gas compartment of a GIS. Large quantities can stay in lower spaces of the compartment. It is not categorized as a hazardous material in any legislation for chemicals. $SF_6$ and its decomposition products do not contribute to the destruction of the stratospheric ozone layer. But due to its high global warming potential (GWP) of 22.800, it is number one in every listing. The gas may contribute to the manmade greenhouse-effect if it is released into the atmosphere. Open applications are forbidden in the European Union. The $SF_6$ concentration in the atmosphere is constantly increasing, mainly due to its long residence time in the atmosphere of approx. 3,000 years. State-of-the-art $SF_6$ electric power equipment is extremely gas-tight and has got usually lower leakage rates than required in the IEC standards ($<0.1\%$ instead of $<0.5\%$ per year per gas compartment). Life cycle assessment (LCA) studies (like “$SF_6$-GIS-Technology for Power Distribution – Medium Voltage –“ by Dr.-Ing. Ivo Mersiowsky (2003)) have proven that the application of $SF_6$ technology in the $SF_6$ electric power equipment results in lower overall direct and indirect environmental impacts compared to air-insulated switchyards (AIS) acc. to Solvay Fluor Brochure (Solvay Brochure Sulphur Hexafluoride 2012). This makes the real impact of $SF_6$ electric power equipment on the greenhouse-effect negligible.

## 23.1 The EU-F-Gas-Regulation (EU) 517/2014

All over the world stakeholders responsible for $SF_6$ electrical power equipment handle $SF_6$ with care. The focus for manufacturers and asset owners is on finding ways of increasing the tightness of equipment and reducing handling losses. This has resulted in self-commitments in our industry (e.g., US EPA) in various countries worldwide. In addition in Europe, a regulation was introduced, the EU-F-Gas-Regulation 517/2014.

There are no restrictions implemented regarding the application of $SF_6$ in electric power equipment in a closed cycle around Europe. In addition new GIS design features reduced the applied amount of $SF_6$ per functionality. The regulation came into effect on January 01, 2015. The content requires a number of topics to be considered for $SF_6$ electrical power equipment: reporting obligations, training of personnel, labeling, and handling. Relevant implementing regulations for gas-insulated switchgear of the EU-F-Gas-Regulation 517/2014 are regulation (EU) 1191/2014 (30th October 2014) (Commission Implementing Regulation (EU) 2014) for “Reporting,” the (EU) 2015/2066 (17th November 2015) (Commission

Implementing Regulation (EU) 2015a) for "Training and Certification," and the (EU) 2015/2068 (17th November 2015) (Commission Implementing Regulation (EU) 2015b) for "Labeling." The "Specific information about the new F-Gas-Regulation 517/2014 regarding $SF_6$-application in electric power equipment" (ZVEI, Jan. 2015) can provide guidance through the relevant articles of the regulation. For all EU documents, see http://eur-lex.europa.eu/homepage.html.

For medium-voltage switchgear – acc. to EU-F-Gas-Regulation 517/2014, Article 21 – paragraph 4 "The EU commission has to report not later than 1st July 2020, if there are any cost-effective, energy-efficient, technically feasible and reliable alternatives which can replace $SF_6$ in secondary medium-voltage switchgear (medium-voltage to low-voltage connections)." No later than 31st December 2022, the EU commission shall publish a comprehensive report on the effects of the regulation. The report shall include in particular a forecast of the continued demand for hydrofluorocarbons, an assessment of the need for further action regarding the reduction of fluorinated greenhouse gas emissions, and a review of the availability of technically feasible and cost-effective alternatives to products and equipment containing fluorinated greenhouse gases.

### 23.1.1 Leakage Detection Systems

From 1st January 2017, electrical switchgear put into operation that contains an F-gas quantity corresponding to more than 500 tons of $CO_2$ equivalents (about 22 kg $SF_6$) must, according to Art. 5 of the F-Gas-Regulation (EU) 517/2014, be equipped with a leakage detection system. Medium-voltage switchgear usually contains significantly less $SF_6$ and, therefore, does not fall within the scope of this requirement. For reasons of operational safety, high-voltage switchgear is commonly equipped with pressure/density monitoring sensors that signal the current operational status to a remote location. As defined in the EU-F-Gas-Regulation:

- Pressure and density sensors alone do not meet the requirements that apply to a leakage detection system.
- Pressure and density sensors with remote signaling function, such as the often used density monitors with control circuit (limit-value switch), meet the requirements that apply to a leakage detection system.

The correct function of the leakage detection system has to be checked at intervals of no longer than 6 years. Operators may carry out the required check of the pressure/density sensor system in the course of a routine check of the switchgear, as is the current practice.

This obligation to check does not apply to electrical switchgear put into operation before January 1, 2017.

### 23.1.2 Handling and Repair

According to Article 3, 4, and 5, intentional release of $SF_6$ is prohibited. Leakages of $SF_6$ in electrical power equipment into the atmosphere have to be minimized and repaired without undue delay within 1 month. The repair has to be verified as effective. Electrical switchgear is not affected by leak checks, provided they comply with one of the following conditions:

1. They have a tested leakage rate of less than 0.1% per year.
2. They are equipped with a pressure or density monitoring device.
3. It contains less than 6 kg of fluorinated greenhouse gases (per compartment).

Usually item (2) applies for high-voltage GIS.

### 23.1.3 Training and Certification

According to Article 8 and 10 of the F-Gas-Regulation and the regulation (EU) 2015/2066, operators shall ensure that the individual handling of fluorinated gases is carried out by natural persons that hold the relevant certificates provided for Article 10. The extended $SF_6$ training and certification have started on January 1, 2017, for handling activities regarding installation, servicing, maintenance, repair or decommissioning, and recovery of electrical switchgear containing $SF_6$. The certification of employees of OEMs for automated processes in factories is not required. Existing certificates issued in accordance with former regulation (EC) no. 842/2006 (Regulation 2006) will remain valid. Member States of the EU shall recognize certificates issued in another Member State.

### 23.1.4 Labeling

Products and equipment that contain fluorinated greenhouse gases shall not be placed on the market unless they are labeled acc. to Article 12 of the F-Gas-Regulation and the regulation (EU) 2015/2068. Since January 1, 2017, reference should be given that the product or equipment contains fluorinated greenhouse gases, its amount in kg $SF_6$, the equivalent amount of $CO_2$, and the GWP of the contained F-Gas. The label should include the wording "Contains fluorinated greenhouse gases" in the 24 official languages of the Member State of the EU, in which the switchgear has to be placed on the market. Information shall be included in instruction manuals and in descriptions used for advertising.

## 23.2 $SF_6$ Handling During Installation and Commissioning

First the $SF_6$ handling was described in the CIGRE brochure No. 276 "$SF_6$ handling guide." The content finally resulted in IEC 62271-4. Please refer also to the instruction manual of the OEM. It is essential that $SF_6$-emissions have to be avoided – where and whenever possible – during every $SF_6$-handling. All work should be done in conjunction with the manufacturer or qualified service company with certified personnel.

## 23.3 Storage and Transportation of $SF_6$ Bottles

With respect to storage and transportation, three gas categories need to be considered for determination of container types and labeling required (see IEC 62271-4):

<table>
<tr><th>Gas category</th><th>Type of labeling</th></tr>
<tr><td>New gas or technical grade $SF_6$</td><td>Green label on bottle</td></tr>
<tr><td>Used $SF_6$ suitable for reuse on site</td><td rowspan="2">Yellow label on bottle</td></tr>
<tr><td>Used $SF_6$ suitable for reuse at gas manufacturer or used $SF_6$ not suitable for reuse</td></tr>
</table>

Usually new $SF_6$-gas is supplied in steel cylinders with a capacity of 5, 10, 20, 40, 43.5, and 600 l, or for larger quantities, special high-capacity pressure drums are available with a capacity of 600 kg $SF_6$ and higher.

The transportation of (new and used) $SF_6$, either in containers or in electric power equipment, shall always be carried out in accordance with local and international regulations. Details for transportation are also given by the $SF_6$ producer, e.g., Solvay Brochure $SF_6$.

## 23.4 Reuse of $SF_6$

Because of the unique qualities of $SF_6$, under normal operating conditions, no degradation occurs. However, in order to ensure that the equipment performs in accordance with its functional purpose, the quality of the gas that must be maintained as contaminants might negatively impact the dielectric and arc-quenching properties of the gas. According to CIGRE Brochure No. 567 (CIGRE 2014b) "$SF_6$ Analysis for AIS, GIS and MTS Condition Assessment" (see also Sect. 23.6), contaminants can arise from different sources: they may be introduced at the time of the initial filling with gas; they may desorb from the internal surfaces of the equipment or may arise as a result of electric activity, either by partial discharges or arcs. Therefore, ensuring that the gas does not contain inappropriate levels of impurities is an important consideration, especially in gas compartments with switching elements. Values of impurity levels are given in IEC 60480, Table 2 "Maximum acceptable impurity levels."

To support the reuse processes, all significant descriptions are given in the CIGRE "$SF_6$ Recycling Guide" No. 234 including:

- The identification of the origin of contaminants produced
- The description of deteriorating effect of contaminants
- The purity levels and checking techniques for recycled $SF_6$ based on functional limits
- The description of $SF_6$ recycling procedures and available equipment

Successful $SF_6$ handling and recycling requires:

- Electrical power equipment designed for easy recycling (reuse)
- Appropriate gas handling and recycling procedures
- Appropriate gas handling and recycling equipment (state-of-the-art)
- Knowledge of the origins and quantities of contaminants to be expected in $SF_6$ used in electrical power equipment
- Purity standards for $SF_6$ to be reused in electrical power equipment
- Methods to verify the quality of reclaimed gas
- A final disposal concept by which $SF_6$ can be converted into environmentally compatible substances

Gas monitoring and reclaiming equipment can be used to keep $SF_6$ in a reusable state by considering the various contamination levels (new gas – non-arced gas; normally arced gas and heavily arced gas). The principles are illustrated in Fig. 23.1.

To make all personnel aware of the necessity for correct application of the $SF_6$ handling procedure, it is strongly advised to place an environmental statement for the use of $SF_6$ gas in all substations provided with $SF_6$ insulated switchgear

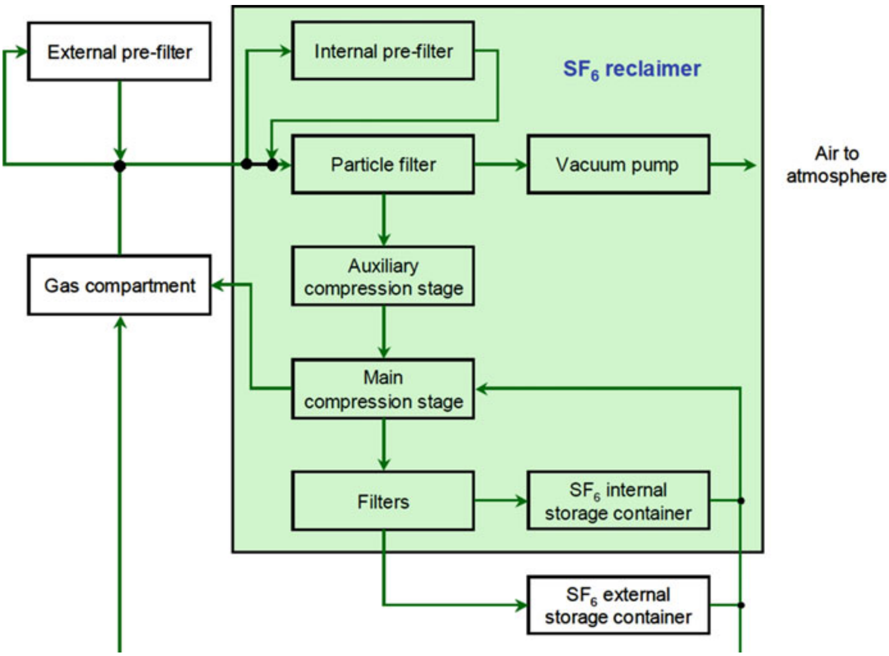


**Fig. 23.1** Basic functional scheme of a general purpose $SF_6$ reclaimer – CIGRE No. 276 "$SF_6$ handling Guide"

## 23.5 Handling of $SF_6$ Decomposition Products

Although $SF_6$ in its pure form is a nontoxic gas, it may, after extraction from the high-voltage equipment, contain toxic decomposition products (see CIGRE Brochure No. 567). Most of the decomposed molecules will recombine back into $SF_6$. Some residual products in the form of toxic and caustic sulfur, fluorine, oxygen, and metal combinations (hydrolysable fluorides (HF)) will remain. Impurities such as water, air, and oil can enter the compartments as a result of penetration through seals, improper filling activities, incomplete functioning of internal filters, use of oil-geared compressors, etc. Filters placed in the equipment will limit the amount of $SF_6$ decomposition products under normal conditions. Nowadays commercially available equipment enables users to check gas quality on a regular basis. Limits and kinds of impurities as well as measuring methods are described in the guides mentioned above. In the event of unacceptable levels of impurities (water, air, hydrolysable fluorides, oil, $CF_4$), gashandling equipment with different capabilities is available to recycle the gas in order to refill the switchgear compartment with gas of acceptable quality. In addition to these "cleaning" operations, gas handling is also necessary whenever the high-voltage equipment needs to be opened for maintenance (see Fig. 23.2).

Hydrogen, gaseous decomposition products, and metal fluorides are absorbed by molecular sieves and activated alumina filters that are usually integrated inside the gas handling equipment. In the event of an unacceptable level of air and/or oil, the

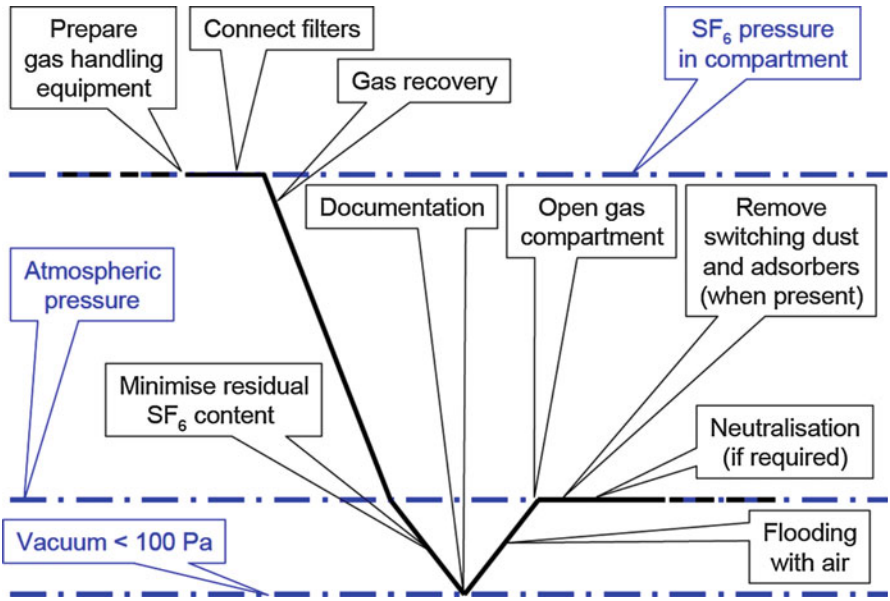


**Fig. 23.2** Diagram of the operations for gas sampling and shipment – CIGRE No. 276 "$SF_6$ handling guide"

best option is to contact the GIS manufacturer or the $SF_6$-gas manufacturer in order to obtain advice for the gas disposal or recycling. Contaminated filter material and used protective clothing, etc. should be transported to disposal plants where it will be neutralized or burnt. It is strongly advisable to recycle the gas in all possible situations in order to reuse the gas as much as possible.

Personnel should be well trained and informed; protective clothing and breathing apparatus or respirators with active carbon filters should be worn.

Maximum protection is given by evacuating the gas out of the compartment and refilling this with air or nitrogen before opening. After this procedure, gaseous decomposition products will have been removed, and protection is only needed for dust containing metal fluoride molecules. This powder should be removed by means of a special vacuum cleaner provided with high efficiency exhaust filters. If a compartment has to be entered, care must be taken that a sufficient amount of fresh air enters the compartment.

## 23.6 Information to Be Given by the Users and the Manufactures

### 23.6.1 Basic Users Input Data

The users input conditions should include at least the following:

- Keep the documentation available about the installed equipment (technical, schematics, reports, and test sheets).
- Information on gas compartmentalization of the switchgear and the amount of $SF_6$ gas needed for filling up to minimal pressure.
- Inform the OEM about minor and major failures (e.g., leakages or arc faults).
- Formalize the process of updating maintenance policies and practices based on latest industry experience.
- Conditions for transportation and storage in the individual country.

### 23.6.2 Basic Manufacturers Input Data

- Recommended accessories for gas handling, storage, measurement, and personnel protection, including advisory specifications
- Maximum allowable levels of $SF_6$ impurities before filling
- Maximum allowable levels of $SF_6$ impurities during operation
- Measuring equipment available
- Manuals for $SF_6$ handling, recycling procedures on-site measurement procedures
- Gas-handling and storage equipment available
- Accessories available
- $SF_6$ pipework connector type
- Gas system ratings

- Conditions for transportation and storage
- Inform the user of changes in maintenance recommendations or other activities if any

## References


CIGRÉ report No. 163 Guide for $SF_6$ gas mixtures (2000)

CIGRÉ brochure No. 234 SF6 recycling guide (Revision 2003)

CIGRÉ brochure No. 276 Guide for the preparation of customized “practical $SF_6$ handling instructions (2005)

CIGRÉ brochure No. 430 $SF_6$ tightness guide (2010)

CIGRÉ brochure No. 594 Guide to minimize the use of $SF_6$ during routine testing of electrical equipment (2014a)

CIGRÉ brochure No. 567 $SF_6$ analysis for AIS, GIS and MTS condition assessment (2014b)

Commission Implementing Regulation (EU) No 1191/2014 of 30 October 2014 determining the format and means for submitting the report referred to in Article 19 of Regulation (EU) No 517/2014 of the European Parliament and of the Council on fluorinated greenhouse gases

Commission Implementing Regulation (EU) 2015a/2066 of 17 November 2015 establishing, pursuant to Regulation (EU) No 517/2014 of the European Parliament and of the Council, minimum requirements and the conditions for mutual recognition for the certification of natural persons carrying out installation, servicing, maintenance, repair or decommissioning of electrical switchgear containing fluorinated greenhouse gases or recovery of fluorinated greenhouse gases from stationary electrical switchgear

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ELECTRA Magazine No. 274, CIGRÉ $SF_6$ position paper (2014)

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IEC 60480 Ed. 2 Guidelines for the checking and treatment of sulfur hexafluoride (SF6) taken from electrical equipment and specification for its re-use (2004–10)

IEC 62271-4 Ed. 1 High-voltage switchgear and controlgear – Part 4: Handling procedures for sulphur hexafluoride (SF6) and its mixtures (2013–08)

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Regulation (EU) No 517/2014 of the European Parliament and of the Council of 16 April 2014 on fluorinated greenhouse gases and repealing Regulation (EC) No 842/2006

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# Training, Service, and Maintenance of Gas-Insulated Substations

# 24

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

24.1 Training of Operation Personnel ... 462
24.2 Operational Aspects and After Sales Support ... 462
24.3 Types of Maintenance ... 462
24.4 Maintenance Policy ... 463
24.5 Operation and Maintenance Provisions ... 464
24.5.1 Operational and Maintenance Safety ... 464
24.5.2 Operational and Maintenance Opening Procedures ... 466
24.5.3 Substation Equipment ... 469
24.6 Special Aspects of Repair Maintenance after Major Dielectric Failure ... 470
24.7 Basic Input Data and Additional Recommendations ... 471
24.7.1 Information to Be Given by the User and the Manufacturer ... 472
24.7.2 Additional Recommendations for the User and the Manufacturer ... 472
24.8 General Training ... 474
24.9 Training for Installation ... 475
24.10 Training for Operating and Maintenance ... 475
24.11 Specialized Training ... 476
24.12 Information to Be Given by the User and the Manufacturer ... 476
24.12.1 Basic Users Input Data ... 476
24.12.2 Basic Manufacturers Input Data ... 477

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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## 24.1 Training of Operation Personnel

Prior to commissioning and formal acceptance, the user's appropriate personnel should be trained by the manufacturers in the operation and maintenance of the GIS equipment.

If possible, key personnel may benefit from taking part in factory assembly and testing, and in on-site erection and testing, ref.: Sect. 24.8.

## 24.2 Operational Aspects and After Sales Support

Subsequent to formal acceptance, operation of the GIS installation is the user's responsibility. Operational together with maintenance aspects are covered under Sect. 24.5.

An important item to be agreed during the contract negotiations is "After-Sales Support." This item covers such aspects as technical support, service at short notice, supply of spare parts, lifetime, etc.

## 24.3 Types of Maintenance

The technical specification and/or manuals prepared by the manufacturer must include at least the following maintenance requirements:

(a) For operational conditions (see ▶ Sect. 16.5)
(b) For condition monitoring and diagnostic facilities (see ▶ Sects. 19.2 and ▶ 19.3)
(c) The work extent, duration, downtime, and deenergization required for different types of maintenance (see below)
(d) The maintenance conditions (climatic conditions, availability of lifting and operating mechanism facilities, spare parts, special tools and accessories, etc.)

Manufacturers normally recommend two major types of maintenance

(a) Inspection carried out at frequent (specified) intervals and including checks (for any abnormal indications) without any need for an outage
(b) Scheduled maintenance, which usually consists of:
   - Routine Scheduled Maintenance – carried out regularly at intervals of 5–10 years if the limit number of mechanical CO switching operations and/or the cumulative energy switched is not exceeded. This includes work which does not cause enclosures to be opened (dismantling) and
   - Overhaul Maintenance – carried out at intervals of 25 years or more or upon accumulation of the permissible number of switching operations and including opening some gas compartments (dismantling)

The recent trend has been towards Condition Based Maintenance (CBM) and/or Reliability Centered Maintenance, which is similar to Scheduled Maintenance but comprises maintenance based on information from monitoring equipment which predicts when maintenance is necessary (rather than maintenance based on time in service or number of operations). Manufacturers should recommend in their specification those parameters which are decisive for such Condition Based Maintenance and determine their permissible limits (ref.: Sect. 24.7.2).

Special types of maintenance are represented by Repair Maintenance and Corrective Maintenance. Repair Maintenance covers all work after a breakdown or a failure of the equipment; Corrective Maintenance serves to correct type faults found during service or during other maintenance and must be performed on similar equipment in the system.

For service availability planning purposes, the manufacturer should be prepared to provide the user with the average repair time. These values should be related either to individual GIS components or at least to the specific single-line diagram circuit breaker bay.

## 24.4 Maintenance Policy

Users should cost their maintenance activities over the expected GIS lifetime. Generalization is not possible, but it is likely that, in the event the user is less experienced and/or the utility has not yet established a maintenance support organization, one option for maintenance (namely, major repair and corrective types, necessary spares included) would be to contract this to the manufacturer or a third party. Some issues to be considered in deciding whether to subcontract maintenance are as follows:

- Capital cost of maintenance facilities required at each substation including:
  - Handling of contaminated gas and compartments
  - Potential cost savings if workshops are included
- Specialist equipment
  - Test equipment
  - Special capabilities for mechanism components
- Number of substations
  - The larger the number of substation the more viable user maintenance becomes.
- Availability and costs of skilled personnel
  - What training, resources, and facilities are required?
  - Is training likely to be forgotten if activities are not regular?
- Age profile of maintenance personnel expected productive life of equipment
  - Availability of components from manufacturer's normal production line or other sources
  - Any specialist processes required for components
- Security of supply from manufacturer/third party
  - Commitment of manufacturer to supply components for equipment not in regular production.

  - Likelihood of manufacturer/third party not continuing in business.
  - Availability guarantees contracts. The manufacturer guarantees certain availability and takes care of all activities necessary to achieve this level.
- Equipment leasing from manufacturer and guarantees
  - Agreement for a manufacturer to construct, install, maintain, and own the equipment while it is leased to an operating utility is possible. (Note: Normally some form of long-term financing or insurance would be required by the manufacturer.) Alternatively, special guarantees covering extended warranty or liabilities may be available.

## 24.5 Operation and Maintenance Provisions

The following steps are to be considered when designing operation and maintenance provisions.

### 24.5.1 Operational and Maintenance Safety

Operational and maintenance safety is achieved by introducing a proper design in the following main fields:

- Primary electrical circuits
- Enclosure designs
- Secondary electrical circuits. (See ▶ Chap. 19 for control and protection systems which include all functions for operation, interlocking, monitoring, signaling, and protection)
- Safety rules and training
- Documentation

Though basic considerations are similar to AIS rules, there are some items typical for GIS. They concern, namely, the following:

#### 24.5.1.1 Primary Circuit Earthing Principles

Several options are available for the user to achieve primary earthing during maintenance or fault repair outages.

- A main option which does not require degassing is the provision of a sufficient number of permanently installed, electrically (as well as mechanically) interlocked, earthing switches at all possible locations where they may be required within the GIS to allow appropriate maintenance earthing. For this function both types of earthing switch are suitable, i.e., those with capability to close onto a short circuit (high speed earthing switches) and those without this capability (slow-operation types).

**Note:**

In the use of non-short circuit making earthing switches, there is a remote possibility that if the appropriate operational permit system and interlocking chain are incorrectly performed then a non-short circuit making earthing switch could be closed onto a live busbar, thus inducing an internal fault with consequential loss of availability of plant and potential operator danger. If the possibilities of such an incorrect earthing switch operation, although small, are unacceptable, then a further option is the application of short circuit making earthing switches at least at line entries or throughout the GIS.

- In some local regulations, it is requested that the absence of voltage be verified prior to connecting a conductor to earth. This requirement can be met by an additional voltage probe. If this is not possible with the GIS equipment, it may be permitted to replace this operation by closing an earthing switch with rated short circuit making current.
- GIS with directly connected overhead lines or those connected by air-insulated conductors offer a possibility of bay earthing by means of conventional air-insulated earthing switches (earthing knifes at support insulators) or portable earthing rods. However, the use of portable earthing rods at higher voltage levels as the only earthing device is not always permitted by local rules.
- Another option for earthing for repair and/or major maintenance purposes within GIS is by portable earthing devices which can be connected at specially adapted places on primary conductors. This method necessitates degassing, removal of access covers, and usually a special installation procedure has to be adopted. Nevertheless, after detailed analysis of all different service requirements needed for major disassembly, repair work or further extension of a specific substation and the need for portable earthing device installation can be minimized. Such analysis needs a close collaboration with manufacturer.
- In some cases, the portable earthing devices should be designed to allow refilling the compartment in order to reenergize a part of the GIS, so as to limit the outages during repair work. This is the case when the earthing device is in the same compartment as the disconnector.

#### 24.5.1.2 Enclosure Design

For enclosure (encapsulation) design, as well as pressurized equipment rules, see ► Sect. 18.2.

All gas zones should be provided with a pressure relief device (like a rupture disk) for safely releasing the overpressure, which might be generated in the event of an internal fault. Burn-through of an enclosure must be avoided within the first stage of protection. Pressure relief device operation (when these are present) must occur prior to reaching to a high overpressure.

If they are used, the pressure relief devices should be located at points which operational personnel do not normally have to access, and the pressure relief device venting should be in a safe direction by means of diverters to avoid injury to personnel.

#### 24.5.1.3 Safety Aspects

Checking of isolating gap and/or earthing connection: The absence of a visible isolating gap on disconnectors has already led to changes in maintenance safety rules required by many users in comparison with rules prescribed for AIS. If GIS enclosures are not equipped with viewports, it is not possible, before starting of any maintenance work, to insist on visual checking ("own eyes") of a disconnector's isolating gap and an earthing switch closed position. Windows can help in this respect but on the other hand they can affect the overall integrity of GIS and introduce additional leakage. The user should be aware that an isolating gap in GIS provides its functional integrity if the $SF_6$ gas pressure is within allowed limits.

Many users nowadays accept the principle of external position indication providing that it always truly represents the state of the internal contacts (IEC 60694, IEC 62271–100/−102/−200) fulfilling the requirements for the 'kinematic chain' for position indication as stated in the standards.

### 24.5.2 Operational and Maintenance Opening Procedures

The overall design of the GIS and each of the primary components should be such as to allow the removal of any defective component with the minimum of disturbance to the adjacent components and preferably without requiring an outage of more than one section of busbar and of one circuit, depending on the specific busbar configuration. The GIS manufacturer should provide user guidance on the methods of achieving this requirement at various locations in the GIS.

The extent of zones which may require an outage coupled with their outage duration represents a very complex issue which depends, in general, on the design and configuration of the substation. It is particularly necessary to pay special attention to the following:

(a) Single-line diagram design – Busbar scheme and number of all switching devices
(b) Configuration and layout design
  - Design and installation of earthing switches
  - Optimization of transversely removable enclosure sections
(c) Gas segregation of gas compartments, internal design of main conductors and joints, and shape and fixing of barriers
(d) Operational and maintenance access
(e) Substation equipment

Provided that the enclosure is designed and tested according to IEC 62271–203, CENELEC, or pressure vessel regulations and cast-resin partitions are designed and tested with the minimum requirements of CENELEC standard EN 50089, the following procedures, in addition to normal safety procedures and outage requirements, are recommended:

(a) Dismantling procedures for routine and major maintenance in compartments without internal arc

- All internal conducting parts concerned during disassembly must be earthed throughout the whole procedure (Temporary earthing connections are permitted).
- Evacuate all respective gas compartments (storing of $SF_6$).
- Ascertain that there is no gas leakage from the adjacent compartments under pressure.
- Fill the compartments with fresh air at atmospheric pressure.
- Open the compartments and ensure air circulation inside the compartments.
- Avoid any mechanical impact on a pressurized cast-resin partition and limit the work on them to the extraction or insertion of conductors with sliding contacts or protection devices.

(b) Dismantling procedure in case of an internal arc
- All safety rules described in or referred to in ▶ Sect. 23.5 must be complied with.
- In addition to item (a), the cast-resin partitions which could have been in contact with the arc must be depressurized before the compartment is opened.

#### 24.5.2.1 Gas Compartment Segregation Aspects

Equipment should be segregated into sufficient independent gas zones to allow the required degree of operational flexibility to be achieved.

Besides the operation and maintenance aspects, the basic gas compartment segregation rules are the following:

- The segregation of gas zones should comply with the protection philosophy and match the parts of GIS which will be disconnected in the event of a failure.
- Easy location and isolation of major and/or minor failures normally requires a higher number of gas compartments than for operational considerations alone.
- Lower probability of premature pressure relief device operation in the event of internal failure calls for a reduced number of gas compartments with larger gas volumes.
- Circuit-breakers should be accommodated in a gas zone independent of other equipment.

It is obvious that these requirements are in conflict. The final solution will result from the optimization process.

Furthermore, traditional maintenance philosophies applied to AIS for the isolation of a circuit or component based solely on the electrical single-line drawing requirements are no longer adequate for GIS, since gas compartment segregation does not necessarily match the primary component physical positioning.

- $SF_6$ must never be removed from a gas compartment which is still energized.
- In the event that $SF_6$ gas must be removed from a gas compartment accommodating two or more devices, conventional electrical isolation points may overlap, requiring an enlargement of the section to be isolated.

- Maintenance or repair activities involving removal of the whole or portions of a component require close scrutiny of the gas compartment segregation of the affected area, so as to ensure that safety standards concerning work done adjacent to pressurized barriers are not violated. Generally, it can be stated that it is desirable to reduce the gas pressure on adjacent gas compartments to a slightly positive level in the event it is necessary to dismantle or remove a primary component. However, exceptions do exist and each case should be looked at separately, both from a safety and a practical point of view.

As it has already been mentioned above, the basic segregation based on gas-tight isolation zones with different disconnection logic during an internal fault might not be sufficient. In addition, in view of GIS design and/or because of local safety regulations, the $SF_6$ gas pressure must be reduced to a certain safety margin in one or more of the compartments adjacent to that one which must be opened or disassembled for work (and/or the adjacent compartment must be opened, too).

The consequences are obvious: Gas compartments at atmospheric $SF_6$ or air pressure are not able to perform their dielectric functions. If this rule affects a disconnector, then another disconnector in series will have to take over its function and a deenergized zone will be extended.

Similar situations can be observed if too many earthing switches are included in a disconnector chamber (one compartment) or if there are no transversely removable enclosures installed in the GIS configuration. The effects of these conditions differ very much in accordance with various manufacturers' designs, single-line diagrams, and layouts. The user must be aware of such GIS service restrictions and must weigh his service requirements and their cost penalty. The manufacturer's assistance and an optimization process are necessary.

Routine maintenance should avoid outages. The optimum conditions for major or repair maintenance (i.e., only one circuit and/or one busbar out of service) may be achieved but at significant additional cost. The user and the manufacturer should agree on the number of simultaneously switched-off circuits. Those which are critical for network operation should not be located in adjacent GIS bays. In a double busbar scheme, a fault in a busbar selector disconnector should not require the outage of the two busbars at the same time. The GIS scope of supply must include covers and shields permitting operation of a busbar or a circuit with some power components removed. Methods of achieving specific conditions at different GIS compartments (as well as special tools if needed) should be described (delivered) in manufacturer's manuals.

Note: Provided the CENELEC standard for insulators (EN 50089) is fulfilled, no pressure reduction is necessary in adjacent chambers. Mechanical impacts on a pressurized castresin insulator must be avoided at all times.

#### 24.5.2.2 Operational and Maintenance Access

There is the question of whether it is appropriate for operators to require high-level access for normal operational functions. Accepting the modern principle of secure external position indicators, it is possible for all normal operational functions to be performed at ground level. Nevertheless, the requirements that all operations be performed from the ground level represent additional costs for various types of external interconnections (gas pipes, cabling, etc.). As there is an extremely low frequency of "manual" GIS operations, these additional costs do not appear justified. The same concerns additional costs for such provisions as permanently installed ladders or walkways.

Operational and maintenance access to $SF_6$ filling points is strongly influenced by the design of segregation and interconnection of gas zones described already in ► Sect. 18.2.2.

In general, easy access to gauges and gas filling points should be provided. On the other hand, from the sealing point of view, piping should be minimized. Problems could arise in the bringing of gas filling points to ground level due to the need to incorporate additional piping and couplings, which may in themselves, induce leakage. If it is accepted that with modern equipment gas leakage rates are very low and the need for access to filling points during the normal life of the equipment is very rare, such access can be gained from a transportable platform or similar temporary means. The final solution has to be agreed between user and manufacturer.

Accessibility can be improved at a relatively low incremental cost if maintainability considerations are taken into account in the initial design. Use of indoor GIS, provision of strategically located dismantling components, provision of cranes or specially built lifting and handling equipment, and properly designed supporting steel structures will enhance total accessibility. A higher number of complex dismantling enclosures is the best solution in the case of high GIS outage costs; standard chambers with a component that can be cut for removal and the use of flexible insertion parts for reassembly usually offers an alternative, less costly, solution.

### 24.5.3 Substation Equipment

#### 24.5.3.1 Mechanisms and Accessories

Cranes or lifting tools, special tools, and accessories needed for operation and maintenance work are usually the same as the equipment necessary for erection. The amount of certain additional accessories depends on the user's maintenance policy (see Sect. 24.4) and shall be agreed between manufacturer and user. Nevertheless, there are some items which should be made available at each GIS substation, e.g., gas leakage detector, $SF_6$ gas refilling unit, spare gas, accurate pressure gauge, and special tools for operation (e.g., handles). $SF_6$ service trucks, humidity and by-product detectors, and special tools for repair or major maintenance can be, on the other hand, either shared by several GIS substations or be made available on request from the manufacturer. Care must be taken to ensure the availability of adapters to fit different types or makes of GIS. The maintenance of such GIS accessories and tools which might be urgently needed in the event of a problem should not be neglected.

#### 24.5.3.2 Spare Part Stocks

A scientific approach to determine the level of spare parts to be held for maintenance and repair purposes can be based on the acceptable level of risk to which the system is exposed, which means the probability of suffering failures in excess of spares available. This probability depends on the failure rate, on the repair and/or replacement time, and on the number of GIS substations in service.

A more subjective approach is one based on users experience and manufacturers' recommendations. Some factors to be considered in such an approach are the:

- Reliability figures for the equipment
- Type of service duty (i.e., harsh, outdoor, frequent operation, etc.)
- Relative location of original manufacturer to the user
- Delivery time for replacement spares
- Capital cost of holding spares
- Strategic importance of the installation
- Age of the equipment

The manufacturer should provide, if required, spare parts that can be used without complex assembly and that are only available in the factory.

#### 24.5.3.3 Management of Spare Parts

Creative approaches to the traditional method of individual users purchasing, stocking, and maintaining a comprehensive assortment of spare parts may be of particular interest for users of GIS, since most of the strategically important and costly parts may never be required in the lifetime of the equipment. An alternative to be considered is the pooling of spares by:

- Similar users located within a serviceable geographical area
- A manufacturer bound by a service contract to multiple users

If the user does not intend to "pool" or stack spare parts, the long-term availability of spare parts beyond the expected productive life of the equipment should be discussed with the manufacturer.

For geographically remote locations, or where travel and importation is restricted, local storing of key components (in particular the main parts of such switching devices as circuit-breakers, disconnectors, earthing switches, or operating mechanisms) is recommended. Specifically designed kits for emergency repairs by less well-trained personnel can provide a means of temporarily restoring limited operation until a complete repair can be effected.

## 24.6 Special Aspects of Repair Maintenance after Major Dielectric Failure

Although the probability of a major failure of GIS is very low generally, the disruptive impact on service quality of a failure in a GIS substation will justify some special effort towards its prevention and/or speedy repair in the initial design of GIS. Failures can be prevented by the use of condition monitoring or diagnostic techniques, and these are being developed to detect incipient faults and to simplify the process of replacement of a potentially faulty component under controlled conditions. The time and effort involved in fault location, access thereto, parts replacement, and restoration of service will vary widely in terms of tens of hours (depending on the complexity, size, and design of the GIS). The location of the GIS also influences repair time, e.g., the distance from the manufacturer, customs clearance times, etc. The manufacturer's assistance is usually required in this case, and the manufacturer's response time should be agreed in advance.

Special attention should be paid to fault location aspects. As with all other aspects related to GIS, fault location must be discussed with the manufacturer in the early design stages. If there is no external sign of dielectric failure (such as response of a pressure relief device operation and following gas drop), commonly used electrical relays (protection systems) are able to provide only an approximate idea of the actual place of failure, limited to an area which is covered by their function. Identification of the specific failed gas compartment usually calls for special measures, the extent of which depends on technical-economical optimization, and normally necessitates the manufacturer's guidance.

The following measures can be taken to locate the fault and thus to minimize total outage time: Advanced protective relaying with supervising (registration) functions, internal on-line monitoring systems, gas sampling, high-voltage testing, optical sensors, temperature-sensitive paints, electromagnetic fault location systems, acoustic detectors, etc.

Special attention should be paid to $SF_6$ handling and recycling. After an internal arc, the gas contains $SF_6$ decomposition by-products; other by-products will occur after pressure relief device operation. For $SF_6$ handling, see ▶ Chap. 23 for recycling procedures.

In order to confirm the integrity of the insulation medium after major work on GIS, it is advisable to retest the dielectric strength of the affected portion of the substation. Instances which could result in the advisability of a retest are:

- Repair after a dielectric failure in the GIS
- Replacement of a major primary component
- On-line monitoring reveals the presence of partial discharges within the GIS

The repeating of an AC dielectric test can be an expensive and complex task on GIS which has already been put into service. The necessity of a retest must therefore be carefully evaluated, along with the advice of the manufacturer, against the risk associated with not performing a retest. The regular maintenance or overhaul procedures associated with GIS do not normally require a follow-up dielectric withstand retest.

## 24.7 Basic Input Data and Additional Recommendations

Special attention should be paid by the user to the following additional data:

- Average number of operations per year
- Operational conditions such as busbar transfer
- Inductive/capacitive switching

### 24.7.1 Information to Be Given by the User and the Manufacturer

Basic input data given by a user in his enquiry and basic input data given by a manufacturer in his tendering specification serve for system planning and technical-economical optimization of a specific GIS design. They should include the following (The minimum of data is marked *):

User's data necessary for manufacturer's design:

- * Ambient service conditions
- * Expected number of CB average annual operations and operation conditions (e.g., busbar transfer, special device switching)
- * Specification of condition monitoring desired
- Specification of conditioning equipment and methods which a user already has available
- * Specification of accessories a user already has available and would like to use
- * Maximum permissible restrictions on operation during maintenance and repair

Manufacturer's data necessary for user's design:

- * Description of recommended monitoring methods and their impact on GIS design
- * Interpretation of monitoring measurements, i.e., how does data enable evaluation of condition assessment and what action is to be taken
- * Ambient conditions required for different types of maintenance or repair work
- * Basic description of different types of maintenance work, periods required for such work, content of such work and specifications for operation during such work, and time to complete work
- * Requirements for special equipment, i.e., lifting and operating mechanisms, access space and for disassembly, special tools, accessories, and availability of spares,
- Description of maintenance and major repair (dismantling) service restrictions and failure location methods
- GIS reliability data, e.g., minor and major failure rate and minor and major repair mean time
- Offer of long-term service and maintenance contracts
- Conditions applying to long-term spare parts supply
- Offer of training for user's staff

### 24.7.2 Additional Recommendations for the User and the Manufacturer

As the effectiveness of maintenance depends mainly on the way instructions are prepared by the manufacturer and implemented by the user, the following recommendations (IEC 62271–1) are well worth following:

#### 24.7.2.1 Recommendation for the Manufacturer

Availability of manuals is a key to the effective maintenance of the plant. Besides the obviously necessary content, these manuals should include isometric or cross-section drawings showing essential components together with precise instructions for assembly/disassembly and recommended procedures. Operating manuals should be detailed and precise; however, the extent of submitted maintenance manuals can vary according to the user's maintenance policy. In a case where the manufacturer or a third party is contracted to maintain the equipment (emergency repairs included), the maintenance manual might be limited to standard information on inspection and/or routine preventive maintenance. The other extreme is a user who performs all the work with their own staff and therefore requires very detailed manuals. The user may have requirements that conflict with the manufacturer's standard procedures in terms of spares ordering, coding, and uniform manual systems.

The manufacturer should issue a maintenance manual including at least the following information:

- Maintenance extent and frequency considering current and number of switching operations, time in service, environmental conditions, diagnostics, and monitoring tests (if any)
- Detailed description of the maintenance work, i.e., procedures for different maintenance types, reference to drawings and part numbers, lubrication procedures, use of special equipment and tools, on-site conditions, precautions to be observed
- Comprehensive drawings of the detailed GIS design with clear identification of assemblies, subassemblies and significant part maintenance limit values, and showing tolerances which, when exceeded, make corrective action necessary
- Specifications for auxiliary maintenance materials, including warnings of known incompatibility of materials (grease, oil, fluids, cleaning and degreasing agents) and associated health warnings to personnel
- List of recommended spare parts and their storage conditions
- List of active scheduled maintenance time
- Information how to proceed with the equipment at the end of its operating life, considering environmental requirements.

  The manufacturer should inform the user of a particular type of GIS about corrective actions required as a result of possible systematic defects and failures.

  The manufacturer should be responsible for ensuring the continued availability of spare parts required for maintenance for a period of not less than 10 years from the date of final manufacture of the specific GIS type.

#### 24.7.2.2 Recommendations for the User:

If the user wishes to perform their own maintenance, they should ensure that their staff possesses sufficient qualifications as well as detailed knowledge concerning the respective GIS type(s).

- The user should record at least the following information:
  - GIS serial number and type
  - Commissioning date
  - The results of all measurements and tests, diagnostics, and monitoring included, performed throughout the lifetime of the GIS
  - Dates and extent of the maintenance work done
  - History of operation, periodical records of the operation counters and indications
  - References to any failure reports
  - Gas inventory and consumption

In the event of failure and defects, the user should make a failure report and should inform the manufacturer by stating the special circumstances and measures taken. Depending on the nature of the failure, an analysis should be performed in cooperation with the manufacturer.

## 24.8 General Training

The general training is intended for user's staff who are directly involved on a regular basis with the operation of a GIS. Depending on the prior knowledge of the staff, parts of the following agenda may be deleted.

- Single-line diagram
  - Electrical functions
    Gas compartmentalization versus electrical functions
- Physical construction
  - Cross-section and details of each major component type
  - Substation layout drawings
    Interfaces with non-GIS apparatus and civil works
- $SF_6$ gas
  - New gas physical characteristics
  - Purity and moisture limits and measurements
  - Gas filling procedures
  - Substation gas pressure/density curves
  - Pressure checking and density monitor operation
    Physical characteristics, safety, and handling precautions for used or arc-exposed gas
- Earthing system
  - Review of earthing system design requirements for GIS
    GIS-specific subjects related to very fast transients, enclosure touch potential and circulating currents.
- Operating mechanisms
  - Operating principles
    Local, remote, and emergency operation

- Control system
  - Operation: interlocking and alarm philosophy
  - Review of sample schematic drawings and panel layout

## 24.9 Training for Installation

This part of the training applies only if the user's staff is undertaking erection of a new or an extension of an existing GIS, assuming supervision by manufacturer's specialists.

- General overview of installation procedures and practices
- Safety precautions
- Main quality assurance subjects and procedures
- Site commissioning test procedures and evaluation of results

## 24.10 Training for Operating and Maintenance

Operational training is based on the general training and covers normal operational precautions. Inspection and maintenance (excluding intervention in switching components) as well as basic activities in the case of malfunction.

Operation

- remote/local operation guidelines
- built-in interlocking restrictions to operation

  Operational limitations of individual components (e.g., earthing switches, disconnectors)

Inspection/maintenance

- Review of inspection and maintenance schedules
- Discussion and recommendations regarding allocation of maintenance tasks and specific training required
- Use of maintenance accessories and tools

  Topping up the gas compartments under energized conditions

Troubleshooting

- Practical troubleshooting demonstration for control system
- Minor failure location techniques on primary GIS equipment
- Recommended procedures for minor failure rectification

  Recommended action for major failure location, isolation, and possible rectification

Safety practices

- Conformity of the GIS with the user's existing safety practices
- Safety practices during operation and inspections of the GIS

## 24.11 Specialized Training

Specialized training depends on the maintenance strategy of the user. It is necessary before users perform major inspections and maintenance or respond to a major failure without site support by the manufacturer to assure quality and reliability of the GIS after such activities.

Subjects to be covered include:

- Use of $SF_6$ gas handling and recovery equipment
- Operation of high voltage testing equipment
- Overhauling of circuit breaker and disconnector mechanisms
- Maintenance of switching components inside the gas compartment
  Procedures and safety practices required for intervention after a major failure
- "End of life" operations
  - Dismantling procedures
  - Evaluation of modules for reuse in other installation or as spare parts
  - Recycling and disposal measures

Users attempting these tasks need to be aware of the relative rareness of such events that would require detailed and up-to-date knowledge and skills.

Alternatively, utilizing the resources of the original manufacturer for these specialized functions offers the benefits of having available experienced experts whose performance of a task will preserve the original operational reliability of GIS.

## 24.12 Information to Be Given by the User and the Manufacturer

### 24.12.1 Basic Users Input Data

- Maintenance concept, i.e., type of maintenance intended to be accomplished by the user
- Number and experience/background of training participants
- General practical training procedures for user's field staff
- Particular training requirements
- Language of training
- Visa and labor regulations for training at site

### 24.12.2 Basic Manufacturers Input Data

- Standard training procedures and contents
- Training facilities at the manufacturer
- Proposed training schedule (for installation as well as for the in-service period (retraining))
- Available training languages
- Training documentation
- Visa requirements for training at the manufacturer's factory

# Execution of a GIS Substation Project

# 25

Peter Glaubitz, Carolin Siebert, and Klaus Zuber

## Contents

25.1 Initiation of a Project ........ 479
25.2 Engineering Planning ........ 480
25.3 Planning the GIS Project Construction and Installation ........ 480
25.4 Site Preparation ........ 482
25.5 Installation of the New GIS ........ 482
25.6 Installation of GIS Extensions ........ 482
25.7 Equipment Access ........ 482
25.8 Preparation of Inquiry for Tendering ........ 483
25.9 Relevant Standards ........ 483

## 25.1 Initiation of a Project

The initiation of a project is the identification of the need for one or more new switching functions in a network. To satisfy an increased need for more power, for general or industrial supply, or for system availability in a certain area, there will be a need for more power generation and/or a higher transformer capacity. In both cases the solution will include a need for new switching functions, either in the form of a new switchgear for a power plant, a new substation, or an extension of old switchgear which may be of AIS or GIS type.

P. Glaubitz (✉)
GIS Technology, Energy Management Division, Siemens, Erlangen, Germany
e-mail: peter.glaubitz@siemens.com

C. Siebert
Energy Management, Siemens AG, Berlin, Germany
e-mail: carolin.siebert@siemens.com

K. Zuber
Energy Division, Gas Insulated Switchgear, Siemens, Erlangen, Germany
e-mail: zuber.scott@t-online.de

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A need for new switching functions may also occur from other demands connected with the operation of a network, e.g., the installation of a reactor or a capacitor bank, etc.

An important parameter will be the possible location of a substation. Therefore the complete budgetary costs for a project should be calculated, including the costs for the site, the building costs, the costs for different solutions for the connecting lines, etc.

It is obvious that the need for switching functions and therefore possibly a gas-insulated substation will first come up during the "network planning stage."

In any event, the responsibility for this stage is in the hands of the system engineers.

It must be their task to present their needs for switching functions and the ratings to the engineers responsible for the planning and building of substations.

Together with the presentation of such needs, a preliminary single-line diagram should be submitted showing the main necessary functions and ratings needed.

Additional care should be paid to the functionality of the planned installation regarding service continuity. IEC 62271-203 Annex F informs about the features to be discussed as operators' requirements together with the manufacturer. Results to be achieved are optimized proposals in design, operational demands, functionality, and economic benefits.

The evaluation in accordance with Annex F recommendations may also provide future advantages during the GIS service period when extension, modification, and maintenance measures are to be performed.

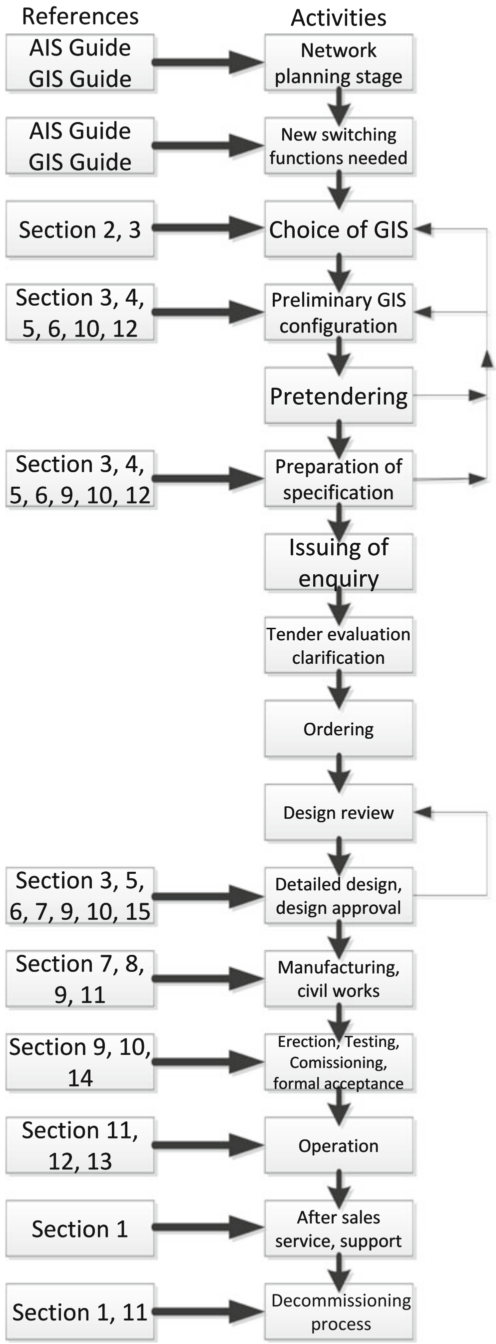
## 25.2 Engineering Planning

Prior to the purchase and the installation of a GIS, the end user needs to determine present and projected future configurations of the station. During this process, electrical and physical parameters and all constraints dictated by the location of the station should be considered as well. Each user needs to review their operating and maintenance procedures to determine whether revisions will be required when transitioning from AIS to GIS. These determinations should be documented in specifications and drawings so that potential suppliers can furnish detailed technical and commercial proposals for the project.

## 25.3 Planning the GIS Project Construction and Installation

A deliberate and complete installation plan, including the future addition of similar equipment, is essential so that all aspects of construction can be reviewed. The preassembled sections of the equipment and the manufacturer's instructions dictate the assembly sequence and, in most instances, follow a series of steps.

**Fig. 25.1** Flowchart for the execution of a GIS project



## 25.4 Site Preparation

Regardless of indoor or outdoor installation, the GIS foundation or space enclosure should be complete and all preparations in place prior to the start of erection. Project scheduling should ensure that inappropriate tasks (e.g., civil work modifications) are not planned for the same installation period. A very important factor for GIS installation is cleanliness. The long-term reliability of the GIS equipment depends greatly on the level of cleanliness maintained during the installation process. This can be achieved by the provision of a defined clean working area. The information in GIS manuals and manufacturers' recommendations are of great importance.

A start-up check by the customer and GIS manufacturer prior to the start of installation on site may ensure and document the required conditions.

## 25.5 Installation of the New GIS

The overall installation process of GIS may encompass many months, during which time other activities associated with the project should continue. Coordination of activities among the project's responsible parties is a necessity, especially with regard to the interface with the HV power transformer and HV cable connections. Time spent on these coordination processes will help to ensure the minimum number of disruptions during the installation process. Disruptions will nevertheless occur, and a certain degree of flexibility on the part of all parties is essential. Specific installation procedures are tailored for each manufacturer's GIS requirements.

## 25.6 Installation of GIS Extensions

The installation of an extension to an existing GIS substation imposes special conditions on both the manufacturer and plant operator that do not normally apply for the installation of new GIS, which is covered under IEEE Guide C37.122.6 in more detail.

In general during the extension procedures on site, the existing switchgear is asked to remain in an undisturbed condition. The availability and service continuity are of importance to be verified between all involved parties on site. IEC 62271-203 Annex F shows arguments assisting this discussion and project preparation. The resulting project steps and procedure's statements are also of great importance regarding working safety for personnel and equipment.

## 25.7 Equipment Access

Structural supports, access platforms, ladders, stairs, cable raceways, conduits, and other auxiliary equipment required for operation and maintenance, as furnished by the manufacturer, should be incorporated into the design. See IEEE C37.122 for more details.

## 25.8 Preparation of Inquiry for Tendering

When all necessary preliminary studies and pre-tendering have been performed and all basic data are conclusive, this information will form the foundation of the technical part of an inquiry.

In fact, by combining the sections "Information to be given by the user and the manufacturers," from all corresponding subchapters, one will to a large extent obtain a "specification" for an inquiry.

When sending out the final enquiry, all information necessary for submission of firm quotations should be defined. This goal is reached by conducting preliminary investigations to a sufficient degree, including pre-tendering if judged necessary. The manufacturers should be allowed to give alternative proposals to the layout design (see ► Sect. 16.1).

## 25.9 Relevant Standards

| | |
|---|---|
| Common clauses for switchgear | |
| IEC 60694 | Common specifications for high-voltage switchgear and controlgear standards |
| IEC 62271-1 | High-voltage switchgear and controlgear – Part 1: common specification |
| IEEE Std.C37.100 | IEEE standard definitions for power switchgear |
| IEEE C37.100.1 | IEEE standard of common requirements for high-voltage power switchgear rated above 1000 V |
| IEC/TS 60815-1 | Selection and dimensioning of high-voltage insulators intended for use in polluted conditions |
| IEC 60071 | Insulation coordination<br>Part 1: definitions, principles, and rules<br>Part 2: application guide |
| GIS systems above 52 kV | |
| IEC 62271-203 | High-voltage switchgear and controlgear. Part 203: gas-insulated metal-enclosed switchgear for rated voltages above 52 kV |
| IEEE Std. C37.122 | Standard for high-voltage gas-insulated substations rated above 52 kV |
| EN 50089 | Cast resin partitions for metal-enclosed gas-filled high-voltage switchgear and controlgear |
| IEEE C37.122.6 | Recommended practice for the interface of new gas-insulated equipment in existing gas-insulated substations rated above 52 kV |
| High-voltage circuit breakers | |
| IEC 62271-100 | High-voltage switchgear and controlgear. Part 100: high-voltage alternating current circuit breakers |
| IEC 62271-101 | High-voltage switchgear and controlgear. Part 101: synthetic testing |
| IEEE Std. C37.04 | IEEE standard rating structure for AC high-voltage circuit breakers rated on a symmetrical current basis |
| IEEE Std. C37.06 | High-voltage circuit breakers rated on a symmetrical current basis: preferred ratings and related required capabilities |

(*continued*)

| | |
|---|---|
| High-voltage circuit breakers | |
| IEEE C37.09 | IEEE standard test procedure for AC high-voltage circuit breakers rated on a symmetrical current basis |
| Disconnector and earthing switch | |
| IEC 62271-102 | High-voltage switchgear and controlgear<br>Part 102: alternating current disconnectors and earthing switches |
| IEEE Std. C37.122 | Standard for high-voltage gas-insulated substations rated above 52 kV |
| Instrument transformers | |
| IEC 60044 ff. | Instrument transformer (current/voltage transformer) |
| IEC 61869 ff. | Instrument transformer (current/voltage transformer) |
| Signals, control | |
| IEC 61850 | Communication networks and systems for power utility automation |
| Backparts | |
| IEC 62271-209 | Cable connections for gas-insulated metal-enclosed switchgear for rated voltages of 72.5 kV and above |
| IEC 62271-211 | Direct connection between GIS and power transformer for rated voltage of 72.5 kV and above |
| IEC 60099-4 | Surge arresters – Part 4: metal-oxide surge arresters without gaps for a.c. systems |
| Earthing | |
| IEC 61936 | Power installations exceeding 1 kV a.c. – Part 1: common rules |
| EN 50522 | Earthing of power installations exceeding 1 kV a.c. |
| IEEE std. 80 | IEEE guide for safety in AC substation grounding |
| Cigré technical brochures | |
| No 150<br>No 513 | International enquiries on reliability of high-voltage equipment brochure no. 150 (year 1967–1995) and no. 513 (year 2004–2007) |
| No 525 | Risk assessment on defects in GIS based on PD diagnostics |
| No 213 | Engineering guide on earthing systems in power stations |

# Part D

# Mixed Technology Switchgear Substations and Gas Insulated Lines

*Tokio Yamagiwa*

Check for updates

# Mixed Technology Switchgear (MTS) Substations

26

Tokio Yamagiwa and Colm Twomey

## Contents

26.1 Introduction to MTS ... 487
26.1.1 Why Use MTS? ... 490
26.2 AIS, GIS, and MTS ... 491
26.2.1 Insulation Technology Considerations ... 491
26.2.2 AIS, GIS, and MTS Definitions ... 492
26.2.3 Evaluation of Applicability of AIS, GIS, and MTS ... 493
26.3 Conventional, Compact, and Combined Switchgear ... 496
26.3.1 Installation and Functionality considerations ... 496
26.4 Conventional, Compact, and Combined Switchgear Definition ... 497
26.4.1 Examples of Compact and Combined Switchgear Assemblies ... 501
26.5 Common Considerations of Insulation and Installation + Functionality ... 502
26.6 Application of Standards to MTS ... 504
26.7 Future Developments ... 505
References ... 506

## 26.1 Introduction to MTS

Gas-insulated switchgear (GIS) and air-insulated switchgear (AIS) use proven technologies to provide safe and reliable power to the public.

New high-voltage switchgear components have been developed based either on AIS or on GIS or on a combination of both. Mixed technology switchgear (MTS) is a switchgear assembly of various high-voltage components introduced into the high-voltage market as a possible solution fitting between AIS and GIS. These solutions

T. Yamagiwa (✉)
Power Business Unit, Hitachi Ltd, Hitachi-shi, Ibaraki-ken, Japan
e-mail: tokio.yamagiwa@gmail.com

C. Twomey
Substation Design, ESB International, Dublin, Ireland
e-mail: Colm.Twomey@esbi.ie

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are often used to replace and/or upgrade open-type substations (air-insulated) or older gas-insulated substations because of their smaller space requirements and reduced outage time demand. These assemblies have now been in use worldwide for several years; therefore a considerable amount of experience is available that can be offered to potential users.

Various manufacturers have developed switchgear components derived from AIS or GIS, which can be assembled in a variety of configurations to perform switchgear and control gear functions as MTS. Numerous arrangements are possible, and this chapter considers the more common approaches to forming an assembly unit.

CIGRE WG B3.03 has published general guidelines for the design of outdoor AC substations (CIGRE Brochure No. 161 2000). Apart from some minor comments, the scope was limited to AIS. WG B3.02 published a guide covering all points which are specific for GIS for rated voltages of 52 kV and above (CIGRE Brochure No. 125 1998).

The general chapters of the previous guides concerning system requirements, network considerations, and the need for a substation include MTS as well as AIS and GIS substations (as MTS module design was derived originally from AIS and/or GIS components). The following evaluation will provide help to decide which technology will be the optimal solution for a substation project.

In general, there is a trend in switchgear solutions toward more compact and integrated gas-insulated solutions for outdoor use.

The different design technologies for high-voltage switchgear can be clustered into three groups:

- Conventional AIS solutions
- Conventional GIS solutions (for indoor as well as for outdoor applications)
- Compact AIS or GIS or hybrid switchgear solutions (mainly for outdoor use) (Fig. 26.1)

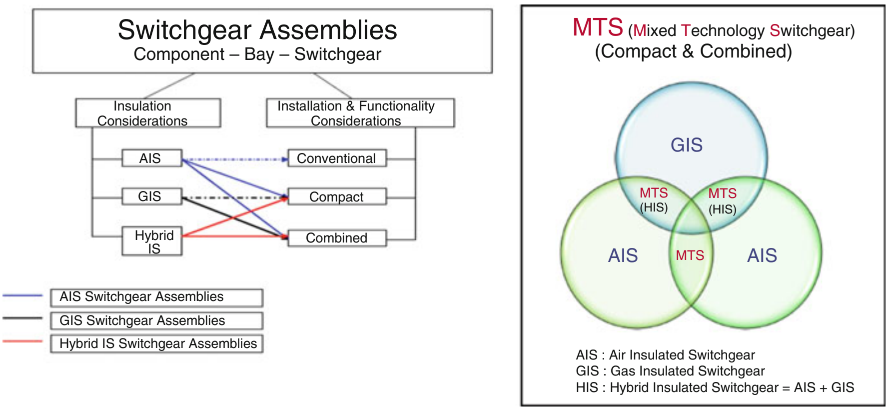



**Fig. 26.1** Mixed technology switchgear (full line connections) built with switchgear assemblies

The terminology used in this chapter is based on definitions from IEC 60050, if applicable, or on relevant IEC product standards, sometimes amended according to the specific use in this chapter, and on previous CIGRE publications.

This chapter is based on the following logical structure for the description of high-voltage installations, starting with single components and ending with a complete substation as shown in Fig. 26.2.

$$\text{Component} - \text{Bay} = \text{assembly of components} - \text{Switchgear} \\ = \text{assembly of bays} - \text{Substation}$$

This chapter introduces mixed technology switchgear using the following terms:

**Insulation Technology**

- Air-insulated switchgear (AIS)
- Gas-insulated switchgear (GIS)
- Hybrid-insulated switchgear (Hybrid IS)

Note: In the abbreviations GIS and AIS, the "S" is often read as "substation." In this document the IEC definition is used, where the "S" is read as switchgear.

**Design and Functionality**

- Conventional compact
- Combined function

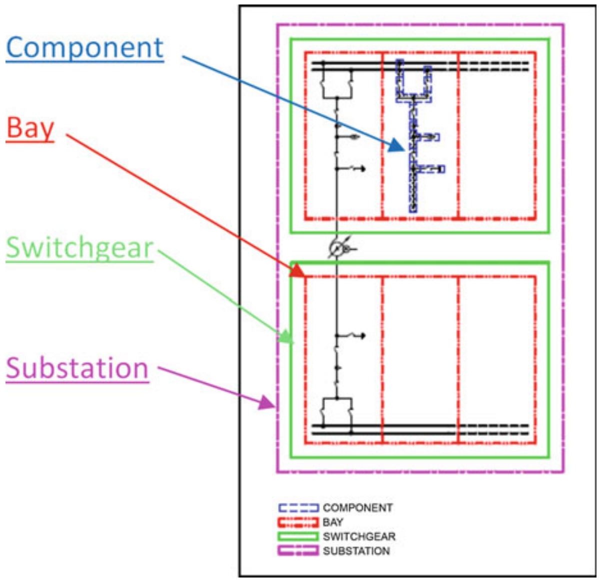



**Fig. 26.2** Logical structure of high-voltage installations description from single component to complete substation

Mixed technology switchgear (MTS) as described in this chapter concerns the following combinations:

- AIS in compact and/or combined design
- GIS in combined design
- Hybrid IS in compact and/or combined design

The aim of CIGRE Joint Task Force JTF B3.02/03 was to provide proposals to make the terminology clear and precise and to prepare a base for its introduction into standardization documents. (This report is included in Brochure of CIGRE WG B3.20 (CIGRE Brochure No. 390 2009).)

Therefore to avoid misunderstanding, the suggested definitions are split into two parts, one according to the insulation technology (Sect. 26.2.1) and the other according to the functionality (Sect. 26.3.1).

### 26.1.1 Why Use MTS?

The drivers for the development of MTS were strictly the demands of the changing world of energy supply. The economic pressures on utilities under the conditions of deregulation demand equipment with minimum life cycle cost, high availability (which will be achieved by highly reliable products with high flexibility for installation and replacement), and compact solutions to extend already existing

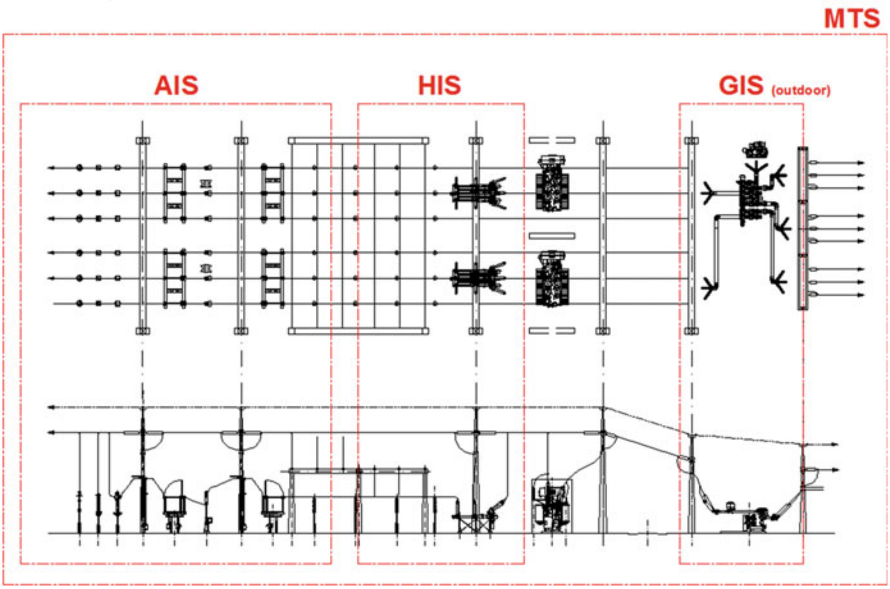



**Fig. 26.3** Mixed technology switchgear – complete solution

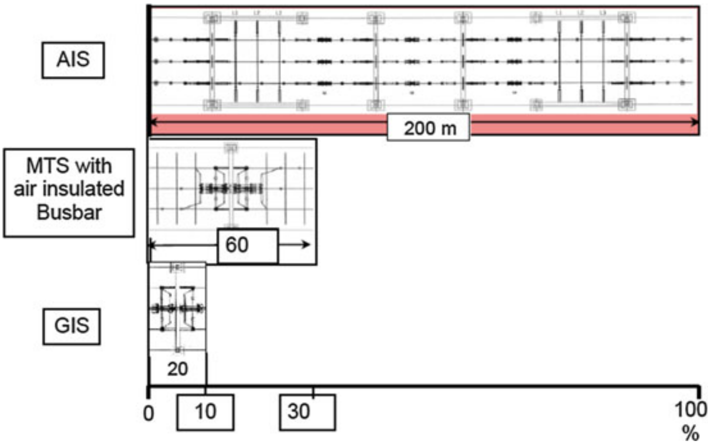



**Fig. 26.4** Space comparison of AIS, GIS, and MTS solution at two CB-bays 420 kV level

substations as effectively as possible. Last, but not least, the suppliers of switchgear needed to change from being "equipment suppliers" to "solution providers."

The following figure (Fig. 26.3) exemplifies how the required space for the same arrangement of 420 kV switchgear with the same single-line diagram, using AIS, GIS, and MTS, leads to a footprint reduction of up to 90% in comparison to AIS. This reduction provides the space necessary to build new substations or to add three or even more bays instead of one when retrofitting/extending the existing substations.

In general, MTS also offers a higher flexibility of layout compared to AIS or GIS equipment due to the modular arrangement. A single-line diagram can be easily improved, or the number of bays can even be increased while using the same space, to extend already existing substations efficiently without exceeding the space limitations.

This is one of the answers to the question "Why use MTS?" (Fig. 26.4).

## 26.2 AIS, GIS, and MTS

### 26.2.1 Insulation Technology Considerations

The features mentioned in Sect. 26.2 are based on their insulation technology, using the following terms as defined in Sect. 26.1:

- Component – bay – switchgear

The components are evaluated from their insulation and enclosure design points of view. Components, in this respect, can be either of gas-insulated metal-enclosed switchgear technology design or of external insulation switchgear technology design.

**Table 26.1** Principal technology designs for substation

| Technology design | Insulation | Insulating medium | Enclosure |
|---|---|---|---|
| AIS technology | External insulation[a] | Air | No enclosure or enclosure (porcelain or composite insulators) under high voltage |
| GIS technology | Internal and external insulation | $SF_6$ or $SF_6$ mixtures | Metal enclosure effectively earthed |
| MTS technology | External insulation[a] | $SF_6$ or $SF_6$ mixtures and air | Combination of all |

[a]Internal insulation can be air, $SF_6$, oil, resin, or all other kinds of insulating media

The following abbreviations are introduced to simplify the text in definitions mentioned in Sect. 26.2:

- GIS technology – for gas-insulated metal-enclosed switchgear component technology designs
- AIS technology – for open-type substations with external insulation switchgear component technology designs

The principal technology designs for substations (their components and bays) are as follows (Table 26.1):

Various assemblies (single-line diagram arrangements and layouts) can be used to optimize the installation, operation, space, and life cycle cost using AIS or GIS component technologies or some combination of these. All of them can, in theory at least, be located outdoor or indoor.

### 26.2.2 AIS, GIS, and MTS Definitions

Table 26.2 shows AIS, GIS, and MTS definitions.

Two exceptions from the definitions are given below the table.

*In general*: In MTS, elements of AIS and GIS technology are mixed. There are two exceptions to this rule:

- If the only component in AIS technology is the HV connection to overhead line, cable, or transformer, the switchgear is considered as GIS.
- If the only component in GIS technology is a dead-tank circuit breaker, the switchgear is considered as AIS.

Any other combinations are considered as MTS (e.g., where only busbars are $SF_6$-insulated, or where a metal-enclosed gas-insulated circuit breaker contains additional equipment such as instrument transformers or earthing switches).

**Table 26.2** AIS, GIS, and MTS definitions

| Technology design | Definitions |
|---|---|
| AIS technology | Switchgear where the bays are fully made from AIS technology components<br>Note:<br>A substation, where only dead-tank types of circuit breakers are installed in the bays, is also considered to be an AIS substation |
| GIS technology | Switchgear where the bays are fully made from GIS technology components<br>Only external HV connections to overhead or cable lines or to transformers, reactors, and capacitors can have an external insulation |
| MTS technology | Switchgear where the bays are made from a mix of GIS and AIS technology components; switchgear, which consists of bays where some of the bays are made of AIS technology components and some of the bays are made either of GIS technology components only or of a mix of AIS and GIS technology components |

### 26.2.3 Evaluation of Applicability of AIS, GIS, and MTS

Table 26.3 contains a summarized comparative evaluation of the applicability of various characteristics to the three types of technology AIS, MTS, and GIS for a rated voltage level of 52 kV and above. More details will be found in the referred CIGRE Brochure No. 390 (2009), explaining the evaluation of the different types of switchgear.

From Table 26.3, a numerical evaluation can be obtained using the following assignment of numbers to the qualitative evaluations.

```
"symbol" : "point"
     "++":  "+ 10",
     "+" :  "+  5",
     "0" : "0",
     "-" : "- 5",
    "—"  : "- 10"
```

When all of the evaluations are added up, the total score became AIS = 165, AIS: MTS = 315, and GIS = 215.

When these results are normalized against a base value of 100 for AIS, the results for MTS and GIS become MTS = 190 and GIS = 130.

This means that MTS is about twice the score of AIS and also can be expected to have an advantage of about 1.5 times as compared to GIS.

It should be noted that the characteristics where MTS shows particular advantage are (1) location, (4) construction, (7) on-site time efforts, (9) availability, (11) flexibility, and (14) life cycle cost.

The areas where MTS scores poorly are (3) engineering and (10) testing.

**Table 26.3** Summary of applicability of various characteristics to the three types of technology AIS, MTS, and GIS

| Title "Various Characteristics" | AIS | MTS | GIS |
|---|---|---|---|
| **(1) Location** | | | |
| Outdoor rural | ++ | + | – |
| Outdoor urban | 0 | ++ | + |
| Indoor | - | + | ++ |
| Underground | – | + | ++ |
| Container | – | ++ | ++ |
| **(2) Equipment design and manufacturing** | | | |
| Conceptual design and its evaluation | ++ | 0 | + |
| Material (*combined equipment) | + | + (-)* | + |
| Manufacturing process and quality control of manufacturing (only manufacturing point of view) | ++ | + | - |
| Manufacturing process and quality control of manufacturing and assembling (from on-site commissioning point of view) | - | + | ++ |
| **(3) Engineering** | | | |
| Project complexity | ++ | + | 0 |
| Planning schedule | 0 | 0 | 0 |
| Contracting schedule | 0 | + | ++ |
| Single-line diagram | 0 | 0 | 0 |
| Specification | + | 0 | + |
| Basic layout | - | + | ++ |
| Civil work layout and earthing | + | - | + |
| Secondary scheme | ++ | + | 0 |
| **(4) Construction** | | | |
| Preparation of site | ++ | + | - |
| Transport and storage | - | + | ++ |
| Civil work (foundation) | + | 0 | - |
| Work crew | + | + | - |
| Erection | - | + | 0 |
| Impact on existing service | + | + | - |
| Commissioning | + | ++ | - |
| **(5) Impact on environment** | | | |
| Aesthetics | - | 0 | + |
| Nature | - | 0 | ++ |
| Noise | 0 | 0 | + |
| Leakages | - | 0 | - |
| EMF/EMC | 0 | 0 | ++ |
| **(6) Impact of environment** | | | |
| Climatic conditions (* indoor application) | 0 | +(++)* | + (++)* |
| Pollution (* indoor application) | 0 | 0 (++)* | 0 (++)* |
| Corrosion (** climatically controlled building) | 0 | 0 | +** |
| Seismic conditions | 0 | + | ++ |

(*continued*)

**Table 26.3** (continued)

| Title "Various Characteristics" | AIS | MTS | GIS |
|---|---|---|---|
| **(7) On-site time efforts** | | | |
| Preparation time | 0 | + | 0 |
| Transportation time | - | + | ++ |
| Erection time | - | ++ | 0 |
| Commissioning time | ++ | + | 0 |
| Repair time | ++ | + | 0 |
| Maintenance time | ++ | + | 0 |
| **(8) Operation and service** | | | |
| Control (* for multifunctional MTS) | + | 0 (-)* | 0 |
| Condition monitoring | - | 0 | + |
| Expected lifetime | + | + | + |
| Decommissioning and disposal | 0 | 0 | - |
| Replacement of components | ++ | + | - |
| Dependence on manufacturer (OEM) | ++ | + | - |
| Dependence on special know-how | ++ | + | - |
| **(9) Availability** | | | |
| Maintainability | - | + | ++ |
| Mean time of maintenance | + | ++ | 0 |
| Reliability (*indoor applications) | 0 | + | + (++)* |
| Mean time of repair | + | ++ | 0 |
| Tools, gas handling | + | 0 | 0 |
| **(10) Testing** | | | |
| Type tests | + | 0 | ++ |
| Routine tests | + | 0 | ++ |
| On-site tests | ++ | + | 0 |
| Test equipment | ++ | + | 0 |
| **(11) Flexibility** | | | |
| Extendibility of existing substations | ++ | ++ | 0 |
| Use for extension of existing substations | 0 | ++ | + |
| Upgrading/refurbishment of existing substations (*for voltages up to 245 kV) | - | ++ | +* |
| Use for upgrading/refurbishment of existing substations | + | ++ | - |
| Mobile and/or temporary installations | + | ++ | - |
| New substation | + | + | + |
| **(12) Personnel safety** | | | |
| Injury risk during service | 0 | + | ++ |
| Injury risk during maintenance | ++ | + | 0 |
| Injury risk in case of major "violent" failure | 0 | + | ++ |
| **(13) Physical security** | | | |
| Security against terrorist attack | 0 | + | ++ |
| Security against vandalism | 0 | + | ++ |
| Security against metal theft | 0 | + | ++ |

(*continued*)

**Table 26.3** (continued)

| Title "Various Characteristics" | AIS | MTS | GIS |
|---|---|---|---|
| **(14) Life cycle cost** | | | |
| Cost of acquisition | ++ | 0 | - |
| Cost of ownership (* heavily influenced by individual utility's conditions) | 0* | ++* | +* |
| Cost of disposal | - | 0 | 0 |

Interpretation of symbols
"++" denotes this technology confers definite advantage
"+" denotes this technology confers advantage
"0" represents neutral status
"-" denotes disadvantage
"–" denotes definite disadvantage

## 26.3 Conventional, Compact, and Combined Switchgear

### 26.3.1 Installation and Functionality considerations

The definitions given in Sect. 26.3 are based on application characteristics such as installation and functionality, using the following terms as defined in Sect. 26.1:

Component – Bay – Switchgear

Contrary to Sect. 26.2.1, there are no direct or paraphrased definitions available in IEC to be used in this section.

The components are evaluated from their installation and functionality point of view. Components in this respect can be either individually installed or multi-installed, i.e., installed in a compact form, placed in a group sharing a common support construction which cannot be installed (placed) individually, or either single function or multifunctional.

Examples for multifunctional components:

- Disconnector-earthing switch (ground switch) in which its function depends on the position of one common moving main contact
- Circuit breaker-disconnector switch and disconnecting circuit breaker in which the open position of the circuit breaker meets all requirements for the disconnector isolating function*

*In their simplest form, these combined-function devices are required to satisfy the basic combination of a circuit breaker (or switch) and one or more disconnectors. In general this applies to AC switchgear and controlgear that is a switching device combination, whose functional requirements are defined in IEC 62271-108 "High-

**Table 26.4** Installation and functionality consideration

| Technology design | Installation | Functionality |
|---|---|---|
| Conventional | Single (independent) installation | Single (independent) |
| Compact | Common support construction – interaction among components | Single (independent) |
| Combined | Single (independent) installation | Multifunctional (dependent) |
| Compact + combined | Common support construction – interaction among components | Multifunctional (dependent) |

voltage alternating current disconnecting circuit breakers for rated voltages of 72,5 kV and above."

The following terms are introduced to simplify the text in definitions mentioned in Sect. 26.4.

- Conventional components – individually installed and single-function components
- Compact components – single-function switchgear components installed in such a close formation that thermal, electrical, and mechanical interaction between the devices can be anticipated
- Combined components – multifunctional switchgear components
- Conventional bays – bays containing only conventional components
- Compact bays – bays containing at least one compact component group, i.e., in which at least some components in a bay share a common support structure and cannot be placed individually
- Combined bays – bays containing at least one combined component

Various functionalities can be used to optimize the operation, the space, and the life cycle cost using AIS, GIS, or their combination component technologies. These functionalities of components define conventional, compact, and combined switchgear.

Table 26.4 shows installation and functionality considerations for switchgear components.

## 26.4 Conventional, Compact, and Combined Switchgear Definition

1. Conventional switchgear
   Switchgear where the bays include only conventional components (Fig. 26.5).

2. Compact switchgear

**Fig. 26.5** Switchgear with only conventional components (CIGRE Brochure No. 390 2009)

**Fig. 26.6** Switchgear with compact bays and conventional components (CIGRE Brochure No. 390 2009)

Switchgear where at least one or more bays are compact bays, i.e., in which at least some components share a common support structure and cannot be placed individually (Fig. 26.6).

3. Combined switchgear
   Switchgear where at least one or more bays are combined bays, i.e., in which at least some components are multifunctional (Fig. 26.7).

**Fig. 26.7** Combined switchgear – circuit breakers, disconnectors, and earthing switches (ABB Catalogue)

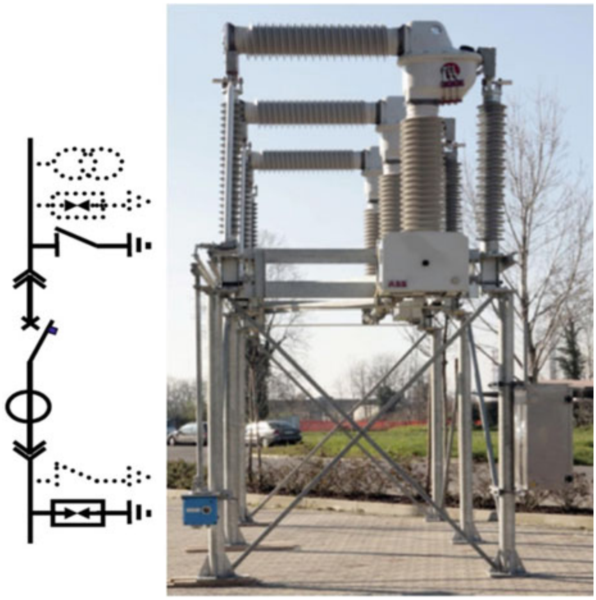


**Fig. 26.8** Compact/combined switchgear (ABB Catalogue)

4. Compact/combined switchgear
   Switchgear where the bays include at least one group of compact components and at least one combined component (Fig. 26.8).

5. Mixtures of different kind of bays
   Switchgear that consists of bays where some of the bays are compact and some of them are conventional is considered as compact switchgear.

   Switchgear that consists of bays where some of the bays are combined and some of them are conventional is considered as combined switchgear.

   Switchgear that consists of bays where some of the bays are compact/combined and some of them are conventional is considered as compact/combined switchgear.

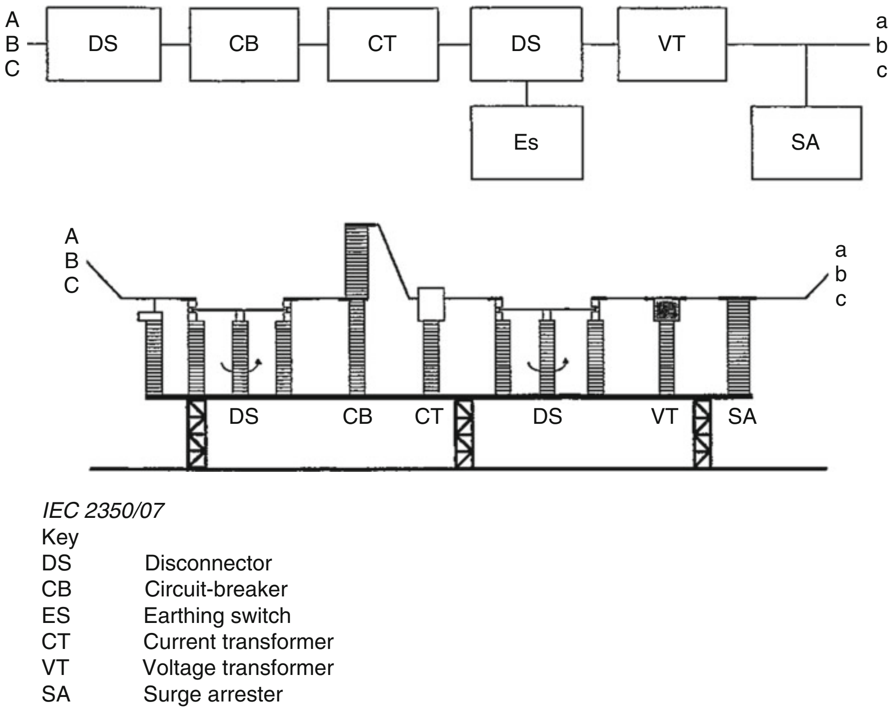
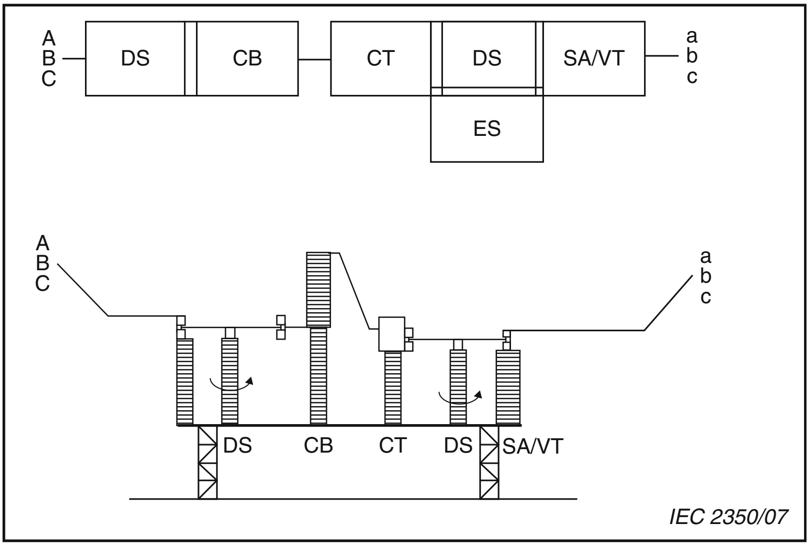



**Fig. 26.9** Example for type 1. Key: *DS* disconnector, *CB* circuit breaker, *ES* earthing switch, *CT* current transformer, *VT* voltage transformer, *SA* surge arrester




Key

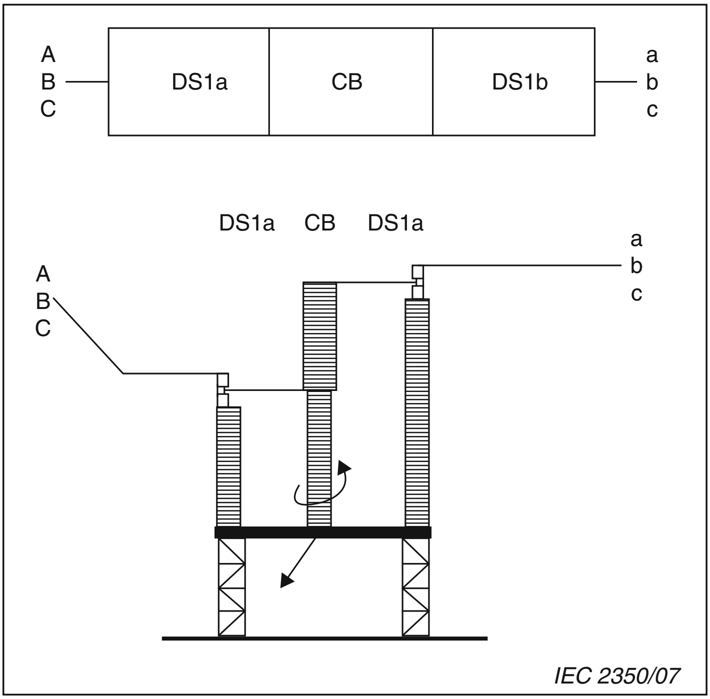
| | |
|---|---|
| DS | Disconnector |
| CB | Circuit-breaker |
| ES | Earthing switch |
| CT | Current transformer |
| VT | Voltage transformer |
| SA | Surge arrester |

**Fig. 26.10** Example for type 2

### 26.4.1 Examples of Compact and Combined Switchgear Assemblies

The following examples illustrate some possible compact switchgear assemblies (IEC 62271-205 2008). Since there are many possible solutions, the types shown below are for indicative purposes only. Compact switchgear assemblies may consist of air-insulated devices, gas-insulated devices, or a combination of both (Figs. 26.9, 26.10, 26.11, and 26.12).

| | |
|---|---|
| Type 1: | Assembly of independently operated switching devices and/or devices which are connected by short connecting parts on a common base frame (similar to a conventional substation design) |
| Type 2: | Assembly of independently operated switching devices and/or devices sharing parts of the neighboring switching device or device. |
| Type 3: | Assembly of independently operated switching devices and/or devices integrated in another switching device |




Key

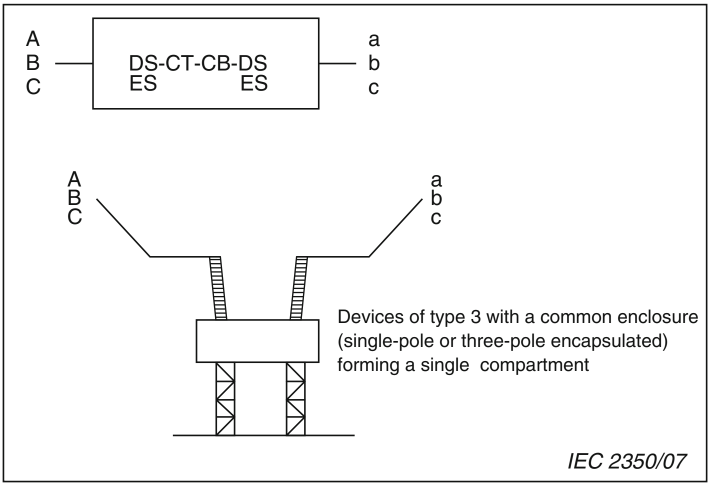
| | |
|---|---|
| DS | Disconnector |
| DS1a | Part a of disconnector 1 |
| DS1b | Part b of disconnector 1 |
| CB | Circuit-breaker |
| ES | Earthing switch |
| CT | Current transformer |
| VT | Voltage transformer |
| SA | Surge arrester |

**Fig. 26.11** Example for type 3 (AIS). Key: *DS* disconnector, *DS1a* part a of disconnector 1, *DS1b* part b of disconnector 1, *CB* circuit breaker, *ES* earthing switch, *CT* current transformer, *VT* voltage transformer, *SA* surge arrester

## 26.5 Common Considerations of Insulation and Installation + Functionality

All of the technologies used have their advantages that are described in detail in this chapter. The comparison of technologies indicates that MTS combines many of the advantages of both AIS and GIS and can lead to a good compromise.

The following table shows a summary of the main MTS benefits (Table 26.5).




**Key**

| | |
|---|---|
| DS | Disconnector |
| CB | Circuit-breaker |
| ES | Earthing switch |
| CT | Current transformer |

**Fig. 26.12** Example for type 3 (GIS). Key: *DS* disconnector, *CB* circuit breaker, *ES* earthing switch, *CT* current transformer

**Table 26.5** Summary of main MTS benefits

| MTS type | Benefits |
|---|---|
| AIS in compact design | Less space required for the same single-line diagram<br>Extends single-line diagram within the same space<br>Easier engineering<br>Easier integration of secondary systems |
| Hybrid in compact and combined design | Less space required for the same single-line diagram<br>Higher flexibility of layout versus AIS<br>Extends single-line diagram with the same space<br>Allows bus reconfiguration for increased system reliability<br>Easier engineering<br>Reduced maintenance efforts and costs<br>Easier integration of secondary systems |
| AIS in combined design<br>GIS in combined design | Extends single-line diagram with the same space<br>Less space required for the same single-line diagram<br>Allows bus reconfiguration for increased system reliability<br>Easier engineering<br>Easier maintenance<br>Easier integration of secondary systems |

## 26.6 Application of Standards to MTS

Regardless of what type of equipment the user is using (compact, combined AIS or GIS, or GIS modules in hybrid installations), the AIS portion is covered by mature AIS standards, and the GIS portion is subject to mature GIS standards.

However, there are some cases which cannot be directly covered by the AIS and GIS standards.

As an example, there is "the capability of the busbar disconnectors and their behavior during busbar-transfer operations." In this situation for the MTS, it is necessary to take into account the standards of both AIS and GIS, and in particular, the voltage which should be used for a GIS busbar disconnector located in an AIS substation should be the AIS value.

The requirement for compact switchgear design flows from situations with limited availability of space and limited budgets for new investments. In MTS the advantages of AIS and GIS are combined to yield a large variety of technical solutions.

The standard IEC 62271-205 deals directly with MTS and was completed in 2007. The scope of this international standard applies to AC switchgear and controlgear that is an assembly of switching devices in close/compact formation with other switching devices or other devices, defined in IEC standards and which are designed, tested, and supplied for single use as an indivisible unit. Such assemblies may contain components of AIS or a combination of AIS and GIS and are designated as MTS.

Due to their compact nature, the interaction between the various devices making up the assemblies is anticipated and has to be type-tested. The new standard should provide the regulations on how such compact switchgear assemblies have to be designed, tested, and specified.

The objective of this new IEC standard is to respond to the increasing use of compact switchgear assemblies that perform the functions of a number of separate devices and their controlgear. Numerous arrangements are possible, and this standard will provide guidance on basic types of assemblies which might be envisaged. Interactions between the different devices within such assemblies have to be considered, and it is necessary to consider the standardization requirements for the switchgear assembly in its entirety.

When designing and producing an MTS, it is recommended to use only devices which are defined in the appropriate IEC/IEEE standards. However each individual switching device, other devices, and controlgear shall comply simultaneously with its specific relevant individual standard.

**Relevant Standards (as of 2015)**

- IEC 62271-1: 2007 + AMD1:2011, "High-voltage switchgear and controlgear – Part 1 Common Specifications"
- IEC 62271-205: 2008, "High-voltage switchgear and controlgear – Compact switchgear assemblies for operation at rated voltages above 52 kV"
- IEC 62271-203: 2011, "Gas-insulated metal-enclosed switchgear for rated voltages of equipment of 52 kV and above"

In addition to the standards of the common characteristics, defined by IEC standards above, there are other standards that are applicable for individual devices as listed below:

| Switching devices | |
|---|---|
| Circuit breakers | IEC 62271-100: 2008 + AMD1: 2011 |
| Disconnectors/earthing switches | IEC 62271-102: 2001 + AMD1: 2011 + AMD2: 2013 |
| Switches | IEC 62271-103: 2011 |
| Disconnecting circuit breakers | IEC 62271-108: 2005 |
| Other devices | |
| Current transformers | IEC 60044-8: 2002, IEC 61869-2: 2012 |
| Voltage transformers | IEC 60044-7: 1999, IEC 61869-3, IEC 61869-5: 2011 |
| Combined transformers | IEC 61869-4: 2013 |
| Surge arresters | IEC 60099-4: 2014 |
| Bushings | IEC 60137: 2008 |
| Insulators | IEC 61462: 2007, IEC 62155: 2003 |
| Cable connections | IEC 62271-209: 2007 |

IEC 60480: 2004, "Guidelines for the checking and treatment of sulfur hexafluoride ($SF_6$) taken from electrical equipment and specification for its re-use"

IEC 60050: 1983, "International Electrotechnical Vocabulary. Chapter 605: Generation, transmission and distribution of electricity – Substations"

**Other Standards**

- IEEE Std.1127-2013, "IEEE Guide for the Design, Construction, and Operation of Electric Power Substations for Community Acceptance and Environmental Compatibility"
- IEEE Std. 980-2013, "Guide for Containment and Control of Oil Spills in Substations"
- IEEE Std. 693-2005, "IEEE Recommended Practice for Seismic Design of Substations"
- IEEE Std. 1402-2000, "IEEE Guide for Electric Power Substation Physical and Electronic Security"
- IEEE Std. C37.122.1-2014, "IEEE Guide for Gas-Insulated Substations Rated Above 52kV"

## 26.7 Future Developments

MTS as described in this chapter is defined by the following combinations:

- AIS in compact and/or combined design
- GIS in combined design
- Hybrid IS in compact and/or combined design

Some developments which will impact on the development of MTS include, in recent years, the widely reported global environmental conservation issues which are having an impact on substation equipment:

1. $SF_6$ gas used in substation equipment has been identified as having about 22,000–24,000 times the global warming potential of $CO_2$. There are increasing requirements for a reduction in usage and for reduction or elimination of leakage or release into the atmosphere.
2. Associated with the promotion of renewable energy for $CO_2$ reduction are requirements for connection of these new generation sources to the grid and for other equipment required for a stable power system.
3. The development of the smart grid-enabled intelligent substation that will require full use of ICT (information and communication technology) to achieve this goal.

## References

CIGRE Brochure No. 125: User guide for the application of Gas-insulated Switchgear (GIS) for rated voltages of 72.5kV and above (1998)

CIGRE Brochure No. 161: Guidelines for the design of outdoor AC substations, 2nd version (2000)

CIGRE Brochure No. 390: Evaluation of different switchgear technologies (AIS, MTS, GIS) for rated voltages of 52kV and above (2009)

IEC 62271-205: High-voltage switchgear and controlgear – Part 205: Compact switchgear assemblies for rated voltages above 52kV, Edition 1.0 (2008–01)

# Gas Insulated Lines (GIL)

# 27

Hermann Koch

## Contents

27.1 Basics ........ 508
27.1.1 Basic Explanation ........ 508
27.1.2 Properties of the Insulating Gas ........ 509
27.1.3 Definition ........ 509
27.1.4 Description ........ 510
27.2 Ratings ........ 515
27.2.1 GIL Electrical Parameters ........ 515
27.2.2 Directly Buried GIL ........ 516
27.2.3 Thermal Layout ........ 516
27.2.4 Short-Time Rating ........ 517
27.2.5 Insulation Coordination ........ 518
27.2.6 Standard Values ........ 519
27.2.7 Capacity of GIL ........ 521
27.3 Installation Options ........ 523
27.3.1 Directly Buried GIL ........ 523
27.3.2 GIL in Structures ........ 528
27.3.3 Automated Laying Processes of GIL ........ 535
27.4 Environmental Impact ........ 537
27.4.1 Environmental Life Cycle Assessment ........ 537
27.4.2 General Environmental Aspects ........ 538
27.4.3 Magnetic Fields ........ 538
27.4.4 Environmental Aspects ........ 539
27.5 Long-Term Test ........ 539
27.5.1 Feasibility Study of 420 kV GIL ........ 539
27.6 Example Projects ........ 540
27.6.1 PP9 Saudi Arabia ........ 540
27.6.2 Limberg, Austria ........ 541
27.6.3 Kelsterbach GIL ........ 542

H. Koch (✉)
Gas Insulated Technology, Power Transmission, Siemens, Erlangen, Germany
e-mail: hermann.koch@siemens.com

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27.7 Future Applications ........ 544
27.7.1 General ........ 544
27.7.2 Possible Future Uses of GIL Associated with Substations ........ 544
27.8 Project Handling ........ 546
27.8.1 Site Assembly ........ 546
27.8.2 Factory Preassembly ........ 548
27.8.3 Gas Handling ........ 552
27.8.4 High-Voltage Test ........ 553
27.8.5 Pressure Test ........ 555
27.9 Operation, Maintenance, and Repair ........ 556
27.9.1 Online Insulation Monitoring ........ 556
27.9.2 Bonding and Grounding for Permanent and Transient Voltages ........ 556
27.9.3 Operation ........ 556
27.9.4 Maintenance ........ 557
27.9.5 Repair Process ........ 558
27.10 Safety ........ 559
27.10.1 Safety Analysis ........ 559
27.10.2 Fire ........ 559
27.11 Cost Analysis ........ 561
27.11.1 Overall Economic Aspects ........ 561
References ........ 562

## 27.1 Basics

### 27.1.1 Basic Explanation

GIL is a transmission system that can be used as an alternative to conventional cables when overhead lines are not a practical solution. It can be used for complete transmission circuits instead of overhead lines, but in this book we are mainly interested in its use as directly applicable to the substation environment.

The first generation of GIL used pure $SF_6$ for insulation, but for long-distance GIL applications, $N_2/SF_6$ gas mixtures are generally used.

GIL has an essentially coaxial structure in which the conductor at high voltage is supported centrally within an earthed, conducting enclosure by solid support insulators. The space between the conductor and enclosure is filled with an electrically insulating gas under a pressure of a 0.7–1.0 MPa. For a 400 kV transmission line, the diameter of one GIL pipe is approximately 500 mm, whereby three pipes are needed for a three-phase electric system. For two systems, the tunnel dimension is approximately 3.5 m diameter if it is circular or 2.5 m height and 2.8 m width. GIL components have been optimized for laying over long distances. Conductor and enclosure lengths together with support insulators are transported to site where they are assembled in situ. The enclosure lengths are usually joined by an automated welding process. The conductor usually consists of an aluminum tube, to achieve a high electrical conductivity. The enclosure, which retains the internal gas pressure, is usually made from an aluminum alloy. The insulating gas contains sulfur hexafluoride ($SF_6$), an inert, nontoxic, non-flammable gas. The dielectric strength of $SF_6$ is approximately three times that of air at a given pressure and is widely used in high-voltage equipment where its insulating properties allow a compact structure to be obtained. In GIL, the $SF_6$ is generally used in a mixture with nitrogen. The addition of 20% by volume of $SF_6$ to nitrogen results in an insulating gas mixture, which, with an increase in pressure of 45%, is comparable to that of pure $SF_6$.

The conductor current induces a reverse current of the same current level to the enclosure, so that the electromagnetic field outside the GIL is negligible. Therefore, no special shielding is required even in areas which are critical with respect to EMC, e.g., airports, hospitals and computer centers. If an insulation failure was to occur inside a GIL, the fault arc remains inside the enclosure and does not influence any outside equipment or person. The GIL is fire resistant and does not contribute to fire load. This means the best protection for persons and the environment. This fact is of particular importance where the connection between overhead line and high-voltage switchgear goes through tunnels and shafts. This has been tested in design tests and in long duration testing simulating the lifetime of the GIL in cooperation with French and German utilities. The results have been published in CIGRE Brochure 218 in 2003 (Cigré Technical Brochure 2003) and are the basis of the IEC standard on GIL IEC 62271-204 (International Standard IEC 2011). A detailed technical overview is given in the GIL Book published by IEEE with Wiley as publisher (Koch 2012).

### 27.1.2 Properties of the Insulating Gas

The insulating gas usually used in GIL is a mixture of $N_2/SF_6$ (80%/20%).

The insulating gas mixture will be filled to a specified filling pressure and then operated in a bandwidth of operation pressures. The minimum and maximum operation pressure depends on the gas temperature and will be fixed specific to each installation. Nitrogen $(N)_2$ is a wholly inert, very steady, and a nontoxic gas. $SF_6$ is used in power apparatus as an insulating and arc quenching medium because of its excellent insulating and arc extinguishing properties. Due to its global warming potential, $SF_6$ substitutes such as $N_2/SF_6$ mixtures are preferred in applications where large gas quantities are used and where dielectric performance is of most interest.

Today, other gases are being developed and evaluated as alternatives to $SF_6$ for insulation purposes with the similar electrical properties (CIGRE Working Group 2000; Christophorou and Van Brunt 1995; Diarra et al. 1997; Ward 1999; Koch 2012). This is an exciting area of research and development. From the enclosure perspective, modifications may be required with regard to operating pressures and gas handling, but in principle the existing design of enclosure is unlikely to change significantly.

### 27.1.3 Definition

The basic structure of GIL is similar to that of well-established gas insulated switchgear (GIS), in which the conductor at high voltage is located within an earthed conducting enclosure and the space between the two filled with a gas under pressure to provide electrical insulation. The conductors are held in position by solid support insulators. The conductors of each phase may be located within separate enclosures (single phase enclosed). Compensation for thermal expansion is provided, often by sliding contacts in the conductor and, where the enclosure is free to move (i.e., in tunnel or trough installations), by bellows as for long GIS bus bars. The GIL is divided along its length into separate gas compartments. GIL dimensions are determined by dielectric, thermal, and mechanical considerations. Conductor and enclosure diameters and thicknesses and gas composition and pressure may be varied according to the application to provide an optimum solution. In many cases, dielectric considerations will be predominant in determining dimensions, and the required current rating will be achieved without difficulty. For more highly rated circuits, thermal considerations may be predominant, and larger dimensions will be chosen to maintain temperatures within acceptable limits.

- Technical:
  - The overall losses are relatively low, because of large conductor cross sections.
  - No significant dielectric losses.
  - Ratings of 2000 MVA with a single circuit and directly buried without cooling.
  - Low capacitance per unit length.
  - Reactive compensation not needed even for longer lengths.
  - Above ground, trough/tunnel, or directly buried installation is possible
  - A GIL is immune to weather conditions: snow, ice, wind, and pollution.
- Environmental:
  - No visual impact
  - Low external power frequency electromagnetic fields
  - No audible noise
  - No risk of fire
  - $SF_6$ gas handling and management
- Economic:
  - Cost of a GIL is greater than an equivalent overhead line.
  - The comparative cost with cable depends on circuit ratings and installation techniques.

All voltages for HV equipment are given as IEC Um, i.e., the highest voltage for equipment. For GIS and GIL, the rated voltage Ur is equal to the highest voltage for equipment, i.e., Ur=Um, according to IEC 60038 of TC 8 (IEC standard 2009).

Moreover, in this section the term ampacity is often used. Its genesis comes from the two words ampere and capacity. It means the current carrying capacity or rated normal current (Hillers and Koch 1998a; Alter et al. 2002).

### 27.1.4 Description

Gas insulated line (GIL) is the IEC acronym. Historical acronyms are GITL for gas insulated transmission line and CGIC for compressed gas insulated cables.

GILs are the direct development of a $SF_6$ insulated substation (or gas insulated substation with acronym GIS), but differently from GIS, GIL does not have switching or breaking functions.

In the past, GILs were called compressed gas insulated cables with acronym CGIC. They were considered as "special cables" belonging to the family of insulated cables. GIL is an electric transmission line, namely, it serves to transmit electric active power (and on the time domain, electric energy) over a given distance.

Even if GIL could be used as a distribution line in LV and MV levels, its economic burden confines and justifies its use only at HV levels as a transmission line.

It is well known that the isolated phase bus ducts have a structure similar to GILs but are often used at MV levels for connecting generators to step-up transformers in power plants. These MV isolated phase bus ducts are insulated with air under atmospheric pressure and are manufactured, as abovementioned, with the same general GIL structure but with larger diameters (since the air has a dielectric strength which is one third of the most used gas, i.e., sulfur hexafluoride or $SF_6$ under a given pressure) and spacing.

There are two different kinds of GIL: single-phase (see Fig. 27.1) and the three-phase design (see Fig. 27.2). The GIL configuration with three conductors in one enclosure does not avoid phase-to-phase faults and significant forces between conductors and, so far, has not been used in a practical application.

The GIL construction is composed of three tubular enclosures (made of high-conductivity aluminum or aluminum-alloy) where each tubular phase conductor (aluminum) is held in a centered position by epoxy resin insulators (see Fig. 27.3).

The GIS and GIL manufacturers have made continuous improvements over the last 30 years to make the GIL virtually leak-free. The need for leak-tight GIL systems is also driven by environmental concerns. Current standards (both IEEE and IEC)

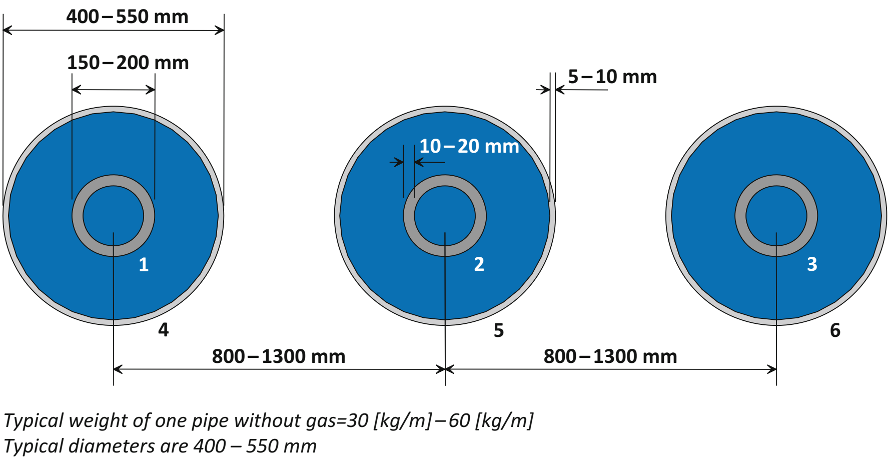


**Fig. 27.1** Indicative dimensions for a flat single-phase enclosed GIL (420–550 kV rated voltage). Typical weight of one pipe without gas = 30 [kg/m]÷ 60 [kg/m]. Typical diameters are 400–550 mm

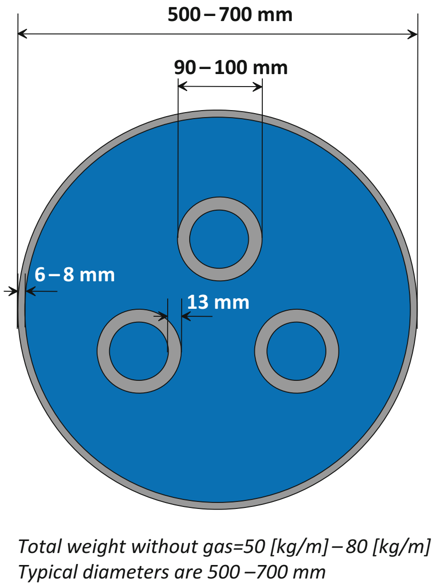


**Fig. 27.2** Three-phase enclosed GIL used in GIS at lower high voltage ranges up to 170 kV. Total weight without gas = 50 [kg/m]÷ 80 [kg/m]. Typical diameters are 500–700 mm

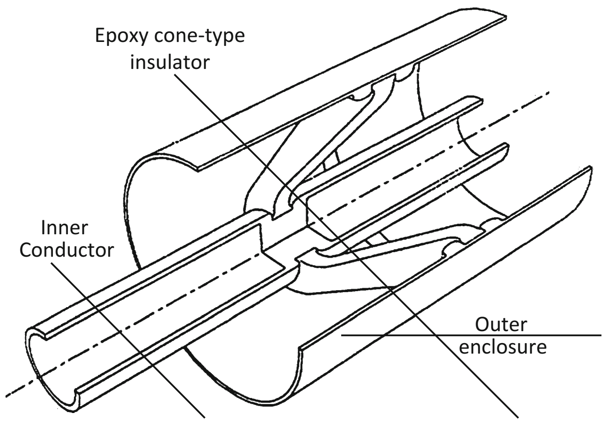


**Fig. 27.3** Design of a single-phase GIL

require GIL systems to lose no more than 0.5% of their volume per year. Designs for both welded and flange bolted GIL have improved to the point where meeting and exceeding the required tightness standards is of no concern. In the case of welded GIL, the gas tightness is even higher, e.g., the first welded GIL installation from 1976 is still in service with the first gas fill, exhibiting effective gas tightness without any losses (Baer et al. 1976; Bär et al. 2002).

The space between phase conductor and enclosure is filled with an insulating gas which must withstand the phase-to-earth voltage. This insulating gas can be pure $SF_6$ under pressures of about 0.3–0.5 [MPa] or a $SF_6/N_2$ mixture (typical ratio of 10–20% $SF_6$ to 90–80% nitrogen) under higher pressures (up to 1.0 MPa): this mixture is more environmentally friendly and less expensive.

In any case, the insulating gas contains sulfur hexafluoride ($SF_6$), an inert, nontoxic, non-flammable gas. More details on environmental impact of $SF_6$ are available in CIGRE Brochure 351 (clause 5.2). In some countries, the handling of $SF_6$ is regulated in IEC 62271-4 “Handling procedures for $SF_6$” (IEC 62271-4 2013). The contribution to global warming of $SF_6$ is small, and the use of $SF_6$ is regulated in several regional directives, e.g., EC 2003/87 European Directive.

The first generation of GIL was built from standard GIS components using pure $SF_6$ as insulating gas and straight enclosures. In the year 2000, a second generation of GIL was introduced for managing longer distances and for reducing the environmental impact of the equipment. It is made of gas mixture (like $SF_6/N_2$) and bending radius of enclosures was introduced (typically 400 m) (Alter et al. 2002).

The optimal ratio to minimize the electric field between enclosure inner diameter and conductor outer diameter should be 2.72. In practical applications, any ratio between 2.5 and 3 can be adopted since in this range the electric field increases only by 0.5%.

By observing one enclosure of a GIL, it resembles a gas transportation pipeline so that, sometimes, GILs are mentioned as electric pipelines. The state of the art indicates that, up to now, all the actual installations of GIL are short runs to provide overhead line substitutions, getaways from hydroelectric, thermal, and nuclear power plants: this seems to be an intrinsic contradiction with the technical features of this electric transmission line that is suitable for long lengths and bulk power transmission as it has been shown in CIGRE TB 351 (Cigré Technical Brochure 2008) (Figs. 27.4 and 27.5).

The most widely used application of GIL application is above ground inside substations to connect overhead lines or transformers with GIS. Typical supports are steel structures to hold the GIL above ground. When applied for long-distance transmission, the connection to the overhead line is the first case of application when the bushing for the link to the overhead line is connected to the GIL (Aucourt et al. 1995; Koch 2000; Tanizawa et al. 1984).

The historical development of GILs is reported in Table. 27.1.

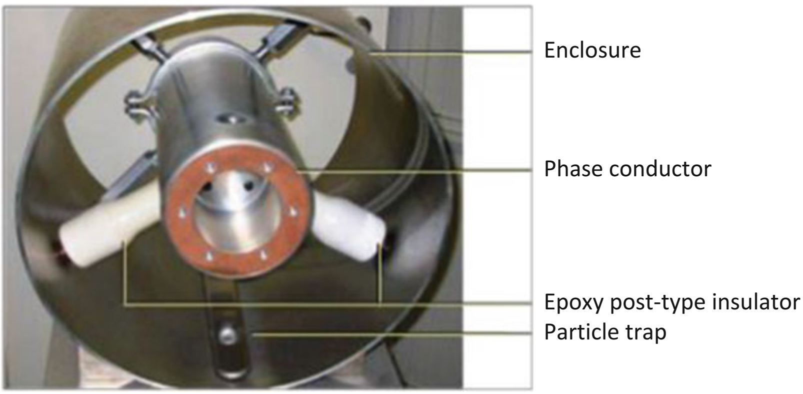


**Fig. 27.4** Photo of the internal structure of a single-phase GIL

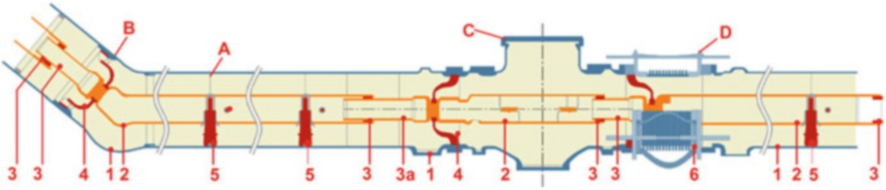


**Fig. 27.5** General overview of all the single-phase GIL units (courtesy Siemens). (*A*) straight unit, (*B*) angle unit, (*C*) disconnecting unit, (*D*) compensation unit. (*1*) enclosure, (*2*) conductor, (*3*) sliding contact, (*4*) nongas tight insulator for conductor fix point, (*5*) sliding post-type insulator, (*6*) longitudinal thermal expansion compensator

**Table 27.1** Historical development of GIL

| | |
|---|---|
| **1971** | First HV installation of a GIL insulated with pure $SF_6$ (first-generation GIL): Eastlake, Ohio, at rated voltage of 345 kV (circuit length 122 m) |
| **1972** | First HV directly buried installation of a GIL insulated with pure $SF_6$ (first-generation GIL) at Hudson Switching Station in New Jersey at rated voltage of 245 kV, 1600 A (circuit length 138 m) |
| **1975** | First HV installation of 550 kV GIL insulated with pure $SF_6$: Ellensburg, Washington, at rated voltage of 550 kV, 3000 A (circuit length 192 m) |
| **1976** | First HV European installation of a GIL insulated with pure $SF_6$ (first-generation GIL) at hydro pump storage plant in Schluchsee, Germany, with rated voltage of 400 kV (circuit length 670 m) |
| **1981** | First HV installation of 800 kV GIL insulated with pure $SF_6$: Guri Dam, Venezuela, at rated voltage of 800 kV, 1200 A, 1925 kV BIL (total phase length 855 m, 5 circuits) |
| **1997** | Longest (phase length) installation of a GIL insulated with pure $SF_6$ (first-generation GIL) at PP9, Saudi Arabia, with rated voltage of 380 kV (circuit length 709 m in 8 circuits for a total phase length of 17,010 m) |
| **1998** | Longest (circuit length) installation (3,3 km) of a GIL insulated with pure $SF_6$ (first-generation GIL) at Shinmeika-Tokai, Japan, with rated voltage of 275 kV (circuit length 3300 m double circuit) |
| **2001** | First HV installation of a GIL insulated with a gas mixture of $SF_6/N_2$ (second-generation GIL) at Geneva, Switzerland, with rated voltage of 220 kV (circuit length 420 m) |
| **2004** | First HV installation of a GIL insulated with a gas mixture of $SF_6/N_2$ (second-generation GIL) in the UK at Hams Hall with rated voltage of 400 kV (circuit length 540 m) |
| **2009** | First HV installation of 800 kV and 4000 A GIL (at higher BIL rating) insulated with pure $SF_6$: Laxiwa Dam, China, at the BIL of 2100 kV (total phase length 2928 m, 2 circuits) |
| **2012** | First directly buried HV GIL of second generation at Kelsterbach substation near Frankfurt, Germany, with rated voltage of 400 kV (circuit length 880 m) |
| **2013** | First installation with 400 m bending radius of 420 kV GIL with $80N_2/20SF_6$ gas mixture to underpass a Bavarian Brewery in Munich, Germany, with 4 three-phase circuits in one tunnel each circuit 3150 A rated current. Circuit length is 1 km and all joints are welded |
| **2014** | Highest vertical GIL in Xiluodu, China, welded design with $SF_6$, 550 kV, 5000 A (7 three-phase systems in 500 m vertical shaft, total length 3,5 km) |
| **2018** | First High voltage installation 1000 kV and 4500 A GIL insulated with pure $SF_6$ in a tunnel at the Yangtze River Crossing in China (2 circuits of total 14 km), under construction |

## 27.2 Ratings

### 27.2.1 GIL Electrical Parameters

For single-phase type GIL with the enclosures solidly bonded at both ends, each phase has series inductance and capacitance to earth. Coupling between phases is negligible due to the screening effect of the enclosures.

The resistance (R) per unit length depends on the conductor and enclosure dimensions and electrical resistivity, the skin and proximity effects, and the conductor and enclosure temperatures. A method for calculating the resistance is given in Cigré Technical Brochure 2008. The shunt conductance (G) per unit length is not significant. Typical values for the electrical characteristics of a 400 kV GIL with a continuous thermal rating of 2000 MVA are shown in Table 27.2. Typical values for cables and overhead lines (OHL) having comparable ratings are shown for comparison. A frequency of 50 Hz has been assumed.

In preparing the above table, values have been sought for GIL, cables, and overhead lines having a continuous thermal rating of approximately 2000 MVA. Other geometries having equivalent continuous thermal ratings but different electrical characteristics are possible; hence the table is intended for indication only.

The overhead line characteristics correspond to a 420 kV line with 3 $\times$ 570 $mm^2$ conductors per phase and two earth wires.

The values given for GIL correspond to a directly buried, single-phase GIL with conductor diameter of 280 mm and enclosure inner diameter of 630 mm. The enclosures are assumed to be solidly grounded. The depth of burial is 1050 mm and axial spacing between phases 1300 mm. The soil conditions are an ambient temperature of 15 °C and a thermal resistivity of 1.2 $K.m{\cdot}W^{-1}$. The continuous thermal rating is determined by the maximum soil temperature, which is limited to 60 °C.

**Table 27.2** Technical data of 2000 MVA power transmission for GIL, OHL, and XLPE cable

| | GIL | OHL | XLPE cable (2 per phase) |
|---|---|---|---|
| Current rating (A) | 3000 | 3000 | 3000 |
| Transmissible power (MVA) | 2078 | 2000 | 2000 |
| Resistive losses at 3000 A ($Wm^{-1}$) | 180 | 540 | 166 |
| Dielectric losses ($Wm^{-1}$) | — | 2.4 | 15.0 |
| Total losses ($Wm^{-1}$) | 180 | 542.4 | 181 |
| AC resistance ($\mu\Omega m^{-1}$) | 6.7 | 20 | 6.0 |
| Inductance ($nHm^{-1}$) | 162 | 892 | 189 |
| Capacitance ($pFm^{-1}$) | 68.6 | 13 | 426 |
| Characteristic impedance ($\Omega$) | 48.6 | 263 | 21.0 |
| Natural load (MW) | 3292 | 608 | 7619 |
| Surge impedance ($\Omega$) | 48.6 | 263 | 12.0 |

### 27.2.2 Directly Buried GIL

Much published work exists on the calculation of current ratings of (a) $SF_6$ gas insulated bus bar for in-air applications above ground and (b) conventional cables for buried (laid direct) applications. However, prospective laid direct applications of GIL may differ in the following respects:

- The GIL conductor is of larger diameter and is of annular geometry.
- Heat transfer through the primary insulation is by convection and radiation.
- The insulation may comprise a mixture of gasses, such as $N_2$ and $SF_6$.
- The gas is contained within a metallic enclosure of large diameter and low electrical resistance.
- The high electrical conductivity of the metallic enclosure permits it to be earthed at its ends by the method of solid bonding, and, although the circulating currents are of almost the same magnitude as those in the primary conductors, the heat generation is small.
- The diameter of the metallic enclosure and the horizontal spacing between the adjacent phases is large compared to the depth of burial, thereby influencing the method of calculation of heat dissipation through the surrounding ground.
- The conductor and metallic enclosure have larger cross-sectional areas and higher thermal capacities; these being of benefit to short-time overload ratings.

The methods of calculation for both the continuous and short-time current ratings are described in Annex A of Brochure 218 (Cigré Technical Brochure 2003), which demonstrates the recommended calculation methods and sensitivity studies for direct burial of horizontal, single-phase GIL sections. The GIL is insulated with either pure $SF_6$ gas or a mixture of $N_2$ and $SF_6$. A summary of the principles is given below. For more details, see Cigré Technical Brochure 2003.

### 27.2.3 Thermal Layout

An idealized thermal model of the laid direct GIL circuit is shown in Fig. 27.6. This model represents both continuous and short-time current ratings, although the thermal circuits for the continuous and short-time ratings are different (Chakir-Koch 2001c).

Heat, Wc, is generated in the conductor by $I^2R$ conduction losses, where R is the temperature-dependent ac resistance of the conductor. The heat is transferred through the insulating gas to the metallic enclosure by the parallel mechanisms of thermal radiation, Tr, and convection, Tc; these are highly dependent on the temperatures of the conductor, c, and enclosure, e. Additional $I^2R$ heat, We, is generated in the enclosure by circulating currents; these flow as a consequence of the magnetic flux linkages with the conductor current, which link to the electrical circuit formed by the three solidly bonded enclosures. The pressure-containing enclosures are of large cross-sectional area and are usually fabricated from an aluminum alloy; hence their electrical resistance is low, permitting the magnitude of the circulating current

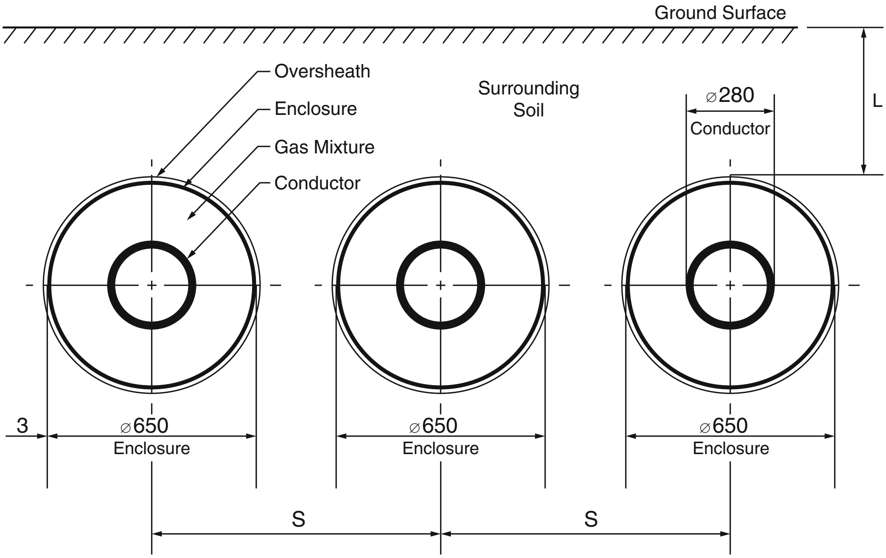


**Fig. 27.6** Cross section of GIL buried directly in the ground

to approach that of the current in the primary conductors. As with the primary conductors, the ac resistance is temperature dependent (Henningsen et al. 2000; Chakir and Koch 2001a).

### 27.2.4 Short-Time Rating

The same representative GIL dimensions were taken for the short-time rating. A higher conductor short-time rating temperature limit of 95 °C was taken, compared to the 3000 A continuous rating conductor temperature of 71 °C. Two examples were calculated, in the first example, a zero starting current was taken. In a 12 h period, it was possible to carry a current of 9840 A (328% of 3000 A full load); this demonstrates the high thermal capacity of GIL. In the second example, the starting current was taken as a steady-state load current of 2550 A (85% of 3000 A full load). In a 12 h period, it was possible to carry a current of 7290 A (243% of 3000 A full load). This illustrates that this particular design of GIL circuit could have taken the additional full load current from a parallel faulted circuit for a useful period of 12 h (i.e., 185% of full load), without reaching 95 °C. The sensitivity study is recorded in detail in Annex A of Brochure 218 (Cigré Technical Brochure 2003) and is summarized as follows:

- The parameter that had the most effect on a 12 h rating period was $K_0$, the gas convection coefficient.
- The second most significant parameter was the soil thermal resistivity.

- The parameter that had the most effect on a 20 min rating period was the specific heat of the conductor, and the second was $K_0$, the gas convection coefficient. This shows that the heating in this short period is nearly adiabatic.

It is recommended that, because the calculated short-time current ratings for GIL are of such high magnitude:

- A factor of safety be included in either the maximum conductor temperature or in the current rating to avoid the risk of overheating the conductor connectors and insulators
- The short-time rating for a particular design of GIL be validated by experimental measurement

### 27.2.5 Insulation Coordination

The insulation coordination is a key issue for the reliability of components, and here only the main aspects are summarized.

- Firstly, a utility must consider the GIL major failure rate (MFR) and its impact on its own grid; in this respect, it is important to derive from Return of EXperience (REX) for equipment of the same type (when possible) or similar type equipment what the achievable MFR is with the present technology and insulation level practice.
- Secondly, the insulation coordination deals not only with the overvoltage aspects but should include also:
  - The insulation characteristics of the GIL insulation
  - The relations that link the dielectric type tests, routine tests, and on-site tests with respect to the overvoltages in service and the self or not self-restoring aspect of the GIL insulation
  - The long-term withstand at service voltage taking into account the random occurrence of insulation imperfections

In addition, online monitoring and diagnostic techniques should also be reviewed together with the enclosure grounding and bonding for permanent and transient voltages (IEC standard 60071-1 1993–12; IEC standard 60071-2 1996–12; Völcker and Koch 2000; Hauschild and Mosch).

**Accepted (Targeted) Major Failure Rate (MFR) and Present REX**
It is always difficult to choose an accepted MFR and the expected availability required from new capacity; indeed very rarely do utilities display clearly the accepted MFR. For GIL, as for insulated cables, according to two utilities that publicly announce their target MFR for GIL, an acceptable MFR for GIL should be no greater than 0.2–0.3 MFailures/100 km of three-phase circuit per year

(0.2–0.3 $\times$ $10^{-5}$ MF/year/meter of circuit per year). This results in a mean time between failures (MTBF) of:

- 5 years for a three-phase GIL circuit of 100 km
- 500 years for a three-phase GIL circuit of 1 km

This reliability aspect needs to be considered in the insulation coordination assessment. The REX on a large GIL population sample together with a GIL MFR derived from a larger population of GIS (similar technology) found that the MFR to be expected from GIL with present technology and insulation practice for GIS and GIL is one order of magnitude larger than the values publicly expressed in Cigré by two utilities. Such a gap between targeted MFR and that which can be expected should be kept in mind when selecting the standard withstand voltage to be applied for the GIL (Cigré Technical Brochure 2003).

**Insulation Withstand and Overvoltage Stresses**
Controlling and thus reducing the transient overvoltages to levels close to the surge arrester protective levels leads to consider that the insulation is distributed all along the GIL. The withstand voltage of many similar insulations in parallel and stressed by the same voltage amplitude is lower than the withstand of only one insulation (Cigré Technical Brochure 2003). Besides when flattening the voltage profile along the GIL, the sensitivity of the GIL is higher in case of the occurrence of defects. So, choosing too low a lightning and switching impulse withstand level and power frequency withstand level for GIL increases the risk of major insulation failure at permanent voltage when random imperfections occur during the GIL lifetime (Cigré Technical Brochure 2003). Nevertheless, based on recent GIL projects, there is no reduction of lightning insulation withstand voltage requested by utilities compared to present LIWL of GIS. By not reducing the LIWV, this leads to an increase of the power frequency withstand (PFW) voltage for $N_2/SF_6$ gas mixtures in GIL and consequently an improvement of their long-term reliability: a positive element to reduce the gap between targeted MFR compared to the expected one.

## 27.2.6 Standard Values

### 27.2.6.1 Voltage Levels and Currents

The values given are related to 80% $N_2$ and 20% $SF_6$ gas mixtures at 0.8 Mpa pressure. The rated current is based on temperature of the ambient air without wind (40 °C according to IEC 62271-1) (2007), the maximum allowed design temperature of the conductor (maximal 105 °C according to IEC 62271-1) (2007), and the touch temperature of the enclosure (70 °C for accessible GIL and 85 °C for non-accessible GIL according to IEC 62271-1) (2007). For long tunnels and bridges, the ambient condition (temperature of air or surrounding soil or rock, wind, sun radiation, tunnel ventilation) influences the rated current. Details for rated currents, power losses,

**Table 27.3** Electrical characteristics by voltage level

| Voltage levels | | 110 kV | 220 kV | 345 kV | 380 kV | 500 kV | 800 kV |
|---|---|---|---|---|---|---|---|
| **Highest voltage for equipment $U_m$** | kV | 123/ 145/ 170 | 245/ 300 | 362 | 420 | 550 | 800 |
| **One-minute power frequency withstand voltage** | kV | 230/ 275/ 325 | 460/ 460 | 520 | 650 | 710 | 960 |
| **Lightning impulse withstand voltage** | kV | 550/ 650/ 750 | 1050/ 1050 | 1175 | 1425 | 1550 | 2100 |
| **Switching surge insulation level** | kV | NA | NA/ 850 | 950 | 1050 | 1175 | 1425 |
| **Rated current** | A | 2500 | 3000 | 3500 | 4000 | 4500 | 5000 |
| **Short circuit current** | kA | 63 | 80 | 80 | 80 | 80 | 80 |
| **Open air power Loss per single phase Meter at rated current** | W/ m | 117 | 150 | 170 | 170 | 232 | 262 |
| **Capacitance per single-phase kilometer** | nF/ km | 60 | 53 | 53 | 54 | 54 | 45 |
| **Surge impedance** | Ω | 56 | 63 | 63 | 63 | 62 | 74 |
| **Inductance per single-phase kilometer** | mH/ km | 0.187 | 0.211 | 0.210 | 0.215 | 0.205 | 0.247 |

Note: For 380 kV and 500 kV GIL, 80% $N_2$ and 20% $SF_6$ have been used; all other voltage levels currently use pure $SF_6$

current in enclosures, and voltage drop are explained in Annex A of Brochure 218 (Cigré Technical Brochure 2003) (Table 27.3).

#### 27.2.6.2 Mechanical Characteristics

Mechanical characteristics have been discussed in CIGRE Brochure 218 (Cigré Technical Brochure 2003) and IEC standard 62271-204 (International Standard IEC 2011). For the application in long structures like bridges or tunnels, special care needs to be taken concerning the impact of vibrations and resonances to the GIL. Calculations are recommended for the specific layout of the design of structures and the possible use of damping elements.

Fatigue analysis for sensitive components like insulators and compensation bellows is recommended to meet the requirements coming from long structures and the related vibrations from traffic, wind, or other structure-related impact. Nevertheless, the GIL is a pressure vessel operating at low pressure, typical up to 7 bar over pressure. The GIL is designed according to the related EN pressure vessel standards (EN 50064 1989) taking into account that only non-corrosive, dry

**Table 27.4** Dimensional characteristics by voltage level

| Voltage level | | 110 kV | 220 kV | 362 kV | 380 kV | 500 kV | 800 kV |
|---|---|---|---|---|---|---|---|
| **Highest voltage for equipment $U_m$** | kV | 123/ 145/ 170 | 245/ 300 | 362 | 420 | 550 | 800 |
| **Enclosure inside diameter** | mm | 226 | 292 | 362 | 500 | 495 | 610 |
| **Conductor outside diameter** | mm | 89 | 102 | 127 | 180 | 178 | 178 |

For 220 kV, 380 kV, and 500 kV GIL, 60% $N_2$ and 20% $SF_6$ have been used; all other voltage levels currently use pure $SF_s$. The diameters are typical values

**Table 27.5** Ampacity of GIL directly buried for 2000 MVA and 3000 MVA with maximum 60 °C soil temperature

| Diameter of enclosure pipe [mm] | Cross-sectional area of the enclosure/ conductor pipe | *Ampacity* Directly buried in the ground at a depth 1.5 m in a soil with $\rho_{th} = 1.0$ K·m/W and $\vartheta_g = 20$ °C | Comments |
|---|---|---|---|
| | [mm$^2$] | [A] | |
| | | Flat with spacing equal to 0.8 m At 0,8 MPa | |
| 500 | 12,000/4300 | 3150 A | 420 kV tested at IPH Berlin and used in the Kelsterbach project |
| 650 | 16,000/5400 | 4000 A | 420 kV EDF France and buried as prototype at IPH Berlin |

insulating gases are used inside the aluminum pipe. Based on these design criteria, no specific requirements for the tunnels and bridges are needed (Table 27.4).

## 27.2.7 Capacity of GIL

The high ampacity of GIL is given by the high cross sections of GIL conductor and enclosure pipes. The current rating needs to be calculated taking into account the conductor and enclosure materials, the laying conditions in a tunnel, shaft, directly buried or any other laying method. This calculation is required for each project if conditions are not comparable (Chakir and Koch 2001b) (Tables 27.5 and 27.6).

Differently from insulated cables, there is not an international standard in order to compute the ampacity of GIL. In IEC 62271-204 (International Standard IEC 2011), there are only the allowable temperatures depending upon the installation type (directly buried or tunnel).

**Table 27.6** Ampacity of GIL tunnel laid for 2000 MVA and 3000 MVA with maximum 80 °C enclosure temperature if not touchable

| Diameter of enclosure pipe [mm] | Cross-sectional area of the enclosure/conductor pipe | *Ampacity*<br>Tunnel laid $\vartheta_g = 20$ °C<br>At 0,8 MPa for gas mixtures and 6,5 MPa for $SF_6$ | Comments |
|---|---|---|---|
| | [$mm^2$] | [A] | |
| 500 | 12,000/4300 | 3150 A | 420 kV GIL at Munich |
| 500 | 16,000/5400 | 4000 A | 420 kV Nathpa Jhakri, India |
| 650 | 12,300/6600 | 4000 A | 800 kV China |

IEC 62271-204 (International Standard IEC 2011) states:

> The temperature of the enclosure shall not exceed the maximum allowable temperature of the anti-corrosion coating if applicable. For direct buried installation, the maximum temperature of the enclosure shall be limited to minimise soil drying. A temperature in the 50–60 °C range is generally considered applicable.
>
> For open air, tunnel and shaft installations, the maximum temperature of the enclosure shall not exceed 80 °C. Parts normally touched during operation not to exceed 70 °C.

There are two ELECTRA papers and other documents which give details on this computation:

- CIGRE Working Group 21.12 "Calculation of the continuous rating of single core, rigid type, compressed gas insulated cables in still air with no solar radiation" (CIGRE WG 21.12 1985)
- CIGRE Working Group 21.12 "Calculation of the continuous rating of three-core, rigid type, compressed gas insulated cables in still air and buried" (Cigre WG 21.12 1989)
- The TB 218 on GIL (Cigré Technical Brochure 2003)
- ANNEX A of IEC 62271-204 (International Standard IEC 2011)

By following the method presented in these papers, it is possible to compute the following ampacities for a directly buried GIL. The physical conditions of soil must be the same used in the following for insulated cables and also the burial depth. The spacing is different since the GIL enclosure diameter is larger than the external cable diameter. The soil thermal resistivity is equal to $\rho_{th} = 1.0$ K·m/W, and the soil temperature is $\vartheta_g = 20$ °C. These are the standard conditions in Italy after IEC 60287-3-1 (1995). The constraint for the ampacity computation is that the soil in contact with the anticorrosion coating does not exceed 60 ° C (see International Standard IEC 2011).

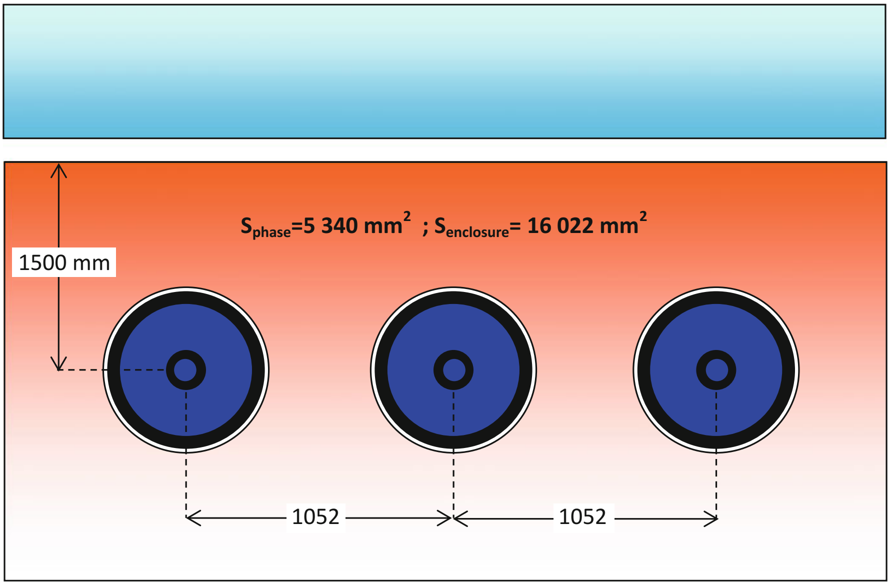


**Fig. 27.7** HV directly buried GIL equipped with an external protective PE coating

In the conditions shown in Fig. 27.7 and reported in Table 27.7, the ampacity results equal to 2390 A. It can be easily ascertained that (leaving unchanged the properties of soil – thermal resistivity and temperature) the ampacity increases if:

- Phase and enclosure diameter increase: for an order of magnitude if $S_{phase}$ = 13,270 mm$^2$ and $S_{enclosure}$ = 20,106 mm$^2$, the ampacity becomes 3524 A.
- Spacing increases, e.g., with a spacing equal to 2000 mm, the ampacity becomes 2737 A.

Both the possibilities yield higher capital costs.

## 27.3 Installation Options

The installation of GIL can be of three different kinds: tunnel, outdoor surface mounted, and directly buried.

### 27.3.1 Directly Buried GIL

The objectives of this section are to describe mechanical, corrosion, and installation aspects of directly buried GIL. For the mechanical aspect, some simple methods for

**Table 27.7** Data assumed for ampacity computation

| | |
|---|---|
| GIL #1 directly buried | |
| Frequency [Hz] | 50 |
| Phase conductor resistivity [Ω ·m] | $2.826 \cdot 10^{-8}$ |
| Enclosure resistivity [Ω·m] | $3.28 \cdot 10^{-8}$ |
| Thermal coefficient α [1/°C] | 0.0047 |
| Phase conductor temperature [°C] | 70 |
| Enclosure temperature [°C] | 60.6 |
| Anticorrosion coating [°C] | 60.0 |
| Phase inner diameter [mm] | 160 |
| Phase outer diameter [mm] | 180 |
| Enclosure inner diameter [mm] | 500 |
| Enclosure outer diameter [mm] | 520 |
| Outside diameter of GIL [mm] | 526 |
| Spacing [mm] | 1052 |
| Burial depth [mm] | 1500 |
| Gas pressure [bar] | 7 |
| Ratio of $SF_6$ | 0.2 |
| Phase outer surface thermal emissivity | 0.2 |
| Enclosure inner surface thermal emissivity | 0.2 |
| Coating thermal resistivity [K·m/W] | 3.5 |
| Soil thermal resistivity [K·m/W] | 1.0 |

the calculation and analysis of the stress on the enclosure are recommended, disregarding the mechanical aspects of the internal components. Effects of short circuit forces on the enclosure are excluded. The main aspects are the calculation of required enclosure thickness, the vertical and horizontal stability, and the interaction between the soil and the enclosure. For the corrosion aspects, two methods are described, the coating and the cathodic polarization. Overground and tunnel installations are not dealt with because they are similar to GIS bus ducts which were first installed more than 30 years ago (Koch 2012; Chakir and Koch 2002b).

#### 27.3.1.1 Mechanical Aspects

**Stresses**

One of the main issues for gas insulated transmission lines is the mechanical behavior in the soil during installation and operation. The GIL consists of three single-phase encapsulated tubes which are directly buried in the ground. Each tube consists of an outer aluminum alloy enclosure and an inner aluminum conductor. In operation, thermal expansion and gas pressure generate the main forces acting on the enclosure. Differential expansion between the inner and outer tubes is accommodated by the use of sliding contacts already widely used in GIS. In addition, the enclosure is anchored in the soil because of the friction which leads to high mechanical loads. The enclosure is also subjected to load bearing, soil pressure, and traffic loads. The GIL has to follow curvatures in vertical and horizontal directions (minimum bending radius approximately 400 m), according to the terrain. Stresses for abrupt changes (e.g., elbows) in direction are not dealt with in this study (Henningsen et al. 2000).

The mechanical design needs to take into account all the effects applied on the pipe listed below in general order of importance:

- Thermal expansion
- Friction between the soil and the enclosure due thermal effect
- Internal pressure
- Bending resulting from the vertical and horizontal curvatures
- Soil pressure
- Traffic loads
- Water pressure (if any)
- Seismic loads (if any)

#### 27.3.1.2 Corrosion Protection

Efficient corrosion protection is essential to ensure a design life of 40 years. Current experience with buried aluminum pipes is very limited; nevertheless the experience already gained with steel pipes can be adapted for the properties of aluminum. Corrosion is always linked with the presence of electrical current circulation due to a potential difference. This can be due to internal unbalanced chemical elements inside a metal which create an elementary battery cell or due to external influences such as a difference in pH between two points on a metallic surface or circulation of vagabond currents through the metal (Chakir and Koch 2002a).

Buried steel pipes have been used for the transport of water, gas, and oil for many years. Two main types of corrosion protection are employed, independently or together: cathodic protection and/or coatings. Cathodic protection consists of applying a negative potential to the metal surface. This is easy for steel because a negative polarity of only −0.8 V applied to the enclosure relative to the copper reference electrode, installed in the surrounding soil, is sufficient for protection. This potential does not electrolyze the water contained in the soil excessively. This negative polarity can be achieved using a zinc anode. As the current flowing is proportional to the enclosure surface in contact with the soil, the size and the number of zinc anodes distributed along the length may be quite large for long steel pipes. In order to reduce the zinc anode size, an insulating coating must be applied around the pipe.

Steel is relatively easy to protect using only cathodic polarization, but this is not the case for aluminum. For aluminum complete immunity from corrosion could only be assured by applying a potential of −2.0 V which would highly electrolyze the water. The electrolyzed water would become alkaline and would attack the aluminum. Cathodic polarization must therefore be limited to a value between −0.8 and −1.0 V to avoid electrolyzation of the water. These values can be achieved with zinc reactive anodes or by a static generator. This is not sufficient to assure an efficient protection against corrosion. To ensure that the polarization remains within the correct limits (−0.8 and −1.0 V), a monitoring system is required.

For aluminum enclosures, therefore the main method of corrosion protection is the use of a coating on the aluminum to prevent direct contact with the surrounding soil. This protection may be complemented by the use of the cathodic protection. The coating must withstand chemical attack and mechanical damage. This is generally achieved by using more than one layer of coating. The inner protective layer will normally be a thin layer of epoxy. This protects against attacks from acids, alkalis, and various salts. This layer needs to be protected mechanically, however. This mechanical protection will normally be polyethylene or polypropylene and will be quite thick. Because of the difficulty of bonding PE or PP to epoxy, an intermediate layer is sometimes used. Choice of PE or PP will depend on factors such as temperature. The coating must be flexible enough to cope with thermal expansion of the GIL without sheering the bonding between layers. The coating has an impact on the heat dissipation of the GIL because of its high thermal resistance (3.5 mK/W). For this reason, as well as cost, the thickness of coating needs to be limited. A thickness of between 3 and 6 mm appears to have only a moderate effect on heating.

Concrete is highly alkaline and attacks aluminum strongly. Where the GIL is to be blocked in concrete, it is necessary to thoroughly check the coating before pouring the concrete because it is difficult to repair the coating afterward.

The GIL enclosures will be delivered to site with the coating already applied. Because the GIL may be welded on-site, it must be possible to apply the coating over the welds on-site. Tests must be carried out to validate the coating, but no standard specific for aluminum coatings exists, but the tests for coating of steels may be employed.

As the earthing circuit is generally copper, care must be taken to avoid creating a natural cell between the copper and aluminum which could lead to ionization of the aluminum atoms. This may be achieved by separating the connection between the two metals with the use of a polarization cell. Due to corrosion risks it is advisable to avoid acid or alkaline soils or areas of industrial contamination. Also, to be avoided are roads which are subjected to salt treatment for snow clearing during long winters. It is also advised to avoid parallel paths with dc-supplied railways as these can generate stray currents. No protection is necessary for the inside of the GIL as the gas mixture is not aggressive for the aluminum.

#### 27.3.1.3 Installation of Direct Buried GIL

The GIL installation is quite similar to the installation of gas or oil pipes, except that the enclosures are aluminum and not steel, and an internal conductor is necessary for transmission of electricity. The main difference is relative to the cleanliness, which must be the top priority in order to avoid the input of particles inside the tubes as much as possible. Particles and particularly metal particles may be at the origin of dielectric flashover (Eteiba 1980). The second difference is relative to the presence of a central conductor supported by spacer insulators. All the GIL components must be handled and assembled with caution in order not to damage these insulators. The people in charge of the assembly must pay special attention to the manufacturer's instructions. Before starting any work, it is necessary to make a complete study of the soil that will be crossed. Some soils can present a danger for the GIL because of risk of corrosion and need at least deeper chemical analyses.

Compared to pipelines the GIL components must be handled with care because of the components inside and the coating on the outside (Henningsen et al. 2000; Chakir and Koch 2002b).

**GIL Assembly Operation**

The trench is prepared in accordance with the consistency of the soil. The extracted materials are stocked in order to be used for backfilling, as much as possible. The bottom of the trench is filled with sand on which the GIL will be laid down (Cousin and Koch 1996–05).

Junction chambers along the GIL are used to fix the GIL, to allow access for monitoring, earthing, and to allow high-voltage testing section by section. These vaults are prepared in appropriate positions in advance of the GIL assembly. After the GIL installation, the vaults are completed. Where anchorages are needed, the process is the same as for vaults.

After inspection, cleaning, etc., the GIL is positioned and the sliding contacts of the conductors are carefully fitted together. The two prepared enclosure extremities are then assembled and welded and tested in accordance with local health and safety regulations. After installation the welds must be protected from corrosion using a nonconducting coating material similar to that used for the rest of the enclosure. The coating then has to be tested for porosity using a "holiday detector." Any weak points found have to be repaired. The trench is then ready for backfilling. Where necessary for thermal reasons and/or integrity of the coating reasons because of rocky soil, the original soil directly against the GIL may be treated or simply replaced with sand. The soil is compacted around the GIL during backfilling to avoid movement later. The rest of the trench can be filled with the natural soil and progressively packed down. It may be necessary to check for damage of the coating after backfilling.

In order to minimize the electromagnetic field, the three GIL enclosures are linked together and earthed at each end and in each vault. Earthing connections are made to an earth mat through a polarization cell to avoid circulation of corrosion currents. Any cathodic polarization system will have to be installed before backfilling and the monitoring installed in the vaults. The $SF_6/N_2$ gas mixture assures the dielectric insulation withstand of the GIL and must be exempt from impurities and moisture. For this reason, gas handling is very important. The accurate mixing and separation of gas mixtures is now well handled by gas suppliers. Before being put into service, the GIL will have to be routine tested. Routine tests include weld inspection (which will have to be carried out before the corrosion protection is applied), pressure testing, leak testing, and dielectric tests. These tests may be carried out during the continuous installation process depending on GIL length and other practicalities.

The control system must also be installed. Each gas compartment must be monitored for gas density, with alarms and lockout thresholds. Other fault detection systems may also be installed. A communication link will have to be installed to connect all the transducers, etc. with a central control unit (Hillers and Koch 1998b; CIGRE WG 23.10/TF 03 1998).

#### 27.3.1.4 Route Planning

Route planning for GIL is very similar to those of oil and gas pipelines.

The main planning parameters are:

- Accessibility of the terrain (e.g., transport, machinery, assembly tent)
- Underground condition (e.g., rock, water, clay)
- Obstacles to be passed (e.g., river, highway, railroad)

Based on the requirements of GIL:

- Transport of 10–20 m long pipes
- Assembly of laying units close to site
- Bending radius of 400 m limit
- Space for preassembly of laying units

The routing needs to be optimized, which has a large impact on the cost.

### 27.3.2 GIL in Structures

#### 27.3.2.1 Examples

Examples of existing GILs are split between special structures, made for the GIL, and shared structures (GIL with rail or road) (Benato et al. 2007b).

GIL installations worldwide amount today to roughly 200 km of system length, and the longest line length is 3.3 km with two three-phase systems in a tunnel. Much longer runs are under study (Cigré Technical Brochure 2008).

Tables 27.8 and 27.9 show examples of characteristics of GIL installations in structures.

#### 27.3.2.2 Structure Requirements

The single-phase insulated GIL circuit needs three pipes, one per phase. Usually two circuits or systems are required; that means a total of six single pipes. Also a four-pipe system, with one pipe as a reserve, can be used. Each pipe has a diameter of appr. 500 mm. The total weight including everything (conductor, gas, etc.) of a single pipe for 400 kV and 3150 A is appr. 30 kg/m. The minimum elastic bending radius is 400 m. Smaller curvatures can be achieved by prefabricated elbow elements. The distance between fixing points on the tunnel wall is approximately 25 m.

The thermal expansion of a GIL pipe depends on the temperature differences during operation. With a temperature rise from 20 to 60 °C, the thermal expansion of a 400 m-long section is approximately 200 mm. The configuration of a three-pipe system and the minimum distance between each pipe depends only on the maintenance logistic and repair equipment. The corrosion protection of the Al pipes needs to be adapted to the requirements along the tunnel. Permanent water penetration in contact with minerals, e.g., chlorides, needs to be avoided. Safety measures are passive corrosion protection, e.g., painting, coating, water protection roofs, and/or

**Table 27.8** Examples of existing GIL (part 1)

| Examples of existing GIL (part 1) | | | | | | |
|---|---|---|---|---|---|---|
| **Owner** | Energie Ouest Suisse | | RWE net | | Chubu electric power company | |
| **Date of commissioning** | 2001 | | 1975 | | 1998 | |
| **Installation place** | Geneva, Switzerland | | Wehr, Germany | | Shinmeika-Tokai, Japan | |
| **Type of installation** | Tunnel | | Tunnel | | Tunnel | |
| **Length of link** | 420 m | | 670 m | | 3300 m | |
| **Number of systems** | 2 | | 2 | | 2 | |
| **Nominal voltage of network** | 220 [kV] rms | | 380 [kV] rms | | 275 [kV] rms | |
| **Highest voltage for equipment $U_M$** | 300 [kV] rms | | 420 [kV] rms | | 300 [kV]rms | |
| **Rated current per system** | 2000 [A] | | 2500 [A] | | 6300 [A] | |
| **Rated frequency** | 50 [Hz] | | 50 [Hz] | | 60 [Hz] | |
| **Insulating gas** | Pressure absolute | 0.7 [Mpa] | Pressure | 0.49 [Mpa] | Pressure | 0. 54 [Mpa] |
| | $N2/SF_6$ | 80/20 [%] | $SF_6$ | 100% | \|$SF_6$ | 100% |
| **Conductor** | | | | | | |
| **Outer diameter** | 180 [mm] | | 150 [mm] | | 170 [mm] | |
| **Wall thickness** | 5 [mm] | | 5 [mm] | | 20 [mm] | |
| **Material** | AI alloy | | E-AIMgSi0, 5 | | Al alloy | |
| | EN AW 6101B | | | | | |
| | E-AI/MgSi0, 5 T6 W19 | | | | | |
| **IACS[a]** | 61% | | 48–54% | | 59.5% | |
| **Conductivity at 20 °C m/Ω·lmm²** | 35.3857 | | 27,84 ÷ 31,32 | | 34,5185 | |
| **Resistivity at 20 °C Ω·mm²/m** | 0.02826 | | 0,032 ÷ 0,036 | | 0,02897 | |
| **Enclosure** | | | | | | |
| **Inner diameter** | 500 [mm] | | 520 [mm] | | 460 [mm] | |
| **Wall thickness** | 6 [mm] | | 5 [mm] | | 10 [mm] | |
| **Material** | Al alloy EN AW 5754 AL Mg3 W19 | | AlMg2Mn0,8 | | Al alloy | |
| **IACS[a]** | 52,565% | | 35% | | 51% | |
| **Conductivity at 20 °C m/Ω·mm²** | 30,4878 | | 20,3 | | 29,5858 | |
| **Resistivity at 20 °C Ω·mm²/m** | 0,03280 | | 0,050 | | 0,03380 | |
| **Connection method of enclosures** | Welded | | Welded | | Welded | |

[a]*IACS* International Annealed Copper Standard (IACS = 100% ⇒ Copper Standard Conductivity = 58,108 m/Ω·mm²

**Table 27.9** Examples of existing GIL (part 2)

| Examples of existing GIL (part 2) | | | |
|---|---|---|---|
| **Owner** | National Grid UK | Entergy | BC Hydro |
| **Date of commissioning** | 2004 | 2001 | 1981 |
| **Installation place** | Hams Hall, UK | Baxter Wilson Power Plant, USA | Revelstoke Hydro Power Plant Canada |
| **Type of installation** | Above ground/trench | Above ground | Tunnel |
| **Length of link** | 545 m | 1250 m | 400 m |
| **Number of systems** | 1 | 1 | 2 |
| **Nominal voltage of network** | 400 kV | 500 kV | 500 kV |
| **Highest voltage for equipment $U_M$** | 420 kV | 550 kV | 550 kV |
| **Rated current per system** | 4000 A | 4500 A | 4000 A |
| **Rated frequency** | 50 Hz | 60 Hz | 60 Hz |
| **Insulating gas** | Pressure: 1.03 MPa | Pressure: 0.373 [MPa] | Pressure: 0.345 [MPar] |
| | $N_2/SF_6$: 80/20% | $SF_6$: 100% | $SF_6$: 100% |
| **Conductor** | | | |
| **Outer diameter** | 512–520 [mm] | 178 [mm] | 178 [mm] |
| **Wall thickness** | – [mm] | 12.7 [mm] | 12.7 [mm] |
| **Material** | Al alloy | Al alloy 6061-T6 | Al alloy 6061-T6 |
| **IACS**[a] | – | 59.5% | 59.5% |
| **Conductivity at 20 °C m/Ω·mm$^2$** | – | 34,57 | 34,57 |
| **Resistivity at 20 °C/Ω·mm$^2$/m** | – | 0,0289 | 0,0289 |
| **ENCLOSURE** | | | |
| **Inner diameter** | 500 [mm] | 508 [mm] | 508 [mm] |
| **Wall thickness** | 6–10 [mm] | 6.35 [mm] | 6.35 [mm] |
| **Material** | Al alloy AlMg$^3$ | AlMg3 | Al alloy 6063 T6 |
| **IACS**[a] | – % | 35.0% | 53.0% |
| **Conductivity at20°C m/Ω·mm$^2$** | – | 20,3378 | 30,737 |
| **Resistivity at 20 °C Ω·mm$^2$/m** | – | 0,0492 | 0,0325 |
| **Connection method of enclosures** | Welded | Flanged | Welded |

[a] *IACS* International Annealed Copper Standard (IACS = 100% ⇒ Copper Standard Conductivity = 58,108 m/Ω·mm$^2$

active corrosion protection. Also, the chemical composition of the shotcrete for the primary tunnel lining should be specified to prevent corrosion effects. The sensitivity of the GIL to vibration is low. Vibrations from sources around the GIL installation may be damped by the support structure using dampers, if needed. If a GIL is laid on a bridge where permanent swing from traffic and wind forces applies, the vibration values need to be specified.

If the GIL is laid in a separate tunnel (pilot tunnel), then there is no vibrational influence from the traffic tunnel. Tunnels with GIL systems in seismic active regions have to reinforce the fixing points to avoid displacements of the pipes. In highly active zones, where displacements of the tunnel itself cannot be excluded, flexible tunnel cross and longitudinal sections may be installed. The electric and magnetic fields in the vicinity of the GIL are negligible. Due to the solid grounding of the enclosure, the electric field is practically zero, and due to the induced current in the enclosure, the magnetic field in the surround of the GIL is low. There are no acoustic noises coming from the GIL. The grounding of the GIL to limit touch voltage needs to be planned with the structure. In the case of a tunnel, the GIL grounding should be connected with the wire mesh. Special attention needs to be paid to the connecting points at the ends and when other infrastructure is getting close, e.g., railway, gas pipelines, and medium-voltage lines (Koch 2007–06).

Although GIL requires little maintenance, provision needs to be made for access when repair work becomes necessary following an internal failure. The repair time includes not only the direct repair work on a pipe but also the time for gas handling (taking out the gas, storage, and refilling) and the high-voltage tests.

In the case of tunnel structures, the transport access from the tunnel entrance to the working place inside the tunnel and return can significantly affect the total repair time. To reduce time for transport and also for safety reasons, transport can be done on rails.

Repair work requires access for gas handling equipment and gas storage containers. A replacement section of GIL will be installed and pressure and dielectric tests will be performed. The safety issues associated with performing the pressure test in the vicinity of shared services must be managed, and consideration must be given to how the high-voltage test equipment will be connected. In order to return the GIL to service within a short period, gas handling plant and spare components must be available.

Existing tunnel owners always have a strong reluctance to add a GIL due to concerns regarding space, responsibility, ownership, maintenance, safety, fire protection, cooling, and heat. Although GIL requires little maintenance, provision needs to be made for access in the event that a repair following an internal fault becomes necessary. The implications for any shared structure must be considered.

Safety distances around the GIL structure are not needed when the GIL is sufficiently earthed; therefore it is also possible to work in the GIL structure without restrictions. The GIL installed in a tunnel or on a bridge is usually only accessible by trained experts (Koch 2012; Cigré Technical Brochure 2008; CIGRE Technical Brochure 2015).

#### 27.3.2.3 Tunnel

In its normal state, $SF_6$ is nontoxic. However, in common with other gases, if released in a confined space such as a tunnel, it can cause oxygen depletion and the associated risk of suffocation. Control measures such as provision of forced ventilation to ensure that the oxygen level remains sufficient in the event of a release of gas should be considered.

It is often convenient to assemble the GIL at a shaft location, where more space is available and welding fumes may more easily be extracted. The enclosure lengths are welded at the shaft position, and the assembled GIL is advanced into the tunnel as each new enclosure joint is completed. Since it is not possible to feed the assembled GIL past a bend with low radius of curvature in this way, at such a bend the GIL must be assembled at its final position.

The environment of GIL installation can bring water or water steam in contact with the enclosure aluminum (or aluminum alloy) causing possible corrosion.

By virtue of the fact that the expected lifetime of a transmission line is rather long (e.g., 30–40 years), the behavior of aluminum alloys exposed to environmental water deserves very careful consideration (Koch 2007–06; Benato et al. 2005).

The scientific literature on chemical and biological behavior of aluminum products following exposure to environmental media is wide and comprehensive. The literature agrees on this fact: the formation of oxide layers on aluminum and its alloys have a protective function. Due to this protective layer, aluminum products are not significantly corroded under environmental conditions (pH 4.5–8.5), unless corrosion takes place through localized formation of elements caused by chemicals and natural substances. The minimum space for long tunnels can be determined by considering ventilation, humidity, temperature, management of any leaking of non-flammable and nontoxic insulating gas, repair concept after internal fault, tolerances of tunnel dimensioning (diameter, straight alignment, gradient), bending radius (400 m), need for elbow elements in order to follow the route, power supply, and transportation of spare parts, See examples in Figs. 27.8 and 27.9.

Inside service tunnels of long structures in certain distances, e.g., each 500 m or 1000 m widening, e.g., technical caverns, directional changes of the GIL are needed, which may be achieved using elbow elements (Koch 2012; Cigré Technical Brochure 2008).

Specific investigations of GIL applied to railway tunnels are given in Benato et al. (2005).

#### 27.3.2.4 Support Structures

When considering using a structure for GIL, it is recommended that the GIL be incorporated into the design. The use of existing structures for GIL needs evaluation of the initial design to accommodate the additional GIL requirements.

The weight of the GIL is about 30–50 kg per meter per phase. This weight is low in comparison to the carrying capability of most major transport structures.

The enclosure needs to be fixed to the structure at relatively long distances (e.g., 10–20 m). The mechanical withstandability of the enclosure allows such long distances between the fixing points. The total weight to be taken by the fixing points is mainly the weight of the length of 10–20 m GIL which is 300–1000 kg. Any vibrations coming from the structure to the GIL should be considered critical because of the rigid design consisting of aluminum pipes, epoxy resin insulators, and insulating gas. Such vibrations can be dampened by the design of the steel

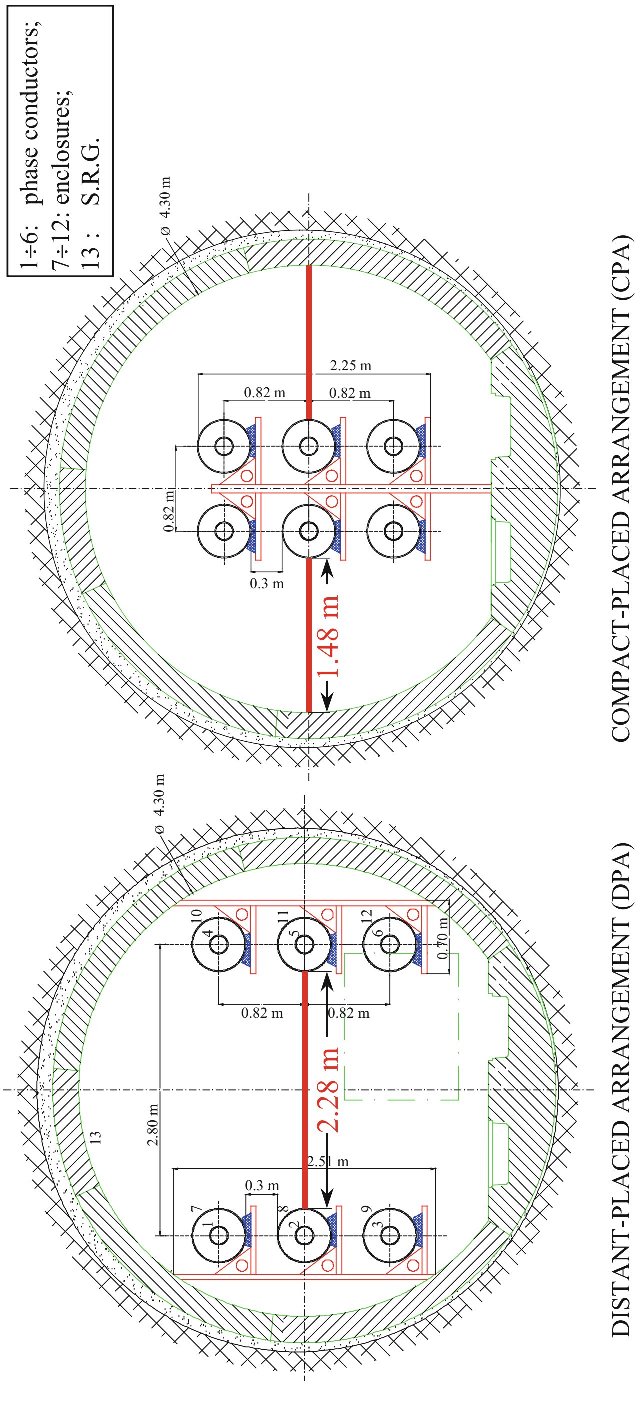


**Fig. 27.8** Possible arrangement installations of double-circuit GIL

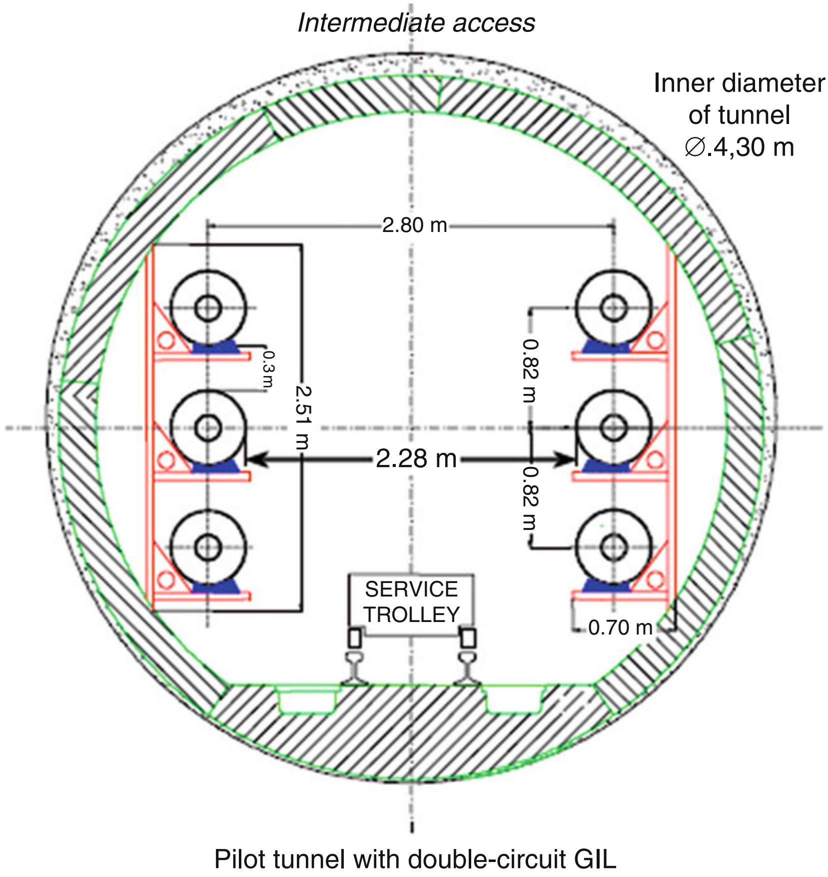


**Fig. 27.9** Typical tunnel arrangement

structure and fixing points. To prove the long-term stability, a fatigue analysis is required. Accessibility of the GIL should allow visual inspection and in case of a repair the exchange of a section.

In normal service the GIL needs no frequent service or checks by operation personnel. In service the structure and GIL will expand and contract, due to temperature changes. Thermal expansion units of the GIL will take care of these movements. There will be only a small impact by the friction of the movement of the GIL that will affect the bridge. Safety regulations concerning the GIL will take care that even in case of an electrical failure in the GIL there will be no critical impact on the structure. The forces coming from the electromagnetic field during operation (short circuit currents) are taken by the steel structure, and in case of an internal electrical fault, the metallic enclosure prevents influences to the surrounding. To prove the functioning of bridge and GIL thermal expansion, a fatigue analysis is required.

Ambient conditions like wind and ice load, solar radiation, seismic conditions, high humidity, and ambient temperature are service conditions as defined in IEC 62271-204 (International Standard IEC 2011) that are considered in the design of GIL applications. The effects of these ambient conditions also need to be considered as part of the design (Cigré Technical Brochure 2008).

### 27.3.3 Automated Laying Processes of GIL

The third generation of compact transmission lines based on gas insulated technology is now being developed. There are two main goals behind this third-generation design: improved assembly and laying of the pipe segments and robust and reliable joint technology using new welding processes.

These improvements will further reduce the time for installing GIL which accounts for almost 50% of the total cost. The mobile factory combines the automated assembly of GIL segments with the welding process. The mobile factory as shown in Fig. 27.10 is equipped with a pipe magazine where on-site-prepared pipe segments are stored and made ready for welding. There are two welding workplaces which work alternately to generate a continuous production of GIL segments to be pulled into the open trench or tunnel section.

The jointing technology of the mobile factory is supplemented by ultrasonic quality control of the welds to ensure that only failure-free welds are installed.

**Mobile Factory for GIL**

Figure 27.10 shows the mobile factory to join the GIL sections by orbital welding of the conductor pipe and enclosure pipe and lay the new section into the trench or into a tunnel. The mobile factory can move by itself from one laying position to the next. The right-hand part of the mobile factory is used as a storage magazine for a total of

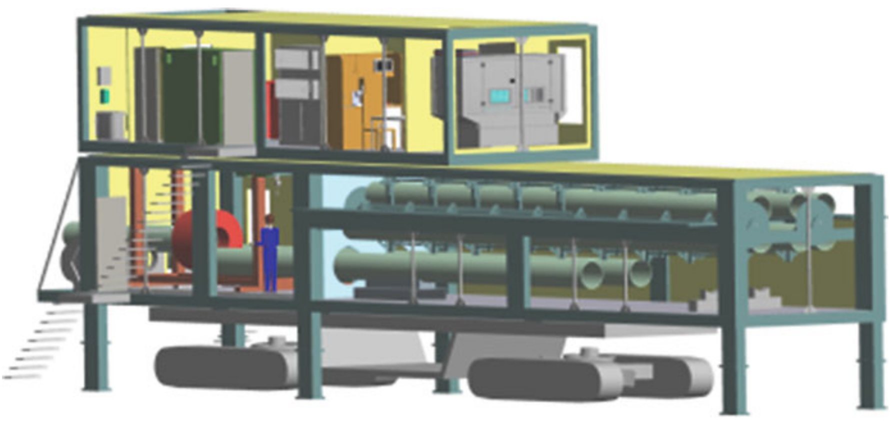

**Fig. 27.10** Mobile factory for on-site assembly and laying

eight GIL sections of up to 13 m length. On the bottom left-hand side of the mobile factory, the welding section is located. In this area the orbital welding machine using the friction steer welding process connects the conductor and enclosure pipes. With two welding locations, the welding machine can make up to eight connections in one working shift, which is equal to the number of prepared GIL sections stored in the magazine.

On top of the welding section on the left-hand side of the mobile factory, the control units, power generation, and room for employees are located. This means the mobile factory does not require an external power supply enabling the use of the mobile factory to lay GIL in remote areas.

When direct buried GIL laying is used the welded GIL, sections leave the mobile factory at the left-hand end to be laid in the trench. In this condition, the mobile factory can move with its own traction system for each new length of GIL, e.g., each 13 m. Another possible laying method when using longer open trenches, e.g., 300–500 m, is that the GIL sections (e.g., 13 m long) are pulled into the trench, and then the mobile factory will be moved for 300 or 500 m to the next laying position.

**Friction Steer Welding of GIL Aluminum Pipes**

A major new advance is the use of a new jointing technology based on friction steer welding. This process has the advantage that the jointing of two pipes can be made in a single orbital process, (see Fig. 27.11) compared to arc welding where five to ten levels of welds are required. This means that the friction steer welding is a much faster process completing a weld in approximately 10 min compared to about 1 h required by arc welding. This reduced jointing time (for approximately 300 welds per kilometer) is significant, reducing the total GIL laying time by a factor of 5–6 giving rise to a reduction in costs.

The friction steer welding process uses the temperature generated by friction to heat up the aluminum material to a soft status, not molten. In this soft state, the aluminum material is merged and will form a solid connection without any break in the molecular structure. The process is very stable under any ambient temperature and weather conditions and can even be done under rain condition. The mechanical equipment is simple a steel screw with a hydraulic drive in a solid steel frame for mechanical stability.

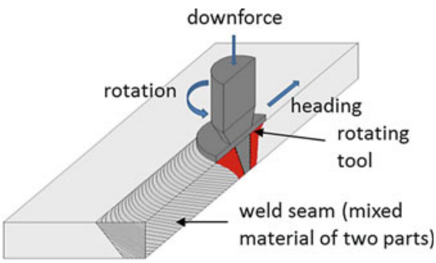


**Fig. 27.11** New jointing technology based on friction steer welding

The quality assurance is given by monitoring the welding parameters of forces, speed, and temperature. In addition, each weld will have a 100% quality control by using an automated ultrasonic sensor system for full gas tightness of the enclosure pipe and full electrical conductivity for the conductor pipe.

It is expected that these new automated jointing and laying machines will provide high-quality, fast laying of GIL transmission lines at much lower cost. The technology was first presented at the CIGRE Session 2016 in Paris.

## 27.4 Environmental Impact

### 27.4.1 Environmental Life Cycle Assessment

A standardized procedure for quantifying the environmental impact of a technology is the environmental life cycle assessment (LCA), the procedural basis for which is documented in the international standard series ISO 14040 (Koch 2012; CIGRE TB 639 2015).

An LCA has been outlined for the case of gas insulated power equipment by CIGRE 2002 (Koch 2002a). The approach is applicable to GIL and is described in the report in a simplified manner as being performed in five steps as follows:

- Choice of a representative functional unit of the technology
- Definition of the "horizon" (frame of reference) of the study
- Establishment of a life cycle inventory
- Derivation of a life cycle impact assessment
- Derivation of life cycle interpretation

The functional unit chosen for the assessment might be a unit length of GIL with a given rated voltage and current.

The horizon of the study includes the life cycle phases which are considered, the material production and energy generation scenarios that are assumed, the types of environmental impact that are to be assessed, and the methodologies to be used. The life cycle inventory (LCI) quantifies the relevant material and energy flows into the system and emissions and waste flows out of it. In the case of GIL, the LCI will include the materials used and the energy consumed in producing them, emissions and waste generated during production and manufacture, energy losses generated during the operational lifetime of the equipment, and energy losses and emissions associated with decommissioning and disposal or recycling. The life cycle impact assessment (LCIA) derives quantitative environmental impacts from the LCI data.

The life cycle interpretation draws conclusions from the LCI and LCIA data.

A comparative assertion is a special type of LCA in which the environmental impacts of two systems of equivalent performance are compared. The report illustrates the basic principles of a comparative assertion for the case of $SF_6$ emissions from systems using pure $SF_6$ and a mixture of $N_2$ and $SF_6$.

Most of the materials used in GIL are easily recyclable at end of life.

### 27.4.2 General Environmental Aspects

A comparison of overhead lines and underground cables, with particular reference to environmental effects, has been reported by CIGRE Joint Working Group 21/22.01 (CIGRE TB 639 2015). Many of the arguments are applicable to GIL. The environmental impact of transmission technologies including GIL has been reported by CIGRE 2006, Paper C2-208 (Benato et al. 2006a). Factors considered in the two reports are:

- Visual impact
- Electromagnetic fields:
  - Magnetic fields
  - Electrostatic fields
- Depreciation of property/land values
- Restrictions on land use: buildings, air traffic, and land cultivation
- Audible noise
- Electromagnetic interference (radio interference voltage)
- Effects on forests and natural environment
- Risk of soil pollution

### 27.4.3 Magnetic Fields

Where a GIL is of the single-phase enclosed design and the enclosures are solidly bonded at each end (which will normally be the case), enclosure currents will circulate tending to reduce the magnetic field external to the GIL. However, due to the spatial disposition of the three phases, screening is not complete. Magnetic fields have been calculated for typical overhead line, GIL, and cable systems. RMS values of the magnetic flux density at 1 m above ground and at different distances from the central axis are shown in Table 27.10. The values correspond to a transmitted power of 2000 MW.

Where a GIL is of the single-phase enclosed design and the enclosures are bonded in such a way that enclosure currents cannot circulate, e.g., where single point bonding is used, eddy currents will flow in the enclosures, but these will provide no effective magnetic screening. The magnetic field external to the GIL will therefore be higher than in the case where the enclosures are solidly bonded. It is thought that such an arrangement will seldom be used.

The magnetic field external to the GIL may be calculated analytically using Ampère’s Theorem and Biot and Savart’s Law. Alternatively, the magnetic field can be calculated using a numerical method, such as the finite element method (Koch 2003; Koch and Connor 2003).

**Table 27.10** Magnetic flux density for 400 kV lines and 3000 A

| | Distance from central axis (m) | | | |
|---|---|---|---|---|
| B (μT) | 0 | 10 | 20 | 30 |
| Overhead line | 42 | 36.5 | 21.0 | 10.8 |
| GIL flat formation | 5 | 0.25 | 0 | 0 |
| XLPE cable<br>1 per phase<br>Flat formation | 109 | 11 | 2.9 | 1.3 |
| XLPE cable<br>2 per phase<br>Trefoil formation | 13.2 | 0.74 | 0.19 | 0.08 |

### 27.4.4 Environmental Aspects

The majority of the insulating gas is with 80% $N_2$. This gas has no environmental impact, as it is naturally available in the atmosphere. $N_2$ is not toxic and non-flammable. However, $N_2$ can suffocate as it can reduce the oxygen content.

In addition to being a more economical solution, the use of a gas mixture addresses environmental concerns, since $SF_6$ has a global warming potential (GWP) of 23,900 times that of carbon dioxide.

However, the absolute contribution by today's amount of $SF_6$ in the atmosphere to global warming is 0.7%. The majority of $SF_6$ in the atmosphere originates from $SF_6$ use outside of the electrical industry.

Most of such use has been banned (e.g., window insulation, tires, and shoes). The welded enclosure structure ensures that a high level of gas tightness is maintained throughout the life of the GIL. At the end of life, the gas mixture can be recovered, recycled, and reused.

The use of $N_2/SF_6$ gas mixture is recommended for long-distance applications of GIL. Most applications are in conjunction with GIS and use pure $SF_6$ because of the arc extinguishing capability of $SF_6$.

## 27.5 Long-Term Test

### 27.5.1 Feasibility Study of 420 kV GIL

A feasibility study began in 1994 and was completed in 1997. Studies have been performed on dimensioning for insulation, thermal behavior, mechanical constraints, and corrosion protection. Laboratory tests have been performed on dielectric performance, short circuit performance, reliability studies, monitoring, and fault location systems. All tests were successful. It was concluded that the required GIL technologies were accessible in the medium term (Henningsen et al. 2000; Koch 2000–10; Miyazaki 2001).

**Table 27.11** Ratings of EDF GIL

| | |
|---|---|
| Rated voltage | 420 kV |
| Lightning impulse withstand voltage | 1425 kV |
| Switching impulse withstand voltage | 1050 kV |
| AC withstand voltage | 620 kV |
| Frequency | 50 Hz |
| Rated current | 3000 A |
| Short-time withstand current | 63 kA |

**Table 27.12** Design of EDF GIL

| | |
|---|---|
| Outside diameter of enclosure | 515 mm |
| Connection method of enclosure | Welding |
| Total circuit length | 300 m single phase |
| Transport length | 15 m |
| Insulating gas | 10% $SF_6$/90% $N_2$ |
| Gas pressure at 20 °C | 8.0 bars abs |

The GIL ratings are summarized in Tables 27.11 and 27.12.

## 27.6 Example Projects

In this section, some examples of installed GIL projects are given to show installation in air, in tunnel, and in direct buried (IEEE Guide for Application and User Guide for Gas-Insulated Transmission Lines (GIL) 2012).

### 27.6.1 PP9 Saudi Arabia

In a project at the PP9 Power Plant in Saudi Arabia, 420 kV GIL is used for connections between transformers and a GIS substation (Koch 2012; Cigré Technical Brochure 2008, 2015). The connections consist of eight three-phase circuits, totalling 17 km of single-phase circuit. The project was completed in four stages and was commissioned from May 1997 to March 2000. GIL was chosen as the only viable technical solution due to restrictions imposed by the route and the very corrosive environment (due to plant emissions and sandstorms). In addition, the GIL solution allows highly reliable transport of high powers with low losses.

The GIL was installed above ground at heights between 7 and 9 m, to allow passage for transformer transportation. The ambient temperature varies between −6 °C and +55 °C. The GIL is subject to winds of 120 km per hour with strong gusts of up to 150 km per hour (Fig. 27.12).

**Fig. 27.12** Views of the 420 kV PP9 GIL: erection and layout

### 27.6.2 Limberg, Austria

The connection of a 420 kV overhead line (OHL) to an underground gas insulated switchgear (GIS) inside a cavern in the Austrian Alps was made with a 450 m-long tunnel. The GIL used $N_2/SF_6$ gas mixture technology. The gas mixture used 80% $N_2$ and 20% $SF_6$ at a pressure of 0.7 MPa.

The small tunnel width was required due to expensive tunnelling works built into the rock. The base line is 3.2 m and the maximum height in the center is 3.4 m. The tunnel slope angle is 42° and the elevation difference is 80 m. This shows the use of GIL in a compact tunnel and also on an angle.

Very high safety requirements with regard to fire protection had to be met. The tunnel is used also as a ventilation shaft for the cavern. Even in the event of an internal arc fault, no impact to the tunnel is allowed. This has been proven for the GIL in several arc fault tests in the test laboratories. This provided the maximum operation safety. As the tunnel is used as an emergency exit way for personnel in the cavern, a minimum electromagnetic field during operation was required. See Figs. 27.13 and 27.14.

In Table 27.13, the technical data of the sloped tunnel GIL at *Limberg* is shown.

The GIL was installed using welding technology and the installation was completed in 2010 (Koch 2012; Cigré Technical Brochure 2008; CIGRE Technical Brochure 2015).

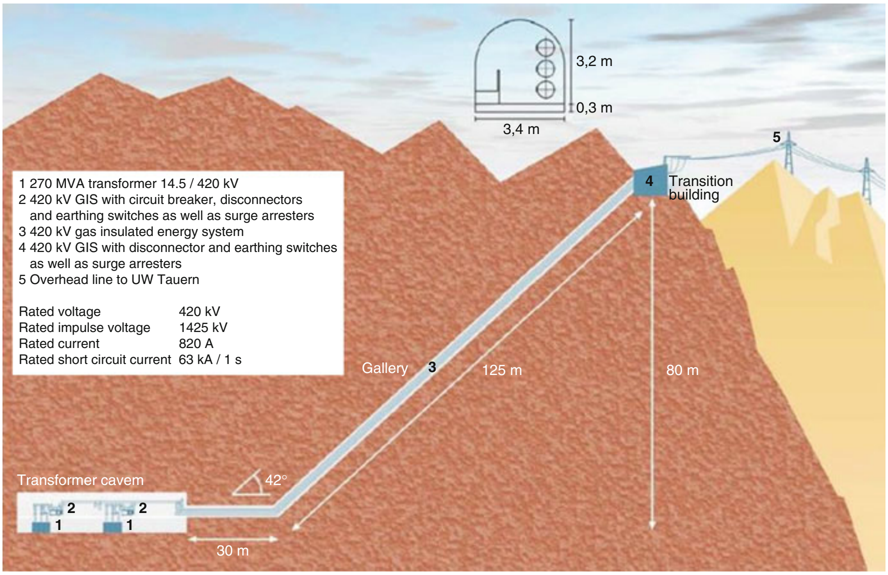


**Fig. 27.13** Overview of hydro power station Limberg, Austria, 2010

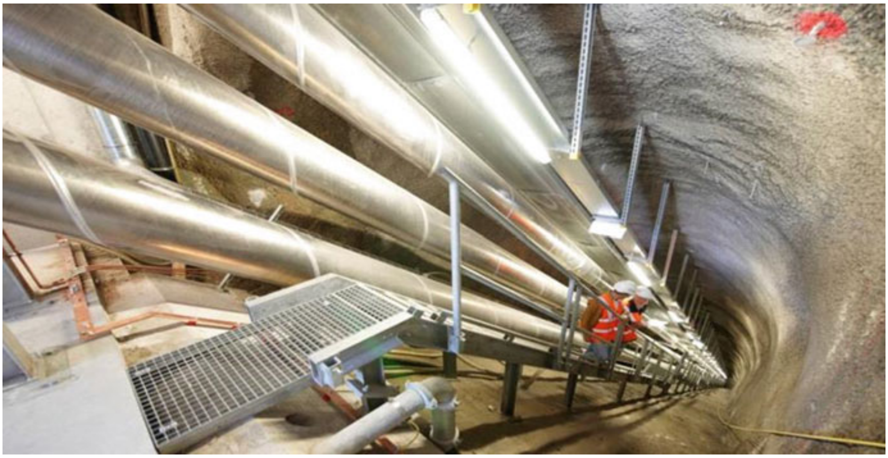

**Fig. 27.14** View into the tunnel slope of Limberg, Austria, 2010

## 27.6.3 Kelsterbach GIL

The extension of the Frankfurt International Airport required the undergrounding of the existing 220 kV overhead lines and the upgrading of the transmission voltage to 420 kV. In Fig. 27.13, a construction site view shows the overhead lines and the

**Table 27.13** Technical data Limberg, Austria, 2010

| | |
|---|---|
| Rated voltage $U_r$ | 420 kV |
| Rated current $I_r$ | 820 A |
| Rated impulse withstand voltage $U_{BIL}$ | 1425 kV |
| Rated short-time current $I_s$ | 63 kA, 1 s |
| Circuit length | 2 circuits of 0.45 km |
| Insulating gas | 80% $N_2$ and 20% $SF_6$ at 0.7 MPa |

**Fig. 27.15** Overview of directly buried GIL at Kelsterbach, Germany, 2010

directly buried GIL laying. In the middle of the photo, the on-site assembly tent is shown which is placed on top of the laying trench. The GIL sections are assembled and welded in the tent and then pulled into the trench (Koch 2012; Cigré Technical Brochure 2008; CIGRE Technical Brochure 2015) (Fig. 27.15).

A view inside the assembly tent is given in Fig. 27.16. The straight units and angle units are preassembled inside the tent before burial.

The straight units are welded on-site using the automated orbital welding process. See Fig. 27.17.

The straight units were welded in the assembly tent and then pulled into the trench. In Fig. 27.18, the trench with six single-phase GIL pipes for the two three-phase systems is shown before the trench was closed.

The technical data of the directly buried GIL using $N_2/SF_6$ gas mixture is shown in Table 27.14.

Fig. 27.16 Inside the assembly tent

Fig. 27.17 On-site welding

## 27.7 Future Applications

### 27.7.1 General

The future need of electric power transmission is increasing because of increasing use of electrical energy worldwide and the concentration of electric load in metropolitan areas or industrial complexes. In addition, the change to renewable energy generation in faraway locations will require additional transmission lines from solar or wind farms, on land and offshore over long distances (Koch 1999).

It is expected that gas insulated line can play a major role in meeting these needs; however this is outside of the scope of this book which is associated with substations.

### 27.7.2 Possible Future Uses of GIL Associated with Substations

There are cases where GIL is a viable option in lieu of EHV overhead lines (OHL). One application could be of GIL linking two EHV substations – "A" and "B" having OHL entering into the substations from remote substations. However, there is no

**Fig. 27.18** Six single-phase GIL pipes in the trench before backfilling

**Table 27.14** Technical data of the directly buried GIL, Kelsterbach, Germany, 2010

| | |
|---|---|
| Rated voltage $U_r$ | 420 kV |
| Rated current $I_r$ | 3000 A |
| Rated impulse withstand voltage $U_{BIL}$ | 1425 kV |
| Rated short-time current $I_s$ | 63 kA |
| Circuit length | 2 circuits of 1 km |
| Insulating gas | 80% $N_2$/20% $SF_6$ |

right of way for OHLs to interconnect the two substations to meet the network configuration, or they are separated by a few kilometers of water (river or sea). GIL buried below ground or inside a tunnel can be used. See Figs. 27.19 and 27.20.

Another possible application is shown in Fig. 27.21. OHL circuits are terminated at an indoor EHV substation. There is no more space for landing additional OHL circuits to the substation. In case circuit expansion is required, GIL/cables can be used to interconnect the substation to the end tower of the new OHL circuits. GIL/cables can be installed above ground, in tunnel, in troughs, or directly buried.

The third possible application is shown in Fig. 27.22 which explains the use of GIL/cables to help migrate the OHL circuits and existing EHV switchgear boards (to be replaced in stages) to new EHV switchgear boards in a new EHV substation at some distance apart. Due to site and system constraints, e.g., in situ replacement of switchgear not possible, diverting of existing OHL circuits not possible, outage constraints, etc., the switchgear and circuit diversion must be carried out in stages, and the existing switchgear boards and the new switchgear boards must be interconnected to minimize the impact to the system security. GIL can be installed above ground, in tunnel, or buried underground.

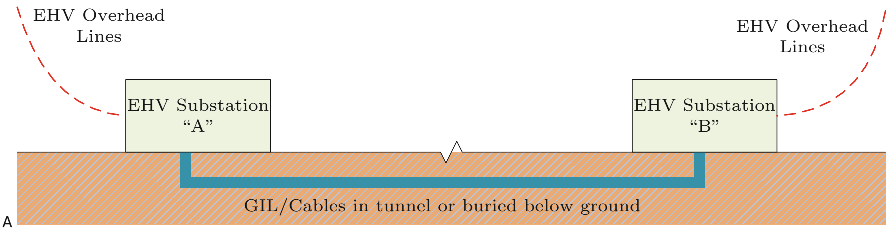


**Fig. 27.19** GIL in lieu of overhead lines (due to no right of way) for linking two substations

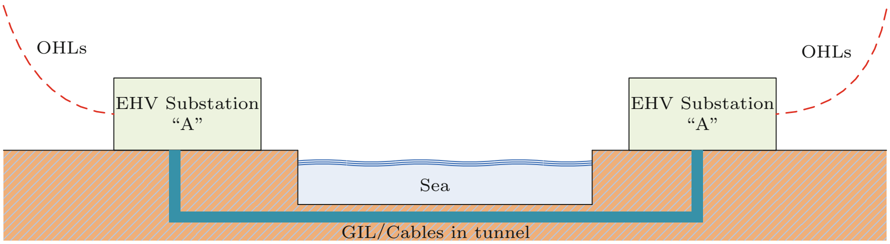


**Fig. 27.20** GIL for linking two substations separated apart a long distance by sea/river

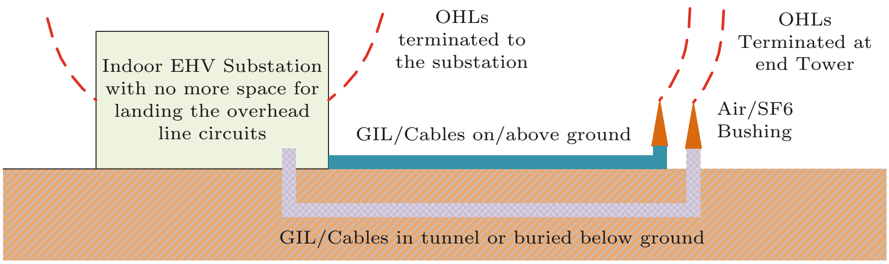


**Fig. 27.21** GIL installed above ground/in tunnel/directly buried to link up the end tower of new overhead lines with an existing substation having no more landing space for overhead line circuits

The above three cases are not exhaustive. The choice of the installation methods will depend on technical, cost, and other related factors (CIGRE Technical Brochure 2015).

## 27.8 Project Handling

### 27.8.1 Site Assembly

The GIL components are delivered to the preassembling site which is usually a temporary facility close to the installation location or to the access point which may be the entrance of a gallery or a tunnel. At the preassembling area, a temporary workshop facility is erected where the individual pieces are put together to create

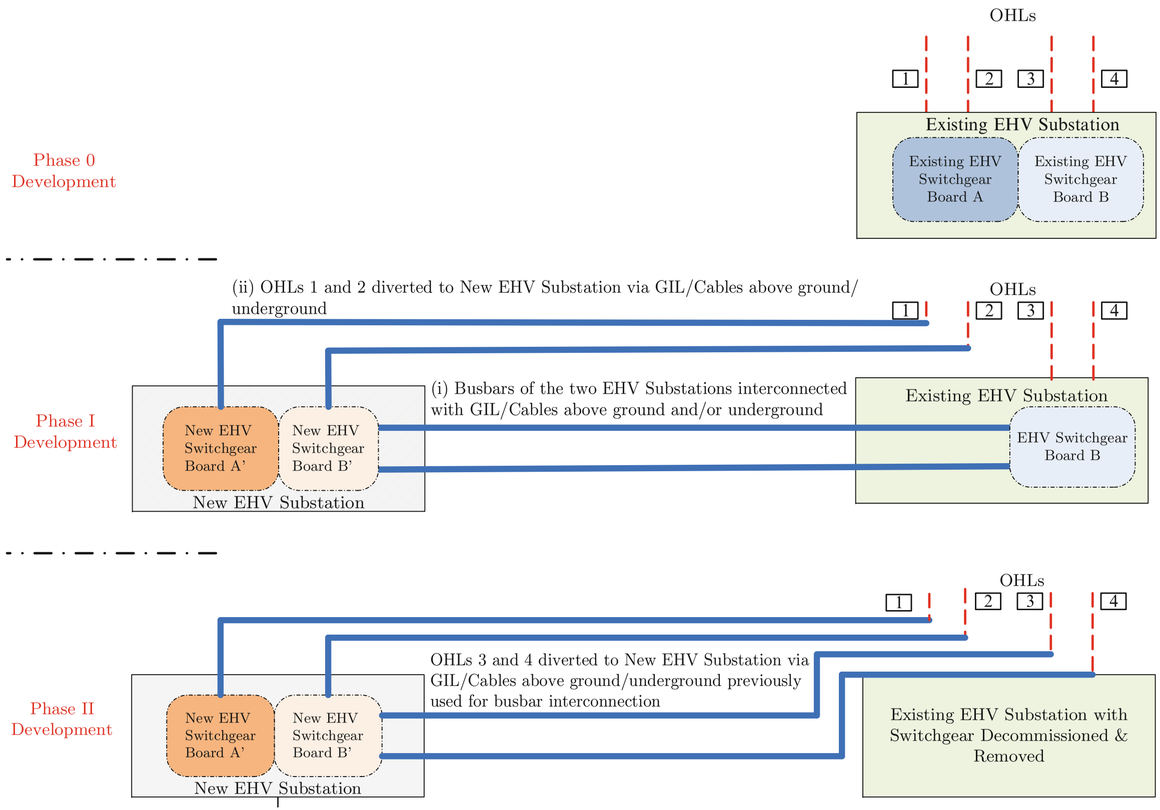


**Fig. 27.22** GIL for EHV switchgear replacement/expansion under site/system constraints, e.g., in situ switchgear replacement not possible, relocation/addition of overhead line towers not possible, long circuit outage not possible

components ready for the final assembly procedure. It is clear that one of the most important requirements is to maintain the cleanliness inside the preassembling workshop. The site of assembly of the GIL must also be equipped with the necessary infrastructure such as offices, various buildings, power supply (not to forget welding and gas treatment machines), water, and access for the site personnel and visitors. Once the components have been completed, they are transported to the assembly location. The latter is the place where the “continuous” tube is put together. This can be done using flanges or welding. The latter is the more economical solution for longer lengths; flanges are mostly used for frequently diverting routings or very short installations. The progress of the installation is determined by the final assembly procedure. A storage facility adjacent to the preassembling site is of advantage.

The testing is divided into two main steps: the ongoing quality assurance during installation and the after-laying tests. The quality assurance during installation covers among other things the ultrasonic inspection of each individual site weld and the appropriate documentation in accordance with international and local pressure vessel code requirements. The tests after burial are mainly the pressure test of the entire system, the dielectric test, and the test of the conductor resistance. Details of the site testing activities are prescribed in IEC 62271-204 (International Standard IEC 2011). Due to the nature of the GIL installation works and mainly related to the requirements of cleanliness, it is obvious that apart from the required health and safety issues a couple of other prerequisites of the site need to be fulfilled before installation can start. The most important of them is that the civil works in the vicinity of the assembling area must be completed and permanent, unimpeded access for the GIL installation crew provided (Koch 2012; Cigré Technical Brochure 2008; CIGRE Technical Brochure 2015) (Figs. 27.23, 27.24, 27.25, 27.26, 27.27, and 27.28).

There are generally two options for the installation of GIL: welding of the pipes in one location and pulling the continuously produced pipe or moving the welding position along the route. The latter is a more complex option due to the fact that the welding equipment and the equipment to maintain a clean welding place will need to be moved. Up to now the assembly location usually remains in place until a certain section of the GIL has been produced (Koch 2012; Cigré Technical Brochure 2008).

### 27.8.2 Factory Preassembly

A concept used by GIL manufacturers, who deliver GIL components to other manufacturers to assemble the GIL on-site, allows for preassembled sections shipped directly from the GIL assembly factory. They are fully assembled and tested in the factory and then sealed and pressurized with dry nitrogen for shipment. The principle however remains the same regardless of the project size or assembly concept and needs to be evaluated as to the most beneficial alternative for any given project.

The bus bar system is made in fully assembled and factory tested sections up to 18 m in length. Changes in direction are accomplished with elbows which are preassembled to individual shipping sections in the factory.

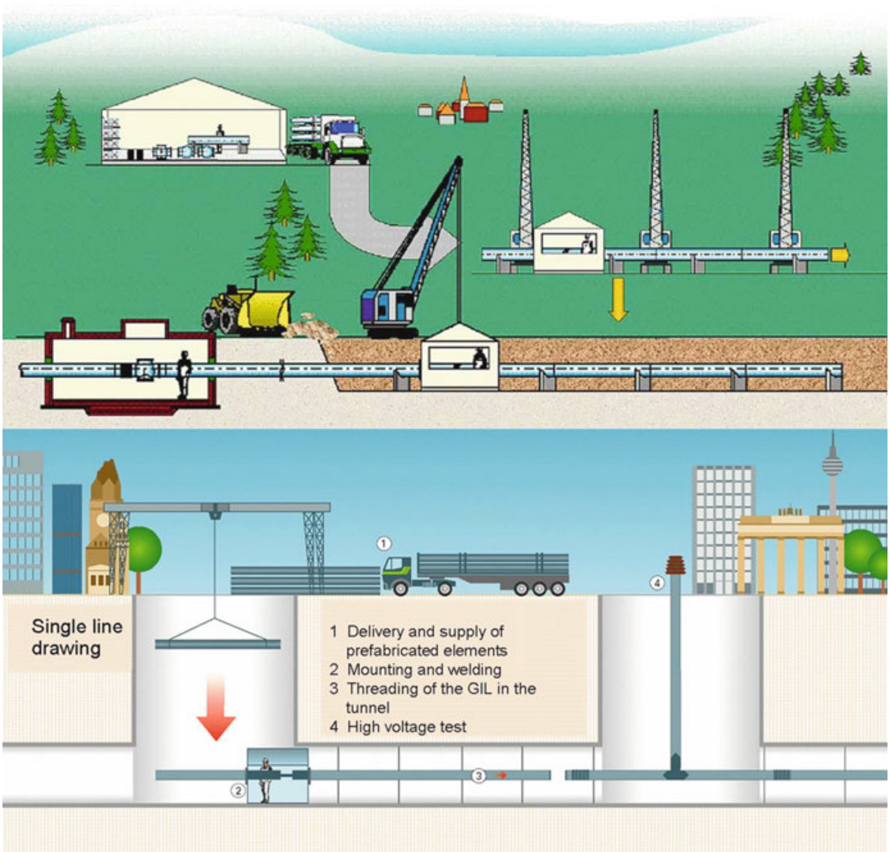


**Fig. 27.23** Site logistics scheme for GIL installation in tunnel, above, and below ground

**Fig. 27.24** Delivery of transport units at preassembly area

**Fig. 27.25** Preassembly of GIL sections

**Fig. 27.26** Welding area in the tunnel

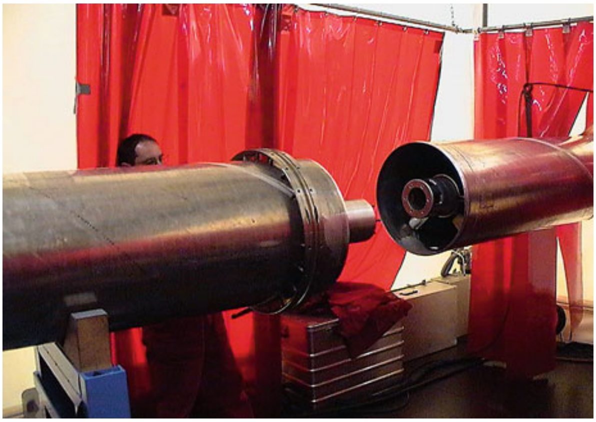

**Fig. 27.27** Bringing in the GIL sections into the welding area

**Fig. 27.28** Orbital welding machine for enclosures and phases

**Fig. 27.29** High-voltage test at the factory

Each shipping section is tested before delivery from the factory to ensure the standards of reliability. Routine testing includes high-voltage power frequency electrical tests, partial discharge tests of each insulator and each shipping assembly, and gas leakage tests on all shipping assemblies.

High-voltage power frequency electrical tests, partial discharge tests of each insulator and each shipping assembly, and gas leakage tests on all shipping assemblies are done before shipping the section of bus bar for installation (Koch 2012; Cigré Technical Brochur, 2008) (Fig. 27.29).

After the pre-testing is complete, GIL sections are ready to be shipped to the installation site for final testing and commissioning (Fig. 27.30).

The utilization of flanged GIL sections makes the installation process simpler on-site, and an expeditious installation program can be accomplished. It also does not require any on-site assembly and testing area. Longer section lengths decrease the number of connections required during installation and lower the risk of gas leakage during operation (Koch 2012; Cigré Technical Brochure 2008) (Fig. 27.31).

### 27.8.3 Gas Handling

Installations of GIL require gas handling facilities. To limit the gas volume necessary to handle and process, the GIL is separated into gas compartments. The handling instructions are defined in IEC 62271-4 gas handling standard (IEC 62271-4 2013). It is necessary to organize sufficient space for the tanks of $SF_6$ and $N_2$. Specialized machines are necessary to draw the vacuum in the tubes before filling, like treating

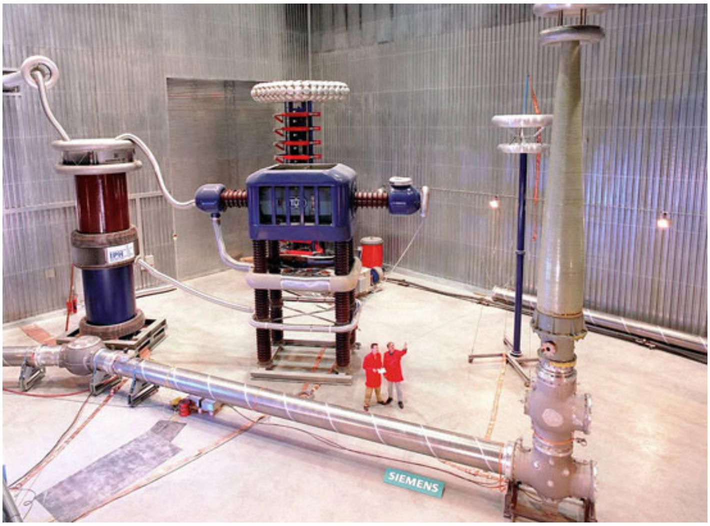


**Fig. 27.30** Shipping of the preassembled sections of bus bar

**Fig. 27.31** Installation of section of bus bar on-site

the gas (drying) and making mixture N2-$SF_6$ before filling. The operation of filling must be permanently supervised (Figs. 27.32 and 27.33).

### 27.8.4 High-Voltage Test

The need to test the GIL on-site after burial imposes certain requirements on the GIL and the structure in which it is installed. The guiding rule for high-voltage on-site testing is not to exceed the maximum test current of about 20 A to limit the energy

**Fig. 27.32** Gas handling device pump and gas mixing unit


**Fig. 27.33** Gas filling Dilo valve to vacuum connect gas handling device

**Fig. 27.34** Gas insulated high-voltage resonance test set-up. Max. voltage 680 kV, max. current 1,5 A, L = 720 mH

**Fig. 27.35** On-site HV testing air insulated high-voltage resonance test setup connecting to the bushing

charged to the system. In GIL, it is possible to use the accessibility to test sections of GIL through the disconnection unit, which is used as an isolation point. One gas compartment may have a maximum length of 1500 m. This also forms one high-voltage test section which needs access for the test equipment. From there the tests can be executed in two directions. Therefore, access to the GIL for high-voltage testing in the tunnel from the main tunnel or from the outside is required at least every 3000 m (Koch 2012; Cigré Technical Brochure 2008; Koch 2000; Chakir and Koch 2001b; Koch 2000–10) (Figs. 27.34, 27.35, and 27.36).


**Fig. 27.36** On-site HV testing air insulated high-voltage resonance test setup connecting to the bushing

**Table 27.15** Pressure vessel standards for GIL

| EN | Title |
|---|---|
| EN 50052:1936<br>EN 50052:1986/A1:1990<br>EN 50052:1986/A2:1993 | Cast aluminum alloy enclosures for gas-filled high-voltage switchgear and controlgear |
| EN 50064:1989<br>EN 50064:1989/A1:1993 | Wrought aluminum and aluminum alloy enclosures for gas-filled high-voltage switchgear and controlgear |
| EN 50068:1991<br>EN 50068:1991/A1:1993 | Wrought steel enclosures for gas-filled high-voltage switchgear and controlgear |
| EN 50069:1991 | Welded composite enclosures of cast and wrought aluminum alloys for gas-filled high-voltage switchgear and controlgear |
| EN 50089:1992 | Cast resin partitions for metal enclosed gas-filled high-voltage switchgear and controlgear |

### 27.8.5 Pressure Test

Pressure tests are required by the EN standards for GIS and local requirements of authorities. The EN standards on high-voltage equipment are written for low-pressure compartments (typical up to 8 bars) and dry and inert gases ($SF_6$ and N2). The EN standards are the following (Koch 2012; Cigré Technical Brochure 2008) (Table 27.15):

## 27.9 Operation, Maintenance, and Repair

### 27.9.1 Online Insulation Monitoring

Activities specific to GIL have been treated in depth in the Technical Brochure 218 (Cigré Technical Brochure 2003). Annex B of TB 218 reviews all the various diagnostic methods to apply either during on-site test or for online monitoring in service: physical sensors and signal processing to detect, locate, and identify the occurring defects. Nowadays, two methods are mainly used to detect online the presence of possible defects: UHF methods for new equipment provided with internal UHF sensors and acoustic methods for other equipment. Up to now, however, the assessment of the actual impact of the detected defects on the GIL insulation and thus on the remaining life is indeed still a difficult matter (Okubo et al. 1998).

This matter is further addressed in Part H.

### 27.9.2 Bonding and Grounding for Permanent and Transient Voltages

The grounding of GIL must be adapted to the different service conditions represented by normal service, short circuit, and overvoltage conditions. The disposition of the GIL (buried, in a tunnel, in a trench) and the possibility of having low-voltage equipment such as gas density monitors, temperature sensors, or partial discharge monitoring systems connected on the enclosure have to be considered when the grounding mesh is studied. The design of the grounding system must provide all the safety regarding persons and equipment in case of potential rise, touch voltage, and step voltage and must remain lower than the limit values for permanent or short circuit conditions.

Optimization of the grounding system can be achieved through modeling. For short lengths of GIL (less than 500 m), the GIS design rules are applicable. For longer ones, the design must take into account the IEC standard 62271-204 (International Standard IEC 2011).

In contrast to insulated cables, the grounding and bonding of the enclosure at short spacing does not affect the thermal rating of GIL because of the good enclosure conductivity. Thus, for safety reasons the enclosure grounding and bonding would be done for directly buried GIL every 500 m to 1 km reducing the power frequency touch voltage to safe limit values and the transient overvoltage between enclosure and ground to ensure very low values which are not dangerous for people or for the insulating layer over the aluminum alloy GIL enclosure.

For GIL in tunnel the enclosure grounding and bonding is repeated more frequently and needs to be part of the tunnel earthing design.

### 27.9.3 Operation

**Monitoring Specific to the GIL**

Each gas compartment must be equipped at least with one gas density monitor. These sensors, which are compensated for temperature, allow the pressure of the mixture of gas in the tubes to be monitored permanently. They are equipped with a display for visual control at the time of inspection, such as several levels of alarm for minimal pressure in the case of leakage or gas loss. These alarms can be transmitted remotely to the control system and/or to alert the personnel. The sensitivity of the monitors and the determination of the alarm thresholds must be carefully studied according to the volume of gas by compartment.

GIL can be equipped with one arc detector and locator system based on the principle of a measurement of the difference in travel time of the wave between the place where the arc occurs and the ends of the tubes equipped with reception antennas; the precision is ensured by GPS synchronization.

**Monitoring of the Installation**

In an installation in a gallery or a tunnel, it is recommended to install $SF_6$ gas detectors as well as the presence of oxygen in the low points. This information can be coordinated with the pressure drop sent by a density monitor of a compartment to help identify the location of a breach or faults and raise an alarm.

The presence of water, for example, related to leaks, can be detected by measuring apparatus of water level with float.

According to the principles of exploitation and the concepts suitable for each company, other monitors can be installed, such as:

- Fire and temperature sensor
- Extinguishing system
- Monitoring of the access
- Video camera

Monitoring requirements and safety rules are very much related to the operator and local authorities. The technical installations and the operation instructions are not different from other high-voltage installations and very similar to GIS. Technology is available on the market (Schoeffner et al.; Boettger and Koch 2005; Koch and Kunze 2006).

### 27.9.4 Maintenance

GIL theoretically requires very little maintenance; however, the limited experience feedback concerning this technology requires the owners to establish an appropriate level of preventive maintenance. The following maintenance actions can be mentioned (Koch 2012; Cigré Technical Brochure 2008):

- Periodic inspection. The interval is to be fixed between weekly (at the beginning of the operation) and monthly. This makes sure that there is nothing abnormal on the level of GIL, but also on the whole of the installation and the end stations. In particular the pressure in the tube (density monitors) should be visually inspected, as well as the general state (water infiltration, cleanliness, etc.) to make sure these are working.

- Each year it is necessary to envisage a control of pressure with pressure gauges of precision and a measurement of the quality of the gas (humidity). This work requires an outage of the installation.
- The density monitors must be calibrated periodically, for example, every 5 years. This work requires an outage of the installation.
- $SF_6$ gas detectors placed in the gallery must be calibrated periodically, for example, every 5 years.
- The oxygen detectors use sensitive cells with a limited lifetime and must be reloaded regularly.
- Depending on the environment of the installation and of the state of pollution, it may be necessary to clean the insulators of the bushings and the surge arresters at the end stations.
- If air filters are not fitted to the ventilation system, then cleaning of the tubes and gallery may be required.
- If there is air filtration or forced cooling, this equipment will have a regular maintenance cycle.
- In the event of water infiltration above the GIL, there is a risk of corrosion of the tubes according to the composition of the fluid. It is desirable to put protections or to require a waterproofed gallery by the construction.
- Various other traditional operations in electric stations must be carried out, such as checking of the tightening of connections and control by means of thermo-vision camera.

### 27.9.5 Repair Process

The principle of GIL is relatively simple and includes few peripheral devices; however even though there are high-quality manufacture and assembly standards, defects or faults are possible; therefore repairs to the installation may be required and appropriate measures put in place to facilitate them (Cigré Technical Brochure 2008).

Consequently, various measures should be incorporated such as:

- To stock spare parts, for example, of the tubes, near to the installation or in the gallery for an underground system
- To ensure permanent or emergency access for vehicles and machines
- To have quick access to cisterns or batteries of bottles to handle and treat large quantities of gas
- To distribute electric power to supply various machines (welding, treatment of gas, ventilation, light, etc.) all along the GIL

The repair process itself consists of the following activities:

- Setup of the repair site
- Removal of gas
- Cutting and removal of the encapsulation and conductor

- Installation of replacement conductor and encapsulation
- Gas filling and high-voltage test

An example of a repair scheme which has been performed and proven is given in Fig. 27.37. The duration of a potential repair is app. 2 weeks including preparation and final testing.

## 27.10 Safety

### 27.10.1 Safety Analysis

The integrity of the metallic enclosure to internal arcs prevents external problems such as fire (Koch 2012; Cigré Technical Brochure 2008).

Third-party accidents in the proximity of the GIL might be a danger for the GIL and separation from vehicles is required.

There is no influence from radioactivity in the tunnel expected to the insulating gas and the electrical stability of the GIL, as the metallic enclosure is shielding the inside from the surrounding.

Oxygen measurements in the tunnel are recommended at low locations in the tunnel to make sure that there is no risk to personnel (asphyxiation).

When the GIL gas compartment needs to be opened, care has to be taken to avoid direct contact with possible decomposition product of the insulating gas. Therefore, the operation manual instructions need to be followed.

The gas handling needs to be carried out in accordance with the IEC 62271-4 gas handling standard (IEC 62271-4 2013).

Touch voltages and touch temperatures need to be limited to values below the required values of the related IEC standards.

Tunnel inspections are recommended to coincide with possible impacts coming from water, dust, or other environmental impact. Such sequences of inspections could be in a yearly cycle.

Seismic requirements should be taken into account in earthquake-prone areas.

During HV testing and during pressure vessel testing at the installation and commissioning process, precautions as used with high-voltage systems have to be taken into account.

Safety assessments need to be made for each installation in tunnels or bridges. The requirement will vary with the use of the structure. Part of the safety analysis is the impact coming from failure in the GIL, e.g., internal arc, fire in the structure, and accidents in the tunnel or on the bridge.

### 27.10.2 Fire

Precaution associated with the GIL is not needed, since only metal and non-combustive materials are used. There is no additional fire risk coming from the GIL.

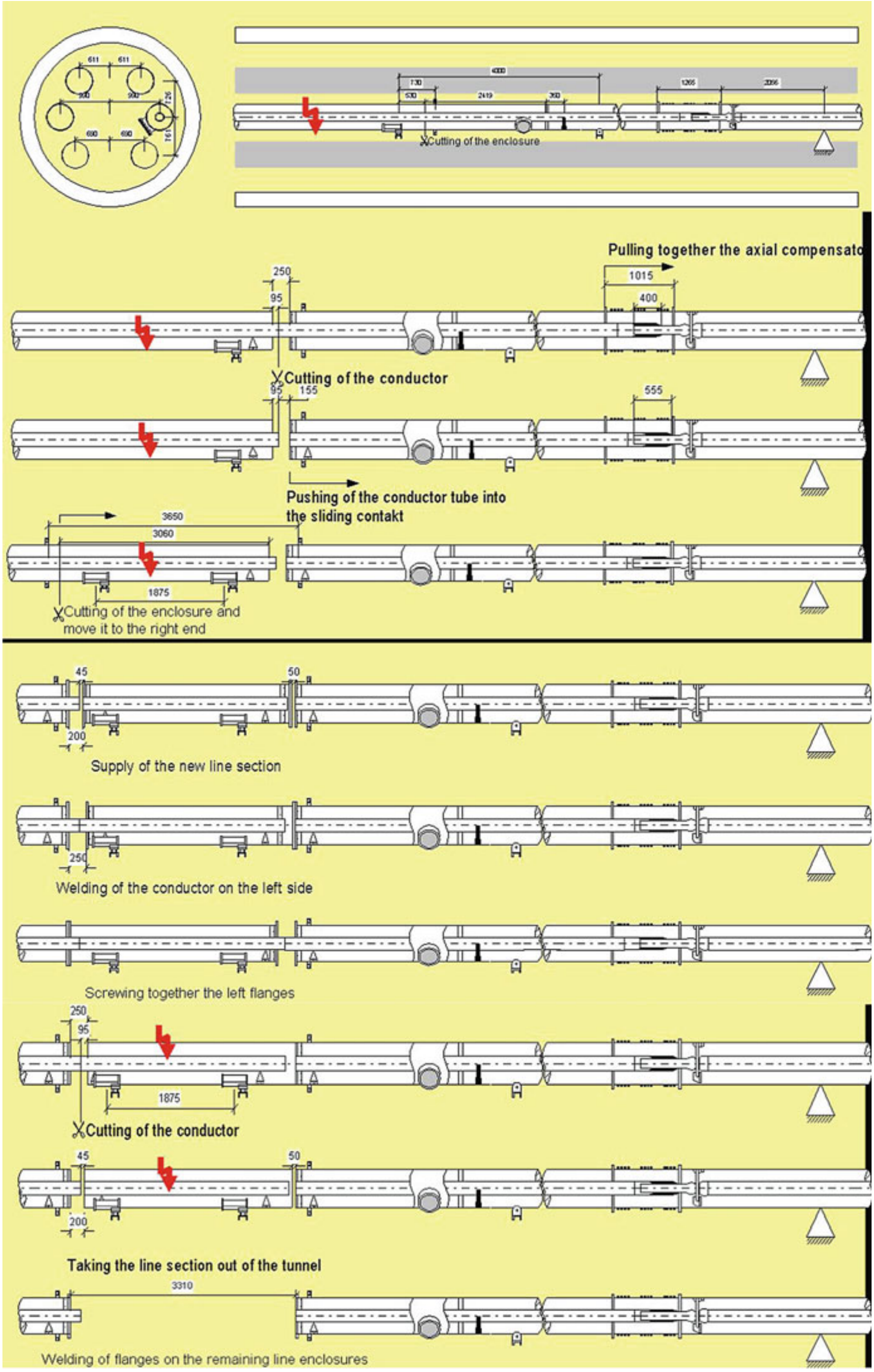


**Fig. 27.37** (continued)

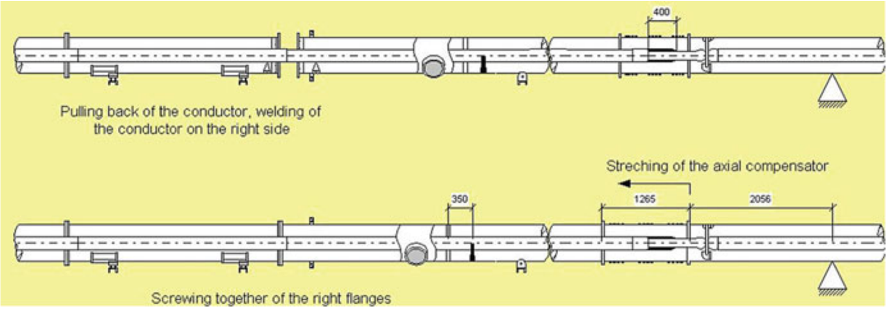


**Fig. 27.37** Repair scheme

In the event of an unmanaged fire, temperatures exceeding 800 °C may cause chemical/physical decomposition products to be produced. The toxicity of such products will need to be considered during any repair or cleanup once the fire is extinguished.

## 27.11 Cost Analysis

### 27.11.1 Overall Economic Aspects

GIL is a means of transmitting electrical power at transmission voltages. It provides an alternative to cables for the undergrounding of circuits. It has comparatively high ratings and is suitable for transmission over long distances (Koch 2012; Cigré Technical Brochure 2008). Factors on investment cost are investigated in detail and in relation to cables in CIGRE Study of B3.B1-27 (CIGRE Technical Brochure 2015). The economic comparison to OHL is investigated in (Benato et al. 2006b, 2007a; Benato and Napolitano 2012).

In terms of capital costs, overhead conductors and AIS connections are the most economical means of high-voltage transmission compared with cables and GIL.

There is a general reluctance toward choosing GIL chiefly due to the high investment costs; however there are other project issues which may be improved or achieved using GIL.

The cost of losses over the lifetime of an installation can be significant. The losses depend on the actual power transmitted and are highly variable. The losses are likely to be highest for an overhead line. For comparison with capital costs, the cost of losses incurred throughout the life of a circuit can be converted to an equivalent capital sum at the time of purchase or capitalized to the present worth. The capital cost of losses will be specific to the particular project.

When comparing the costs of GIL with cables, it is difficult to state a clear boundary due to the large number of variables that influence the economics, many of which depend on the particular project. GIL terminations are less expensive than cable sealing ends.

To match the ratings of some overhead lines, it is sometimes necessary to use two cables per phase, thus increasing the cost per unit length of the cable option. GIL has a significantly higher rating than cable, and it may be possible to match the overhead line rating with a single GIL per phase.

The design of a GIL must satisfy dielectric, thermal, and mechanical requirements. If the current rating for an application is low, it does not follow that GIL dimensions may be reduced. GIL may therefore be less competitive than conventional cables at lower ratings.

For those wishing to compare the costs of GIL with cable installations, reference should be made to CIGRE TB 639 “Factors for Investment Decision GIL vs. Cable.”

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# Part E

# UHV and Offshore Substations

*Kyoichi Uehara*

# UHV Substations

# 28

Kyoichi Uehara

## Contents

28.1 UHV Substations .......... 568
28.2 Technical Requirements for UHV Substation Equipment .......... 572
28.3 Reliability Issues in Substation Equipment .......... 576
28.3.1 Data on Reliability Issues in Substation Equipment .......... 576
28.4 Transportation and On-Site Tests of UHV Substation .......... 579
28.4.1 General Consideration Concerning Transportation .......... 579
28.4.2 Transportation Restriction for Transformers .......... 579
28.4.3 On-Site Tests .......... 582
28.5 Maintenance and Diagnostic Tests .......... 582
28.6 Recommended Optimization of UHV Substation .......... 582
28.6.1 Insulation Coordination for UHV Substation .......... 583
28.6.2 Layout for UHV Substation .......... 585
28.6.3 On-Site Acceptance Test and Commissioning Tests .......... 587
28.6.4 Substation Comparison (GIS, Hybrid-IS, and AIS) .......... 588
28.7 Future UHV AC Transmission System Planning, Design, On-Site Assembly and Test, Maintenance, and Operation .......... 589
References .......... 590

Ultrahigh-voltage (UHV) and offshore substations are fast-becoming mature applications, but there is a big difference between substation technologies. UHV technology has a relatively long history, and offshore substation technology meets the necessity of recent sustainable electricity supply and the application of the cutting-edge substations. In this part, UHV substations are described in Chap. 28 and offshore substations are described in ▶ Chap. 29.

K. Uehara (✉)
Transmission and Distribution Systems Division, Toshiba Energy Systems and Solution Corporation, Kawasaki, Japan
e-mail: kyoichi.uehara@toshiba.co.jp

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## 28.1 UHV Substations

UHV AC transmission technologies have been installed and in service since the 1980s. In the 1980s, USSR, Italy, Japan, China, and the United States were all developing UHV equipment and technologies.

During the years 1983–1988, many of the research projects on UHV AC transmission neared completion of their research activities and tested prototypes of the main components. The USSR first commercial 1200 kV systems (Ekibastuz to Kokshetau, 500 km, and Kokshetau to Kostanay, 400 km) were placed into service in 1985 (ELECTRA 1989). The USSR 1200 kV lines were reduced to 500 kV operations due to partial discharge issues of transmission line equipment. After the initial project, there were no commercial UHV projects for more than 20 years. In early 2009, China's first UHV transmission line, the 1000 kV Jindongnan to Nanyang to Jingmen UHV AC project, was placed into operation successfully, and the transmission capacity was expanded to 5 GW at the end of 2010. India began to verify 1200 kV transmission technologies in Bina substation in 2012 (Fig. 28.1).

Large-scale power sources have developed as the need and growth of electricity have become a necessity in society. It is important to transmit the electric power efficiently from these power sources to the area of consumption. Moreover, network enhancement has the potential to decrease the system stability and worsen fault current levels. To counter energy growth problems in existing high-voltage transmission systems, multiple transmission lines and switchyards may be necessary due to the shortage of transmission capacity and the need for improvement of system stability. As a result, large facility investment may be required, and the effect of transmission losses would be considerable.

To solve the abovementioned problems, UHV AC and UHV DC transmission systems were developed to transmit large amounts of electric power by the minimum number of transmission lines effectively, efficiently with stability.

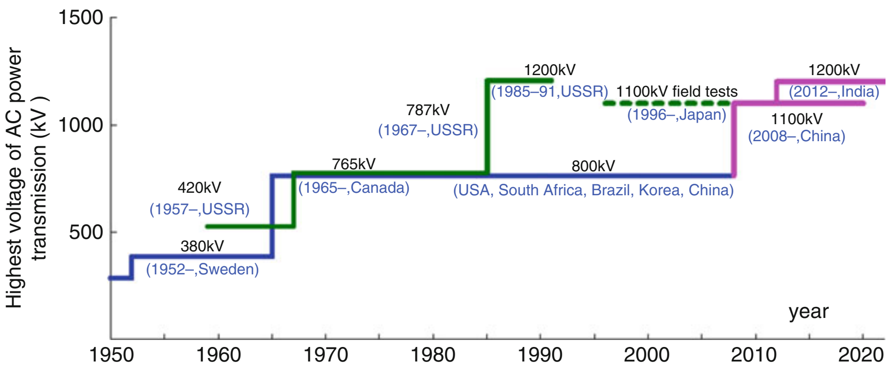



**Fig. 28.1** Highest voltage of AC power transmission. (CIGRE WG A3.22 2008)

There are advantages in both UHV AC and UHV DC, and Table 28.1 shows the comparison between HVAC and HVDC systems.

At present, UHV DC transmission systems are applied as point-to-point, but UHV DC grid (multiterminal systems) will be constructed in the future. UHV AC transmission systems are used as a networked grid, and substations play an important role in the case of the power delivery system. UHV AC systems are mainly described in this chapter.

UHV AC transmission systems are necessary to meet the following specific requirements similar to UHV DC system:

1. Limitations of transmission right-of-way
   Figure 28.2 shows the difference of the required right-of-way between 550 kV AC and UHV (1100 kV AC).

Due to the increase of electric power demand, new transmission lines are necessary. Obtaining additional rights-of-way from the existing transmission lines and environmental restrictions is a constraint. UHV AC and UHV DC transmission lines are economic countermeasures to mitigate this issue. UHV AC and DC allow the

**Table 28.1** Comparison between HVAC and HVDC systems

| Characteristics of AC systems | Characteristics of DC systems |
|---|---|
| Easy to keep stability | Simple transmission line design |
| Easy to control the whole network system | No cable loss by charging current |
| Easy to form new work configuration | No care for short circuit capacity |
| | Improve stability for long-distance transmission line |
| | Quick and flexible power flow control |

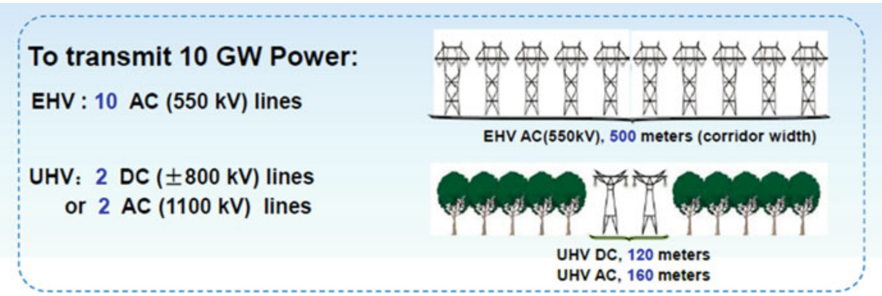



**Fig. 28.2** Right-of-way comparison between 550 kV transmission system and UHV DC and AC system

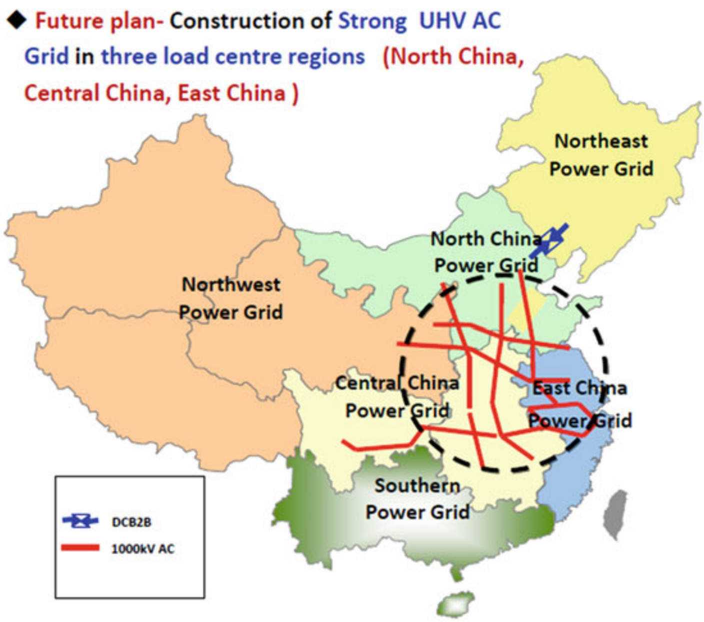



**Fig. 28.3** UHV AC transmission system plan in China in 2015

transmission of larger amounts of electricity in a smaller space. Right-of-way availability and space are becoming more difficult to obtain and gain regulatory permission.

2. Bulk electricity transmission and stability issue

The amount of renewable energy is increasing at a rapid rate, and the consumption location is often very far away from the generation sources.

UHV AC and UHV DC transmissions are efficient ways to transfer bulk electricity over longer distances.

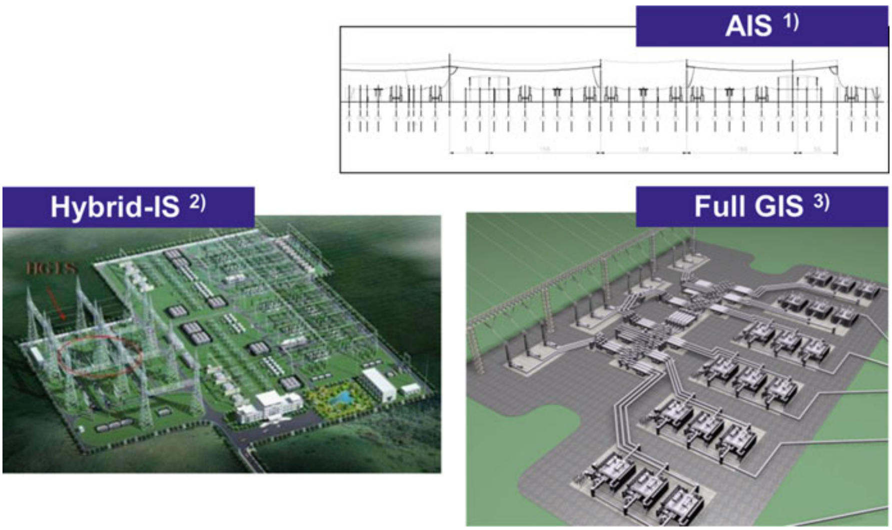
Figure 28.3 shows one example of UHV AC transmission system plan in China to transfer huge amounts of wind power from the northwest to the eastern coastal area (consumption area) and coal and hydropower from the west to the eastern coastal area (consumption area). The distance between these generation bases and the consumption area is of the order of 800–3000 km.

A large amount of electricity transmission would not be practical without the introduction of a UHV AC system and UHV DC system. In the case of more than 1000 km transmission system, UHV DC systems are adopted.

3. Large area of land needed for UHV substation and comparison of UHV switching facilities

**Table 28.2** Comparison of AIS, Hybrid-IS, and GIS. (CIGRE WG B3.22 2009)

| | AIS | Hybrid-IS | Full GIS |
|---|---|---|---|
| **Insulation** | Mostly air insulation | Air insulation main busbar<br>Switchgears gas insulated | Fully enclosed in enclosure except entrance bushing |
| **Height** | Tall equipment | Low profile for switchgears<br>High bus conductors | Low profile<br>Only entrance bushing |
| **EMF** | Issues on switching equipment | Easy to control<br>(bushing and main bus) | Easy to control<br>(entrance bushing) |
| **Seismic** | Issues on various equipment | Issues on limited equipment | Only entrance bushing |
| **Pollution** | Issues on various equipment | Issues on limited equipment | Only entrance bushing |
| **Equipment costs** | Low | Intermediate | High |
| **Substation costs** | Depend on circumstances | Intermediate | Depend on circumstances |
| **Maintenance and Operation** | High | Intermediate | Low |
| **Installation time** | Long | Intermediate | Relatively short |
| **Construction costs** | Depend on circumstances | Intermediate | Depend on circumstances |




Based on the experiences of Japan, China, and India, it is difficult to acquire the large area of land required for UHV AIS substations. An AIS substation requires a very large amount of space for the switching equipment and bus layout.

Hybrid-insulated switchgear (Hybrid-IS sometimes known as mixed technology switchgear (MTS)) (CIGRE WG B3.20 2009) and gas-insulated switchgear (GIS) are practical solutions to reduce space and are commonly applied for UHV substations.

Hybrid-IS or GIS substations have the following benefits (green or yellow colored) in Table 28.2.

4. Economic consideration of UHV substations

The cost of UHV substations is still considerably high compared to existing EHV (extra-high-voltage) substations, because the technology for UHV equipment is still new and the number of manufacturers is limited. Therefore, cost evaluation is an important planning aspect to consider in the decision to construct UHV substations. Total life cycle cost and optimization of the design are key requirements of the cost evaluation when planning UHV facilities.

GIS substations may appear to be costlier than AIS; however, it depends upon many factors such as the possibility of land acquisition, geographical condition, environmental condition, labor cost, local laws, etc., and these aspects vary from country to country. With regard to the UHV-specific technical requirements, such as seismic qualification, pollution, and EMF, there are rather more technical issues to be solved in the case of AIS. Therefore, Hybrid-IS or GIS is usually more suitable for UHV AC transmission facilities in order to achieve a reliable and compact substation (CIGRE WG B3.22 2009).

The following measures have been taken in order to reduce the cost of UHV substation equipment (CIGRE WG B3.22 2009; CIGRE WG C4.306 2013; CIGRE WG A3.06 2011):

1. Insulation level (LIWV and SIWV) reduction by applying surge arrester with low protective level.
2. Closing and breaking resistor application to GCB in order to reduce the test voltage of equipment.
3. Disconnector with resistor suppresses VFTO surges.

## 28.2 Technical Requirements for UHV Substation Equipment

The following are specific requirements for a UHV AC transmission system:

1. Secondary arc extinguishing requirement
   One of the special system requirements of UHV AC systems compared with lower-voltage systems is the extinguishing of secondary arcs. The secondary arc associated with a UHV transmission line fault can last longer due to the

**Fig. 28.4** Artificial staged fault single-phase-to-ground testing on Nanyang-Jingmen UHV line

electrostatic induction from the other healthy phases (induced current). In order to quickly extinguish the secondary arc and successfully secure high-speed multi-phase reclosing, there are two possible measures to cope with this issue.

One is the introduction of a high-speed earthing switch (HSES). HSES closes to quench the secondary arc and then opens again to allow auto-reclose of the circuit breaker. The AC temporary overvoltage (ACTOV) tends to be higher due to the Ferranti effect and load rejection. Special attention is necessary to mitigate these tendencies.

The other is the four-legged reactor to extinguish the secondary arc.

A four-legged reactor consists of each phase reactor and a neutral reactor from the star point of three reactors to earth.

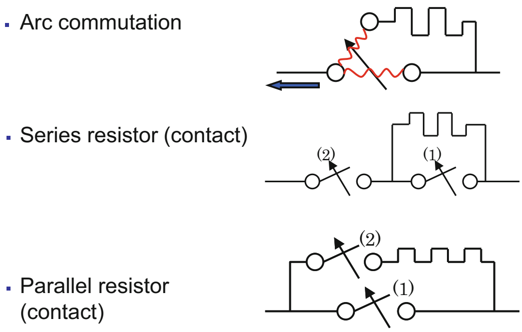
Figure 28.4 shows the artificial single-phase-to-ground testing; after a fault, the secondary arc should be rapidly extinguished. The fault test was triggered by a metallic wire fired to contact the main circuit by means of a rocket. A four-legged reactor was applied to quench this secondary arc ($11.6A_{peak}$, initial short circuit was $9.7kA_{peak}$ in this case).

2. Insulation coordination to reduce the system cost and to improve the reliability (reduction of UHV testing voltage which has enough insulation margin compared with existing transmission system)
   - Surge arrester with lower protective levels (suppression of all kinds of surges)
   - GCB with closing and opening resistors (suppression of switching surge)

   Pre-insertion resistor during closing and post-insertion resistor during breaking are applied to mitigate switching overvoltages.
   - Disconnectors with resistors (suppression of disconnecting surge)

A pre-inserting resistor during closing and post-inserting resistor during opening are applied to mitigate very fast transient overvoltage.

There are three ways to insert a resistor. China, Japan, and Korea have adopted 500 Ω arc commutation-type resistors.




3. Earthing systems used for switchgear in the UHV substation for reduction of surges in secondary circuits
   When designing a GIS and Hybrid-IS for the UHV substations, a multiple earthing method is employed to reduce electromagnetically induced current in the secondary circuits.
   An auxiliary earthing mesh is installed under the switchgear for grounding and bonding of high-frequency touch potential. Whether the substation equipment is GIS or Hybrid-IS, it is necessary to reduce the electromagnetic-induced surge voltage in secondary circuits during earth faults.
   - Reduction of the inflow current into the earthing mesh

   UHV transmission lines normally have a very high current rating for the greatest economic transfer: examples of 6 kA or even 8 kA are common. In the case of a multiple earthing system, the inflowing current at the end of the line can increase up to the rated current of the line. Some countermeasures are necessary to reduce the inflowing current at the bushing terminal. A shunt bar is connected between phases to reduce the inflowing current into the earthing mesh. These shunt bars need to be of significant cross-sectional area in order to carry the 6–8 kA currents involved.
4. Reduction of required substation space area for a UHV substation
   Hybrid-IS and GIS substations are methods which can be used to reduce substation space. The use of $SF_6$ gas to reduce equipment size and clearance is an advantage over AIS.
5. Ensuring the reliability of UHV equipment
   - Seismic design

   Due to equipment size and construction of UHV substation facilities, it is very important to design and test the seismic performance of all UHV equipment. It is especially important for top-heavy porcelain-type gas bushings to use heavy porcelain, porcelain-housing to have heavy porcelain, porcelain-housing surge arresters, and supporting insulators in a region where earthquakes are common.

- Salt contamination

  Larger diameter of UHV equipment bushing needs more increased creepage distance compared with lower-voltage class; however, the height of bushings has to be limited for seismic considerations. In order to achieve a satisfactory compromise between pollution design and seismic design, shed shape and creepage distance should be analyzed. IEC 60815-3 and CIGRE Brochure 532 are a good reference for determining creepage distance and for designing AIS substation equipment in a contaminated environment.
- Transportation and assembly of UHV equipment on-site

  Since the rated voltage of UHV substation equipment is more than twice that of 500 kV class, the size of the equipment tends to be significantly larger. Transformers are the largest items both in size and weight. Transportation restrictions must be taken into account in the design of UHV transformers.

  For UHV-class equipment, the number and size of subassemblies are exceptionally large. In most applications, UHV substations are constructed in locations which are very far away from the manufacturing factories. It is therefore important that quality control during transportation is carried out. Monitoring shipments with an accelerometer is important. Mishandling of equipment during shipment can be a factor for equipment failure and reliability.

6. Environmental design considerations

   At the planning stage, it is essential to evaluate the harmonization of the UHV substation with the environment. Here are some examples on how to evaluate this issue:
   - A UHV substation model to check the harmonization with the landscape
   - A 3D model to check the harmonization with the landscape
   - Reducing the overbearing and pressuring of large equipment by substation design
   - Reducing the height of a substation by introducing lower equipment BIL accomplished by applying surge arresters with low LIWV and SIWV protective level
   - Reducing the substation space by adopting the compact equipment and structure
7. Electric and magnetic field control (main circuit is UHV so the following aspects should be considered)
   - Protecting the human body from exposure to electromagnetic field by choosing the appropriate levels of electric and magnetic fields and clearance

   According to ICNIRP Guidelines and IEEE C95.6 Standard, E-field (electrical field) and B-field (magnetic field) are determined for occupational exposure. In the case of UHV substation, specific level should be adopted, for example, 200 V/cm as maximum E-field. Unlike the E-field, specific levels are not required for the magnetic field. Design should allow adequate approach distance for maintenance and switching.
   - Control audible noise by making the appropriate design

     Specifying the proper or required audible noise from substation facilities is a design requirement. The normal procedure is to calculate the noise level from the surrounding area with higher accuracy and introducing noise reduction technologies such as walls.

Some designs are adopted in UHV substations and transmission lines to reduce the audible noise caused by the wind vibration and flow.

- Avoiding the disadvantageous effects of corona discharge on the environment and controlling the corona losses

  Corona losses are affected by the environmental conditions, such as rain, and the data on annual average corona loss from energized UHV lines is measured and used for the design of UHV substation (CIGRE WG B3.22 2009).

## 28.3 Reliability Issues in Substation Equipment

UHV transmission systems are capable of transferring large amounts of electrical energy. Consequently, if a failure occurs in a UHV transmission system, the influence on the system is significant from the viewpoint of reliability and stability of the power system. Since UHV equipment is relatively new, there is limited experience with equipment failure; consequently, referring to the reliability data for existing EHV equipment is necessary. Preventing a forced outage of a UHV substation should be a principal design aspect to prevent a single point of failure. On-site tests are important to ensure the reliability and performance of the equipment after transportation and assembly. Replacement of failed equipment can be difficult as lead times could take more than a year. Spare equipment to implement rapid restoration of service should be part of the original design requirement.

There are some failure statistics for EHV equipment. CIGRE failure survey report shows us GIS and transformer failure data up to 800 kV. Based on this data, an assessment of the reliability of UHV equipment can be performed.

### 28.3.1 Data on Reliability Issues in Substation Equipment

A detailed survey of field service experience with circuit breakers and gas-insulated switchgear during the period from 2004 to 2007 was performed under the activities of CIGRE WG A3.06 “Reliability of HV Equipment.” Similar surveys have been carried out twice in the past, during the years 1974–1977 and 1988–1991, respectively.

Results of the WG survey were published with several technical brochures, and the summary was introduced as a tutorial at the colloquium of SC A3 held in Vienna in September 2011 (Fig. 28.5).

By reviewing the failure results from the survey, the requirements for on-site acceptance tests can be clarified.

Major failure frequencies for all the voltage classes have decreased compared to previous surveys. In the case of circuit breakers, the failure rate is almost half of the

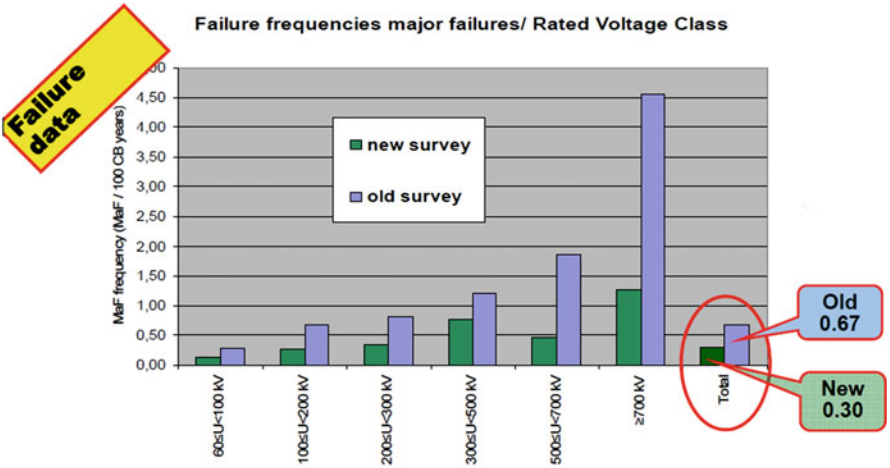



**Fig. 28.5** Major failure frequency of GCB (Quoted from the tutorial at the colloquium of SC A3, held in Vienna in September 2011). (CIGRE WG A3.06 2011)

original rate. The results of the survey indicate a high failure rate for 700 kV and above classes compared to the lower-voltage classes. It should be noted that the amount of data in 700 kV class and above field is too small to confirm the trend.

The results for circuit breakers indicate that live tank breakers have a three times higher failure rate than GIS or dead tank breakers. Higher failure frequencies are shown, as operation year's increase for both live tank and dead tank breakers, and also significantly higher failure frequencies are shown for older live tank breakers. According to the results for GIS manufactured between years 2004 and 2007, the cause of more than 70% of the failures is recorded as "dielectric breakdowns." For older GIS manufactured before 1993, the cause of about 70% of failures resulted from "failing to perform requested operation." Since "dielectric breakdowns" on the primary circuit of GIS should be less affected by age, the increase in "failing to perform requested operation" in the recent survey may be caused by the increase in the proportion of older switchgear in the field or the survey sample.

A major failure in a UHV substation causes severe impact on the whole transmission system; consequently, higher reliability is necessary for UHV equipment than in lower-voltage classes. The survey indicates that dead tank breakers and GIS have higher reliability than other types. The selection of the appropriate circuit breaker is a difficult decision; factors that may influence selection are standard insulation level, breaker monitoring, and proper insulation coordination.

For GIS, the majority of major failures for the products newly installed in the field are listed as "dielectric breakdowns," emphasizing the need for on-site dielectric tests to confirm reliability. Assessing plant manufacturing clean conditions for the appropriate voltage and UHF PD measurements in addition to dielectric tests can significantly affect switchgear reliability. On-site dielectric tests to check for the presence of metallic particles unintentionally left inside GIS enclosures during site assembling work, as well as any physical damage during transportation or site activities, should be added to all commissioning test procedures.

Investment for a high-voltage on-site test equipment should be considered and can be included as part of the initial capital expense. GIS equipment flashover while in operation may result in extensive site investigation and repair work; therefore, utilizing effective detection of any trigger for flashover and reduced dielectric test voltage is recommended.

The CIGRE survey results for the 700 kV and above class indicated that “the partial discharge measurement in addition to power frequency voltage application” was carried out for all the products, and further “impulse voltage test (LI or SI) in addition to power frequency voltage application” was also universally performed.

Considering that failure frequencies may increase in older products, performing appropriate maintenance, particularly on a mechanism under operational conditions, is important. Proper maintenance and testing can improve reliability and extend the life of most GIS equipment.

An ongoing survey for field service experience on power transformers during the operational period from 1996 to 2010 was carried out under the activities of CIGRE WG A2.37 “Transformer Reliability Survey.” The WG 12.05 “Transformer Reliability” also surveyed the field service experiences with power transformers during the operational period of 1968–1978 and published the report in Electra in 1983 (Bossi et al. 1983). Ten years later, WG 12.14 attempted to conduct improved surveys; however, it was unsuccessful with reported difficulty in compiling and analyzing the data from the survey. The CIGRE Advisory Group on “Reliability” in SC A2 was established in 2000 (Lapworth 2006) and later WG A2.29 established in 2004, which were also unsuccessful at compiling a survey.

The survey period for field service experience on power transformer in WG A2.37 was from 1996 to 2010 and analyzes the failures occurring after 2000. This survey is ongoing, and an interim report (Bossi et al. 1983) was published in Electra. The CIGRE interim report shows that transformer windings were reported to have the highest failure rate.

The most recent reported failure rate of power transformers with rated voltage of 700 kV and above is significantly lower than the reported failure rate of the same devices in the 1970s. The failure rate for the substation power transformers with ratings of 700 kV and above is approximately six times higher than generator step-up transformers with the same voltage ratings. Again, windings were reported as the predominant cause of failures. Tap changers are reported as the second leading cause followed by bushings as the third. The proportion of failures reported as due to these three causes is approximately 90% (Fig. 28.6 and Table 28.3).

The substation transformer failure rate values for the 700 kV and above class are approximately ten times higher than the 300–500 kV voltage level. The sample number is not large enough to confirm a trend.

This survey is still ongoing, but reliability improvements for higher-voltage class levels may be needed. Improvements related to commissioning and verification tests prior to transformer energization should reduce the failure rate of power transformers in service.

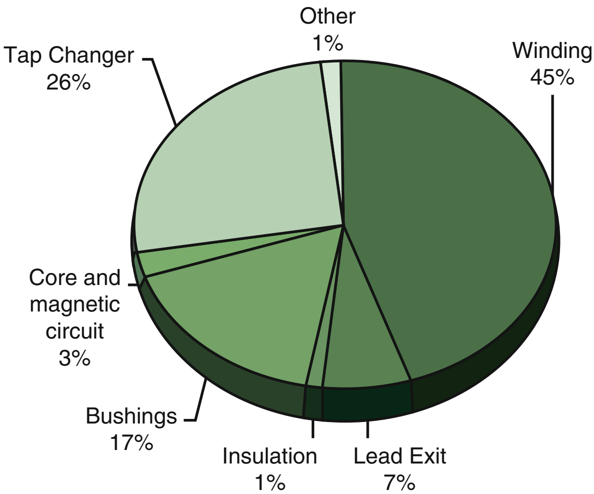



**Fig. 28.6** Failure location of substation transformer. (Bossi et al. 1983)

## 28.4 Transportation and On-Site Tests of UHV Substation

### 28.4.1 General Consideration Concerning Transportation

UHV substation equipment is rated more than twice that of 500 kV class or below; the size of the equipment is larger. It is more important to take into account the transportation restrictions in the design of the equipment. Special trucks, trains, and boats may be necessary to transport equipment from the factory to site. In some cases, roads or bridges will have to be improved or modified for equipment to be delivered to site.

For the equipment such as GIS, each component should be designed so as to be an optimum transportation unit considering assembling and testing at the factory and on site. In the meantime, for GCB being the largest component of a GIS, height and weight should be specified to ensure delivery can be achieved. A suitable vehicle for transportation should be recommended by the equipment manufacturer.

### 28.4.2 Transportation Restriction for Transformers

Transformers are the largest equipment in both size and weight among UHV substation equipment. Transportation route and restriction must be taken into account in the design of UHV transformers.

For example, UHV transformer specifications are approximately double the voltage and power of the highest system voltage transformers (500 kV) currently used in Japan. However, these UHV transformers must be transported on the same

**Table 28.3** Failure rate of power transformers. (Tenbohlen et al. 2012)

| Failures and population information | Highest system voltage [kV] | | | | | |
|---|---|---|---|---|---|---|
| | $69 \leq kV < 100$ | $100 \leq kV < 200$ | $200 \leq kV < 300$ | $300 \leq kV < 500$ | $kV \geq 700$ | All |
| (a) Substation transformers | | | | | | |
| Failures | 145 | 206 | 136 | 95 | 7 | 589 |
| Transformer – years | 15,077 | 46,152 | 42,635 | 29,437 | 219 | 135,491 |
| Failure rate | 0.96% | 0.45% | 0.32% | 0.32% | 3.20% | 0.43% |
| (b) Generator step-up transformers | | | | | | |
| Failures | 0 | 6 | 27 | 59 | 4 | 96 |
| Transformer – years | 143 | 2842 | 4838 | 12,132 | 740 | 20,695 |
| Failure rate | 0.00% | 0.21% | 0.56% | 0.49% | 0.54% | 0.46% |

railway with the same restrictions as the conventional transformers. The Japanese railway transport dimension limit is 4.1 m in height and 3.1 m in width.

The rating of the UHV transformer needed was 3000 MVA, so the single-phase main tank was divided into two units according to the railway transport limit. One tank of 1/2 phase unit was transported by rail to the nearest rail station to the site and was then loaded onto a special trailer for transport to the site. The shipping weight was approximately 200 t. Figure 28.7 shows the transportation of UHV transformer to the site in Japan.

As a second example, a special truck-tractor and bridge-frame-type trailer was used in China. The maximum transportation weight capacity of a Chinese highway was 450 T total mass including transportation vehicles. The maximum road clearance height was 5 m. So, the transportation limits for the UHV transformer in China were 12 m long, 4.15 m wide, 4.9 m high, and 375 T. For highway transportation, the ground slope could not exceed 15°, and the turning radius should be more than 28 m. Several bridges on the transportation route had to be modified to transport the UHV transformer to the substation. Figure 28.8 is an example of the transformer trailer used.


**Fig. 28.7** Transportation of UHV transformer to the site in Japan

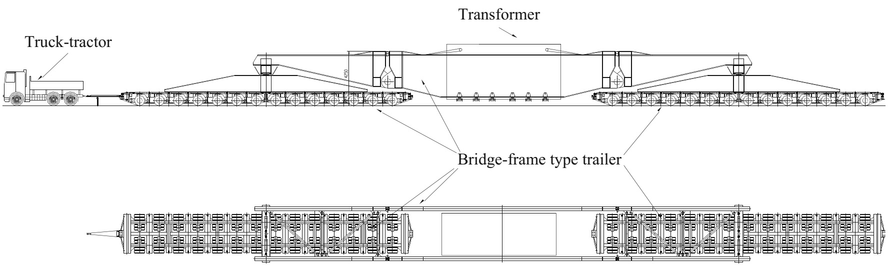



**Fig. 28.8** Transportation equipment for a UHVAC transformer in China

### 28.4.3 On-Site Tests

As described earlier, most UHV substations are located remote from city areas and from the manufacturing plant, and the size and weight of the equipment are considerable. The installation time on site is also very long.

Consequently, UHV substation equipment that passed routine factory testing should be subjected to an on-site acceptance test and a rigorous commissioning program. Maintenance tests and diagnostic tests are needed to determine the operational condition and to monitor the equipment soundness during its service life. Gas monitoring and condition-based monitoring should be considered to monitor equipment performance and prevent a forced outage. Total gas and moisture monitors are a mature technology and should be considered for all UHV transformers. The use of monitors to trend and perform analytics may significantly increase reliability, performance, and life of the equipment. The objective is to use monitoring to prevent a forced outage and the end of equipment life.

On-site acceptance tests are designed to check the correct operation and the dielectric integrity of the equipment after shipping and site assembly. These on-site tests are generally performed by a manufacturer with the close cooperation of a utility, with the aim of verifying the results from the factory tests (Table 28.4).

## 28.5 Maintenance and Diagnostic Tests

Maintenance includes a range of diagnostic and maintenance tests and substation equipment refurbishment activities to ensure the proper operation as shown in Fig. 28.9.

A diagnostic test is conducted to determine the health of the equipment to ensure that it operates effectively during its designed lifetime. Maintenance tests obtain the operational condition and also check if the equipment is free from abnormalities, including degradation that may occur during operation. Maintenance activities, such as examination and inspection, are usually performed during substation outages. IEC 62271-1 recommends how instructions are to be prepared by the manufacturer and implemented by the user. The key is to develop an experience-based program to repair, replace, or refurbish the UHV equipment.

## 28.6 Recommended Optimization of UHV Substation

The optimization of a UHV substation is an essential procedure. UHV substations may consist of three types of switchgear: GIS, Hybrid-IS, and AIS. Any UHV substation should satisfy the following specific requirements of the UHV design: (a) satisfying UHV-specific function, (b) saving land (because UHV equipment is overly large), (c) safety in operation and easy to operate and maintain, (d) easy for maintenance and equipment erection work, and (e) saving material and cost reduction.

**Table 28.4** Flow and outline from on-site acceptance to maintenance test

| | Factory test (routine test) | Transportation and installation on-site | On-site acceptance tests | Commissioning tests | Maintenance tests<br>Diagnostic tests |
|---|---|---|---|---|---|
| **Location of tests** | | | | On-site | |
| **In charge** | | | Manufacturer (user) | User | User |
| **Test area (equipment / substation / grid)** | | | Each equipment<br>Each unit of equipment | A unit of equipment<br>Whole equipment<br>Substation<br>Power grid connection | Each equipment<br>Each unit of equipment |
| **Purpose** | | | 1. Checking the correct operation and the dielectric integrity of the equipment after shipping and site assembly, verifying the quality in the factory. | 1. Confirmation of dielectric and thermal performance of each equipment, appropriate operation of relays and total-system confirmation of substation system<br>2. Dielectric and thermal performance of each equipment connecting to the grid | Maintenance are categorized into "maintenance test," "diagnostic tests," and "overhaul"<br>1. Obtaining the initial data for the operation. (maintenance test)<br>2. Checking if the equipment is free from abnormality including degradation during operation. (maintenance test) |
| **Test items (examples)** | | | <Typical examples of GIS in IEC 62271-203><br>1. Dielectric test on the main circuit<br>2. Dielectric tests on auxiliary circuits<br>3. Measurement of the resistance of the main circuit<br>4. Gas tightness test<br>5. Checks and verifications<br>6. Gas quality verification | <Examples in TEPCO><br>1. Visual check<br>2. Earthing resistance check<br>3. Insulation resistance<br>4. Tests for protection equipment<br>5. Tests for CB<br>6. Alarm and indicator tests<br>7. Supervision and control tests<br>8. Energizing test from tertiary winding (PD measurement)<br>Connecting to the power grid<br>9. Withstand voltage test<br>10.Load test(temperature rise test)<br>11.Inrush test<br>12. Electromagnetic environmental test of substation | <Examples of GIS in SGCC><br>1. SF6 gas humidity<br>2. SF6 gas leakage test<br>3. Insulating resistance of auxiliary circuit and control circuit<br>4. AC withstand voltage test<br>5. Switch impulse withstand voltage test<br>6. AC withstanding voltage test of auxiliary circuit |
| **Remarks** | | | Normally the dielectric test shall be made after the GIS has been fully installed and gas-filled at the rated filling density preferably at the end of all site tests. (IEC 62271-203) | In Japan, there are some regulations as follows:<br>1. Electricity Business Act<br>2. Technical Regulations on Electrical Equipment<br>3. Standard on Power Plants and Substations | IEC 62271-1 recommends the way instructions are prepared by manufacturer and implemented by the user |

## 28.6.1 Insulation Coordination for UHV Substation

From the viewpoint of compactness, insulation reliability, size and weight of substation equipment, and the cost, UHV substation insulation coordination should take into account low test voltage (LIWV, SIWV) and the special equipment to reduce the surge of GCB and disconnector.

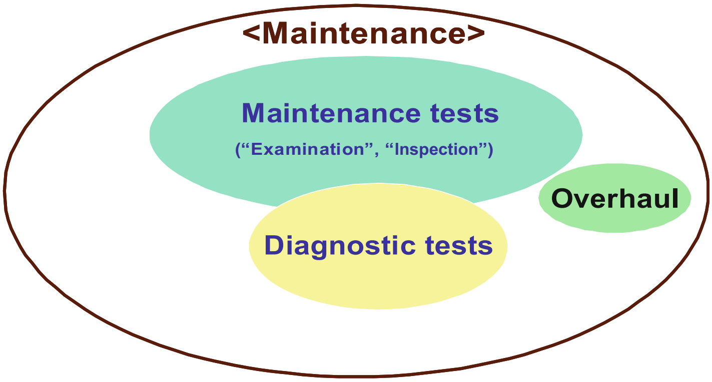



**Fig. 28.9** Definition of maintenance

**Table 28.5** Surge arrester with low protective level characteristics

| kV | Japan | China | India |
|---|---|---|---|
| Rated voltage (rms) | 826 | 828 | 850 |
| Peak at 10 kA (8/20 μs) | 1550 | 1553 | 1600 |
| Peak at 20 kA (8/20 μs) | 1620 | 1620 | 1700 |
| LIPL (p.u.) | 1.80 | 1.80 | 1.73 |
| SIPL (p.u.) | [a] | 1.62 | 1.53 |

[a]Note: SIPL (p.u.) is defined as $V_{2\ kA}$/peak value of max. Line-to-ground voltage. But Japanese standard for SA doesn't specify the $V_{2\ kA}$ value

The basic requirement for surge arresters is a crucial issue concerning the protection level for lightning surges. Guidelines for the selection of arresters in IEC 60099-5 surge arresters – Part 5: Selection and application recommendations. Section 28.6.1 covers details on the selection of UHV arrester.

The selection of surge arresters with low protective level as defined in Table 28.5 is based on Japanese 1100 kV verification of surge arrester with low protective level for 1100 kV system, Chinese 1100 V project application, and Indian application for verification site of 1200 kV system. In UHV substations, the use of these surge arresters with low protective level characteristics is becoming a normal practice. UHV AC insulation coordination can be achieved mainly by the use of UHV surge arrester with low protective level.

Figure 28.10 shows the difference between conventional style UHV AC insulation coordination concept and recent UHV AC insulation coordination. Reduction of the impact of surges can lead to higher reliability of system and equipment and compactness of UHV AC substations and transmission towers. Application of arrestors with lower protective level has contributed to better economic design and lower capital costs.

Figure 28.11 shows one example of recent UHV AC insulation coordination level.

- Conventional Insulation coordination
- Based on conventional Surge arrester
- Only simple study and coordination engineering work
- Tend to higher insulation level (i.e. LIWV = 2550 to 3000 kV)
- Size of facilities is large
- Total cost tends to be high.

- Sophisticated Insulation coordination
  -Based on high-performance Surge arrester and measures for lowering insulation level
  (ie. GCB with closing resistor, DS with resistor)
- Comprehensive coordination study and engineering work, including precise computer-aided calculations
- Lower insulation level ( i.e. LIWV = 1950 to 2400 kV)
- Size of facilities is small
- Affordable & reasonable cost in total

**Fig. 28.10** Comparisons between conventional way and sophisticated way

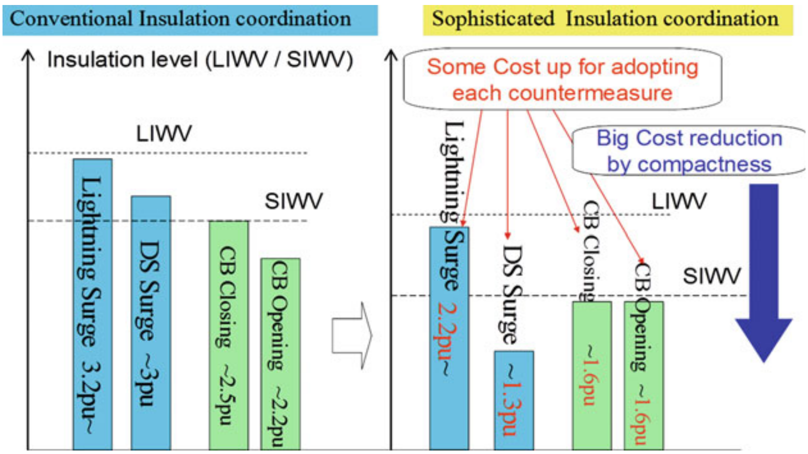



**Fig. 28.11** Concepts of insulation coordination in UHV substation

## 28.6.2 Layout for UHV Substation

The substation layout is likely to be determined by the following fundamental factors:

- Bus system (1 1/2 CB bus system, double bus system)
- Selection of switching equipment (GIS, Hybrid-IS, AIS)
- Selection of LIWV, SIWV, and air clearance

Figure 28.12 shows the typical procedure of UHV substation layout.

**< Selection of Bus scheme>**

1) Reliability
2) Operation Experience
3) Maintenance Experience
4) System Configuration
5) Others

Based on 1)-5) (Mentioned above), Each utility selects the bus system.

**< UHV Bus scheme>**

Based on WG B3.22 WG investigation, UHV Bus system are typically followings.

1) One and half CB system ( Including the transition system of this, Double breaker system)
2) Double bus and 4 bus-tie System

**< Basic Design of UHV substation>**

1) Compact
2) Less impact on the environment
3) Optimizing cost

This basic design concept is recommended for UHV AC substation.

**< Appropriate Insulation Coordination>**

High-performance MOSA is recommended to adopt in UHV substation.

1) High-performance MOSA (1100 kV,class $V_{20kA}$=1620 kV, 1200 kV $V_{20kA}$=1700 kV)
2) Appropriate selection of UHV Surge arrester : type (Porcelain type or Tank type)

-Protective characteristics
-Substation construction (AIS/Hybrid-IS/GIS)

**< Appropriate Clearance and SA arrangement>**

1) Determination of SA arrangement by analysis.
2) Determination LIWV, SIWV of S/S facilities
3) Based on above, select appropriate clearance

AIS insulation coordination procedure is based on IEC.pub60072-2.GIS / Hybrid-IS are introduced by carrying out surge analysis. Surge analysis based on the recent analysis technology.

*Safety factor Ks is used now for AIS. But new surge analysis has been already introduced for GIS and Hybrid-IS. It's necessary to propose IEC to add new concept to consider the margin based on severe surge analysis condition.

**Fig. 28.12** (continued)

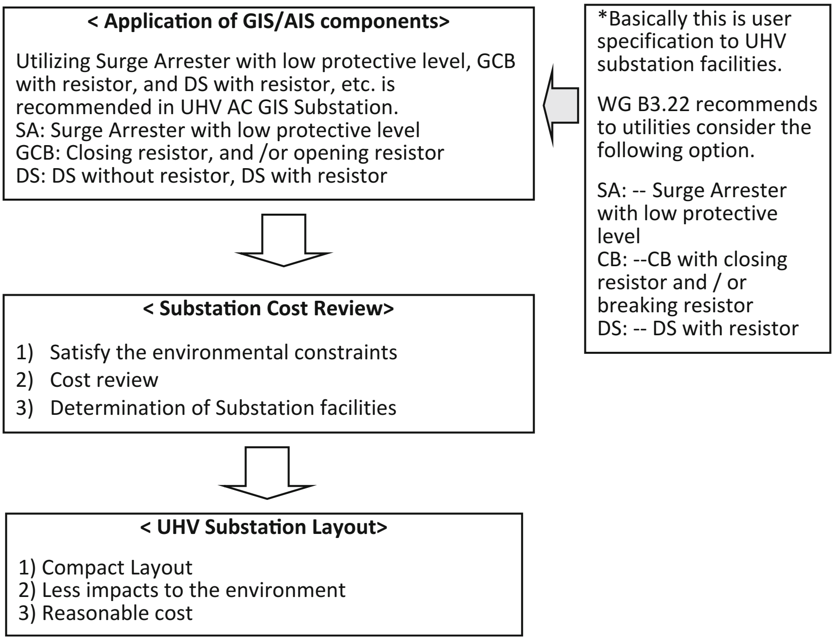



**Fig. 28.12** Typical procedure to determine the UHV substation layout

### 28.6.3 On-Site Acceptance Test and Commissioning Tests

1. **On-Site Acceptance Tests**

WG B3.29 investigated on-site acceptance tests through existing standards. It was found, however, that there were no standards relevant to on-site acceptance tests except for IEC 60060-3. As mentioned earlier, on-site acceptance tests are crucial for UHV substations to ensure the reliability of equipment and the system after transportation and assembly. WG B3.29 proposed IEC and IEEE standardization concerning on-site acceptance tests of UHV equipment.

As mentioned in the CIGRE Technical Brochure No 400 (previous WG B3.22 activity) and existing IEC (IEC 62271-203) and IEEE GIS standards (C37.122), on-site acceptance tests are described as informative.

2. **Commissioning Tests**

At present, there are a number of different regulations for commissioning tests in different countries. It is therefore difficult to standardize the commissioning tests for different utilities. Further work is needed in CIGRE, IEC, and IEEE to develop consistent procedures for UHV applications. Each utility or ECP construction firm should work with the manufacturers and use their internal experience to develop procedures.

### 28.6.4 Substation Comparison (GIS, Hybrid-IS, and AIS)

All mature electrical equipment technologies have their advantages. The comparison of technologies indicates that Hybrid-IS combines a lot of advantages of AIS and GIS and leads to a good compromise. The following table shows a summary of main Hybrid-IS benefits.

There is no recommended general solution for all applications. The individual conditions of each case will have a strong impact on the overall evaluation and can lead to different conclusions (Table 28.6).

**GIS (Gas-Insulated Switchgear)**

Switchgear of which the bays are fully made from GIS components.

Only external HV connections to overhead or cable lines or to transformers, reactors, and capacitors can have an external insulation.

**Table 28.6** Substation switching facilities' comparison (GIS, Hybrid-IS, and AIS)

| | GIS | Hybrid-IS | AIS |
|---|---|---|---|
| Reliability | Most devices are sealed in enclosed metal tanks; they are rarely affected by environmental impacts, and anti-earthquake capability is preferable | By introducing GIS technology, the reliability of Hybrid-IS is improved, but probability of pollution flashover on open air-insulated busbar is higher | The probability of pollution flashover is highest |
| Maintenance and operation | Needless of maintenance, but cannot be resumed in a short time after failure | Lack of operating experience, but the working load is higher than GIS | Operating experience in abundance, but the working load is highest |
| Installation | Easiest, and installation time is shortest | Installation of high frame is inconvenient | Installation time is long |
| Layout | Compact, easy of outgoing | Easy of outgoing | Easy of outgoing |
| Expansion | Easy expansion | Easy expansion | Easy expansion |
| | But restricted by manufacturers | But needs a lot of space | But needs much more space |
| Circumstance | Sealed in enclosed metal tanks, EMI and noise are small, little impact on the environment | Little impact on the environment | Strongest impact on the environment |
| Construction cost | Highest | High | Lowest |

**Table 28.7** Principal technology designs for substations (their components and bays)

| Technology design | Insulation | Insulating medium | Enclosure |
|---|---|---|---|
| AIS technology | External insulation[a] | Air | No enclosure or enclosure (porcelain or composite insulators) under high voltage |
| GIS technology | Internal and external insulation | $SF_6$ or $SF_6$ mixtures | Metal enclosure effectively earthed |
| Hybrid-IS technology | External insulation[a] | $SF_6$ or $SF_6$ mixtures and air | Combination of all |

[a]Note: Internal insulation can be air, $SF_6$, oil, resin, or all other kinds of insulating media

**Hybrid-IS (Hybrid-Insulated Switchgear)**
Switchgear bays are made from a mix of GIS and AIS technology components and switchgear that consists of bays where some of the bays are made of AIS components and some bays are made either of GIS components only or of a mix of AIS and GIS components.

**AIS (Air-Insulated Switchgear)**
Switchgear of which the bays are fully made from AIS components.

Note: Substation, where only dead tank types of circuit breakers are installed in its bays, is also considered to be AIS substation (Table 28.7).

## 28.7 Future UHV AC Transmission System Planning, Design, On-Site Assembly and Test, Maintenance, and Operation

Utilities worldwide may be forced to consider long-distance bulk transmission of electrical energy due to a range of reasons, and many are either implementing or planning UHV grids. In recent years, high economic growth can be observed in developing countries, and demand for electricity is increasing, mainly in large cities. To cope with these circumstances, new power plants including hydro, coal fired with improved emission reduction, large-scale windfarms, or photovoltaic generation plants (renewable), both onshore and offshore, are planned or are under construction. All of these examples are driving the need for high-power and long-distance transmission lines. In developed countries, the worldwide trend and the shift to a low-carbon society are dominant, and therefore there is a need to consider UHV AC transmission systems due to the lower overall transmission costs and to reduce losses.

China has already started to operate commercial UHV AC systems, and India is going to operate 1200 kV UHV system. UHV AC transmission system has to handle a large capacity of electricity with high reliability.

IEC TC122 (UHV AC transmission systems) started on Oct. in 2013. The working group will handle the new system standard dealing with system planning, design, on-site assembly and test, maintenance, and operation. TC122 will propose needed documentation for system standards to meet the special requirements of UHV transmission system.

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# AC Offshore Substations Associated with Wind Power Plants

# 29

John Finn and Peter Sandeberg

## Contents

29.1 Introduction and Fundamental Considerations ..... 592
29.1.1 Introduction ..... 592
29.1.2 Fundamental Considerations ..... 594
29.2 System Considerations ..... 599
29.2.1 Reliability and Availability ..... 599
29.2.2 Overloading Capability ..... 602
29.2.3 Substation Size and Number Required ..... 602
29.2.4 Grid Code Compliance ..... 603
29.2.5 Reactive Compensation and Voltage Control ..... 606
29.2.6 Fault Level ..... 608
29.2.7 General Substation Configuration ..... 611
29.2.8 Neutral Earthing ..... 613
29.2.9 Insulation Coordination ..... 613
29.2.10 Flicker and Voltage Fluctuations ..... 615
29.2.11 Systems Studies Required ..... 617
29.3 Electrical Equipment Considerations ..... 617
29.3.1 Introduction ..... 617
29.3.2 MV Switchgear ..... 618
29.3.3 Main Transformers and Reactors ..... 626
29.3.4 Earthing/Auxiliary Transformers ..... 640
29.3.5 HV Switchgear ..... 644
29.3.6 Export and Inter-array Cables ..... 648
29.3.7 Site Tests and Commissioning ..... 651
29.4 Physical Considerations ..... 656
29.4.1 About Design Considerations ..... 657
29.4.2 Overall Health and Safety Aspects ..... 658

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

P. Sandeberg
HVDC, ABB, Vasteras, Sweden
e-mail: peter.sandeberg@se.abb.com

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29.4.3 Fundamental Design Parameters .... 659
29.4.4 Additional Design Inputs .... 660
29.4.5 Development of Design .... 665
29.4.6 Platform Concepts .... 674
29.4.7 Substructure .... 675
29.4.8 Fire and Explosion Design .... 681
29.5 Substation Secondary Systems .... 683
29.5.1 Power Supplies .... 683
29.5.2 DC Supplies .... 686
29.5.3 Protection .... 690
29.5.4 Control and Supervisory Control and Data Acquisition (SCADA) System Requirements .... 698
29.5.5 CCTV and Security Systems .... 703
29.5.6 Navigation Aids .... 704
29.5.7 Communications .... 705
29.5.8 Equipment Accommodation and Environmental Management .... 706
29.5.9 Maintenance Management .... 707
29.5.10 Metering .... 707
29.6 Special Considerations When Connected by HVDC Link .... 708
29.6.1 System Design .... 710
29.6.2 Grid Code Compliance .... 720
29.6.3 Power Quality .... 723
29.6.4 Technical Studies .... 726
29.6.5 Protection, Control, and Communications .... 726
References .... 727

## 29.1 Introduction and Fundamental Considerations

### 29.1.1 Introduction

It is recognized that there is a global dependence on the finite energy resource of fossil fuel and that alternative and sustainable sources of electrical generation are required. Present developments show a growing interest in renewable and clean energy sources. Rising temperatures, rising sea level, and increasing occurrence of extreme weather conditions have led people to believe we need to change our ways.

Many countries have committed themselves to decrease emissions and to invest in renewable energy. For example, by 2020, 20% of the energy in Europe has to be produced by renewable sources, and the goal is set for 20% reduction of greenhouse gases. Elsewhere in the world similar goals are being pursued.

A popular renewable energy source is wind. Worldwide hundreds of gigawatts of wind power have been installed successfully on land. Recently the wind energy industry has moved offshore where wind speeds are generally higher than on land, where larger machines with higher energy yields can be installed, and where constraints from land area and planning are reduced. The North Sea is a particularly attractive area where water depth is limited and wind is abundant, but also the Baltic Sea and shallow coastal areas near the USA and China are being considered.

The distance from shore of the new offshore wind power plant developments has led to the need for offshore high-voltage AC substation platforms. A number of these

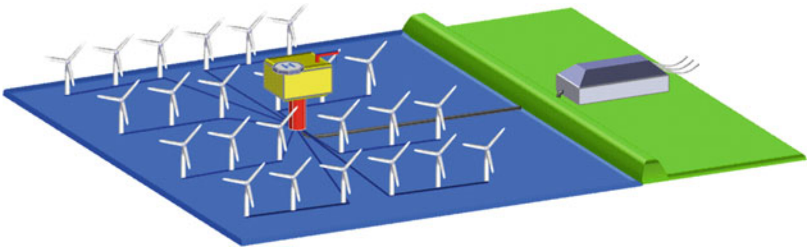


**Fig. 29.1** Typical layout of an offshore wind power plant

platforms have already been installed, and many more are being designed or constructed. This section presents information for the design of offshore AC substations, based on the lessons learned so far.

In order to understand the relevance of offshore substations, this section presents a short description of a typical offshore wind power plant. (The figures and numbers used are typical for wind power plants developed around 2010, but may not represent the optimal configuration. This is only an example.) Most wind power plants existing or under development at that time consisted of between 40 and 300 turbines. Each turbine would typically generate a maximum of about 3–5 MW, though these numbers are changing as development progresses. The turbines usually produce energy at a nominal voltage of 36 kV (after internal transformation), and together these turbines form the wind power plant. Strings of MV cables with up to 10 turbines connected to them form an inter-array cable network (mostly radial). Wind power plants located further (>10 km) from shore will normally be equipped with one or more offshore HV substations where a transformation from 36 kV to 132, 150, or 220 kV takes place for more efficient transmission to shore.

This section concentrates on the design of offshore HV substations (OHVS) as part of an AC interconnection to shore.

The challenges encountered when designing an offshore substation can be divided into four main areas, system considerations, electrical equipment considerations, secondary systems and layout, and civil works and HSE considerations (physical). These aspects are covered in the following sections (Fig. 29.1):

Some innovative solutions are being considered such as gas-insulated lines or high-temperature superconducting cables, which could provide bulk power transmission over large distances.

For bulk transmission over large distances, HVDC transmission becomes a viable option. It is expected that multiple wind power plants or large wind power plants with multiple substations may be connected to one offshore power hub. The wind power plants would still have their individual AC substations, but instead of a direct cable connection to shore, these are connected to the offshore power hub, where the AC/DC converter is located. The power is transmitted to shore using HVDC, and there will be an onshore converter station to convert back to AC. The design of these

| | |
|---|---|
| 29.2 | System considerations – concerning interaction with other parts of the wind power plant system (outside the substation) as these may have an impact on the substation design and single-line diagram |
| 29.3 | Electrical equipment considerations – concerning the choice of equipment, the specific adaptations needed for the harsh offshore environment, and the modular approach required to minimize the maintenance intervention time |
| 29.4 | Physical considerations – concerning the challenges of building a substation offshore and the precautions taken to protect people and equipment |
| 29.5 | Substation secondary systems – concerning the design guidelines and considerations to support the design of a robust secondary system |

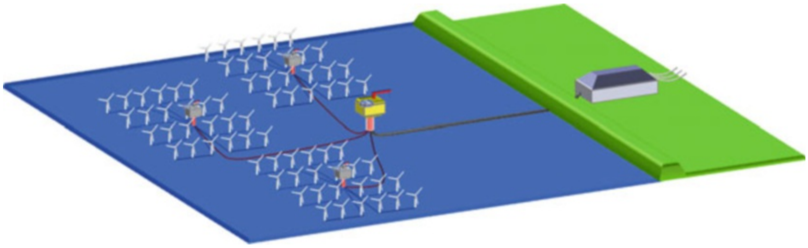


**Fig. 29.2** Possible configuration with HVDC transmission

AC offshore substations used in conjunction with HVDC bulk transmission will be different in some aspects from a pure AC system, and these are discussed in Sect. 29.6 (Fig. 29.2).

## 29.1.2 Fundamental Considerations

This section introduces key considerations of risk, maintenance, and certification which will produce a significant impact upon the design of the substation.

### 29.1.2.1 Risk Management and Assessment Process

It is essential to continuously identify, assess, and mitigate risks by using effective risk management and assessment processes in the offshore substation design. This will assist in the development of the health and safety strategy to be applied by the owner/operator. To do so, it is recommended that a risk management best practices process be applied. Once an effective risk management and assessment process has been implemented, all substation design risks can be taken into consideration.

One method which may be required to fulfill national requirements is to perform a hazard identification study (HAZID) for the substation. The primary objective of this HAZID is to identify specific potential hazards, operability problems, environmental considerations, and impacts associated with the design concept and, where appropriate, to recommend actions to resolve findings that are identified. The objective of the HAZID is to obtain a complete list of such events including:

- Structural integrity or foundation failure
- Electrocution
- Fire
- Explosion
- Physical danger
- Release of toxic or other hazardous substance
- Radiation
- Escape and rescue
- Transfer and access

**Risk Rating**

The identified hazards can be ranked according to the description given below. The ranking is used in order to identify the important hazards that may be analyzed further and which hazards can be neglected.

The applied general risk acceptance principle is based on qualitative risk assessment and a risk ranking concept expressed by a colored risk matrix. The risk matrix is the overall tool for checking and documenting whether the risk is acceptable (green), unacceptable (red), or tolerable (yellow) when reduced to ALARP (as low as reasonably practical) level.

The risk may be evaluated by using a risk matrix and an example is given below:

| | Probability of failure scale / year | | | |
|---|---|---|---|---|
| Consequence | Unlikely | Low | Moderate | High |
| Catastrophic | | | | |
| Severe | | | | |
| Moderate | | | | |
| Low | | | | |
| Indicative values only | 1/10 000 – 1/1000 | 1/1000 – 1/100 | 1/100 – 1/10 | > 1/10 |

Legend:

| Area | Risk | Criteria |
|---|---|---|
| Red | High | Unacceptable |
| Yellow | Medium | Tolerable if ALARP |
| Green | Low | Acceptable |

## (i) Risk Considerations that Affect the Single-Line Diagram

**Optimal Levels of Redundancy**

For onshore substations associated with conventional generation, there are well-defined rules for the level of redundancy to be applied (e.g., N-1). However, as the generation capacity of wind plant is not available all of the time (capacity factor typically 30–40%), the client needs to assess the risk of curtailment of the available energy. Existing wind farms have used redundancy of N or even N+"a little bit" (not quite sufficient to carry full load output) based on intuitive feel. It is recommended that a more structured quantitative assessment should be undertaken which can also be used for optimizing the size of the export cables between capital cost and cost of losses.

(ii) **Risk Considerations Affecting the Offshore Substation Physical Design**

In this section, some of the key risks are identified.

1. ***Basic Design Concept***

Is the platform to be designed to ensure the safety of the personnel who need to operate and maintain the substation only (this is a minimum consideration), or is it also to be designed to protect the assets and the overall integrity of the platform in the event of a catastrophic failure of some items of plant? The design of the layout and some of the systems provided will be greatly affected by which of these considerations is to be taken into account. Let us consider these below.

2. ***Personnel Aspects***

The following aspects need to be considered:

- Transport to and from the substation
  Should this be by boat or by helicopter.
- Transfer from and to the transport at each end
  If boat transfer is to be used then the means of approaching the platform, the boat landing locations, and the ladder and climb assist facilities to be provided need to be considered.
- Emergency evacuation – by sea and/or by air
  The emergency evacuation of persons from the offshore platform must be considered at the design stage of the offshore platform as it will influence the facilities to be included on the platform, typically:
  - Type and location of life rafts and means of lowering them to the sea
  - Type and location of descent systems to the sea/life raft for persons
  - Type and location of other lifesaving equipment
  - Muster area and public address systems
  - Evacuation routes and markings, etc.
- Emergency evacuation of injured persons/stretcher cases
- The emergency evacuation of injured persons/stretcher cases from the offshore platform must be considered at the design stage.
- Exposed locations on the substation platform (walkways and staircases)
- Restricted working areas due to compact design
- Electrical hazards when testing or operating

- Unfamiliarity with the layout and equipment
- Loss of services such as lighting, heating, or communications
- Working in confined spaces
- Fire
- Explosion

3. ***Assets***

If the assets are to be protected against certain catastrophic events, then the following contingencies need to be considered:

- Fire
- Explosion
- Collision from shipping
- Security (protection against malicious acts)

(iii) Operational Aspects

The following operational risks may be encountered and these will be expanded upon in the following sections:

- Depletion (reduction) of protection systems (Sect. 29.5)
- Deterioration of equipment due to uncontrolled accommodation environments (Sect. 29.3)
- Fouling of cooling or ventilation system intakes and exhausts (Sect. 29.4)
- Increased downtime due to spare part unavailability (Sect. 29.3)
- Increased downtime due to inaccessibility of defective elements (Sect. 29.3)

(iv) Commercial Aspects

The following commercial considerations may have an impact upon design decisions:

- Uneconomic repair costs

Repair of any item of plant offshore will be much more costly than performing the same repair onshore. This will generally mean that repairing equipment offshore will very rarely be a cost-effective option. Replacement modules will need to be considered as the normal method of carrying out repairs.

- Loss of production

This should already have been taken into account in the considerations regarding redundancy as mentioned in Sect. 29.1.2 1(i) above with regard to the choice of the single-line diagram.

- Insurance costs/claims for accidents

As the risks associated with offshore substations are so much higher than for onshore ones, then the cost of insurance is likely to be substantially higher. Consideration may need to be given to the design of the plant to enable insurance to be obtained at a reasonable cost or even at all. This may well be true for aspects such as firefighting.

- Transport/repair equipment costs

These considerations will affect the choice of spare parts, accessibility, modularization, etc. which will be expanded upon in Sect. 29.3.

#### 29.1.2.2 Maintenance

Any activity to be carried out on an offshore substation platform will typically cost approximately ten times that of a similar activity carried out onshore. Hence the amount of maintenance intervention must be kept to a minimum compatible with reasonable capital investment. Consequently, the design of the equipment and the substation layout must take this into account.

The following bullet points highlight some of these aspects:

- **Accessibility Within the Substation of Equipment Needing Repair**
- **Equipment Tagging**

A detailed equipment tagging system should be developed such that all items of equipment can be specifically identified at the time of reporting a defect to ensure the correct replacement is dispatched to the platform.

- **Diagnostics and Communications to Allow Focused Maintenance**

Consideration should be given to the use of condition monitoring equipment and communication of the information using the SCADA system. This needs to be carefully evaluated as the reliability of some monitoring equipment can be lower than the equipment it is actually monitoring.

- **Minimizing the Need for Routine Maintenance**
- **Equipment and Spare Parts**

Ensure that suitable landing points for spare parts and for the staff are provided.

- **Availability of Maintenance Specialists with Offshore Training**

Ensure that staff have the relevant training for attendance on an offshore platform or employ a specialist maintenance contractor. The decision should be taken early in the design.

#### 29.1.2.3 Verification and Certification

In the process of performing a good, top quality design process that conforms to the relevant national and international health and safety requirements and best industry practice, the developer of the substation will perform a number of verification activities. These could include internal assessments based on the owner's or engineering company's internal quality system or independent, third-party verification including certification. Certification is mandatory in countries such as Denmark and Germany and commonly follows the requirements set out in IEC 61400-22. According to this standard, Statements of Compliance (or Conformity Statements) are issued for individual phases of a project, while a Project Certificate is issued for the entire (substation) project based on the individual conformity verification activities.

The common practice in this field should be followed or possibly be enhanced for offshore installations. The verification and certification process may be applied to the following stages:

- Engineering design studies and design basis
- Structures, foundation, and systems fabrication and components
- Transportation and installation phase
- Commissioning onshore and (hookup and commissioning) offshore
- Operation and maintenance phase

## 29.2 System Considerations

This section describes the offshore AC substation design issues ranging from those that involve more than one component up to the complete system. This includes reliability, availability, and maintenance issues as well as system characteristics like total substation power flows, reactive power management, applied voltages, and harmonics. Focus is on the electrical system. The physical (offshore) aspects are covered in Sect. 29.4.

This section does not provide standards or solutions to design issues, but it seeks to provide guidance and highlight considerations that should be taken into account when designing an offshore AC substation.

### 29.2.1 Reliability and Availability

When designing an offshore substation, it is important to realize the consequences of the design on upfront capital investment costs, operational costs, and the impact on overall system availability. A balance has to be found between reducing capital investment and operational costs and achieving the required system availability. To maximize revenue, some general guidelines are listed below:

- No redundancy of expensive and/or reliable components
- Minimization of offshore installation and maintenance work

- Smart planning of maintenance (prevention rather than repairs)
- Maximize availability in terms of energy transmission (not time) (Fig. 29.3)

When measuring the availability of an offshore wind power plant substation, it is advised to express availability relative to production. The relevant question being: What percentage of the energy produced can be transmitted? This way of thinking has a large impact on the redundancy considerations.

An alternative to complete redundancy of a system component, where you install two components capable of 100% of nominal capacity, is to install two times 50% or two times 60%. This will still result in loss of capacity when one component fails, but not all capacity is lost. The lifetime cost associated with different transformer configurations is compared taking into account lower losses, extended lifetime, and reduced energy losses. (See Fig. 29.4.)

In case of wind power transmission systems, it is useful to study different approaches to redundancy because (N-1) redundancy can be prohibitively expensive (not only the cost of extra equipment, but also increased platform weight and space are an issue) and the load factor is well below 100%. In many cases loss of part of the transmission capacity due to failure of a component will not impose a constraint on the energy transport. The load duration curve in the previous section (Fig. 29.3) shows that in fact 70% of the time the actual power production is below 50% of maximum production. As a result, if one assumes a 50% system availability and integrate the energy under the curve in Fig. 29.3, this shows that approximately 80% of the energy can be transmitted.

Continuing this train of thought, one could reason that installation of less than 100% of the nominal system capacity is perhaps economically feasible. For instance, transformers or cable systems can be temporarily overloaded, so when only 90% of nominal system capacity is installed, the peaks in wind power can still be transmitted for limited periods utilizing the overloading capacity of the system components. The idea of installing less than nominal capacity is often referred to as N + "a little bit" redundancy.

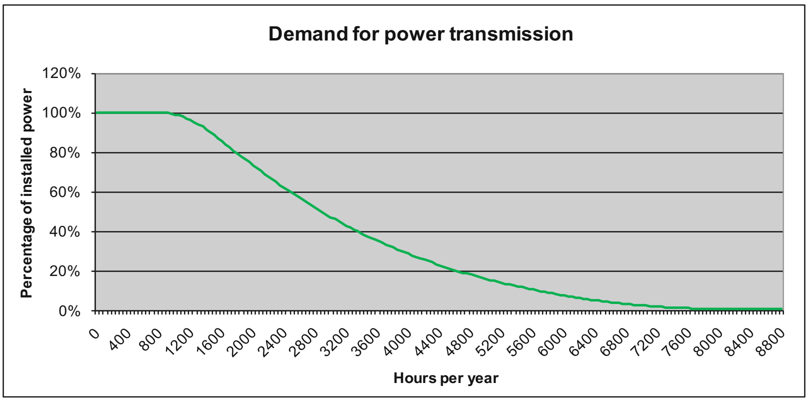



**Fig. 29.3** Wind power duration curve expresses demand for power transmission

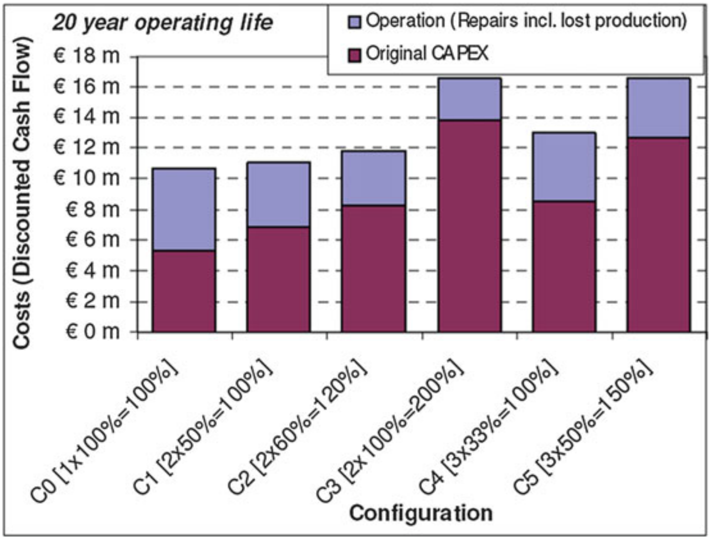



**Fig. 29.4** Ownership costs for 20-year operating lifetime

In practice, most systems are not designed with complete redundancy, but some critical components will be (N-1) redundant, e.g., secondary equipment and communications, HVAC, and cooling systems.

**Export Cable Considerations**

Most offshore AC substations are connected to shore (or to an HVDC system) by one or two export cables, usually three-phase 132 kV or 150 kV XLPE cables. Most of these cables are between 10 and 60 km in length, making them costly assets. Cables generally have low rates of failure, but long repair times and high impact when not available. As a result of the high cost of the offshore cable and their installation, full redundancy on the export cable is rarely an option. However, installing two cables with less than 100% rating or three cables instead of two could be worthwhile; this is comparable to the earlier example of transformer redundancy. As the vast majority of the export cable failures are due to some kind of physical damage, the cables should ideally be installed in cable traces separated by some distance from each other in order to take full advantage of the redundancy aspect.

**Interconnecting Wind Power Plants**

Another method of providing redundancy in export cable systems is by interconnecting adjacent wind power plants. If one wind power plant's export cable fails, the adjacent cable can be used to export energy from both wind power plants. Another advantage is the possibility to provide emergency power in case of failure of the export cable. However, since the nominal capacity of the export cable of a wind power plant is usually equal to the wind power plant's maximum capacity, it will be possible to export part of the energy from the other wind power plant with only one cable during cable fault at one of the wind power plants.

## 29.2.2 Overloading Capability

### 29.2.2.1 Overloading in Normal Operation

Due to the high investment costs of offshore equipment and the characteristics of wind energy, overloading of equipment can be an attractive option. The equipment for transmission of energy from the wind power plant to shore is only utilized at 40–50% on average. By overloading the equipment, i.e., specifying equipment at 80–90% of full capacity, the investment costs of offshore substations and cables can be reduced.

Equipment most commonly considered for overloading are cables and transformers because of their high investment costs. The main disadvantages of this option are shorter lifetime of the equipment and higher losses.

### 29.2.2.2 Overloading in Case of Failure

If a substation consists of two main transformers working in parallel and designed for taking the full capacity of wind power plant when working together, the case of one transformer being disconnected would require the other one to take over entire load to avoid any loss of availability. However, as the full output of the wind farm is not always available, it has to be considered at the early design stage to which continuous and which overload capacity such a transformer should be designed. Even if the full power availability scenario is more likely (e.g., due to very good wind conditions), it might still be beneficial to consider a design taking into account overloading the equipment for short periods of time. The specified overload capacity of the equipment should be thoroughly analyzed at the stage of systems design studies and should include probability of overload situation, level of overload, and its expected duration.

## 29.2.3 Substation Size and Number Required

The question of determining the optimal number and location of substations in an offshore wind power plant should be based, like any other engineering matter, on a techno-economic assessment, although the marine environment poses additional factors to be considered to make the best decision.

In general terms, the following key factors should be considered to choose the optimal place for an offshore wind power plant substation:

- The size and shape of the wind power plant area
- The position of the onshore grid connection point and requirements of the grid owner
- The route of the export cables

- The possibility of a common energy export along with neighboring wind power plants
- Permitting and legislation issues
- Water depth and seabed characteristics
- Project installation plan
- The arrangement of the wind power plant internal collection system
- Shipping lanes
- Access by boat/helicopter

Given the constant increase in the installed capacity (MW) of new offshore wind projects, it is necessary to go further and assess the possibility of installing more than one offshore transformer platform, and therefore some additional factors have to be considered:

- The length of the collection system circuits, involving the maximum acceptable voltage drops and electrical losses
- The installation procedure, involving the availability of technical means and their cost
- Operation and maintenance issues

The decision about the optimal number of substations (commonly one or two) to be installed in an offshore wind power plant should be the result of considering all the previous factors for each one of the different alternatives by means of a techno-economic study to choose the best option.

However, when making the final decision, it is important to consider how the substations will be installed, as heavy lift vessels will normally be required for both the foundation and the topside. Once the weight of either of these exceeds approximately 1500 t, the number of suitable heavy lift vessels is significantly reduced, and checking the availability and suitability of specific vessels for the installation will be required.

### 29.2.4 Grid Code Compliance

With the increase in the use of wind power, countries have developed specific grid code requirements for individual wind turbines or for wind power plants as a whole. The location of the connection point where the grid codes apply differs from country to country.

**Point of Common Coupling**

The main issue in this is the question of where the grid codes apply: at the connection point to the onshore grid, at the individual turbines, or at the connection point to an offshore substation. This point is called the point of common coupling (PCC), and its location will affect the form and location of reactive compensation and other equipment and can therefore introduce extra costs.

It is recommended that these considerations be taken into account when grid codes for offshore wind power plants are designed or adjusted. One logical connection point for application of grid codes would be the location where the wind power plant is actually connected to a grid node which affects multiple parties (e.g., an onshore grid or an offshore substation connecting multiple wind power plants). Figures 29.5 and 29.6 give an overview of different possible connection points in two situations.

**Grid Code Requirements**

The following items are common grid code requirements for wind turbines or wind power plants:

**Fault Ride Through**

Grid codes usually define a minimum time in which the turbine should stay connected to the grid in case of certain voltage dips.

**Frequency Response**

Some countries require wind power plants to contribute to frequency control. Sometimes this may be limited to reducing active power output at a time of high frequency but in other countries contributing more active power when the frequency falls are required. This latter requirement means not generating the full amount possible from the available wind (Fig. 29.7).

**Voltage and Reactive Power**

In countries with high wind penetration or island systems, the wind power plants are normally required to be able to perform continuous voltage control at the point of common coupling (PCC), with a **set point voltage** and **slope** characteristic as

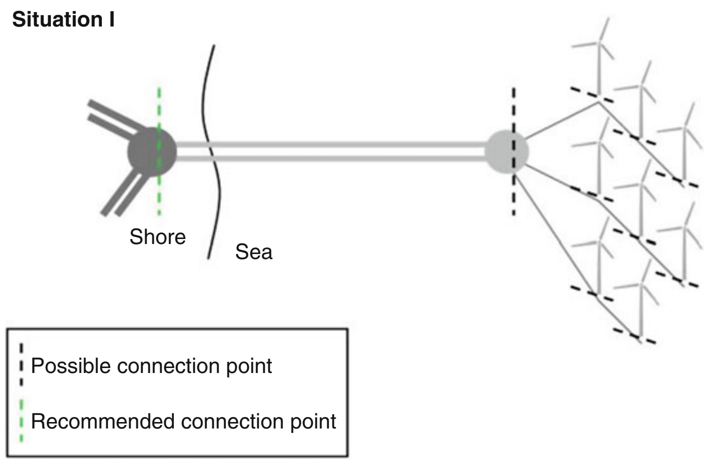



**Fig. 29.5** Recommended PCC for single wind power plant situation

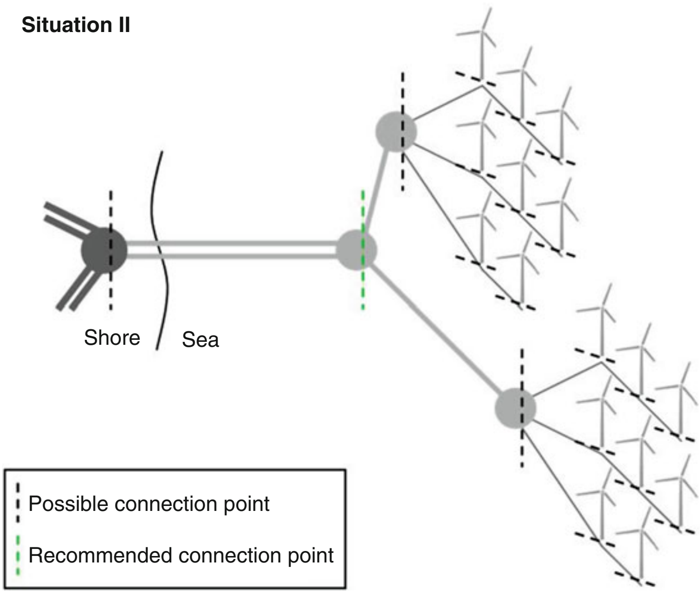



**Fig. 29.6** Recommended PCC for multiple wind power plant situation with offshore TSO

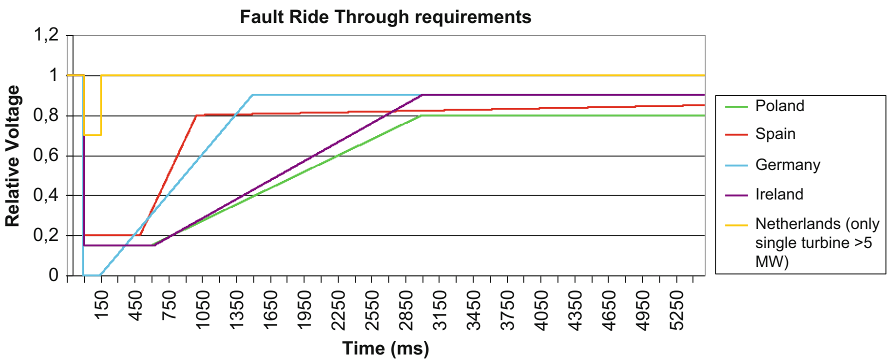



**Fig. 29.7** Example of FRT requirements in grid codes (EWIS study 2008)

illustrated in Fig. 29.8. The wind power plant should be able to operate with different set point voltages and slopes, according to grid code requirements.

The $Q_{max}$ and $Q_{min}$ values (see Fig. 29.8) are dependent on wind power plant rated active power.

In case of offshore wind power plants, the grid connection will be realized by submarine cables, producing reactive power. To compensate for this reactive power, static or dynamic compensation can be used, but it is also possible to use the wind turbines to (partly) compensate for the reactive power of the cable connection. This

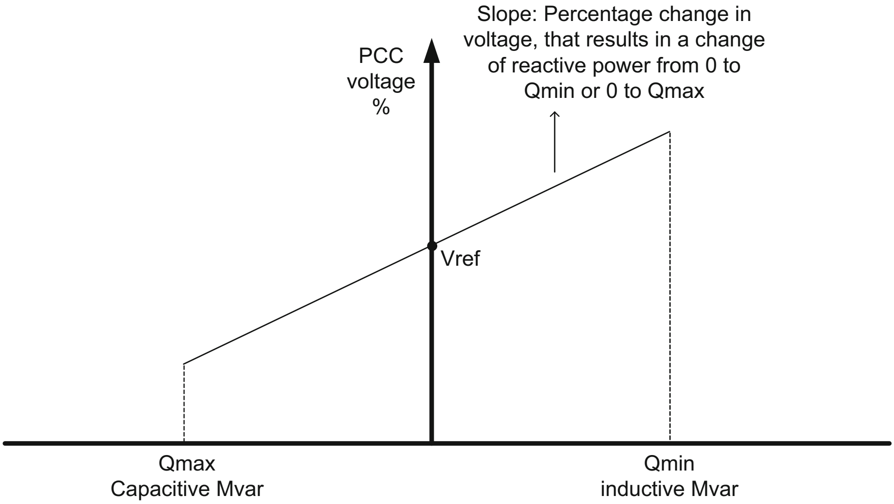



**Fig. 29.8** Voltage control droop characteristic at the PCC

however is only possible if the grid code does not apply at the turbine, but at the actual connection point to the grid.

**Active Power Control and Remote Operation**
In most countries, the philosophy is to get as much energy as possible out of the wind turbines. In some countries, this is not desirable at all times, for example, if a single fault can cause a disconnection of an amount of wind power, greater than the residual import capacity, wind turbines in the area will be constrained in order to maintain secure grid operation. In this case, remote operation of the wind power plants by dedicated control centers will also be required.

## 29.2.5 Reactive Compensation and Voltage Control

Reactive compensation and voltage control require special attention when considering offshore installations. This is mainly caused by the fact that cables are used for the transmission of power. Cables behave capacitively over their full load range. Due to changing wind speeds, and therefore active power variations, the capacitive behavior of the cable will constantly change, and therefore reactive power control is necessary.

### 29.2.5.1 Reactive Power Balance

The need for compensation within offshore wind systems is determined mainly by two aspects, the compliance with grid code requirements and the achievement of an optimal utilization of the electrical infrastructure. Compensation is related to system stability and thus to reactive power and voltage control concepts. Bus voltages undergo continuous fluctuations owing to power flow changes or sudden contingencies. The injection of reactive power increases voltage level and the absorption reduces it. The reactive power control is used to keep or restore power factor and voltage to the desired targets.

The need for, and rating of, the compensation equipment depends on the system configuration, wind power plant power capacity, distance to shore (length of the cable between the onshore and offshore substation), voltage and power ratings, type of wind turbines, transformer impedance, and other electric devices such as harmonic filters.

The compensation can be done through the reactive capability of generators and the use of transformer tap changers. Other additional devices can be applied to the wind turbines (distributed compensation), to the offshore and onshore substations (centralized compensation), or to both (mixed compensation).

For long cable connections, the capacitance generates a charging current that reduces the load current which can be carried. Application of compensation can improve the utilization of the cable, which is important considering the increasing distance to shore and voltage levels which give rise to higher charging currents.

#### 29.2.5.2 Contributions to Reactive Balance

The required reactive balance can be achieved by one or more of the following means.

- Wind turbine contribution (dependent upon the type of generator used)
- Purpose-designed reactive compensation equipment

The optimal points for reactive power generation in offshore wind power plants very much depend on the configuration of the overall power system. When a wind power plant is connected to the network through long AC submarine cables, the utilization of wind turbines for reactive power generation may not be the optimal solution considering the reactive power losses along the length of the cable. When a reactive power operating range for a wind power plant (as specified by the grid code) is required at the point of connection to the onshore network, additional sources of reactive power (e.g., SVC, STATCOM) may be required at this point.

#### 29.2.5.3 Dynamic Voltage Response

Wind power plants are normally required to be able to perform continuous voltage control at the point of common coupling (PCC) as described in the section on grid code requirements.

Other grid code requirements like maximum dead time before wind power plant response begins allowed overshoot and speed of response and have an impact on the design of the voltage control scheme.

A number of the possible options are mentioned here.

- **Use of on-load tap changers (OLTC)**
- **Use of wind turbine reactive capabilities**
- **Reactive compensation plant (switched reactive plant, SVC/STATCOM)**
- **Flexible AC transmission systems (FACTS)**

More information on the use of these devices and their optimization is given in Brochure 483.

#### 29.2.5.4 Harmonic Performance and Filters

The total harmonic distortions at the PCC and within the wind power plant are the overall effect of harmonic injections from the wind turbines, dynamic reactive power plant (SVC, STATCOM), and interactions with the onshore grid. These interactions pose new challenges to utilities and the industry in understanding the individual phenomena, developing appropriate study methods, identifying economic countermeasures for the identified points of concern, and proving effective technical solutions.

Harmonic studies determine whether or not filters are necessary as well as their rating and frequency characteristics. As passive filters could have a significant impact on the wind power plant's reactive power compensation scheme and may require large space and increase noise levels, harmonic studies should be carried out at the earliest possible stage in the project.

There are two main types of filter, passive and active.

- **Passive filters**
- **Active filters**

More detail on these types of filters is given in Brochure 483.

### 29.2.6 Fault Level

#### 29.2.6.1 What Is the Limiting Factor on Fault Level?

Electrical networks are characterized by a particular short circuit capacity design, relating to the rating of the switchgear and network equipment. Large wind power plants are typically connected to HV networks and therefore contribute to the total fault level of the network, determined by the combined short circuit contributions of the upstream grid and the various wind turbine sources within the wind power plant. The internal impedance of all generators and system impedance, i.e., cable and transformer impedances, will limit the fault level. With offshore wind farms, usually the critical component requiring the limitation of fault level is the MV switchgear located at the connection point of each wind turbine. When checking the capability of the equipment to withstand the relevant fault levels, both the make fault level and the break fault levels should be checked.

#### 29.2.6.2 Infeed from Grid System

The fault contribution from the upstream grid can be calculated from the PCC equivalent impedance and the cable and transformer impedance up to the fault point. The type of transformer used and its corresponding impedance will tend to have the greatest impact upon the offshore fault levels. If fault levels on the wind power plant prove problematically high, the transformer design can be adjusted to give optimum fault reduction and power losses.

With the infeed from most wind turbine generators decaying rapidly with time, high fault level design considerations are mostly focused on the make fault level for offshore AC substations and the limiting of the fault levels at the point of connection of the individual generators. This connection point can be a critical factor for the rating of the switchgear installed in the turbines.

#### 29.2.6.3 Infeed from Wind Turbines

The type of wind turbines (WTs) used in the wind power plant will determine the magnitude of fault contribution.

Rule of thumb assumptions for rms instantaneous fault level contribution from the different generator types is shown in Table 29.1.

The fault contribution of these generators reduces with time, and the break fault current contribution can be assumed to be negligible for the squirrel cage induction generator (SCIG), DFIG, and full-scale converter-connected generators. A synchronous generator can however contribute up to 4.5 times rated current to the rms system break fault current at its terminals.

#### 29.2.6.4 Transformer Impedance Choice (Including Interaction with Reactive Design)

Standard designs from manufacturers have an inherent value of impedance determined by established arrangements of core and windings. It may however be desirable to decide on a transformer with impedance greater than standard to limit the short circuit duty on downstream switchgear or to select a transformer with lower impedance to relieve plant energization effects by reducing the voltage drop. When a transformer with a high impedance is selected, the effect of the reactive losses upon the reactive balance must be considered.

#### 29.2.6.5 Consideration of Two- or Three-Winding Transformers

At present WTs generate at a voltage level between 690 V and 2.4 kV that is transformed to the collector voltage level of 36 kV via two- or three-winding transformers. Higher collector system voltage levels may be an option in the future.

**Table 29.1** Fault level contribution from the different generator types

| | Synchronous | SCIG | DFIG | Full-scale convertor |
|---|---|---|---|---|
| Load | $I_n$ | $I_n$ | $I_n$ | $I_n$ |
| Contribution to make fault levels | $7\ I_n$ | $6\ I_n$ | $6\ I_n$ | $1.2\ I_n$ |

The step-up transformers used on the offshore substation may also be either two-winding or three-winding. A three-winding transformer offers the opportunity for the collector circuits to be split between the two secondary windings. This has the advantage of reducing the fault levels at the collector circuit level by effectively reducing the fault current contribution from the offshore wind turbines and can offer a better interconnection in terms of redundancy as shown in the figure below. Care must be taken in specifying the impedances between windings as manufacturers have many options which might not necessarily suit the service requirements. If voltage control using transformer taps is required, it is preferable to have a balanced load on each of the LV windings to ensure balanced secondary voltages (Fig. 29.9).

#### 29.2.6.6 Effect of External Faults

The actual fault level at the offshore substation is dependent on the strength of the system source, which has inherent system impedance.

#### 29.2.6.7 Operating Scenarios

The presence of two (or possibly more) main transformers at the substation, and possible bus-ties on the MV side, allows the system to be managed with the transformers in parallel. Careful selection of the busbar configurations together with transformer choice and impedances is required to optimize the fault level control both under normal operating conditions and under depleted conditions when more wind turbines may be connected together.

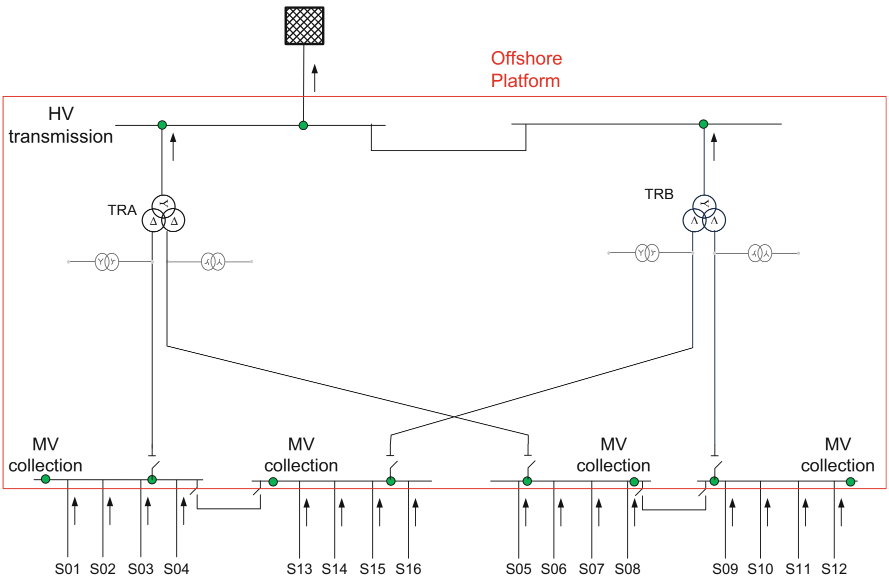



**Fig. 29.9** Typical three-winding connection arrangement

### 29.2.7 General Substation Configuration

#### 29.2.7.1 Choice of HV and MV Voltages

The voltage levels within the electric infrastructure of a wind power plant comprise commonly a medium-voltage level for the internal collection system and a high-voltage level for the export circuits.

**Medium-Voltage Level**

The voltage level of the collection system has been driven mainly by the availability of switchgear and transformers that fit inside the wind turbines. This has resulted in the use of $SF_6$ insulated, metal-enclosed, secondary distribution switchgear. The maximum rated voltage is 36 kV thus determining the collection system voltage. The use of higher voltage levels (up to 66 kV) for the collection systems of larger offshore wind power plants is being considered, but considerable development of the switchgear and the collection cables will be required.

**High-Voltage Level**

In most of the offshore wind projects in operation or under construction, the voltage level for the export system is the typical sub-transmission one from every country, commonly between 110 kV and 150 kV AC. This range of voltages is largely driven by the technical limitation in practice to install three-core submarine cables over 170 kV given their high diameters and weights, although a 245 kV three-core submarine cable has recently become available which may lead to a wide use of this voltage level for larger projects. For larger powers and longer distances from shore, the use of HVDC voltage source converters will become the most common solution.

#### 29.2.7.2 MV Busbar Layouts

These have mainly been of the single busbar design with bus section breakers connecting sections of busbar. In some cases the single busbar has been connected in a complete ring. (See Fig. 29.10.) Care needs to be taken in the way the step-up transformers and the inter-array cable strings are connected to the different sections of busbar in order to achieve flexibility and availability while still limiting the fault levels.

#### 29.2.7.3 High-Voltage Busbar Layouts

Usually because of the space and weight restrictions on an offshore substation, the HV switchgear is kept to the minimum often only consisting of disconnectors, earth switches, and surge arresters. Even when multiple export cables are necessary, this same simple approach is used; however sometimes circuit breakers are required to minimize the switching inrushes when energizing the transformers. (See Fig. 29.10.) Some redundancy can be provided by placing a number of breakers between the cables and the transformer and between the cables. The configuration in Fig. 29.11 enables you to isolate either a cable or a transformer separately. In case of a cable

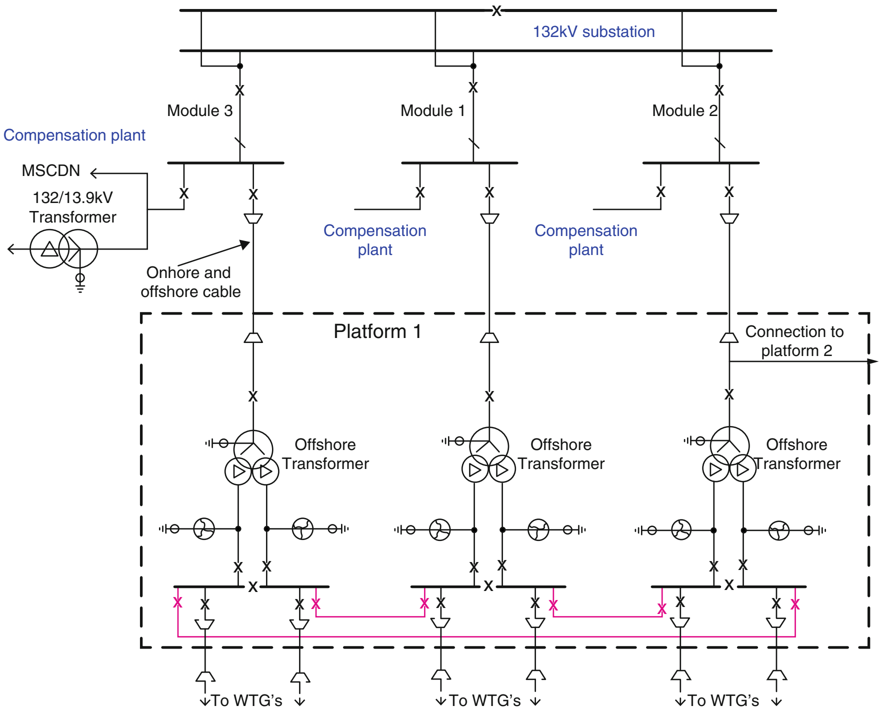



**Fig. 29.10** Example of offshore substation with three transformers and MV ring busbar

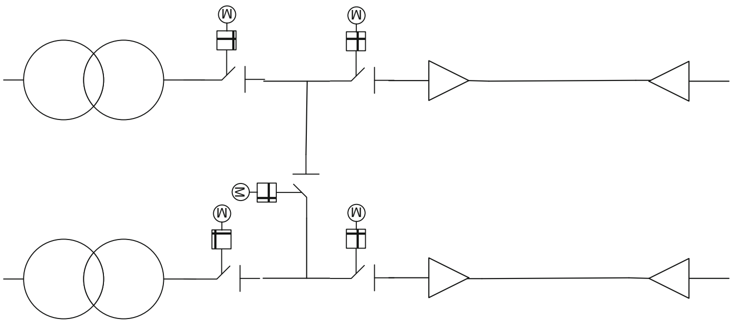


**Fig. 29.11** Highly flexible (and expensive) HV configuration

failure, one could utilize, maybe even overload, the other cable without overloading the transformers.

### 29.2.7.4 Compensation or Filters Required on the Offshore Platform

In the case that studies determine that reactive power compensation in the form of reactors or capacitors is needed at the offshore substation, then the connection point should be analyzed. Compensation at the medium-voltage level usually requires less space in the platform, less insulation levels, and therefore lower price.

Filters should be avoided on the offshore platform if possible. If harmonic studies determine that filters are required in the offshore platform, harmonic performance studies (see Sect. 29.2.5.4) should determine the rating, type, and location of such filters, taking into account that connection of filters to HV levels might be costly and challenging.

## 29.2.8 Neutral Earthing

In offshore substations the earthing of the MV network is usually designed to limit the earth fault current to less than 1,000 A in order to reduce the currents which may flow in the inter-array cable sheaths. The MV networks are usually fed by transformer windings connected in delta, and so an earthing transformer, usually with an interconnected star (zigzag) winding, is used. The current can be limited by connecting a resistance into the neutral connection of the winding or in order to reduce the space used on the platform; quite often the earth fault current is limited by designing a suitable zero sequence impedance into the earthing transformer.

Direct grounding in high-voltage systems is a common practice and avoids overvoltages during earth faults.

In order to simplify and increase the effectiveness of the export cable protection scheme, both onshore and offshore transformer neutral points should be solidly earthed. With this solution the earth fault factor can be kept low (<1.4).

**Trapped Charges and Location of Circuit Breakers**
In case of offshore wind power plants, there is a large presence of long export cables, and therefore trapped charges need to be considered. The location of circuit breakers will have an effect upon this condition. Please refer to Brochure 483 for more information on this aspect.

## 29.2.9 Insulation Coordination

A detailed overvoltage analysis is necessary to determine the risk of exposing equipment to high overvoltages. The overvoltages can be either short duration (fast-front and slow-front overvoltages) called transient overvoltages or longer duration temporary overvoltages (TOV), both of which can occur in offshore networks.

The practice of insulation coordination for offshore wind power plants follows IEC 60071-1 and 60071-2, although the types of overvoltages experienced by electrical equipment are different to those in typical onshore networks. The main source of transient overvoltages in offshore wind power plants is switching operations, unlike overhead line systems where lightning is the predominant source of transient overvoltages. The extensive cable systems in offshore wind power plants combined with a large number of step-up transformers at the wind turbines also result in many surge impedance boundaries, where voltage reflections can occur and possibly cause flashovers. This means that there will be different levels of stress on the insulation of electrical equipment depending on its location within the system. A key point to note about cable systems is that the surge impedance is around 40 Ω which is much less than overhead lines, where it is typically 300–400 Ω. This difference has an impact on the time derivative of transient overvoltages, as a lower surge impedance results in a higher time derivative of the transient overvoltage. Proper coordination of surge-protective devices with the insulation strength of electrical power equipment is essential for protecting the offshore substation from overvoltages.

System operating voltages can be classified into five groups according to the IEC 60071-1. These are continuous operating voltage, temporary overvoltages, slow front (switching), fast front (lightning), and very fast front.

#### 29.2.9.1 Continuous Operating Voltage

The export cables will see a steady-state voltage rise when one end is opened. Typically shunt reactors may be required to keep the voltage down to acceptable levels.

#### 29.2.9.2 Very-Fast-Front Transients

Very-fast-front transients could occur in offshore wind power plants due to the reflections within the network. The combination of surge capacitor protection and surge arresters may provide the best solution.

#### 29.2.9.3 Fast-Front Overvoltages

The direct influence of fast-front overvoltages from lightning is unlikely to occur in the closed cable systems associated with offshore wind power plants.

#### 29.2.9.4 Slow-Front Overvoltages

Slow-front overvoltages are mainly coming from switching operations or capacitor discharges if filters are used. Slow-front overvoltages could occur during energization and during disconnection in normal operation or during a fault. Ground faults could also produce transient overvoltages in a similar way to switching operations.

Switching studies need to be carried out on both the MV collection network and the HV export network. Typically, the transformer is a buffer, but the transfer of overvoltages via the transformer interwinding capacitance should be examined.

The SIWV is not specified in the IEC standard for rated voltages of 245 kV and below, because normally the level of switching surges is much less than the level of LIWV and covered by it. Test conversion factors given in IEC 60071-2 can be used to convert required switching impulse withstand voltages to short-duration power frequency and lightning impulse withstand voltages. With the complex networks offshore, it is dubious if these factors are really satisfactory.

To limit possible overvoltages on switchable reactors used to compensate cable charging currents during disconnection due to circuit breaker re-strikes or reignition, controlled switching and arresters can be used. When using vacuum breakers, high-frequency voltage oscillations in the reactor can occur during disconnection due to circuit breaker re-strikes. The use of special RC damping circuits may be employed to avoid current zero crossing after the first re-strike and therefore prevent high-frequency voltage oscillations and damage to the reactor.

#### 29.2.9.5 Temporary Overvoltages

While fast-front and slow-front overvoltages typically recede to normal steady-state levels within a few cycles, a temporary overvoltage (TOV) can last for seconds. Below the typical causes for TOV in offshore wind power plants are listed.

- **Transformer energization**
- **Ground faults**
- **Load rejection**

The arrester rated voltages must be selected to suit the temporary overvoltages arising from these causes.

#### 29.2.9.6 Mitigation Strategies

(i) **Point on Wave Switching**

Point on wave switching is one method employed to reduce transients by controlling each of the three poles in the circuit breaker individually, closing (or opening) each pole with a certain time delay.

(ii) **Selection of Surge Arresters**

The rated voltage of the surge arresters should be selected based on the actual maximum continuous operating voltage (MCOV) and the temporary overvoltages in the system.

All the expected TOV magnitudes and durations should be compared with the manufacturer's TOV capability curves (power frequency voltage vs. time characteristic) for the surge arresters installed.

The surge arresters' energy capability must be chosen to withstand the TOV for the associated duration.

### 29.2.10 Flicker and Voltage Fluctuations

#### 29.2.10.1 Flicker

Voltage flicker is an entirely human perception/irritation problem. A cyclically varying voltage source supplying the power to incandescent bulbs will cause a cyclical variation in the bulbs' luminescence which above a certain level will be perceived by many people and may cause irritation.

**Sources of Flicker**

Wind power generators may now become a source of flicker. This is because wind turbines have a variable output which is due to the natural variation in wind input, wind turbulence, and the wind turbine's uneven power output as it completes each rotation. In general, while the flicker performance of early fixed speed wind turbines with simple control systems was poor, modern large wind turbines have improved their performance with variable speed operation, back-to-back converters, and pitch regulation. Also, as early wind turbines were connected in remote locations with weak grids and low X/R ratios, the level of flicker being produced was higher.

**Mitigation of Flicker**

Typical measures employed to reduce flicker to acceptable standards at the grid connection point (PCC – point of common coupling) are:

- Specify the best flicker-performing wind turbines possible (should be in their evaluation criteria)
- Increase the short circuit level at the PCC (and grid angle if possible)
- Modify the wind turbines' back-to-back converter control system to improve flicker performance
- Use an SVC or similar device to smooth wind power plant output to acceptable levels

#### 29.2.10.2 Voltage Fluctuations

Apart from flicker voltage fluctuations in offshore, wind power plants take place due to:

- Energization of main electrical components
- Variation in wind speeds (wind turbine output)

The acceptable magnitude of the voltage fluctuations at the point of common coupling (PCC) is normally limited by grid codes or connection agreements; therefore studies need to be conducted in order to determine their magnitude and possible countermeasures.

- **Energization of transformers:** A typical case to be considered is the energization of power transformers. Both onshore and offshore transformers should be investigated. In case the inter-array cable strings are energized with all wind turbine transformers, this should also be included in the investigations. Worst-case switching instant, as well as worst-case transformer residual flux and system strength, should be taken into account.
- **Energization of export cables/filters:** The energization of export cables or filter units may also cause voltage changes at the PCC which should also be investigated.

Apart from the mitigation strategies mentioned above, the following may be considered in order to reduce voltage fluctuation at the PCC during energization of main electrical components.

- Pre-insertion resistors
- Point on wave switching

### 29.2.11 Systems Studies Required

In order to bring together all the relevant aspects in the complex process of designing large offshore wind power plants, several systems studies need to be carried out.

The design aspects can be summarized as follows:

- Grid code compliance
  - Reactive power
  - Harmonic performance
  - Static and dynamic stability performance
- Wind power plant and export circuit component ratings
- Protection and safety

All of these aspects should be addressed through comprehensive systems design studies as listed below:

- Load flow study
- Short circuit study
- Harmonics study
- Insulation coordination study
- Electromagnetic transient studies
- HV export network transient studies
- Flicker and voltage fluctuation study
- Dynamic stability study
- Safety earthing study
- Neutral grounding study
- Protection coordination study
- Electromagnetic field (EMF) study

## 29.3 Electrical Equipment Considerations

### 29.3.1 Introduction

This section gives guidance on how to write the technical specifications for the main electrical equipment to be located on an offshore substation. These are MV switchgear, main transformers and reactors, auxiliary transformers, HV switchgear, and export and array cables. When considering the specification aspects for equipment, these can generally be divided into four main sub groups as follows:

#### 29.3.1.1 Parameters Coming from the Systems Studies

These parameters are technical requirements such as the short circuit level, full load current, lightning impulse withstand level, transformer impedance, etc.

#### 29.3.1.2 Parameters Defined by the Operation and Maintenance Regime

These parameters are the requirements for modularity, any requirements for condition monitoring, and need for special tools, e.g., tap changer removal tools.

#### 29.3.1.3 Parameters Specific to the Type of Plant Itself

These are items specific to the type of plant itself and could cover environmental considerations, vibration and transport forces, special technical considerations, and physical and interface requirements.

#### 29.3.1.4 Important Items to Define to the Platform Supplier with Regard to the Accommodation for the Equipment

It may well be necessary for the equipment supplier to define to the platform supplier specific requirements for the room in which the equipment is to be accommodated.

In the following sections of this chapter, these four basic aspects will be considered for each of the main items of equipment.

### 29.3.2 MV Switchgear

#### 29.3.2.1 Aspects of Specification Which Come from Systems Studies

(i) **Voltage and Current Ratings**

For virtually all offshore wind power plant systems which have required an offshore substation, the voltage has been 33 kV nominal, i.e., 36 kV IEC rated voltage.

If we consider the current rating of the array collection circuits, then 40MVA would require a current of approximately 700 A, thus requiring the use of 1250 A panels. If the array collection MVA is limited to 36 MVA, then 630 A panels could be used.

For most manufacturers 2500 A is the maximum standard rating. This means that the maximum transformer winding rating which can be connected via a single circuit breaker is 142 MVA. Higher winding ratings can be accommodated by connecting two panels in parallel, but adequate allowance has to be made for the unequal sharing between the two panels. It is expected that ratings up to approximately 250 MVA could be accommodated in this way.

Busbar ratings up to 4000 A are available, equating to a rating of 228 MVA. To accommodate connection of 250 MVA transformer, the relative placing of the circuit breakers on the board needs to be taken into account.

### (ii) Fault Level Ratings

The fault level required for the switchgear will have been defined by the short circuit study. Fault level rating of the 36 kV switchgear in the substation is never a problem, as switchgears with short circuit ratings up to 40kA at 36 kV are fairly readily available on the market. The normal limitation on short circuit level is the rating of the ring main units at the transition pieces on the WTGs which frequently are rated at 20kA. The fault level rating at the substation switchboard should therefore generally be rated at the same rating as the WTG switchgear to avoid paying for an unnecessarily high value of short circuit rating.

### (iii) Lightning Impulse Withstand Level (LIWL) and Surge Arrester Ratings

Usually if the switchgear is rated at 36 kV, then the LIWL rating of the equipment in accordance with IEC will be 170 kV peak. However, from experience on some wind power plants, the phase to phase surge voltages can give rise to high switching surge voltages. Some manufacturers have extended the capability of their 36 kV equipment to operate at 40.5 kV, and this may have a LIWL rating of 185 kV peak associated with it. Usually, it is the phase to phase overvoltages which are a problem rather than the phase to earth voltage, so one way of dealing with this is to specify switchgear which is fully phase segregated or specify the 185 kV peak equipment.

In order to control the overvoltage on the 36 kV system transferred through the transformer, surge arresters may sometimes be fitted at the incomer circuits of the 36 kV switchboard. The rated voltage of the arrester and its energy capability as derived from the insulation coordination studies must be specified.

### (iv) Configuration

There are various different configurations which can be used for the 36 kV switchboards. In this section only a few of the basic options will be mentioned.

The first choice is should the switchboard be a double busbar design or a single busbar design? A double busbar design means that every circuit either incomer or array cable can be selected to either busbar. The two busbars can either be run separate with the bus coupler circuit breaker open or run coupled with the bus coupler breaker closed. If the substation has two transformers, then one transformer can be run normally connected to the main busbar and the other connected to the reserve busbar. In theory the double busbar arrangement has the advantage that if a busbar fault occurs to one busbar, all circuits can be connected to the other busbar. The reality of this very much depends upon the physical construction of the busbar. However, double busbar switchgear is more costly and requires more space because the switchboard is deeper than the single switchboard option. In the majority of offshore substations built to date, the switchboards have been of single busbar design.

If single busbar design is chosen, then the next question is how many separate sections of switchboard are required? This decision will be driven by the type of transformer being used. If the transformers are two-winding, then each transformer gets its own section of 36 kV switchboard. Another consideration is whether or not these two separate sections of switchboard are to be located in two separate rooms to avoid a fire from affecting both switchboards. If one room is acceptable, then the two switchboards will normally be connected via a bus section panel, while if separate rooms are required, then an interconnector possibly using bus duct connections will be required.

If the transformers being used are three-winding type, then for a station having two transformers, it would be normal to have four separate sections of busbar, with one winding from a transformer connected to each busbar. This cross connected configuration with bus section circuit breakers between the two sections enables all of the inter-array cables to be connected to either transformer in the event of loss of one transformer. This type of configuration has been used and proposed for various wind power plants.

Another possibility with the single busbar arrangement is to connect the separate sections of busbar in a ring. This configuration has been used with three off three-winding transformers where the three-winding transformer was used to more evenly share the load currents rather than for fault current limiting.

Clearly there are various different options which can be chosen, but the option selected must align with the assumptions used in both the load flow and short circuit studies and also take account of the reliability and availability calculations.

(v) **Types of Circuit to Be Switched**

As a minimum the types of circuit to be switched from the 36 kV busbars will consist of the main transformer incomers and the inter-array cable outgoers. There will also usually be either bus sections or bus couplers depending upon the choice of single or double busbar switchgear. However, additional switch panels may be required for shunt compensation elements such as reactors or capacitors if these are shown to be necessary from the load flow studies. As the switching duty for some of these components can be problematical, then, for example, with shunt reactors, it may be necessary to use RC elements to ease the switching duty and avoid re-strikes. If the harmonic studies show that filters are required on the offshore platform, then these may also be connected to the 36 kV switchboard. Finally, if the earthing transformers are connected to the busbars rather than to the transformer LV windings, then these will also need to be switched.

#### 29.3.2.2 Aspects of Specification Which Come from Generic Operation and Maintenance Considerations

Experience with offshore installations to date has shown that the cost of maintenance and the downtime during faults or equipment failures are two of the most significant differences when it comes to the specification of MV switchgear for offshore installations compared to onshore installations. In the first instance, a very high level of reliability is an economic imperative, and this is achieved through very exacting and accurate specifications. A very rapid repair time is also necessary to achieve minimal revenue losses during equipment failures. A further consideration is the harsh corrosive environment that the equipment will be located in. While it is assumed that the MV switchgear will be housed in environmentally controlled switchrooms, an allowance for additional corrosion protection would be recommended as inevitably the external environment will have some impact on the equipment during any downtime of the environmental control units and when the switchroom is exposed to the elements during major maintenance activities.

Modular construction will help with maintenance by enabling fast changeout. This also keeps the skills required to effect a replacement basic, reducing the need for specialist engineers on the platform. Smaller modules are easier to transport and move around the platform.

In order to achieve minimal repair times, detailed consideration should be given to the handling and storage of spare components, tools, and the breakers themselves and also the ease with which they can be moved around and on and off the platform.

(i) **Condition Monitoring**

There are a number of areas where CM can assist in the determination of switchgear performance and avoid intrusive procedures or unnecessary visits to the platform. Where possible, trending of the switchgear condition (timing, contact resistance, partial discharging level, thermal imaging, and data made available onshore) should be employed, rather than remote alarms as these may mal-operate and incur unnecessary emergency offshore visits.

(ii) **Remote Monitoring**

The remote monitoring of many parameters of switchgear is also desirable; however, the user should be aware of the significantly higher level of failures generally of monitoring equipment, and this monitoring equipment, if it is not carefully specified and designed, may in itself become a significant maintenance cost and reliability issue. Sensors should be kept simple and robust. It also requires knowledgeable resources onshore to observe and analyze the data from the platform.

(iii) **Spares**

As the equipment will normally be modularized and most of the components in a bay are common, so generally keeping a spare bay onshore will address most issues.

(iv) **End of Life Replacement**

The platform has a normal design lifetime of 25–40 years depending on the developer's requirements. The lifetime of the MV switchgear should exceed or align with the lifetime of the platform, and, therefore, consideration of end of life replacement should only arise (excepting major fault) if the platform is returned to shore for major overhaul.

#### 29.3.2.3 Aspects of Specification Which Are Plant Specific

(i) **Environment**

Most of the MV switchgear employed in offshore substations will be $SF_6$ gas-insulated switchgear (GIS) or cubicle-type gas-insulated switchgear (C-GIS) inherently designed for controlled indoor switchroom environment.

In order to achieve reliable control of switchroom environmental conditions, it is recommended to install salt filters in any air inlets and let the indoor environment be slightly overpressured compared to the outside and install heating systems to avoid any condensation.

(ii) **Vibration and Transport Forces**

The standards for switchgear (e.g., IEC) do not include any dedicated provisions for specification or type testing to demonstrate insensitivity to prospective mechanical impacts which may be encountered by electrical apparatus on offshore platforms, such as wind gusts or wave loads. Insisting on seismically qualified apparatus is not a suitable solution as the type of vibrations is totally different.

The switchgear must be fully assembled onshore before it is transported and exposed to all kinds of forces and vibrations. This is especially critical for connections and interfaces between components. The limiting motion criteria for the sail-out should be confirmed at an early stage of the substation design process.

The design of the switchgear should make due allowance for these additional external forces such as the fitting of sea transport fastening, and the design should also consider any forces that may be introduced at the time of lifting the complete substation for moving to the vessel and for installing on its foundation (Fig. 29.12).

(iii) **Special Technical Considerations**

1. **Circuit Breakers**

The use of vacuum breakers is the usual choice, and this has advantages in that switching of capacitive currents of no- or low-load cables is easily achieved by vacuum breakers. The generation of overvoltages caused by chopping of the small currents during switching today is reduced in state-of-the-art vacuum breakers by the selection of suitable contact material and its mechanical design.

2. **Interlocking**

During normal operation the complete offshore wind power plant is remote controlled from a central control room located onshore. A project key decision is


**Fig. 29.12** Enclosure of containerized offshore substation

the application of manual maintenance interlocking for use as part of a safe system of work, e.g., "permit system."

3. **Accommodation for Cable Terminations**

The medium-voltage switchgear cubicles in an offshore substation will accommodate the terminations for incoming feeders from the collection system of the wind power plant or the outgoing cables to the power transformers.

36 kV GIS with inner or outer cone cable connections can use either a plug-in connector or a T-connector (not considering the bus duct solution here). The T-connectors can be plugged onto one another (typically up to three connectors per "outer cone" bushing) – and this means that adding another cable later such as wind power plant extension is straightforward. The T-connector system will, however, introduce bolted 36 kV connections which is why provisions for arc detection in the cable compartment should be made available.

(iv) **Physical and Interface Considerations**

While the aim is to provide a reliable and compact switchboard, there are factors which need to be considered in the design of the switchboard, typically:

- Protection relays can be mounted within the top chamber of the switchgear front; however, these will need to be accessible for commissioning, manual interrogation, and/or maintenance activities. Any necessary access platforms, whether

fixed or temporary, will need to be designed into the substation layout and provided for use offshore.
- The protection relays should include basic SCADA and fault recording facilities.
- The platform layout may dictate that the control cables may need to approach vertically from above the switchgear so the top chambers would need to be designed to suit this arrangement.
- The switchgear and any connected power cables will need to be electrically tested so provisions should be included within the design for suitable bushings and/or cable test sockets.
- If VTs are required on the turbine feeder circuits, then they may need to be mounted remotely and cable connected to the switchgear. Due allowance must be made for the cable connections and VT mounting space.
- The switchgear will generally be connected to the system via power cables or bus ducts from below, and due allowance needs to be made for these connections. The use of disconnectable cable terminations would be preferred with the female portion of the termination and insulator included in the switchgear cable chamber. Allowance has to be made for the minimum bending radius of cables.
- The bays should be arranged to mitigate external cable crosses where possible.

#### 29.3.2.4 Specific Requirements for Rooms or Enclosures

In order to keep the room dimensions to a minimum, the following items should be considered in the design of the room/enclosure:

- The switchgear manufacturer must confirm the minimum amount of space around the switchboard to permit all aspects of planned and unplanned operation, maintenance, and repair works
- If the switchgear includes a withdrawable circuit breaker (CB), then sufficient space must be allowed for the CB and any necessary handling device.
- Sufficient space must be allowed for handling of any large-sized test equipment.
- When GIS switchgear is used, sufficient space must be allowed for a gas cart to be used during filling and/or maintenance operations unless sealed for life.
- Sufficient space must be allowed for any necessary fixed or temporary access platforms required to access specific parts of the switchgear.

The power cables and/or bus ducts would generally approach the switchgear vertically from below, and if the cable head is close to the floor level, space may need to be allowed below the floor level by using a false floor. The penetrations through this floor should be effectively sealed against the marine environment or to limit the spread of fire.

All penetrations through walls, floors, and ceilings will be suitably sealed during installation in the onshore fabricator's yard and temporary seals installed into the penetrations for array cables prior to sail-out. These would be replaced by the final seals after cable installation. Similar requirements apply to control and multicore penetrations.

The cable installer would need to be able to work through the penetration in this false floor to lay and terminate the cables/bus ducts; hence the opening must be sized to suit (Figs. 29.13 and 29.14).

The floor fixings/rails must be suitably designed to accept the static and dynamic loads resulting from operation of the switchgear plus any imposed loads during the sea transport and offshore lifting operations, where applicable.

Access doors or removable panels should be sized to enable equipment access during initial installation and lifetime maintenance or repairs, together with personnel access.

The switchroom should contain a fire detection/alarm system, and the substation fire plan will detail if the switchroom/enclosure is to be designed as a passive fire protection or contain an automatic fire suppression system. Where a fire rating is assigned to the switchroom wall, then any access doors within the wall must be suitably fire rated to match that of the wall.

During an internal fault, or failure of a gas zone, high-pressure gasses may be vented into the room/enclosure. Consideration should be given to suitable pressure relief devices built into the room.

**Fig. 29.13** Example of 36 kV bus duct entry to switchgear with transit sealed

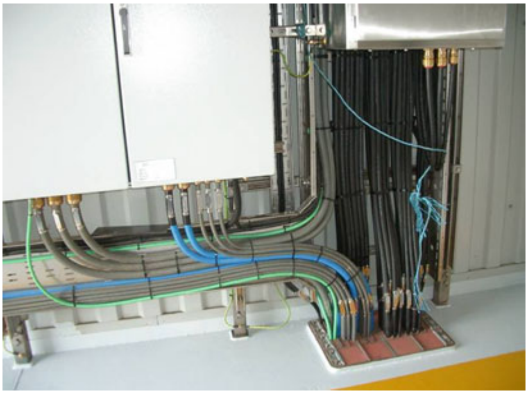


**Fig. 29.14** Example of control cable transit in steel floor to room

Given the $SF_6$ alarm systems integral to the switchgear, the beacon and sounder could be initiated from the switchgear negating the need for an independent scheme. This solution should be investigated where practical.

The electrical equipment which will be housed in these rooms has usually been designed for indoor use in *normal service conditions*.

The heating system to these areas should maintain a minimum ambient air temperature of +5 °C.

The ventilation system should incorporate maintainable salt filters.

Effective performance of the HVAC system is very important so effective remote monitoring of substation operating conditions is a crucial factor. Continuous measurement of actual switchroom temperature and humidity employing low-set alarm thresholds with remote annunciation is recommended.

### 29.3.3 Main Transformers and Reactors

The main transformers are the largest single equipment installed on the platform, and they affect the overall electrical and physical layout. Reactors may also be installed on the platform to absorb reactive power.

There are two types of structure for reactors. One is radial core block type, and another is air core type. Other parts (coil, tank, radiator, conservator, etc.) are the same as transformer structure. Therefore in this section, we will show the transformer example, but this is also applicable to reactors (Fig. 29.15).

Transformers on the platform ideally need to be lightweight, small, low maintenance, and reliable in order to reduce the building and operational costs.

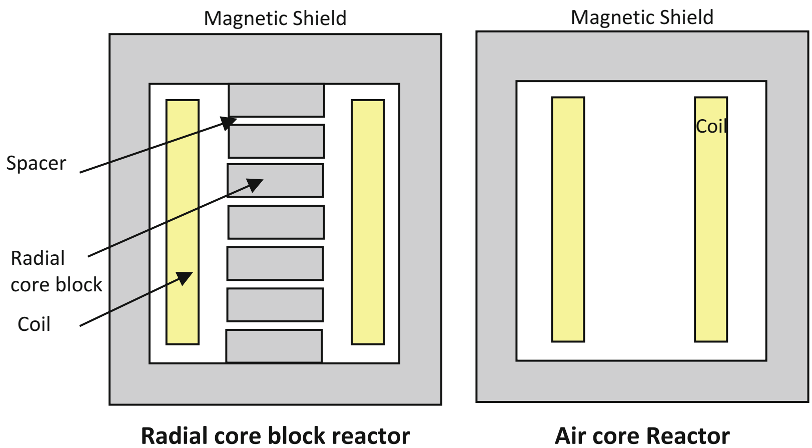



**Fig. 29.15** Core structure of reactor

#### 29.3.3.1 Aspects of Specification Which Come from Systems Studies

(i) **Voltage Ratio**

At present for the majority of offshore wind power plants, the collection voltage is 36 kV so this tends to set the value for the low-voltage side of the transformer. In many cases the HV side voltage is set by the system that the wind power plant will connect into onshore, e.g., 110 kV, 132 kV, 150 kV, or 220 kV. However, if the wind power plant requires further onshore transformation, then a suitable intermediate voltage has to be chosen which will be dominated by the availability of suitable cables.

(ii) **MVA Rating**

The MVA rating of the transformer will often be closely linked to the rating of the submarine cables connecting from the offshore substation to the shore. The final choice will take account of the load flow studies including making allowance for the reactive power as well as the real power to be transmitted, harmonic currents, and taking account of the redundancy policy adopted for the substation.

(iii) **Impedance**

Usually a dominant factor in choosing the impedance of the transformer will be the need to limit the fault level to that which can be accommodated by the 36 kV ring main units associated with each wind turbine generator (WTG). However, the impedance of the transformers also has a significant impact on the system's reactive compensation requirements. Also the impedance may have an effect upon resonant frequencies occurring within the wind power plant, thus impacting on harmonics. Hence the final choice of the transformer impedance may depend upon the results of the load flow, short circuit, and harmonic studies.

(iv) **Tap Change Range and Tap Steps**

The transformers on the offshore platforms often have tap changers fitted to control the voltage at which the 36 kV collection system operates typically to approximately 1.0pu (33 kV) voltage. The number and size of taps required to achieve this will be determined by the load flow studies taking into account the policy adopted for voltage control including reactive compensation. One other factor to be considered if three-winding transformers are being used is that the tap changer will normally be located on the high-voltage winding. Consequently only the voltage on one of the two secondary windings, or the average voltage of the two windings, can be controlled by the tap changer, and so the sensitivity of the voltage control is significantly reduced.

(v) **LIWL**

The LIWL will be defined by the insulation coordination study. Usually there will be surge arresters on both the HV and LV terminals so phase to earth surges should not present any difficulties. Information should be obtained from the transformer manufacturer on the relative strength against phase to phase surge voltages. On occasions a slightly higher LIWL may be specified to cover phase to phase surge voltages on the 33 kV windings.

(vi) **Two or Three Windings**

There are normally two reasons for using three-winding transformers. The first is to help limit the fault levels when one transformer is out of service as the $Z_{L1\text{-}L2}$ will help to reduce the fault level when all turbines are connected to one transformer. The other reason is to share the load current more equally to two parallel LV breakers. This load sharing reason only becomes critical if the size of the transformer is such that the 33 kV current is close to the rating of two circuit breakers in parallel. If there is a reasonable margin between the secondary current rating and the rating of the two circuit breakers in parallel, then a two-winding transformer will be satisfactory.

(vii) **Neutral Earthing**

The usual vector group for these offshore transformers is star/delta with the star winding on the HV side. In most countries the HV star winding will be solidly earthed, but may in some countries be unearthed requiring the winding to be fully insulated rather than using graded insulation. The decision on earthed or unearthed star windings will need to be agreed with the system operator of the system into which the wind power plant is connecting.

The 33 kV delta systems will normally be earthed either by resistance earthing or by using the zero sequence impedance of the earthing transformer to limit the earth fault current to an acceptable level such as 1kA.

#### 29.3.3.2 Aspects of Specification Which Come from Generic Operation and Maintenance Considerations

The key O&M issue is based around establishing the asset condition and determining whether maintenance is required and what is the risk associated with not carrying out the traditional time-based regime adopted onshore.

Other major issues include accessibility, space limitation, and general inability to bring in third-party services without incurring a massive cost penalty.

(i) **Maintenance Strategies**

The offshore O&M regime is likely to be a combination of time-based and condition-based maintenance (CBM), where condition monitoring and risk assessments will be overlaid on a rudimentary time-based plan, to minimize the need for site visits.

The designer must consider how either preventative or corrective maintenance can be achieved, without a return trip to shore, by developing method statements, tools, work space, and spare part provision. This work needs to be achievable without the need to send specialists offshore. Where necessary, special tools should be kept on the platform.

(ii) **Oil Management**

One important aspect is to protect the oil sealing flange from corrosion, since exposure to a corrosive environment will result in deterioration of the gasket, and this may lead to oil leaks from the tank and also moisture getting into the oil. The oil management for an offshore transformer is different to onshore so the different lifetime phases which involve movement or oil changes need to be considered and what impact this has on the mechanical design.

1. Delivery from the manufacturer's works to the quayside (normal practice)
2. Transfer from the quayside to the final platform location (this is fraught with risks and unconventional) since the transformer will be filled with oil while in transit, so the transformer designer and transporter will need to consider how the movement of oil will be affected by the sea transport and what internal impact this may have on sensitive components like oil membranes, bladders, or breathers
3. Platform-based inspections and repairs (post fault forensic testing, changing out radiators, tap changer, bushings)
4. Replacement (transformer fault)

Where possible the insulating oil should be kept in the tank since moisture will lead to degradation of the insulation performance. Whatever method of cooling is employed with liquid-immersed transformers, double valves should be used between the transformer tank and cooling (e.g., radiators, etc.) such that, when disconnection of a radiator is required for repair, there is no need to drain the oil from the radiator or the main tank.

Transformer breathers should be chosen to be maintenance-free.

(iii) **$SF_6$ Management**

If $SF_6$ gas-insulated transformers are used, then all of the procedures associated with responsible handling of $SF_6$ must be followed. These are detailed in the CIGRE Reference Book on $SF_6$ Management.

(iv) **Condition Monitoring (CM)**

While CM can significantly improve the understanding and therefore performance of the transformer, the real purpose here is to avoid unnecessary visits to the platform; therefore only CM which can reliably achieve this should be considered. Monitoring the oil flow, temperature, and core temperatures will help to minimize unnecessary maintenance intervention.

Dissolved gas analysis (DGA) is one of the best methods to establish the status of the core and insulation performance.

One application which may be more relevant offshore than onshore is consideration of an accelerometer to detect major impacts which could move or damage winding or tap changer components. This may need to be transformer specific; otherwise it would be difficult to locate potential damage. For advice on obtaining value from condition monitoring, refer to CIGRE Brochure 462.

(v) **Tap Changer(TC)**

The use of vacuum switch tap changers is recommended, which offer the potential to significantly increase the interval between maintenances; however even if the maintenance is eliminated, the possibility of a fault and repair or replacement must be catered for.

(vi) **Bushings**

Transformers are not generally transported onshore with bushings installed, so accelerometers to ensure transportation do not exceed design forces (need to be carefully considered at the specification stage). Marine specialists should be consulted when identifying typical conditions to design for offshore. The HV connections will normally be either cable using plug-in connectors or gas-insulated bus duct (GIB) with oil/$SF_6$ bushings. Spares and the replacement procedure to change out any suspect or failed bushings need to be established. The LV connections may either be cable or solid bus ducts. For cable, again proprietary plug-in connectors will normally be used, but for solid bus ducts, oil/air bushings are used and then enclosed in a suitable housing.

(vii) **Cooling**

The use of natural cooling would provide a significant improvement to reliability and maintenance requirements; however this would expose the unit to the severe marine environment and require a much larger footprint. Forced cooling is likely, and this will have a big impact on auxiliary power demand; change over facilities will be necessary to manage redundant cooling systems.

Table 29.6 summarizes the differences between different cooling designs.

In a marine environment, water cooling systems can be used, eliminating the impact of the harsh atmosphere on the moving parts. However, maintenance of pumps is still required in such a case.

**Fan Cooling**
Both direct air cooling and closed water cooling systems retain the use of fans, which should have an adequate level of redundancy.

**Seawater Cooling**
This technique is widely employed offshore in fixed installations and vessels, and advice should be sought from the marine industry to benefit from their experience.

(viii) **Repair and Replacement**

A fault is likely to result in a long outage since the replacement time will be between 2 and 18 months depending on whether a spare unit is available. A replacement strategy should be produced. Refer to Brochure 483 for more details.

1. Spares

The storage of spare parts will be onshore, so transportation and platform access limitations need to be taken into account. To minimize the variety of spares, the parts and units should be standardized taking into account the manufacturing lead times.

**Strategic Spares**
Retaining strategic spare parts will be an important economic decision, since offshore, full redundancy of primary plant is unlikely. However a spare transformer and reactor may be a requirement. In addition the project should order an extra set of bushings, TC components, radiators, and/or heat exchanger and earthing transformer. The number depends on the total number of that design in the whole wind park.

**Routine Spares**
Routine spares are just as important as strategic spares. Pumps and motors for the cooling, fans, and breathers depending on the design chosen should be considered.

**End of Life Replacement**
End of life replacement offshore is not anticipated but only replacement in the case of a fault.

#### 29.3.3.3 Aspects of Specification Which Are Plant Specific

(i) **Environment**

1. **Paint Finish: Main Tank/Radiators**

If the transformer is located outdoors, where the atmospheric conditions contain salt, the material should be resistant to such conditions. The purchaser should specify the required paint specification and thickness.

Transformers could be located indoors to protect from the environment, but the radiators or coolers should be located outside, and the painting of the radiators should also be considered. It is necessary to check the thickness of the painting film.

The manufacturer should also consider the tank structure to prevent the buildup of water.

2. **Deterioration of Plastic Material by Ultraviolet Ray**

The ultraviolet rays offshore are stronger than onshore. Therefore, lifetime of some plastics or synthetic rubbers may be affected by it, and appropriate materials should be selected.

3. **Ambient Temperature Offshore**

According to IEC 60076-1, the normal ambient temperature is indicated as not below −25 °C and not above 40 °C. However generally the change in the temperature of the ocean is known to be smaller than on land; consequently, consideration may be given to reducing the specified ambient temperature to achieve a more cost-effective solution.

(ii) **Vibration and Transport Forces**

In the case of transformers for offshore substations, the transport forces and vibrations are expected to be more complex and can be divided in five major groups, depending on their frequency and duration:

- Forces related to land transportation
- Forces related to transport of transformer fully assembled on the platform to the offshore destination
- Forces of lifting platform from the barge and locating on the foundation out at sea
- Vibrations from earthquakes, wind gusts, and waves when installed on the platform
- Vibrations from electrical equipment transferred through construction components

Consideration for all modes of the forces or vibrations should be taken into account at the design stage of the transformer. The platform designer should specify the expected level of vibrations arising from environmental impacts, and the transformer manufacturer should indicate the maximum permissible level of forces or vibrations allowed for in the given design. Temporary bracing will be required for sea transportation (Figs. 29.16 and 29.17).

(iii) **Special Technical Considerations**

1. **Early Requirement for Substation Design Information**

The data on transformer weight and dimensions is critical to platform designers, so it is extremely important that physical characteristics of the transformers resulting from the chosen design concept will not be changed later, when platform design or construction is already in progress (Table 29.2).

**Fig. 29.16** Example of temporary bracing on a transformer for sea transportation

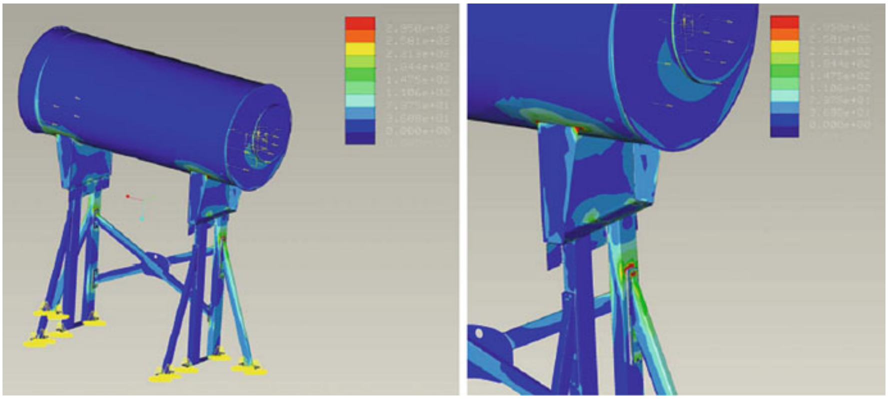


**Fig. 29.17** Stress analysis of conservator support

2. **Need for Minimizing the Total Cost**

Specific attention needs to be paid to the weight and size of the electrical equipment, as it will have both a direct and indirect effect on the total weight, as reduction in electrical equipment weight by 1 t could further reduce the topsides and supporting structure weights by 3 t.

To minimize the life cycle cost (LCC), the transformer designer should discuss with the system designer and the platform designer in order to obtain the overall optimum solution for the transformer, platform, and foundation.

**Table 29.2** Required information for platform design

| No. | Required information item | Note |
|---|---|---|
| 1 | Transformer weight | Guaranteed value |
| 2 | Transformer dimension | Guaranteed value |
| 3 | Mineral oil/liquid volume | Guaranteed value |
| 4 | Auxiliary power for cooling, etc. | |

3. **Insulation Systems in Power Transformers**
   There are three major technologies available in transformer construction:
   - Liquid-immersed transformers
   - Gas-insulated transformers (GIT)
   - Dry-type transformers

Each of them has got their advantages and drawbacks. Some limitations or special requirements are applicable for each technology.

(a) **Liquid-Immersed Transformers**

The liquid-immersed transformers are the most common type of technology. Apart from its dielectric role, the fluid transfers heat from windings to tank surface and coolers. Mineral oil is the most common insulating and cooling medium used in transformers.

The use of oil in large quantities in transformers can be a major issue in offshore installations as it combines aspects related to maintenance, impact of harsh environment, and safety problems (both fire and environmental).

The systems used for protection of oil against the environmental impacts from the air include according to IEC 60076-1:

- Freely breathing systems with dehydrating breathers
- Diaphragm or bladder-type liquid preservation systems
- Inert gas pressure systems
- Sealed tank systems with gas cushion
- Hermetically sealed completely filled tanks

Hermetically sealed tanks provide best protection against moisture and oxygen access to the transformer fluid and are suitable for small transformers up to 60 MVA, 110/33 kV.

The majority of transformers installed so far use more conventional oil protection systems. Access of air over the oil surface in the conservator is enabled through dehydrating breathers, which remove moisture from the incoming air. The use of rubber bags or bladders in conservators together with low-maintenance breathers is preferred to free breathing systems for offshore transformers.

Consideration of the environmental protection and fire safety must be fully considered.

Transformers filled with mineral oil are notorious for their fire behavior, and fire protection systems are necessary to limit damage resulting from oil fires. This issue is critical in case of offshore installations, where the quick access of firefighting personnel is not possible.

The use of multiple pressure relief devices distributed on tank walls and transformer cover may be advantageous to minimize the risk of explosion.

Mineral oil used in transformers is harmful to the environment and is not biodegradable. Consequently, oil collection systems to prevent oil spillage are required, for example, dump tanks.

(a-1) **Use of Alternative Fluids**

In order to reduce the environmental and fire safety hazards posed by mineral oil, it is possible to use fire-resistant biodegradable alternative insulating fluids. A full discussion of the properties of these alternative insulating fluids can be found in the CIGRE Technical Brochure 436 "Experiences in Service with New Insulating Liquids," 2010.

The most common and commercially available fluids fall into three main categories:

- Synthetic ester
- Natural ester
- Silicone fluid

(a-2) **Impact of Less-Flammable Fluids on Requirements for Fire Protection Systems**

Equipment filled with less-flammable fluid is less likely to burn in case of overheating or electrical fault, and if a fire starts, the fire will usually extinguish by itself. It is recommended that such fluids are used for auxiliary transformers.

The specific allowance reduction of firefighting requirements will depend on national regulations.

(a-3) **Alternative Insulation Systems in Liquid-Immersed Transformers as per IEC 60076-14**

Consideration can be given to the use of alternative insulation systems in liquid-immersed transformers, such as hybrid insulation in order to increase the allowed operating temperature or achieve higher overload capability without compromising the life. Reference should be made

(b) **Gas-Insulated Transformers**

The GIT/GIR has the advantage of being non-flammable and nonexplosive and so it is not necessary to take the fire prevention distance between transformer and other equipments or to apply fire extinguishing equipment. Furthermore it is lighter and less prone to low-frequency vibrations from wind gusts and waves.

Of course this transformer has some disadvantages, such as:

(i) Auxiliary loss is bigger than conventional transformer.
(ii) Natural cooling rating is smaller than conventional transformer.

If gas-filled transformers are to be used to reduce the total cost for building an offshore substation, it is desirable that the purchaser and manufacturer discuss the most suitable specification of transformers for the offshore substation.

(c) **Dry-Type Transformers**

Dry-type technology is normally used for low-voltage and small-capacity transformers. However, the sensitivity of dry-type transformers to harsh environments means that they are not well suited to offshore substations.

4. **Method of Cooling**

Cooling can be either by air or by water. Air cooling can be by conventional radiators, with or without forced air flow. Forced air flow will reduce size of cooling system, but it requires fans which need maintenance.

Water coolers require pumps and piping which are both slightly costly and space consuming. Water cooling can be considered in two ways, one is using seawater (open water) cooling and another is closed water cooling. With seawater cooling, marine debris/obstacles adhere inside of pipes, water coolers, and pumps requiring cleaning to keep the cooling capability during operation. Usually the water in the cooling system should be divided into two systems. Primary water system uses seawater, while secondary water system uses pure water (closed system). Alternatively, a closed water cooling system, which doesn't use seawater, can be used. All these systems are available for both liquid-immersed and gas-insulated transformers.

A comparison of these cooling systems is given in Tables 29.3 and 29.4.

5. **Air-Cooled Radiators: Tank Mounted or Separated**

The pros and cons between air-cooled radiators which are mounted on the transformer tank and separated are described in Table 29.5.

(iv) **Physical and Interface Considerations**

The connections to the transformer will either be by bus duct or cable. If bus duct connections are used, consideration must be given to differential movement during transportation and to suitable sealing around the penetrations which should meet the same fire level as the walls. If cable connections are used, then the bending radii must be considered and adequate space allowed for termination. If the transformer is

**Table 29.3** Comparison with cooling methods (1)

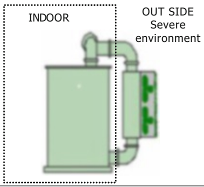
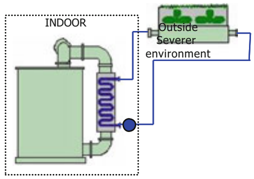
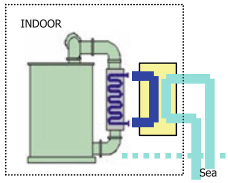
| | Air cooling | Closed water cooling | Seawater cooling |
|---|---|---|---|
| Configuration |   |   |   |
| Advantage | Simple structure<br>Initial cost is low | Heat exchanger can be changed easily without oil handling. The area of the equipment is small | Compact and highly preserved feature under the severe environmental condition. The area of the equipment is small |
| Disadvantage | Heat exchanger cannot be changed easily. The area of the equipment is large | System is slightly redundant and complicated. Initial cost is high | It is necessary to remove marine debris/obstacles; it is more complicated with high redundancy. Running cost is high |

**Table 29.4** Comparison with cooling methods (2)

| | Natural air | Forced air | Forced water |
|---|---|---|---|
| Initial cost | Δ | O | X |
| Transformer size of weight | X | O | O |
| Auxiliary power | O | X | X |
| Big maintenance<br>(e.g., exchange of coolers) | Δ | Δ | O |
| Small maintenance<br>(e.g., exchange of fan bearing) | O | Δ | Δ |

Good: O Δ X: Bad

located outside, then the cable entries should be from below to avoid the risk of water ingress. The cables should be fitted with plug/socket connections with the plug on the cable end and the socket on the transformer. Consideration should be given to the need for removable links in the transformer cable boxes to allow for cable testing. The routes for all auxiliary cables to and from the transformer need to be managed.

#### 29.3.3.4 Specific Requirements for Rooms or Enclosures

During the early stages of the substation platform design process, the physical parameters of the transformer must be identified, typically weight, oil volumes, footprint, cable entry points, type of HV and LV connections, and direction of approach of connections.

While the overall weight is an important factor in the design of the primary steel members for the platform, the footprint is vital to determine the actual locations for the main steel deck members. The steel deck members must be located to match the

**Table 29.5** Comparison between tank-mounted radiators and separated

| | Tank-mounted air cooler | Separated air cooler |
|---|---|---|
| Advantage | Overall footprint is smaller | Only coolers need high levels of ventilation:<br>1. Making fire suppression around transformer tank easier<br>2. Allowing a more controlled environment around the transformer tank |
| | No issues with differential movement of tank and radiators during transport or in service | Transformer tank assembly is smaller and lighter reducing the necessary capacity of the support structure |
| | Significantly less platform volume required if we assume the coolers need both enclosure (to prevent oil spills) and maintenance access to the coolers | More flexibility in platform design? |
| | Should be easier to assemble on-site | The transformer and coolers are lifted separately and empty which reduces the capacity of the crane required |
| | | Easier access for maintenance of radiators than for tank-mounted version; radiators could be more easily exchanged (?) |
| | | More suited to an enclosed topside concept – e.g., floating platforms which self-install, as the transformer space can be almost completely enclosed |
| | | Potential to locate the coolers at a relatively higher level to the transformer, and as a result use the platform space better |
| | | Separate coolers mean we can replace individual cooler cartridges at a time while keeping the whole transformer live and not entering the transformer space |
| | | Option to address the amount of enclosure of the coolers. Some suppliers have been designing the coolers to stand in the open on the platform |
| | | Separate coolers allow to consider alternative forms of oil cooling. This will be more important for HV/DC platforms which have an inherent need for more cooling of equipment |
| Disadvantage | Concentrated load requires stronger platform structure (cost?) | Additional support structures are required for the oil pipes between tank and cooler |

(*continued*)

**Table 29.5** (continued)

| | Tank-mounted air cooler | Separated air cooler |
|---|---|---|
| | Whole of transformer space has to have high levels of ventilation:<br>1. Making fire suppression more difficult<br>2. Exposing the transformer tank to more salt corrosion and contamination | Filling of the transformer and coolers with oil is more difficult as the location of the transformer is typically a number of meters above ground level in the shipyard |
| | Larger crane will be required for lift especially if it is filled with oil at ground level | Needs careful design of the piping systems |
| | Access for maintenance of the coolers is more difficult | |
| | Heavier transformer means a heavier offshore installation vessel should the transformer need to be replaced | |

points where the transformer load is transferred into the deck, typically beneath the anti-vibration pads and jacking points.

The locations for cable entry points need to be identified to ensure that the support steel for the deck does not interfere with the cable access. The design should identify access positions for HV power cables or GIB ducting, LV power cables or solid insulation bus ducts, multicore control cables to the transformer, tap changer, fans, etc.

The platform designer must determine the minimum amount of space around the transformers to permit all aspects of planned and unplanned operation, maintenance, repair works, location of testing equipment, tap changer extraction tools, and temporary access platforms.

The design must allow for future replacement of radiator elements, a complete radiator bank, and also the replacement of a transformer tank. The following items should be considered in the design of the room/enclosure:

- The radiator elements will generally be in an open location; however, access needs to be allowed for removal either by the platform crane, suitable lifting beams, or a vessel-mounted marine crane. If the radiators are covered by a roof section, then this may need to be removable.
- The transformer should be positioned such that removal can be effected by the use of a vessel-mounted marine crane/jack-up crane. To facilitate this procedure, the roof of the transformer room may need to be removable.
- The design will need to consider the draining and re-filling with oil which will necessitate suitable 400 volt electrical supplies to power the filtration equipment and space to position the equipment together with the oil.

Heat will be generated by both the transformer tank and the radiators during service, and the room dimensions and ventilation systems will need to allow for the dissipation of this heat in their design. If the enclosure has walls, then they could typically comprise open mesh, louvers, or a similar construction. If the radiators are in an open location, then measures should be taken to discourage roosting seabirds with their attendant guano pollution.

The transformer room/enclosure needs to be constructed with an oil retaining bund which would prevent any escape of oil from entering the sea. The bund deck/floor should be constructed with falls (typically 1:80 or 1:100) to direct fluids into drains to a remote oil containment tank.

The oil containment tank must be suitably dimensioned to accept as a minimum the full volume of oil from the largest oil-filled device plus the full volume of water from an automatic fire suppression system plus spare capacity (suggest 15%). The method of specifying the tank capacity may vary to meet local regulations.

The drain pipework between the transformer bund and the containment tanks should discharge fluids at a minimum rate of 7,000 liters per minute.

Where a fire rating is assigned to the transformer room walls, then any access doors within the wall must be suitably fire rated to match that of the wall.

### 29.3.4 Earthing/Auxiliary Transformers

#### 29.3.4.1 Aspects of Specification Which Come from Systems Studies

(i) **Connected to Transformer or Busbar**

An earthing/auxiliary transformer can be connected to the 36 kV network either to the busbar or directly to the transformer connections. Connection to the busbar will usually necessitate that it has a circuit breaker to disconnect the transformer in the case of a fault on the unit. It may be that connecting to the busbars will reduce the number of earthing transformers required. However, if the bars are run split for fault-level control, then the same number will be required as if they were connected to the 33 kV windings of the main transformers. Connecting to the 33 kV windings of the main transformer saves on the need for a circuit breaker but does mean that for an earthing transformer fault the main transformer will be disconnected, but it is unlikely that the transformer can run for any length of time without an earth connected. The other reason for considering connecting the earthing/auxiliary transformer to the busbar is discussed in the following paragraph.

(ii) **Required to Provide Auxiliary Power for Platform Only or also for Turbine Strings**

Usually the earthing transformers will have secondary windings allowing them to also act as auxiliary transformers for the platform supplies. This saves the cost and weight of providing separate auxiliary transformers. On the majority of offshore substations built to date, the auxiliary transformers have only been rated to supply the auxiliary supplies of the offshore substation itself and have not been designed to allow powering up the 36 kV array strings to feed auxiliary power for the WTGs when the AC supply from the shore is lost. If this powering of the WTGs is to be provided, then this needs significant consideration as follows:

(a) That they are connected to the 36 kV busbars
(b) That they are rated for a high kVA to allow for the reactive power of the array strings unless additional reactors are provided for this purpose
(c) That normal platform diesel would need to be designed very large with the associated requirement for the fuel storage

If powering of the WTGs in system black conditions is required, it is recommended that this is a separate specially designed system.

(iii) **Rating**

The rating of the transformers will be decided by the loads to be supplied and the number of transformers to be operated to supply the auxiliaries simultaneously. It is often designed such that all earthing transformers are equipped with secondary windings, but only one feeds the auxiliaries at any time. This decision is dependent upon the redundancy strategy. An alternative is to run with two transformers feeding separate LV boards with an interconnector in case of failure of one of the transformers. In either case each of the transformers will have to be rated to carry the full load of the substation auxiliary system.

(iv) **Off-Load or Off-Circuit Tap Range**

Normally, off-circuit taps will be sufficient, and the use of a tap range of +/−5% in 2.5% steps as is common for onshore auxiliary transformers will suffice as the 33 kV voltage is usually controlled by an automatic voltage control scheme.

(v) **Impedance**

The zero sequence impedance will be determined by which type of earthing scheme is used to limit the earth fault current. If resistance earthing is to be used, then the zero sequence impedance of the earthing transformer will normally be designed as low as possible. If however the current is to be limited by the earthing transformer, then the zero sequence impedance will be selected to limit the current to the chosen value.

The positive and negative sequence impedances will normally be similar to those used for onshore auxiliary transformers in the range 5–9%.

(vi) **Number Required**

The number of earthing transformers will be dictated by the running arrangements as to how many separate sections of system will require earth connections.

The number to be used as auxiliary transformers can be decided by the redundancy requirements for the auxiliary system.

#### 29.3.4.2 Aspects of Specification Which Come from Generic Operation and Maintenance Considerations

(i) **Oil Management**

If the auxiliary transformer is of oil/liquid design, then they are normally hermetically sealed so there is very little to manage in terms of oil handling. These are small capacity devices; however since they may be adjacent to the main tank, a high-temperature flash point insulating fluid should be considered.

(ii) **Repair and Replacement**

A fault is likely to result in reduced auxiliary power or more importantly an unearthed transformer; therefore this affects the transformer availability.

(iii) **Major Replacement Strategy**

The design phase should cater for the emergency replacement of an auxiliary/earthing transformer.

The unit is approximately 1–2 t in weight so could possibly be lifted from a vessel using the platform crane; however it still needs to be moved around the platform. Access hatches may be necessary. If it is hermetically sealed, there should not be any need for oil management, unless the faulted unit experienced a rupture and cleanup is required.

(iv) **Spares**

**Strategic Spares**
A spare earthing/auxiliary transformer should be considered. Along with a set of bushings, the number depends on the total number of that design in the whole wind park.

**Routine Spares**
None.

#### 29.3.4.3 Aspects of Specification Which Are Plant Specific

(i) **Special Technical Considerations**

1. **Insulation System**

   Liquid type possibly using esters should be considered.

2. **Oil Conservator Type or Sealed Type**

   Preference is for hermetically sealed type.

3. **Avoiding Excessive LV Voltages During HV Earth Faults with Earthing/ Auxiliary Transformers**

In case of an earth fault, the earth fault current in the HV system of the earthing/ auxiliary transformer flows via the neutral of the earthing/auxiliary transformer and is limited by the zero sequence impedance. During HV earth faults the LV voltages to earth can be displaced causing an overvoltage and damage.

The solution to this problem is to install an additional neutral coupler in order to form a new independent neutral for the LV winding of the earthing/auxiliary transformer.

(ii) **Physical and Interface Considerations**

The auxiliary/earthing transformers may be located within a separate enclosure or within the main transformer room. They could be mounted on cantilever brackets from the side of the main transformer tank and the HV connections made using bus duct, or alternatively they may need to be mounted separately and either cable connected or bus duct connected.

The connections to the transformer LV windings would generally be made using either cables or solid insulated bus ducts, and the method of connection needs to be identified at an early stage to allow the mechanical design of the transformer to proceed.

Cables to transformers located outdoors should enter from the bottom. Allowance has to be made for bending radii of the cables, and again plug/socket connections are preferred.

#### 29.3.4.4 Specific Requirements for Rooms or Enclosures

The earthing auxiliary transformer may be located within the same room as the main transformer or reactor, in which case the oil containment conditions for the main plant would be adequate for the smaller earthing/auxiliary transformer. If, however, the earthing/auxiliary transformer is located within a separate room, then facilities will need to be provided to handle any fluid spills.

The locations for cable entry points need to be identified to ensure that the support steel for the deck does not interfere with the cable access. The design should identify access positions for HV and LV power cables or solid insulation bus ducts, multicore control cables, etc.

The platform designer must determine the minimum amount of space around the transformer to permit all aspects of planned and unplanned operation, maintenance and repair works, and testing.

The design must allow for access to install the transformer initially and also access for future replacement of a defective transformer. The transformer should be positioned such that removal can be effected by the use of a vessel-mounted marine crane/jack-up crane or the integral platform crane. To facilitate this procedure, the roof of the transformer room may need to be removable.

Refer to the requirements for the main transformer rooms for other factors to consider.

### 29.3.5 HV Switchgear

The high-voltage switchgear utilized on offshore platforms will be the metal-enclosed $SF_6$ (sulfur hexafluoride) type which is often referred to as GIS (gas-insulated switchgear).

#### 29.3.5.1 Aspects of Specification Which Come from Systems Studies

(i) **Voltage and Current Ratings**

The voltage to be used for the transmission of power from the offshore substation to the shore will have been decided largely based upon optimizing the submarine cable. Typically the voltage will be 110 kV, 132 kV, 150 kV, or 220 kV. Voltages in excess of this are unlikely to be utilized unless gas-insulated lines become feasible. The current ratings will be identified by the load flow studies; however, a typical standard rating of 2000 A is likely to suffice for most cases.

(ii) **Fault Level Ratings**

If the wind power plant is being connected directly into the onshore system, then the fault level of the switchgear is likely to be dictated by that utilized by the utility onshore. If onshore transformers are used to connect into a higher onshore voltage system, then the impedance of the onshore transformers will have the biggest impact on the fault level.

(iii) **LIWL**

The LIWL for the HV switchgear is likely to be that normally used for that voltage level in accordance with IEC 60071. The value will be confirmed by the insulation coordination studies.

(iv) **Surge Arrester Ratings and Location**

Surge arresters will normally be required on the connection to the offshore transformers. The surge arresters in some cases may be connected directly on the transformer, but in many cases they will be located in the switchgear. If high energy rating is required, additional matched arresters may be used on the cable connection side also. The surge arrester ratings and energy ratings will be confirmed by the insulation coordination studies.

(v) **Configuration**

The simplest switching configuration found on offshore platforms is simply a disconnector between the submarine cable circuit and the transformer together with earth switches either side of the disconnector.

The next most common configuration is to simply add a circuit breaker between the submarine cable and the transformer. The main factors to consider with regard to configuration are the amount of submarine cables and transformers. A design with one submarine cable and two transformers will typically give a configuration with one GIS bay for the submarine cable, a busbar, and two transformer GIS bays. A design with two submarine cables and two transformers will typically give only two GIS bays (one for each transformer) as very often the transformer and the submarine cable are rated the same, which means transformer cross-connecting switchgear is located on the MV side.

(vi) **Requirement for Point on Wave Switching**

If the HV switchgear is used for energizing transformers or switching shunt reactors, then there may be a requirement for point on wave switching facilities to be specified.

#### 29.3.5.2 Aspects of Specification Which Come from Generic Operation and Maintenance Considerations

GIS is relatively maintenance-free and typically it has a low failure rate (onshore!). Modular construction will help with O&M enabling fast changeout and reducing the need for specialist engineers on the platform.

(i) **$SF_6$ Management**

$SF_6$ gas density monitoring is increasingly being used to provide indicators as to the GIS condition. Leaks can be detected, location, and time to lockout, giving a longer window of opportunity to carry out preventative topping up rather than having to deal with a lockout.

As it will be impractical to transport a cart each time degassing is required, a gas handling facility together with a gas bottle should be kept on the platform.

(ii) **Condition Monitoring**

There are a number of areas where CM can assist in the determination of switchgear performance and avoid intrusive procedures or unnecessary visits to the platform. Where possible, trending of the switchgear condition should be employed rather than remote alarms as these may mal-operate and incur unnecessary emergency offshore visits. Keep the sensors simple and robust.

(iii) **Operating Mechanism**

Moving parts such as the operating mechanism will require periodical maintenance. Designs aiming to be maintenance-free will be desired with applying solid lubrication or greaseless pins and shafts.

(iv) **Repair and Replacement**

The procedure to replace each major component should be established at the design stage to ensure sufficient space is available for both the failed and replacement in the enclosure. At design stage, it is also important to consider if any temporary facilities need to be provided such as I-beam in the ceiling, permanent crane support, etc. The supplier will know what needs to be in place to keep future maintenance and repair time at a minimum.

(v) **Spares**

Most of the components in a bay are common, so generally keeping a spare bay onshore will address most issues.

**Strategic Spares**
- Spare GIS bay incorporating CT, VT, CB disconnector, and ES (remember that all bays on the platform may not have a similar configuration, so 1:1 replacement may not always be an option)
- Spare set of surge arresters
- Mech box for each moving part

**Routine Spares**
- Gas density monitors, breaker contacts, flange sealant, and control cabinet heater elements

#### 29.3.5.3 Aspects of Specification Which Are Plant Specific

(i) **Environment**

The GIS will typically be installed indoor in the offshore substation in a room with HVAC.

(ii) **Vibration and Transport Forces**

It is known that offshore substations will vibrate, even if they are in a non-earthquake zone. The severity of these vibrations will depend heavily on one major factor – the type of foundation for the substation where a monopile will give rise to much higher vibrations than a jacket foundation. Another issue is the direct impact forces equipment can experience during transport (move to the offshore site).

It is typically understood that GIS has a lower center of gravity compared to AIS (air-insulated switchgears) at the same voltage level. Still the important measure which should be taken into consideration is to take care of a very rigid connection between the GIS bays, the GIL (gas-insulated line to transformer – if that's applied), and the base frames of the bays.

The local control panel of the GIS (which can be mounted on the GIS or separately) should also take vibrations into account, and self-tightening cabling terminals and bolt solutions for vibrating environments should be considered as standard.

Transport forces can typically only be minimized by the carrying vessel and off-loading units. The complete substation should be monitored with shock recorders, and any impacts higher than accepted should be discussed thoroughly with the supplier of the GIS.

(iii) **Special Technical Considerations**

1. **Selection of Type of Equipment**

All three phases in a common tank-type GIS are widely used for 170 kV class and below.

Isolated phase type for feeder units is common for 245 kV and above. Either three phase common or isolated phase is used for the main bus.

2. **Design of Voltage Transformers**

Instrument transformers used as a component in GIS are generally winding-type voltage transformers. A check should be made to see if the voltage transformers may have to be capable of discharging long cables, and if so they will need to be specified accordingly. It should be checked if any disconnection facilities may be required for the voltage transformer.

3. **Location of Current Transformers**

Usually current transformers will be located on one side of the circuit breaker only and the protection designed to avoid blind zones.

(iv) **Physical and Interface Considerations**

The main primary interfaces with the switchgear are the export cables and the transformer connections. The transformer connections may also be cable but can be gas-insulated bus duct. The cable connections will normally use plug and socket connections. Consideration should also be given for connection of the test equipment for both the switchgear test and also the power cable testing.

As the equipment will be subject to external forces due to the sea transport and lifting, the switchgear design needs to allow for these and include any necessary attachment points for fitting of external sea-fastening straps (Figs. 29.18 and 29.19).

#### 29.3.5.4 Specific Requirements for Rooms or Enclosures

In addition to all of the normal considerations for an onshore switchgear room, the following aspects should be considered.

**Fig. 29.18** Example of cable entry to 132 kV switchgear


The support points should be designed to accept the static and dynamic loads imposed by the switchgear. With the agreement of the switchgear manufacturer, it may be acceptable to weld the support frames directly to the deck plates in preference to bolting.

During an internal fault, or failure of a gas zone within an $SF_6$ switchboard, high-pressure gasses may be vented into the room/enclosure. The resulting overpressure needs to be evaluated and if necessary suitable pressure relief devices built into the room. The $SF_6$ alarm systems integral to the switchgear could also be used to initiate a beacon and sounder from the switchgear.

The room should be air-conditioned and designed to have a minimum ambient air temperature of +5 °C. The ventilation system should incorporate maintainable salt filters.

## 29.3.6 Export and Inter-array Cables

### 29.3.6.1 Aspects of Specification Which Come from Systems Studies

The cable ratings should be dimensioned for the voltage, the power requirement at the generating end, plus the load factor. After this information the conductor diameter and material are best selected by the cable manufacturer. Conductor material can be either copper or aluminum.


**Fig. 29.19** Example of export cable entry with transit sealed

The inter-array cables are typically for 36 kV system voltages, although with increasing generating capability of the turbines 69 kV cables may be used in the future. In most cases it is more economical to have two or three different conductor diameters for a larger wind power plant.

The system voltage for the export cables will come from the systems studies and may be any IEC system voltage. Up to 245 kV systems, these cables are typically three-phase design.

Communication is needed due to the offshore application, and both array and export three-phase cables have integrated fiber-optic cables (FOC) which should include enough redundancy backup.

#### 29.3.6.2 Aspects of Specification Which Come from Generic Operation and Maintenance Considerations

Both cable types are to be installed on platforms with hang-offs for the armoring and J-tubes often with bend restrictors. Typical terminations at the platforms are of the plug-in type for the GIS substations.

The design of the J-tubes should meet the requirements of the cables inside them, mainly regarding minimum internal diameter and bend radius of the bottom part. The J-tubes are normally made of carbon steel and protected against corrosion by means of a suitable coating, although some models are manufactured with polymer material. Besides the J-tubes, the other indispensable element to terminate a submarine cable entering an offshore platform is the hang-off which is located immediately above the J-tube, fixed to the deck of the platform. For three-core cables, the hang-off devices include a chamber for trifurcating the cores that will run for connection to the bushings of the switchgear. In any case the hang-off should seal the top of the J-tube, and the hang-off itself should be protected against corrosion by means of a suitable coating.

(i) **Maintenance**

Typically cables are maintenance-free. However, it is possible to measure temperatures with special fiber-optic cables that indicate the conductor temperature of the cable with an accuracy of around 5°K. These DTS systems may give an indication of overloading risks or failure/problems of the cable. They must be installed together with the original installation.

(ii) **Spares**

Normally spares ordered together with the delivery include one or two terminations, some submarine repair joints, and spare cables of length for at least two repairs. Spare inter-array cables should be of the largest size as joints to connect dissimilar sizes are available. These repair joints should also include splice boxes for the FOC, if used.

#### 29.3.6.3 Aspects of Specification Which Are Plant Specific

First of all it is necessary to review the calculations to establish the cable load limits during the pulling operation. Then a thorough analysis should be carried out to decide the best places for locating the pull-in equipment on the deck: this includes the winch, the pulleys, the load-monitoring device, and any other associated equipment. The mechanical ratings of this equipment should be suitable for the characteristics of the pull-in operation to be developed, and the position of the different elements should be such as to avoid exceeding any of the mechanical limits of the cable (Fig. 29.20).

(i) **Physical and Interface Considerations**

Interfaces for the subsea cable installation may vary dependent upon the design of the substation (refer to Brochure 483 for details).

To meet constraints imposed by the heavy lift of the jacket foundation and the topsides, it may be necessary to provide filler sections installed for each J-tube to bridge the gap between jacket and topside and complete the J-tube. Access facilities need to be considered to permit these J-tube extension sections to be installed offshore.

The cable terminations should be suitable for the marine environment (Figs. 29.21, 29.22, and 29.23).

**Fig. 29.20** Hang-off block anchoring a high-voltage three-core cable (right) and entry for a connection to a GIS substation

## 29.3.7 Site Tests and Commissioning

### 29.3.7.1 Overall Strategy

The cost of carrying out any work offshore is approximately ten times the cost of the same activity performed onshore. This dictates the overall strategy for performing installation and commissioning activities. Everything that can be done onshore before the substation platform leaves the construction yard should be done so that only those activities which can only be performed offshore are left to be completed when the platform is installed on its foundation. The onshore testing should be as comprehensive as possible to find out any problems before the substation is transported.

Furthermore, all equipment should be as completely installed as possible onshore. Dismantling of any parts of the equipment for transport on the barge and reassembling offshore should be avoided. The equipment needs to be designed such that it can withstand the forces which it will experience when being transported on the barge. This is particularly relevant to oil filling of transformers and gassing up of GIS switchgear equipment.

There are some activities which can only be completed when the substation is installed on its foundation offshore. Such activities include termination of the submarine cables and their associated fiber optics. The testing of these parts has to be performed offshore. With regard to equipment which has been thoroughly tested onshore, then the testing to be carried out on this equipment should be kept to the absolute minimum to ensure that the equipment has not been damaged in transit and that it is functioning correctly.

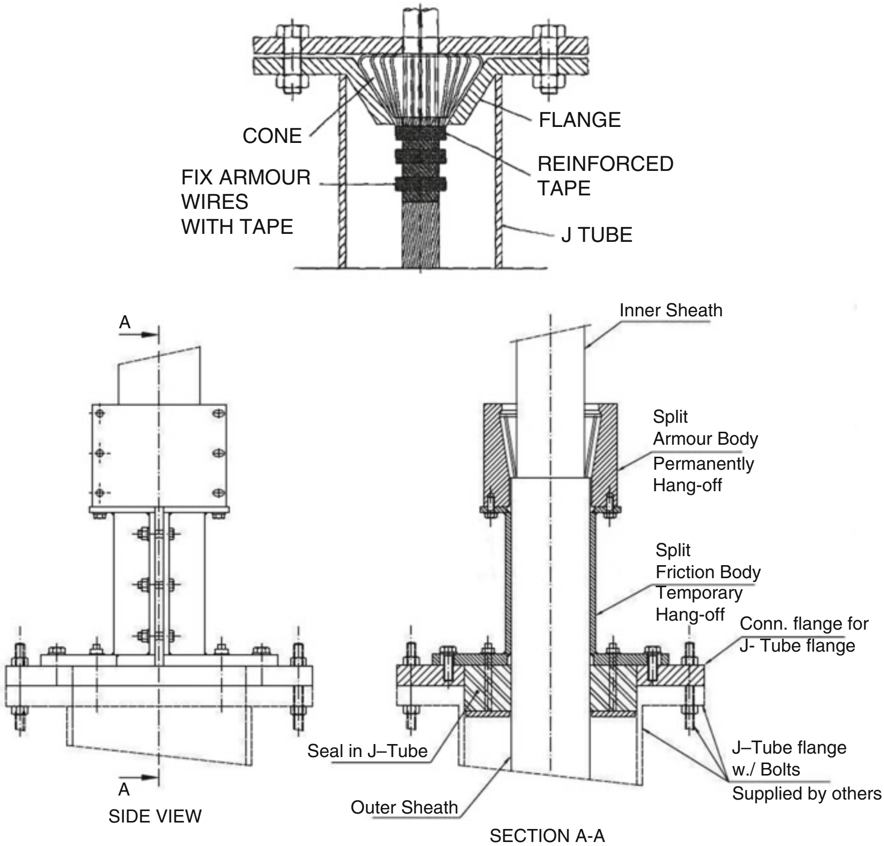



**Fig. 29.21** Two types of cable hang-offs, being the first a very simple design and the second a more elaborated one, similar to that used in offshore wind power plants

#### 29.3.7.2 Pre-energization Onshore Commissioning

Commissioning of an offshore substation can be broken into two aspects which follow the principles of an onshore substation. These can be referred to as stage 1 and stage 2 commissioning, i.e., “pre-” and “post-” HV energization.

The significant issue which faces an offshore substation is that the stage 1 pre-commissioning is performed onshore, typically within a fabricator yard or dockside area. The substation is then transported before stage 1 activities can be fully completed and the project progress onto stage 2 commissioning.

As with onshore substation commissioning, the pre-energization typically requires proving of the individual equipment functionality and circuitry connection prior to intersystem checks. It is not the aim of this document to provide a detailed explanation of a commissioning process but to illustrate key differences between the commissioning of an onshore facility and that of an offshore substation.

**Fig. 29.22** Example of J-tube filler sections being installed between jacket and topside

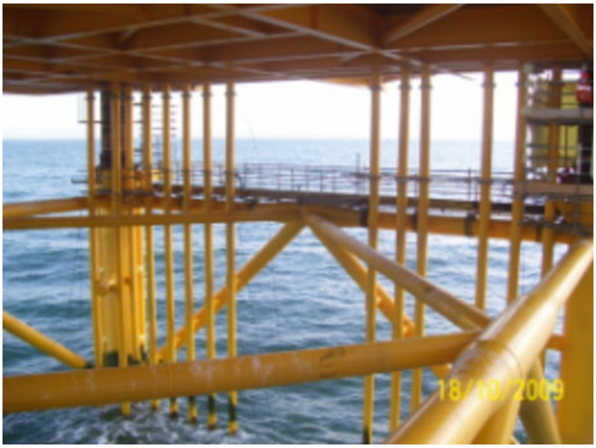



**Fig. 29.23** Example of completed J-tubes

Pre-commissioning onshore will be preceded by the equipment Factory Acceptance Test (FAT), including routine tests. These will have been completed in accordance with the standards to which the equipment is manufactured.

After the installation of the individual equipment and manufacturer checks on the respective equipment, the pre-commissioning can be broken down into the general areas of:

- Transformers
- Switchgear
- Building services (including lighting, heating and ventilation, CCTV, fire and safety systems)
- LV systems
- DC systems

- SCADA and control systems
- Telecommunication (including VHF, UHF radios)

These tests are basically the same as the stage 1 tests which would be carried out on an onshore substation and should be carried out to the maximum extent possible.

Prior to transportation offshore, the extent of the test and commissioning engineers and equipment specialists which require to be fully offshore trained should have been assessed. Furthermore, the operation of the auxiliary generator during transportation should be considered. Alternatively, the duration between leaving the dockside and running of the auxiliary generator should be assessed for impact on equipment preservation requirements in uncontrolled temperature environments.

(i) **On-Site High-Voltage Tests**

On the offshore substation platform, the HV and 36 kV switchgear will be HV pressure tested. This will also include any bus duct installed to the power transformer.

The interconnecting cables between the transformer and items of switchgear would also normally be installed and tested in the onshore fabricator's yard prior to sail-out of the platform. These include from the HV switchgear to transformer HV windings and from the transformer LV winding to the 36 kV switchboard(s).

#### 29.3.7.3 Pre-energization Offshore Commissioning

The initial task offshore after the substation installation is a visual inspection to assess any damage, or obvious changes, to equipment conditions and contents (i.e., $SF_6$ or oil levels).

The work offshore may need to be carried out under a totally different safety and permit system. After a visual inspection is performed, an assessment of the safety systems should be undertaken including inspection of any alarms on equipment or the SCADA system and confirmation of the HVAC system operation.

The pre-commissioning works offshore will then focus upon:

- Securing any gratings which were lifted for transportation (e.g., gratings lifted at padeyes)
- Removal of any transportation bracing or temporary supports
- Removal of door locking plates (or similar to ensure doors remain closed during transportation) to provide access to rooms
- Testing of platform and internal lighting
- Erection of lightning masts and antenna (if fitted and lowered during sea transportation)
- Fitting of any ventilation units removed during sea transportation
- Operation check of the platform cranes

The electrical pre-commissioning will then recheck a number of items which were tested on the dockside. This is required to ensure that no changes have occurred during the load-out.

An essential requirement for completing the offshore tests is the establishment of the telecommunication system to shore. This will usually require termination of the export cables as the fibers are usually embedded in these cables.

(i) **High-Voltage Tests for Power Cables**

After installation, there are a number of options for the testing of the cable circuit which presents various limitations and difficulties, including individual interpretation of the results which can be determined from the cable testing. Testing can include:

1. DC test on the oversheath
2. AC insulation withstand test:
   - Power frequency testing
   - Very low frequency (VLF) testing
3. Partial discharge

Normally one prefers to carry out a power frequency test. However, because of the cable capacitance causing very high charging current, it can be difficult to achieve the necessary values via a test set. A more practical solution may be the application of service voltage (U0) for 24 h as a soak test when the platform is first energized. This test utilizing energization from the electricity grid must be discussed with the transmission system owner at an early stage in the design process.

#### 29.3.7.4 Post-energization Commissioning

(i) **Energization of Sub-circuits**

The energization procedure should follow a Commissioning Switching Programme. Typical stages through the switching and energization for a single cable and two transformer systems would be:

1. Confirm all wind power plant equipment is ready for energization.
   Configure grid connection point for commissioning activities (more sensitive protection settings, adopt grid commissioning operational state to limit disturbance in case of faults).*
   
   * This is executed by/together with the transmission/distribution system owner.
2. First energization of the connection assets located onshore.
3. Energization of the subsea cable. The charging current of the cable can be used to prove the stability of the onshore upstream differential protection.
4. Perform export cable soak test.

5. Energization of the HV switchgear.
6. Energization of first transformer including tap changer and soak test.
7. Energization of second transformer including tap changer and soak test.
8. Energization of 36 kV switchgear busbars and auxiliary transformer from HV system.
9. Energization of WTG arrays and test.
10. Carry out final commissioning control schemes on the offshore platform.
11. Reconfigure power system to meet operational requirements.

At each stage of energization the equipment recently energized should be inspected for signs of distress, and while under load, various checks can be carried out. This includes current/voltage transducers, remote indications of current differential scheme, phase rotation checks, protection relay indications (V, A, f, MW, MVar), and power quality monitoring systems. All checks performed should be recorded in a commissioning record.

(ii) **Post-energization**

When the system has been energized for a few days, one should attend the substation to inspect (see, hear, smell, touch) all equipment, cables, and associated plant. In some cases, the supplier of each equipment will have a clear instruction on post-energization checks – but in most cases, the commissioning team will have to use/invent their own checks.

(iii) **Monitoring for Power Grid Connection Compliance Commissioning**

In many cases, the substation will include the point where a power generating facility is connected to a power grid system. Where this is the case, connection compliance commissioning tests would need to be performed following energization of the substation. All circuits and generation facilities that are connected to the substation would need to be fully commissioned prior to the compliance testing. For more details of these tests, refer to Brochure 483.

## 29.4 Physical Considerations

The main objective of this section is to discuss design considerations with respect to the high-voltage AC substation platforms and its associated substructures and foundations including environmental impacts, remote location, maintenance issues, access management, etc.

The following areas are briefly covered:

- Important parameters that need to be considered including health safety and environment (HSE)

- Boundary conditions that cannot easily be changed, e.g., local and global legislations, site location, and ambient conditions
- Parts or aspects of the transmission system that will have a significant influence on the platform design but may still be subject to discussion and/or iteration, e.g., electrical components and secondary systems, substructure interface, installation, etc.
- Design philosophies, design parameters, and issues within its own discipline that will have a major influence on the final platform design
- Different types of platform concepts like container deck, semi-enclosed, and fully enclosed topsides
- Different types of substructure solutions
- Load-out, transportation, and installation and the consequences these may imply on the overall design of the topside and substructure
- Fire and explosion design, fire detection/alarm, and passive/active fire suppression

### 29.4.1 About Design Considerations

When designing HV substations offshore, there are a number of requirements that need to be taken into consideration as compared to designing an onshore station; examples of these are:

- Strict HSE requirements including firefighting, evacuation plans, emergency shelters, sump tanks, drainage systems, etc.
- Harsh ambient conditions such as salt, wind, waves, currents, bird excrements, etc. Corrosion protection, heat and ventilation, water jets, and other means to withstand the stresses coming from the environmental conditions are crucial.
- Compactness and weight of platform including HV-specific equipment; weight is a primary cost driver.
- Support structure (if applicable), i.e., jacket, monopile, or similar; all loads need to be transferred into few supporting points.
- Installation methods; transport by sea of the completed substation topside, lift-install, self-installing, float-over, jack-up, gravity base, or floating.
- Lifetime; it must last for at least 25–30 years and be cost optimized.
- Reliability, availability, and maintainability; offshore work is very expensive, and downtime means loss of revenues for the owner.
- Material handling will have a major impact on the overall layout.
- Remote operation (normally not manned platform); keeping permanent personnel offshore is very costly.
- Access and egress systems from the sea (by boat) and from the air (by helicopter).

The approach must be to maintain a wide perspective considering many different aspects in order to gain an optimized overall system performance – all the way from the turbines to the mainland grid.

### 29.4.2 Overall Health and Safety Aspects

The health and safety requirements for the wind power plant as a complete system will need to be considered and an overall strategy developed by the owner/operator.

This overall procedure must consider events which influence the design of the offshore platform such as normal access, normal egress, abnormal events, and emergency response for the offshore structures. The designers of the offshore substation must be aware of these procedures to include suitable facilities and should be involved in the overall HAZID/HAZOP process.

Safety aspects of offshore platforms are covered by national and international standards to a varying degree. Offshore installations are of such a complex nature that simple compliance with prescriptive requirements may not lead to an acceptable level of safety. Instead, it will generally be necessary to evaluate safety aspects of each platform in detail. When choosing such a performance-based approach, safety assessment is applied throughout the design process to ensure that the health and safety of personnel, the environment, and the installation itself meet minimum safety targets.

Health and safety procedures developed by the owner/operator which may have an impact on the platform design could typically comprise:

- Electrical safety – working with low, medium, and high voltages
- Work at height – scheduled and unscheduled maintenance work on the platform
- Vessel access – normal activity boat access, procedures for visitor access
- Helicopter access – normal activity access, procedure for visitor access
- Emergency – fire in the platform, accident on platform, stretcher casualty
- Emergency – stranding by inclement weather, man overboard, incapacitated transfer vessel
- Provision for stranded mariner

#### 29.4.2.1 Vessel Access: Normal Activity Boat Access

Statistics show that one of the high-risk areas for personnel injury is the transfer of people from a vessel to an offshore structure, so this activity requires careful consideration. There are a number of techniques available and these are being constantly improved.

#### 29.4.2.2 Emergency Evacuation

The emergency evacuation of persons from the offshore platform must be considered at the design stage of the offshore platform as it will influence the facilities to be included on the platform. Lifesaving equipment should be dimensioned for the maximum persons onboard (POB) at any time, e.g., including additional persons during shift changes.

The health and safety plan should identify the planned means of escape following an incident typically:

- Primary – via helicopter and/or via the transfer vessel which may be close to or docked at the platform
- Secondary – to the sea by life raft
- Tertiary (if needed) – to the sea by life raft

The emergency evacuation of injured persons/stretcher cases from the offshore platform must be considered already at an early design stage of the offshore platform as it will, most likely, have a major influence of the layout and the facilities to be included on the platform.

#### 29.4.2.3 General Safety Equipment

A functional evaluation of the offshore substation should be undertaken to determine the requirements for general health and safety equipment.

### 29.4.3 Fundamental Design Parameters

#### 29.4.3.1 Functional Requirements

The functional requirements are the main purposes of the platform. It can be the required MW throughput of the platform, voltage levels, and the number of radials from the wind power plant. The next important requirement is the availability, which influences redundancy and maintenance philosophy for the platform operations. The operational and availability requirements will result in the selected redundancy level for the component configuration.

The topside and structural design layout is governed by how the connected import and export cables are configured and the extent of equipment and their configuration on the platform. There can often be 10–20 incoming and 2–3 outgoing cables. Furthermore, requirement for permanent or temporary accommodation, material handling, etc. will also have considerable impact on layout and cost.

A rescue or transport helicopter flying pattern is a parameter that will have an impact on the position and layout orientation of the platform, particularly with respect to the direction of the prevailing winds. The transport to and from the platform of personnel and goods by sea will influence the orientation of the supporting structure and position of the boat landings with respect to the current directions. The wind power plant and cable field layout, together with the risk of vessel impact, determine the platform position.

#### 29.4.3.2 Environmental Conditions

The layout of the platform and the structural design should make sure the equipment is adequately supported and protected for the duration of the design life. The fundamental design parameters are the harsh environmental conditions offshore with waves, wind, humidity, ice, and fluctuating temperatures. There are several offshore design codes and practices that will guide the designer in the consequences of the environmental parameters to the platform design.

Other aspects of the design related to environmental conditions and particularly with relevance to fatigue are vibrations and oscillations. Vibrations from wind and waves as well as oscillations from equipment such as the main transformers or diesel generators may affect the long-term withstand capability of both the mechanical structures and the electrical equipment.

#### 29.4.3.3 Risk, Safety, and Rules

The platform and the equipment, or system, will have a configuration and set of requirements that are deduced from the functional and availability requirements. These requirements and their consequences on the equipment selection and the platform layout are also influenced by the safety and risk philosophy and the rules defined by the authorities. Risk and safety assessments and the rules regime will continue to govern the design throughout the project. The rules set by the authorities are often related to personnel risk, but there are also rules that control the equipment quality or required limits to be followed for environmental impacts.

#### 29.4.3.4 Legislation

Requirement from legislative authorities with respect to the installations, operation, and approvals needed from affected authorities and interest groups (fishing, maritime operations, and sea bottom recourses) will most likely have a major influence on the project.

Each system and component may also need to adhere to national, European, US or other area legislation.

#### 29.4.3.5 Lifetime Operational Cost

The lifetime operational cost will be a factor for typically 20–30 years. The operational/maintenance requirements need to be part of the design from the beginning, and the operational requirements may change during the lifetime.

### 29.4.4 Additional Design Inputs

In addition to the fundamental design parameters which are characterized that they cannot be easily changed, there are also a large number of other design factors that can significantly influence the final platform design. The designer(s) must consider the impact of the additional factors as part of the final platform design to optimize both the CAPEX and OPEX perspective while ensuring safety in design. The additional design inputs are often established through an iterative process and are not generally considered to be fixed as the fundamental parameters.

Below are some of the key interactions which should be considered with the design of the offshore AC platform.

#### 29.4.4.1 Electrical Equipment

The overall project design basis will outline the voltage levels and primary equipment required to be housed on the offshore platform. This includes aspects such as physical size and weight, the rating and number of power transformers, the number of export cables and array circuits, etc.

#### 29.4.4.2 Topside Layout

Once the project SLD is known, the starting point for the design will be to clearly assess the number of rooms and areas required on the offshore platform. This will require interaction with the substructure design (monopile, jacket, gravity based, or self-installing) which will likely have been established prior to the topside design.

The location of equipment and rooms should consider which contain hazardous materials and those which could be habited during normal operations. The layout must also allow for the fundamental principle that escape routes are designed to ensure that personnel can leave by at least one safe route to a designated muster/evacuation area.

The use of multi-decks may introduce restrictions to the options available for removal of equipment during either maintenance or changeout.

The safety assessment of equipment and room locations can also influence the design where, for example, the location of a control room over a power transformer would typically require consideration of blast and fire events if the transformer was to have a catastrophic event.

The platform layout should also consider routine maintenance and how these tasks will be achieved.

**HV Transformers**

The power transformer can be located indoors, outdoors, or a combination. The positioning on the platform is important as the units are likely to be the heaviest items on the offshore platform. Often transformers and other heavy items are located on the upper deck so they can be accessed through roof hatches in the event of major works becoming necessary. The maintenance of the unit (including tap changers) and any oil processing can also influence the area required around the transformer in addition to the extent of bunded areas and location of oil drain tanks.

**HV Switchgear and MV Switchgear**

Typically HV and MV switchgear will be located within individual temperature-controlled rooms. The location and extent of the switchgear (i.e., number of bays) will be determined by the system configuration; however the location of the rooms on the platform should consider the connection from the export cable(s), cables to and from the transformer, the outgoing array cables to the WTGs, and bus duct if it is used.

Other aspects that need to be considered include access required around the equipment, installation procedures, possible replacement of switchgear components, and handling of equipment required for gas treatment.

**Protection, Control (SCADA), and Telecommunication**

In providing a layout of panels, the access requirements should be determined as this will significantly impact on the room layout. For example, the room layout may be reduced if panels are front access only; however, due to type of equipment located within the panel, very often the design is such that front and rear access is required.

The cabling to and from the panels must also consider if top or bottom access is possible. This has a direct impact upon the extent and routing of cable tray/ladder and if bottom entry, the floor design.

**Auxiliary Generators**

The rating of the diesel generators used for emergency and auxiliary power will influence both the actual size and weight of the generators and the required day tank and backup diesel storage tank. Other aspects that may influence the location of the generators are the required refuelling provisions and required sump tanks.

**Accommodation and Emergency Shelter Rooms**

The strategy and requirements for any accommodation offshore will be driven by the fundamentals of the platform location and the maintenance requirements.

The extent of the accommodation and welfare facilities will have an obvious impact on the platform layout. This must be clearly established at an early stage to ensure that the functionality is suitable and safely integrated into the design.

The inclusion of emergency overnight accommodation and temporary refuges/safe haven implies different design requirements. The requirement should be clearly established early in the design process to ensure that the layout of the platform meets the specific needs and that the legislative aspects are covered.

**Workshop and Storage Rooms**

The maintenance strategy will determine if a workshop is required offshore and the extent of the workshop and storage needs to be established. This can range from the storage of simple maintenance spares (e.g., fuses and bulbs), to medium strategy spares (e.g., air filters for HVAC or protection relays), to significant items (e.g., 36 kV circuit breaker).

**Standby Supplies and Battery Rooms**

The platform will require backup supplies for the loss of the onshore connection. This can consist of DC batteries and UPS systems. The extent of this requirement will also be a factor with the auxiliary generator standby time and systems connected, including the separation of “essential” and “nonessential” supplies.

**Platform Crane**

The installation of a platform crane is likely to be required on the platform to facilitate material handling and service tasks to and from transportation vessels. In addition, if a multilevel platform is utilized, the crane may require to access different levels through service hatches.

The platform crane should be able to access all the relevant laydown areas of the platform in conjunction with unloading from a vessel.

**Firefighting System**
The requirements of the firefighting system will be governed by the safety assessment of the platform; however this will be a significant factor of the topside layout. The fire system may require water storage if a water mist, deluge, or similar is required. The volume of water will also be dictated by the system to be deployed. In addition, inert gas could be required for equipment rooms which will require either to be centralized or decentralized depending upon the redundancy required in the system. A key factor is that the fire cylinders will require to be replaced approximately every 7 years, and therefore provision for this activity will have to be designed for in the topside layout.

**Helicopter Access**
To date the majority of offshore platforms have been installed a distance from the shore which permits access via vessels. However, many include an option for helicopter access. Furthermore, as distance increases from shore, the only viable access is in practice via helicopter.

There are legislation and performance standards for helicopters to ensure that helicopters are afforded sufficient space to be able to operate safely at all times in the varying conditions experienced offshore. This broadly includes helideck dimensions, emissions and exhausts, areas where obstacles are permitted, areas where obstacles are prohibited, and visual aids which are required.

**Security**
Even though the offshore platform will not be easily accessible for unauthorized people, security to prevent intrusion will be required. This will typically feature security systems similar to an onshore substation. However legislation at sea requires that the facility provides shelter from the sea for any distressed mariner.

#### 29.4.4.3 Ownership Boundaries and Separation
In case the platform shall be accessible by more than one legal entity (e.g., OFTO and WFO), the boundaries for equipment must be clearly established for the project as this can have an impact on the layout. Equipment may need to be installed in individual, sometimes lockable, areas.

#### 29.4.4.4 Topside Lift
The platform manufacturing yard and the heavy lift vessel capability need to be considered from the very beginning of the design process. Limitations in capability of the lift vessel will provide design inputs into the topside through the lifting requirements. This could, for example, dictate that the topside cannot be assembled and lifted as one complete module but may require the platform to be installed in sections out at sea which will impact on the layout design to permit this activity.

Consideration must be given to all different lifts: on the yard, from the dockside to the barge, and finally from the barge to the substructure. There are different techniques to be employed including lifting eyes at the top of the structure or lifting from the base of the structure. The lift may also feature spreader beams or be a single hook lift.

The route and angle required for chains/slings during the lift should be considered to ensure that the lift is not restricted by platform equipment.

The topside should also consider any areas around the lifting eyes to ensure hooks and slings can be connected. This can also require sizable laydown areas for chain/slings and should be included in the design. The lifting chains/slings for an offshore platform can be substantial as the lift can easily be in excess of 1,000 t.

#### 29.4.4.5 Reactive Compensation Plant

A significant design item is the inclusion of the reactive compensation equipment (e.g., shunt reactors and SVCs). This requirement can vary depending upon the ownership boundaries and the point of common coupling (PCC).

#### 29.4.4.6 Future Expansion and Expandability

Once the primary and secondary plant is established, the project should determine if there is likely to be any future expansion to the equipment. In an onshore substation, it is common practice to allow for the inclusion of an additional circuit breaker bay at either end of a switchboard to allow for possible future expansion. In an offshore substation, however, this could be termed as a "nice to have" and would result in additional costs. A realistic assessment should be made judging if a new circuit such as a WTG array or an export cable to shore is likely to be installed in the future.

The trend going in the direction of larger offshore wind power plants, multiple platforms, and offshore grids may bring a new perspective to building in capacity for future circuit connections.

#### 29.4.4.7 Spare Philosophy and Redundancy

The requirements for operational and reliability spares are often left until later in a project once maintenance teams become involved; however advantages can be gained if the spare parts philosophy is known at the time of platform design.

The spares can range from small items to strategic items. For the latter the platform will require to be designed to accommodate adequate storage areas.

The necessity to have a complete, or partial, exchange of equipment will result from the consideration of different failure scenarios. The probability of a specific failure; the consequences, e.g., limitation of the transmission capacity; and the necessary efforts for the restoration of the fault will impact on the arrangement of the equipment on the platform and its decks.

#### 29.4.4.8 Cable Deck

The cable deck, or installation area for the subsea cables, is a concept which is generally not encountered within an onshore substation. This is largely driven by the feature of the offshore platform where the primary plant (i.e., transformers and switchgear) is not present offshore until the topside is delivered. This therefore creates a design aspect which may potentially dictate the installation program.

The cable deck is often part of the substructure and hence installed at the offshore site before the delivery of the topside. The export and wind power plant array cables can thus be laid onto the seabed, installed in the J-tubes, and placed on the cable deck prior to the delivery of the topside.

Alternatively, if the cable deck is part of the topside, the cable installation works cannot commence until the topside is installed. In this scenario the cables from the seabed, via the J-tubes, will require to be winched into position with the complication of the topside being in position.

For both approaches, the area required on the cable deck cannot be underestimated. Cable winches, formers, pulley blocks, winch wires, and operatives are required to pull the cables into position.

#### 29.4.4.9 Routes for Walkways and Minimum Walkway Sizes

The design layout of the platform can have a fundamental impact on the safety of the platform during normal operation, maintenance activities, and also emergency situations. The NORSOK safety standard highlights this design aspect as “the layout of an installation should reduce probability and the consequences of accidents through location, separation and orientation of areas, equipment and functions.” It should however be noted that the standard refers to the petrochemical industry, and although safety is no less important on an offshore electrical substation, a number of the hazards (in particular the hydrocarbons) are not present in a similar manner on an electrical installation.

#### 29.4.4.10 Fabrication Site

The basic dimensions (width, length, height) of the platform or at least the topside of the platform must not exceed the capacity of the fabrication site. The bigger the dimensions, the less the number of available fabrication sites.

If the yard is connected to the sea via channels, the passage through these channels may be a limiting factor. A narrow channel limits the width, at least for the wet part of the transportation unit; above the waterfront the size may exceed the channel width slightly. In the same way, narrow bridges may limit the width and the height.

The draught during transfer to the final site may also be restricted which may direct the design toward certain buoyancy.

### 29.4.5 Development of Design

This section will discuss important design philosophies, design parameters, and issues within its own discipline that will have a major influence on the platform design.

The final design may be developed through several stages with different names and meanings. Typical stages are:

- Feasibility study – evaluates the feasibility of a project or parts of it
- Concept study – evaluates different concepts and/or develops a preliminary design (concept)

- Front end engineering and design (FEED) and pre-engineering design – outlines a design with a level of detail somewhere between concept and detail design
- Detail design – design of the elements that proves it can be built and produces detail design drawings used for fabrication

It is recommended to plan the stages based on what is required with respect to decisions, budgets, and contracts. The development of the design is closely linked to the contracting philosophy described and gathered in the overall project execution plan.

#### 29.4.5.1 Design Codes

Standards are consensus documents. In the context of offshore substations, standards should help to produce a "safe" plant. However, not all cases or configurations of offshore platforms can be anticipated; therefore standards have to be supplemented by formal safety assessment, design guidelines, and industry best practice. For this reason, regulations have generally evolved from prescriptive to performance standards, but due to the variety of design issues to be addressed, both types of standards still play an important role in offshore substation design.

Historically, design codes for the maritime industry were developed first; they were then leveraged for the offshore oil and gas industry. Although there can be significant differences due to the absence of hydrocarbons, guidance for offshore oil and gas is highly applicable to offshore wind. With the growth of the offshore wind industry, dedicated guidance such as the present document and DNV-OS-J201, Offshore Substations for Wind Power plants, become increasingly available.

#### 29.4.5.2 Structural Integrity

Regardless of the type of concept chosen, the substructure and topside have to be seen as one installation which has to withstand the loads from equipment as well as the natural forces of wind, waves, and unforeseen accidental scenarios.

For optimization of the structures, and their integrity, two main parameters are to be considered:

- Center of gravity
- Fail-safe design

For an optimal utilization of the structural steel, a well-placed center of gravity is essential. A center of gravity not placed ideally can result in an oversized substructure resulting in unnecessary costs for material and fabrication.

The physical location of heavy components on the topside will implicate both on the topside structure and the substructure. Ideally located equipment and the load distribution in the topside structure with respect to the substructure interface will result in an optimal utilization of the structural steel. The platform must also be designed for changeout of heavy equipment like the power transformers. It may be necessary to confirm that the design can withstand a displacement of the COG.

The main objective with the fail-safe design is that the structural integrity should respond in such a way that it will not cause a collapse of the structure or that a limited damage will not lead to a total collapse should a failure such as overstress occur.

A basic input for structural design and integrity is the overall lifetime for the substation in respect of fatigue calculations.

**Collision Withstanding Capability**

The design requirement for collision of vessels in the vicinity of the platform will be deduced partly from vessel traffic pattern from the platform's own service vessels, vessels servicing other offshore installations, or other merchant ships' sailing pattern.

**Weight and Size of Components**

The weight control is an important part of the platform design and requires a systematic approach from the very beginning. The main objective is to have control over the weight and its impact and to ensure that all the necessary consequences from the component weights to other parts of the platform with regard to local reinforcements as well as global structural design and lifting design are considered.

**Oscillations and Accelerations**

The design of structures may have a major effect on platform equipment in terms of oscillations and accelerations. The structures are exposed to forces that unavoidably will introduce stresses that the equipment on the platform will have to withstand. This may have consequences on the overall concept of the structural foundation and design.

**Dynamic Loads**

Dynamic loads include wind, wave, current, fatigue, and ice loads.

International design standards cater for proper care of the wind, wave, and current loading. One should be aware that the consequences from these condition parameters depend on decisions on platform position, orientation, layout, and initial structural design.

**Truss Versus Stressed Skin**

Considerable experience has been collected over the years for some evident applications of the two principles: truss braced and stressed skin solutions. The keyword to success is "synergy" between different functions.

A comparison of the overall functions and advantages between a design based on stressed skin and a design based on truss is given in CIGRE Brochure 483. From the manufacturing point of view, the stressed skin can be produced at many shipyards at a reasonable cost. One can assume that a truss structure would be rather complex to handle for a shipyard used to doing a lot of the welding with robots running in straight lines for stiffeners on flat plates. The robotized production is an effective way of making large thin-walled steel boxes.

On the other hand the platform yard is usually not in possession of a robotized welding system meaning that there is a risk that they are not as efficient as shipyards producing stress skin solutions.

#### 29.4.5.3 General Arrangement

The overall layout of the platform, i.e., the general arrangement (GA), will have a major influence on the total weight and hence the cost of the topside and the substructure. There are many other parameters that will affect the final layout of the platform. The "main process" on an offshore substation for wind power is the HV power flow (transformation). It would be natural to start finding an optimal "process flow," beginning with the incoming MV cables (J-tubes, cable hang-offs, etc.) further on to the MV switchboards and the power transformer to end with the HV GIS switchgear and the outgoing export cables.

A typical layout arrangement will include separate areas for the main equipment starting with MV switchboards, main transformer(s), HV GIS unit(s), and possibly also shunt reactors and harmonic filters. These units are the basic equipment for the transformation of the MV electricity to a higher HV level suitable for export to onshore grid. If a wind park is divided into parts (normally two halves) for redundancy of electrical production, one should also consider arranging the main equipment in such a way that the objective with respect to redundancy will be maintained. For utility systems as well as substation and wind park control, fire and safety issues and operability of systems must be evaluated.

The HSE perspective must permeate the design in all its aspects, including accommodation/emergency shelters, muster points, access/egress, fire and explosion, etc.

From a structural integrity point of view, the GA needs to ensure effective transfer of the loads through the topside and substructure to the foundations combined with an optimized location for the center of gravity. Adequate walkways, stairs, etc. to ensure operability and maintainability of the platform need to be provided.

#### 29.4.5.4 Material Handling

This material handling philosophy must consider the complete life cycle of the project including installation, testing, maintenance, replacement, and decommissioning of the equipment.

The material handling should be considered for three main phases: (i) construction and installation phase, (ii) performing operating and maintenance procedures, and (iii) transferring equipment and supplies.

Initial consideration of material handling must be completed early in the design and include requirements with respect to construction and equipment installation. A risk assessment exercise will provide input into the strategy for the material handling of large primary plant items.

The material handling philosophy is critical for the operational phase of the project. The fundamental design basis to ensure that the substation provides a safe environment for operational and maintenance work must be adhered to while personnel are protected against the offshore environmental conditions.

An assessment should be undertaken early in the design process to provide information on the handling of equipment, devices to be used, and routes to laydown areas including moving of equipment between levels on the platform.

**Manual Handling**

In general mechanical handling aids are required for all activities that require a lift/movement of components in excess of 25 kg.

**Material Handling Aids**

To assist with material handling, a number of handling aids can be used. These include padeyes, gantry cranes, pedestal cranes, and Davit cranes.

To assist with the movement of equipment around the platform and to laydown area, typical portable devices are forklifts, trolleys, specific equipment trucks/wheels, pallet lifters, chain blocks, pull lifts, and lifting tackles, but taking account of any need to move devices between decks and any battery charging stations is required.

**Storage Areas**

The storage areas required on an offshore platform require an early philosophy to be developed on the materials that should be stored on the platform and those which will be carried to the platform by transportation vessel as, and when, required.

#### 29.4.5.5 Primary Access and Egress Systems

An offshore substation needs to be accessed from time to time by persons for routine or breakdown inspections and maintenance. Large platforms far away from the shore may be permanently manned and thereby require more frequent access. During the construction, commissioning, and run-in periods, daily transfers are not uncommon.

Basic means of transport and access include helicopters and vessels. It is an advantage if the access system used on the offshore substation is compatible with that used for the wind turbines, even if just as a backup. Hazard identification and risk analysis can provide designers with useful information for the design process.

**Helicopter Deck**

The offshore substation may be equipped with a helicopter deck onto which a helicopter can land. As a minimum, the platform should have a heli-hoist area onto which personnel can be lowered or from which they can be winched up. Local requirements exist in most countries, but standard CAP 437 is an internationally applied guidance document.

Helicopter decks and heli-hoist decks used for transfer of personnel and cargo by helicopter must be fit for purpose. More guidance is given in Brochure 483.

**Boat Landing**

Offshore installations allow access by vessel in more or less sophisticated ways. The most basic approach for a boat landing is a ladder with impact protection bars which allows the vessel fenders to contact impact bars and personnel to step from the vessel directly onto the ladder. In more exposed locations the boat landings could be supplemented by docking systems. Motion compensated gangway systems are also being introduced. An alternative used in oil and gas are crane-lifted personnel carriers. Together with the vessel, all marine access systems have a limit regarding the sea states they can operate in, including wave height, wave direction, and currents.

**Ladder Access/Egress Systems**

Ladders and access platforms should conform to relevant standards applicable to the location of the platform.

#### 29.4.5.6 Emergency Response

Emergency response in connection with offshore substations is the sum of efforts by persons and systems to mitigate the impact of an incident on human life (workers, public), environment (marine), and property (the offshore substation asset and associated equipment such as means of transport). These aspects should be addressed at an early stage of the design to ensure a fit for purpose cost-effective design. Hazard identification and risk analysis (HAZID) can provide designers with important information for the design process. Effective communications both on and from the platform are essential, and these together with navigation aids should be powered from backup supplies.

All offshore substations should have at least one launchable life raft which can take the maximum number of persons on the installation. The potential of a stretcher casualty has to be given particular attention, i.e., such a stretcher must be recoverable by helicopter, or, for transfer to a vessel, a crane with "man-riding capability" is required. Arrangements should be made to rescue persons from the sea or near the installation such as persons falling overboard or being involved in a helicopter incident.

#### 29.4.5.7 Platform Auxiliary Systems

The platform auxiliary systems are defined as all the secondary systems (as opposed to the primary which is the MV and HV systems) that are required to safely operate the platform. Examples of these are:

- Auxiliary power supply including diesel generator, LV, MV, batteries, converters, and switchboards
- Lighting and small power
- Earthing and lightning protection
- Heat, ventilation, and air conditioning system
- Submersible pumps and heat exchangers
- Water handling; fresh water, seawater
- Drainage system; black water, gray water
- Oil containment; bunded areas and dump/sump tanks
- Oil/water separation
- Fire detection and firefighting systems
- Navigational lights and day identification
- Aeronautical systems
- Fuelling systems
- Water jet to clean the decks

- Crane
- Lifeboat/rafts
- Public address (PA) system

**Inert Gas System**
Inert gas on the platform can be used as firefighting of fire from electrical component failure. The inert gas will displace the air in the room and is therefore hazardous to humans in confined spaces. There are codes and standards for these systems, which gives guidance and requirement for the inert gas system.

**Lighting and Small Power**
The general platform lighting should be switched on when the platform is manned during visits, with on/off push buttons, lighting control, and indication lamp for switching off the lighting placed at the boat landing and on the helideck (and possibility of remote control).

Luminaires and floodlights should be supplied either from normal power supply with UPS-supplied power for evacuation lights in emergency situations or when normal power supply is down.

**Lightning Protection for the Platform**
The lightning protection of the platform, dimensioning and protection, is proposed to follow the instructions in code EN/IEC 62305 (Class 1). The metallic structures on the platform are used as both air termination system and down conductors.

**Earthing and Bonding**
On the platform it is necessary that all exposed and extraneous conductive parts of the electrical installations should be earthed, and metal parts of the structures should be bonded to the main earthing system for safety and for protection against electric shock. Further the metallic structures all around on the platform should be bonded if they do not have safe connection to the other neighboring parts of the structure.

**Ventilation and HVAC**
The main objective of the HVAC system is to provide a controlled environment to safeguard the platform equipment against corrosion, humidity, cold, and heat. Furthermore it should also provide comfort for personnel. A slight overpressure inside the room can be used, to reduce the concentration of saltwater aerosols and dust from outside.

**Water Handling: Sea and Fresh Water**
The potable water system may be solved with a dedicated desalination plant or may be chosen to be “carry-on” when there are a limited number of personnel onboard at any one time.

Fresh water quality for toilets and sinks/showers and miscellaneous cleaning purposes is usually not suitable as drinking water and must be separate systems or contained locally without a piping distribution system.

Seawater for firefighting or wash-down purposes (helicopter deck or oil drain) requires heavy-duty pumps and costly piping systems. The design of this system has an impact on all main cable routing and on the platform as such.

**Drainage for Gray and Black Water**

Drains from toilets and sinks/showers should be directed to a sewage treatment unit according to the legislation in the area. The option for overboard dumping of waste for small vessels and commercial ships is regulated by Marpol rules. Marpol rules are recommended as a minimum where no national rules apply. Chemical toilet types are options but only low-maintenance types similar to WC are recommended.

**Auxiliary Systems Control and Monitoring**

The auxiliary systems should be equipped with level transmitters and level gauges and necessary valves for operation and maintenance. The safety system (firewater supply pump) or primary systems (cooling system pumps) should be monitored by the SCADA system.

**Oil System and Containment: Separator Tank**

Diesel fuel oil system supplies fuel oil to the diesel generator(s) unit and consists of a storage tank, a day tank (can be part of diesel gen. unit), piping, and pumps (if needed). The lubrication oil system consists of a tank and diesel motor feed piping.

Bunkering of diesel generator fuel or lubrication oil is a comprehensive operation offshore and needs to be thoroughly designed, with piping and bunkering station in connection with a boat landing area. The bunkering station should be designed with the right interface couplings and possibly hoses.

Helicopter fuel systems are usually avoided as it constitutes a different more stringent safety regime.

An open drain system for collection of drain water from deck drains and bunded areas on the platform will be needed. Usually an overflow system caters for heavy rainfalls/deluge water flows. The legislation regime in the area will govern the allowable oil/water separation requirements.

#### 29.4.5.8 Corrosion Protection System

Different types of corrosion protection can be used depending on the structure/substation part in mind.

For the topside, normally all exposed surfaces are protected by coating (paint) systems. Different types of coating systems are specified, and coating procedures are described in several codes and standards, e.g., in the North Sea area where the NORSOK M-501 is widely used.

Corrosion on the substructure can be dealt with in two ways: either corrosion control and/or corrosion allowance. Corrosion control is a technique and method to prevent or reduce corrosion damage (corrosion protection), while corrosion allowance means adding extra steel during design (typically 3–10 mm). The corrosion protection system can further be divided into painting and anodes (cathodic protection). Normally a combination of coating systems and a cathodic protection system is used.

#### 29.4.5.9 Operation

**Operational Modes**

The operator's safety officer will ensure that work operational procedures are followed onboard the platform and that the control center onshore is kept informed of all personnel activities offshore, a work permit system. Work permits are necessary even on a "cold" platform isolated from the grid. The transfer of goods to and from the platform is also thoroughly planned and includes diesel bunkering, fresh water bunkering, other consumables and waste transfer, equipment hoist, heavy hoist, personnel transfer from boat, and helicopter operations.

For the planning of hookup and commissioning phase, input from experienced operations personnel is important in order to design and plan for the work offshore. The requirement for communication, transport, resting areas, toilet, shower, and catering service will be much more important during hookup and commissioning than in remote operation mode, and good planning gives savings as well as good quality work.

**Operations with Personnel Offshore**

Based on the parameters for operations with regard to power flow and uptime, the operations and maintenance philosophy set the requirement for emergency or permanent accommodation areas on the platform.

To include the possibility for transfer by helicopter, a hoist is recommended, either for emergency or quick component exchange reasons. Training requirement for hoisting personnel is however extensive. A medical room with defibrillator/medicine/stretcher/ is recommended on the platform. One of the persons onboard should be trained as a medic.

**Emergency Accommodation**

Emergency facilities should be required as a minimum. Examples of equipment in an emergency accommodation are sleeping bags, mattresses, VHF communication/satellite telephone, emergency light, sanitary facilities, and food/kitchen. A muster area should also be considered in connection with the accommodation area.

**Permanent Accommodation**

If the platform will be used as a base for working with maintenance, modifications or as hub for wind power plants or other platform installations in the vicinity, it may not be appropriate to certify it as a normally not manned platform. Hence, requirements on permanent accommodation, toilet, and kitchen facilities will be required accordingly. For safety reasons it is preferred to keep the accommodation area sheltered from fire areas, e.g., the transformer.

An alternative to an integrated accommodation module is to have a separate accommodation platform.

**Workshops**
It is emphasized that minimal work should be planned to be carried out offshore. However several issues as mentioned in this book can argue otherwise. Required hookup and commissioning work can be chosen to be done offshore, or contingency plans can make such arrangements necessary. It is recommended that as a minimum, a small workshop is designed and that some storage space is reserved for mechanical and electrical spare parts.

### 29.4.6 Platform Concepts

There are three different principal topside concepts: container deck, semi-enclosed, and fully enclosed topside.

#### 29.4.6.1 Container Deck
A container deck-type topside should be understood to be a single or multilevel deck structure supported by a lattice structure extending from the substructure interface. On this deck several containers (standard or purpose built) containing electrical and auxiliary systems as well as crew areas are placed and fixed. The containers are in many cases preassembled by the different suppliers of equipment/system and are installed by the deck fabricator in cooperation with the supplier and finally commissioned by the equipment supplier.

#### 29.4.6.2 Semi-enclosed Topside
A semi-enclosed topside should be understood as a structure with purpose-built building facilities. These are integrated into the main topside structure supporting the structure integrity. They could also be combined with separate installed purpose-fabricated containers and externally freestanding equipment. Containers (if included in the arrangement) are in most cases preassembled by the different suppliers of equipment/system and are installed by the deck fabricator in cooperation with the supplier and finally commissioned by the equipment supplier.

One variant of the semi-enclosed concept is that the transformer is out in the open, just sheltered from the deck below and potentially with louvers on the side. The other rooms are enclosed with access walkways louvered or in the open (Fig. 29.24).

#### 29.4.6.3 Fully Enclosed Topside
A fully enclosed topside should be understood as a structure with completely designed and purpose-built buildings to fit equipment, integrated into the main topside structure and supporting the structure integrity. All areas are purpose sized for equipment and systems, and the whole topside is fabricated with indoor areas for all equipment. The indoor areas could either be naturally ventilated or controlled by air-conditioning.


**Fig. 29.24** Topside with two container decks. (Source: ALSTOM Grid GmbH)

## 29.4.7 Substructure

Today the best known substructure types are the monopile, jacket, gravity based, and self-elevation. Besides these four (4) "basic" substructures, there are also combinations of them such as tripods, suction bucket, etc.

The main purpose of the substructure is to transfer loads from the topside and support structure to the seabed. The type of substructure is primarily selected based on the ability to support the topside while meeting the environmental and seabed conditions at the specific site. There are also several other functional requirements like supporting of J-tubes and pull-up equipment that needs to be considered. The decision on which type of substructure to be used in the end must be based on detailed studies. Aspects to consider include but are not limited to:

- Meteorological and oceanographic conditions, often called metocean
- Environmental loads including wind, waves, current, water level, temperature, ice, salinity, seismicity, etc.
- Geophysical conditions such as distribution of soil layers and seabed conditions
- Operational loads
- Accidental loads

### 29.4.7.1 Monopile

The monopile is the simplest substructure which essentially is a single large pile made of steel that is driven into the seabed. The topside is supported by the monopile through a transition piece.

The topside is either supported directly on the lower transition piece (yellow in the picture below) or by four (4) so-called cow horns. The cow horns are a part of the upper transition piece (gray in picture below) that is bolted to the lower transition piece. The transition piece is jointed to the monopile through a grouted connection with shear keys (Fig. 29.25).

**Fig. 29.25** Monopile substructure: Gunfleet Sands. (Source: DONG Energy)

#### 29.4.7.2 Jacket

The jacket typically consists of four strong legs – supported by piles driven into the seabed – interconnected by cross bracings, all made in tubular pipe sections and welded together.

The location where one or more braces are welded to a leg is called a joint. Such welded joints have a number of weaknesses when it comes to fatigue loading as the stress concentrations become very high. However for a substation structure fatigue is relatively benign, and hence there is a good balance between fatigue and ultimate resistance in the welded jacket.

The ease and speed of fabrication is essential for the price of the jacket. Where the price split between materials and fabrication on a monopile is approximately 60/40, a jacket has a split around 30/70 due to the complexity and manual work to be done (Fig. 29.26).

#### 29.4.7.3 Gravity-Based Foundation

A gravity-based foundation is a heavy substructure located directly on seabed. Gravity foundations are very cost optimal on lower water sites with strong soil conditions. However, the weight of a gravity foundation increases rapidly with increased water depth.

**Fig. 29.26** Jacket substructure: Walney 1. (Source: DONG Energy)

**Fig. 29.27** Installation of gravity foundation. (Source: Energinet.dk)

The gravity structure is fabricated of reinforced concrete or steel. The gravity foundations may be filled with ballast weight, olivine, or rocks to increase the weight and increase topside loads. Topside is located directly above the substructure or with a steel transition piece. Topside, transition piece, and substructure may be bolted, grouted, or welded together (Fig. 29.27).

#### 29.4.7.4 Self-Elevating

Once the self-elevating platform is positioned, no cranes or lifting devices are required to install or raise the platform above sea level to its design-specified height. The self-elevation substructure consists of four (4) strong legs connected to the topside. The topside can be jacked along the legs by the associated jacking systems.

Generally, two (2) models are available: with and without a base frame.

The base frame is the foundation of the platform. The base frame can be a part of the legs or installed separately. The base frame has two (2) functions: shorten length of piles and/or serving as an interface with the piles driven into the seabed to connect the platform legs.

Instead of piles, the legs can be designed with a footing system (mud mats, buckets, etc.) versatile to accommodate a range of soil conditions in the field. This solution is useful for both models – with and without base frame.

#### 29.4.7.5 Load-Out

The term load-out is used to describe the process where the structure is transferred from a fabricator's yard/quayside to the transport barge.

For a traditional substructure and topside arrangement, the T&I (transport and installation) contractor would normally deliver the barge to the quay adjacent to the fabricator's yard where the fabricator takes over control.

With the barge moored against the quay, the heavy lift must be transferred from the quay to the barge. For a heavy structure, such as the substation topside, the weight of the module would be taken on multi-axle trailers installed at suitable points below the module. The module would then be gradually moved from the quay to the barge under tightly controlled conditions. As the weight of the module is slowly transferred to the barge, the water-filled barge ballast tanks would be sequentially emptied to maintain the trim (Fig. 29.28).

#### 29.4.7.6 Sea Transportation

Transportation of big structures is usually achieved by use of a barge moved by tugboats. There are also special transporting vessels with large barge-like loading deck, some of them submersible. Big concrete gravity-based foundations may also be floated out to site.

Once the barge and its load are towed out to sea, the whole structure may be subjected to external forces as a result of barge motion. The structure and any equipment within the structure, typically transformers, switchgear, fabricated buildings, etc., will be subjected to these forces resulting from vessel roll, pitch, and heave. The complete structure, including all topside equipment, needs to be designed

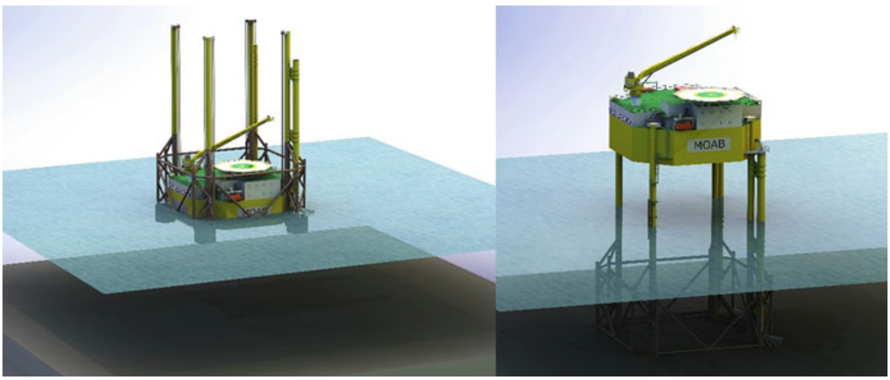



**Fig. 29.28** Self-elevating installation. (Source: Overdick GmbH & Co. KG)

to withstand these conditions. If neither a motions study nor model tests have been performed then for standard configurations, the motion criteria contained in Noble Denton 0030/ND – Guidelines for Marine Transportations – may be acceptable.

#### 29.4.7.7 Hook Lift

The bulk of experience to date relies upon the traditional hook lift by a heavy lift vessel for installation of substructures and topsides.

Prior to arrival of a topside structure, the substructure, either jacket legs or piles dependent upon the arrangement, would be leveled, marked, and cut to the design height.

The selection of the heavy lift vessel (HLV) would be dependent upon many factors.

For any specific HLV, the design of the structure could be developed to give the optimum lift conditions for the works; hence it is vital that the choice of HLV is made early in the design process, ideally at the concept stage.

The illustration below shows a typical lift arrangement for a topside structure, and from this the interdependency of the equipment can be visualized. It is imperative that the topside does not clash with the HLV jib during the lift.

As with the transport, the heavy lift operation is weather dependent and requires the same level of forecasting and planning.

#### 29.4.7.8 Self-Installing

The self-installing substation could either be wet towed or transported on a barge or heavy lift carrier to the offshore installation site. The decision is a result of a techno-economical study in which also risks due to bad weather, availability of emergency shelters, navigational restrictions, and governmental requirements have to be taken into consideration.

Once arrived at the offshore site, the self-erecting substation will be positioned by means of tugboats or by a marine mooring/anchoring system for its final installation (Fig. 29.29).

When the self-erecting platform is correctly positioned, the legs will be lowered down by the leg jacking system. The most critical phase during the installation process occurs when the legs of the floating platform have first contact with the seabed or with the preinstalled base structure. Due to the relatively small size and mass of the platform, movements like pitch and heave can lead to large leg contact forces while the platform is in the transitional situation from the floating to the fixed condition. Depending on the sea area where the platform is to be installed, the waiting time for a suitable weather window with the specified limiting wave conditions can be considerable and may represent a major risk and cost factor of this platform concept. In order to minimize that risk and reduce the time period of the transitional situation from the floating to the fixed platform condition, technical systems have been suggested allowing quick lowering of the platform (Fig. 29.30).

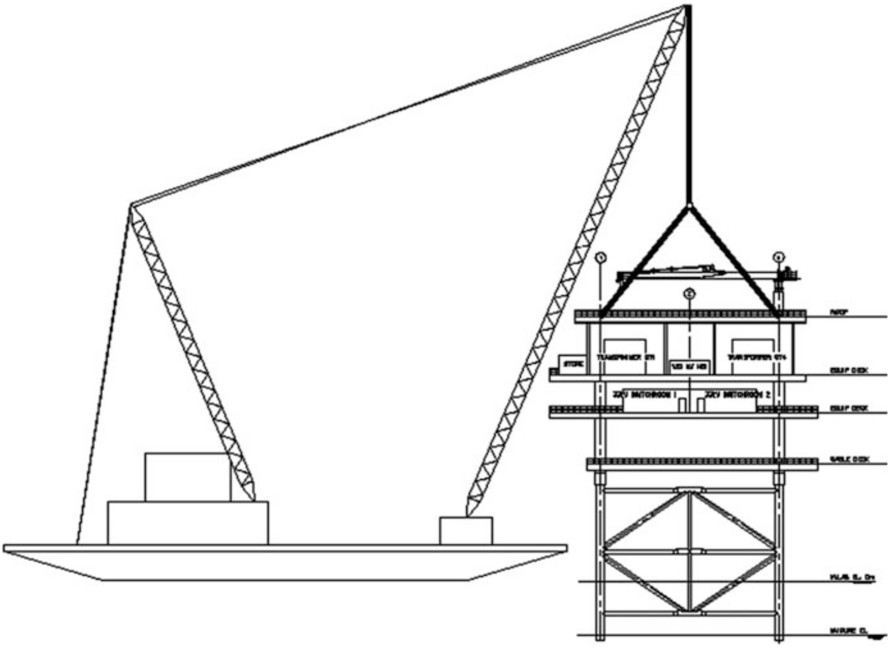


**Fig. 29.29** Lifting arrangements

### 29.4.7.9 Float Over

Another type of installation method is the so-called float over operation. With this type of operation, it is possible to avoid engaging the heavy lift vessel needed for the previously mentioned hook lift type of installation. The float over operation is used in oil and gas installations worldwide for topside structures, mainly as an alternative depending on specific circumstances, e.g., when there is no suitable heavy lift vessel available or in case of specific site conditions such as shallow water in combination with heavy lift vessel stability requirements. Yet another reason may be that the topside structure is of such a size that no existing lift vessel can be used.

A float over operation can be executed by either an offshore transport barge or a special semisubmersible heavy transport vessel (ship). The operation principle is that the vessel transports the topside to the location where a substructure has been preinstalled and off-loads the topside structure onto the substructure by ballasting the barge/ship to transfer the weight loading from the transport vessel to the substructure.

### 29.4.7.10 Installation Hookup Works of Jacket and Topside

Before de-mobilization of the heavy lift vessel (HLV), the topside should be welded to the substructure. This may involve the fitting of crown shims, welding, and nondestructive testing of the arrangement.

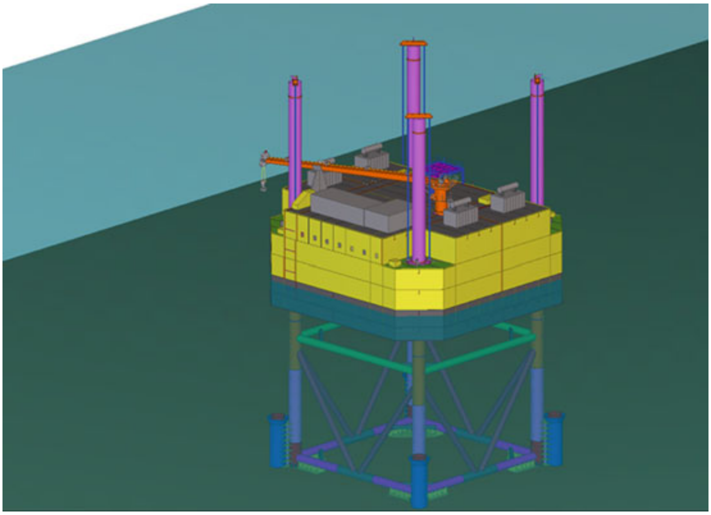


**Fig. 29.30** Self-installing, self-floating platform. (Source: IMPAC GmbH)

Also part of the hookup works would be the pulling into the J-tubes of the subsea cables followed by the stripping, fitting of clamp and hang-off, laying onto the support system, terminating, and sealing of penetrations.

#### 29.4.7.11 Removal/Replacement of Large Plant Items

On an offshore substation, it is inevitable that some equipment (most often the power transformers) cannot be readily replaced by the platform crane and normal material handling procedures. This means that measures have to be taken and procedures defined from the beginning of the topside design on how to be able to replace those large items. A cable-free zone on one side of the platform may be required should a jack-up vessel be used for the heavy lift. Furthermore, the location of the large and/or heavy plant items is essential not only from a material handling perspective. It is also important that the center of gravity is not jeopardized during the replacement operation. The repair time for, e.g., a transformer may be significant, and thus, it is important that the construction can withstand the stresses caused by the dislocation of the center of gravity.

### 29.4.8 Fire and Explosion Design

The overall main objectives of the fire and explosion protection system are to:

- Minimize the risk of fire and explosion
- Automatically monitor, detect, and give alarm in case of smoke, fires, or explosions
- Minimize the propagation and consequences of a fire and/or explosion

The fire safety philosophy generally includes life safety, property protection, environmental impact limitation, and provision of continuous operation.

In order to minimize the risk of fire and explosion, a risk assessment study should be conducted early in the design process or even before the actual design phase commences, identifying all of the possible different hazard needs and measures and mitigation plans defined.

Fire protection can be divided into two categories: passive and active protection. Passive fire protection includes separation of equipment in cells by graded fire walls and floors. It can also mean that the platform is designed in such a way that essential equipment/systems can withstand a fire for a certain time period and that the integrity of the steel structure is maintained. Examples of active firefighting are foam, deluge, sprinkler, water mist, and inert gas systems. The selection of system must take into account the object/area to protect, and one system may not necessarily exclude the other. Most often a combination of passive fire protection and different systems of active fire protection should be considered.

A performance-based approach to fire protection based on fire safety goals and objectives, deterministic and probabilistic analysis of fire scenarios, and quantitative assessment of design alternatives should be used.

#### 29.4.8.1 Fire and Smoke Detection

Examples of fire and explosion indicators are smoke, heat, and flame. Depending on the area to monitor, the detection principle is often based on a combination of these quantities.

#### 29.4.8.2 Explosion Protection

The objectives of explosion protection are to reduce the probability of explosions, reduce the explosion loads, and reduce the probability of escalation. Explosion events offshore include release of physical energy (e.g., pressure energy in gas, in particular for transformer explosions) and chemical energy (chemical reaction, e.g., for hydrogen explosion). Explosion loads are characterized by temporal and spatial pressure distribution with rise time, maximum pressure and pulse duration being the most important parameters.

The following explosion hazards could happen on offshore transformer platforms:

- Main (oil-filled) transformer tank bursting
- HV switchgear explosion
- Hydrogen explosion associated with battery charging
- Aviation fuel storage explosion

Where possible, the severity of an explosion should be lowered by reducing the degree of congestion and by increasing the availability of venting. For some areas, blast walls could be an appropriate measure.

## 29.5 Substation Secondary Systems

The substation secondary systems are those systems which provide the functionality necessary to:

- Ensure safety of personnel engaged in operation of the substation and associated systems
- Permit operation of the substation primary circuits
- Monitor the performance of the installation
- Detect and manage abnormal conditions on the system and in primary equipment
- Manage the environment in which the equipment operates

The guidelines set out below assume that the offshore substation is classified as a normally unmanned (unattended) installation.

### 29.5.1 Power Supplies

#### 29.5.1.1 Statement of Requirements

The safety and security of the substation and personnel depends partly on the availability of auxiliary power supplies which support the operation of subsystems within the substation which manage and control its operation. In common with any other substation, there is a need for both LVAC and DC power supplies, and the detailed requirements and suitability of the LVAC and LVDC systems depend on a number of factors which are listed below:

#### 29.5.1.2 LVAC Supplies

In order to operate the equipment within the substation, a suitably rated low-voltage alternating current (LVAC) supply is required, distributed throughout the substation to feed the associated loads. Typically, this would be a 50/60 Hz, three-phase, 400 V supply.

(i) **LVAC System Loads**

The loads which have to be supplied can be divided into two categories, namely, those loads which are supplied when the substation is connected to the grid (normal loads) and those supplies which need to be maintained when the connection to the grid is lost (essential loads), i.e., under abnormal or emergency conditions. The loads can also be further subdivided into two types of load, load associated with the substation main plant and load required for “building services.” The following sections set out the requirements for “essential” loads and “nonessential” loads, with the “normal” load being the sum of both.

(ii) **Essential Loads**

The LVAC distribution system must be designed to inherently segregate the essential and nonessential loads, noting in particular that many of these "building services" loads will be fed from distribution boards directly from the "essential bus" of the main LVAC board. These sub-distribution boards must provide for the segregation of the "essential" load category from the "nonessential" load category. The items listed below are for guidance and are not exhaustive.

- Fire protection supplies
- Battery charger supplies
- Switchgear supplies
- The LVAC supplies required to the switchgear under abnormal conditions are limited and may include:
  - Anti-condensation heating – normally on (may be thermostat or humidistat controlled)
  - Cubicle lighting (normally off)
  - CB mechanism spring charging (DC motors are an alternative)
  - Disconnector drives (DC motors are an alternative)
- Transformers
  - Mechanism and control kiosk anti-condensation heating
  - Cubicle lighting
- Environmental control
  - Air pressurization and ventilation systems
  - Limited heating for anti-condensation purposes
  - Drainage pumps
- Emergency accommodation
- Emergency and access lighting
- Operational/repair
  It is considered prudent to ensure that items such as the substation crane and Davit crane remain operational to enable repair equipment and spares to be brought onto the platform.
- Safety systems
  Any systems which do not have their own inbuilt backup supply

(iii) **Nonessential Loads**

- Transformers and other main plant
- Maintenance and testing supplies
  - Deck wash pumps
  - Welding and oil treatment socket outlets

#### 29.5.1.3 LVAC System Operation

(i) **Normal LVAC Operation**

The LVAC system normally supplies all of the auxiliaries on the substation platform and the auxiliary loads of the substation equipment. There is usually no provision to support any auxiliary power loads associated with the wind turbine generators (WTG). (See 29.3.4 a) ii).)

(ii) **Source of Auxiliary Supply**

In order to provide this 400 V supply, auxiliary transformers are required to step the voltage down from the (typically) 36 kV voltage used for the connection of the WTGs by inter-array cables. (Refer to Sect. 29.3.4 for more details.)

The transformer will normally have to be capable of supplying the normal (essential and the nonessential) load of the substation.

(iii) **Separation of the "Essential" and "Nonessential" Loads**

The separation of the "essential" loads from the "nonessential" loads is usually achieved by having a separate section of LVAC board connected by a bus section switch. The physical design of the switchboard and isolation facilities must ensure that a fault in the bus section circuit breaker panel does not result in the loss of the "essential" section of the board.

(iv) **Abnormal LVAC System Operation**

Under abnormal operating conditions, the LVAC loads must be provided by a backup supply. Usually a diesel generator needs to be rated to supply the whole of the "essential" load from within the substation.

#### 29.5.1.4 Construction and Installation

(i) **LVAC Board Construction**

The configuration and construction of the LVAC system switchboard can have a significant impact on the overall availability of auxiliary power supplies. In assessing the configuration and construction, the failure modes and consequences of the failure must be considered to achieve the performance required.

(ii) **LVAC Cable Systems and Routing**

Wherever practicable, auxiliary power supplies supporting "redundant" functions should be segregated, using diverse cable routes to avoid a single incident taking out both supplies. For example, where there are duplicate battery chargers, the AC cables feeding them should be run on segregated routes.

(iii) **Protection, Control, and Automation for the LVAC system**

The LVAC system and its associated protection should be designed such that a fault on any part of the system can be cleared without taking out of service any un-faulted equipment or adversely affecting the availability of the main transmission connections. The LVAC board and backup supply system need to be fully automated to ensure that a supply can be provided to "essential" loads at all times. This needs to be coordinated with any local "supply changeover" arrangements.

It also needs to be interlocked to avoid paralleling of the diesel generator with the system. Protection systems for the generating sets should only cause tripping for faults which will cause immediate damage to the equipment.

#### 29.5.1.5 Black Start Capability

When the wind power plant is being installed, initially there will be no grid supply. Under these conditions the backup generator will have to feed the "essential" loads, possibly for a period of time much greater than the designed "abnormal operation duration." When deciding on the "essential" loads, all of the loads required under a black start condition should be taken into account (Figs. 29.31, 29.32, and 29.33).

### 29.5.2 DC Supplies

#### 29.5.2.1 LVDC Supplies

Typically the LVDC system would be a secure 110/125V DC supply using a combination of storage batteries and chargers.

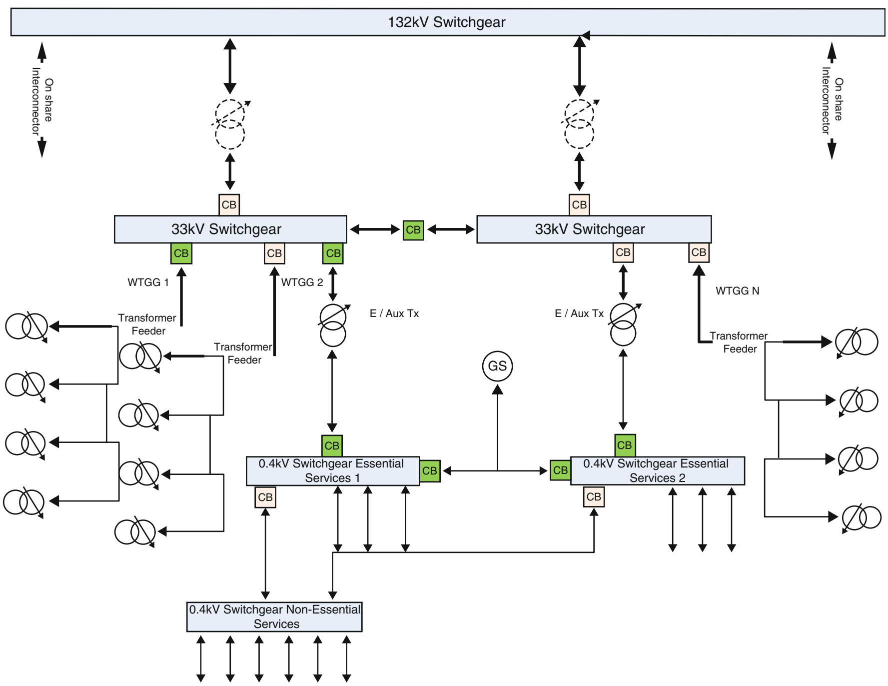



**Fig. 29.31** LVAC derived from collection system busbars

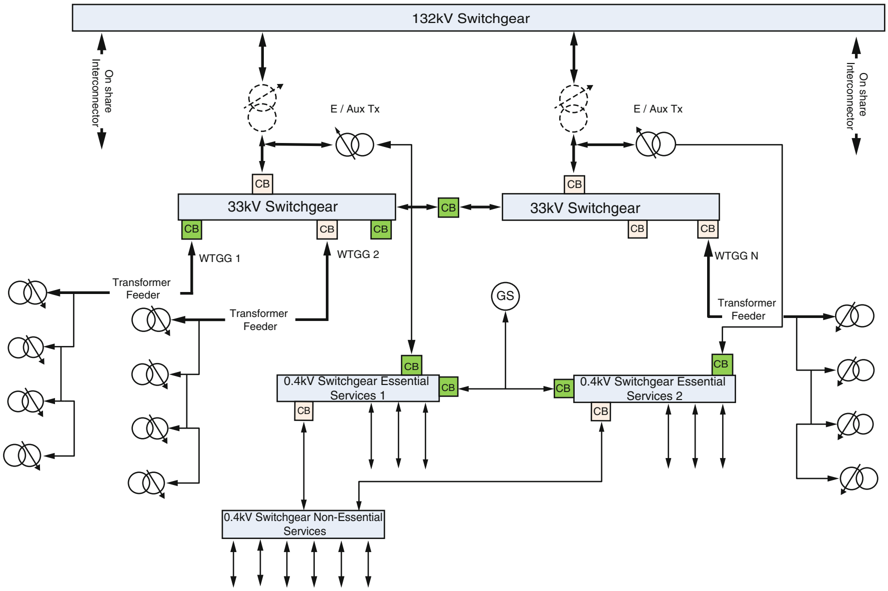



**Fig. 29.32** LVAC derived from main transformer LV connections

In the operational condition when no LVAC supply (from any source) is available, it would be necessary to consider the energy storage capacity required. To minimize the required battery capacity, it is possible to consider the segregation of LVDC loads required for safety systems from purely operational LVDC loads.

### 29.5.2.2 LVDC System Loads

For offshore applications, the loads to be supplied may be divided into two categories, namely, those loads which are supplied when the LVDC system is energized from the LVAC system (normal loads) and those supplies which need to be maintained when the LVAC supply is lost (essential loads).

(i) **LVDC Essential Maintained Loads**

The LVDC distribution system must be designed to inherently segregate the essential and nonessential loads. The items listed below are for guidance and are not exhaustive:

- Communications, control, and SCADA
- Protection supplies – substation auxiliary systems
- Switchgear supplies –substation auxiliary systems
- Emergency and access lighting
- Safety systems – however these may have their own inbuilt backup supply.

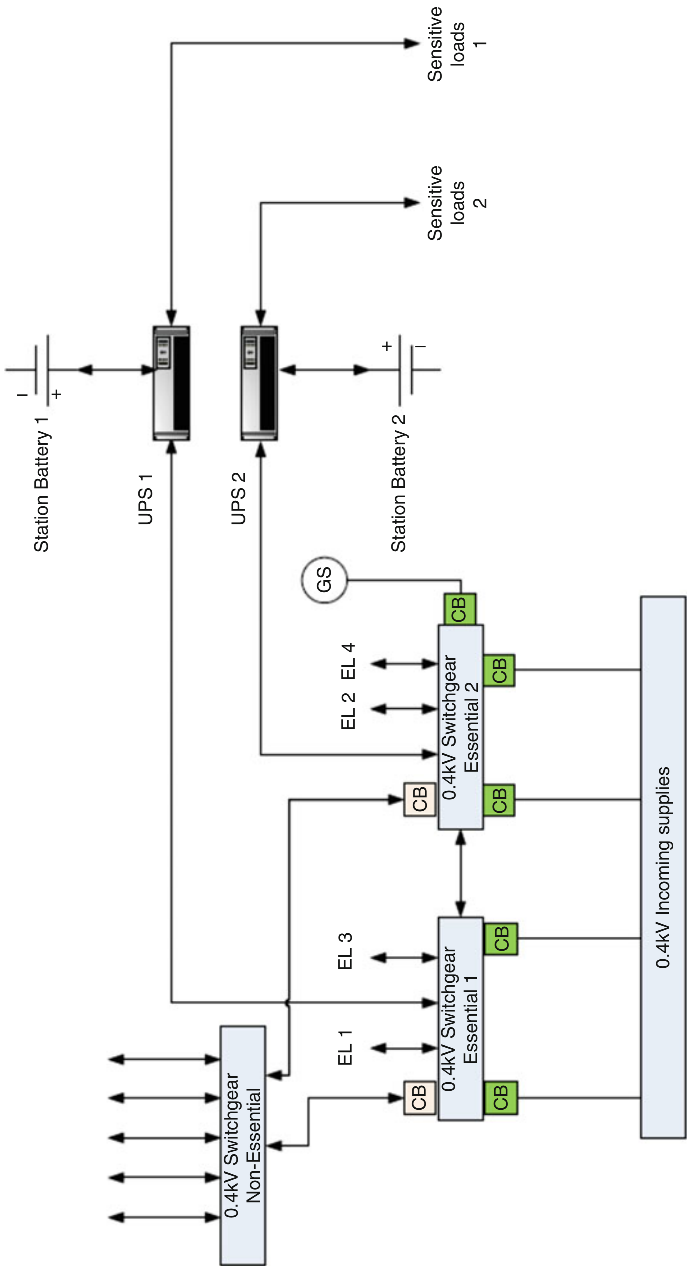



**Fig. 29.33** Centralized UPS from essential services boards

(ii) **LVDC Operational Loads**

Operational loads are those loads which will need to be supported only when the HV or MV systems on the platform are energized.

- Protection supplies – substation high-voltage and medium-voltage systems
- Switchgear supplies – substation high-voltage and medium-voltage systems
- Maintenance and testing supplies
  - Test supplies for protection and control systems

#### 29.5.2.3 LVDC System Operation

(i) **Normal LVDC Operation**

The LVDC system normally supplies all of the direct current auxiliaries on the substation platform, but the DC is usually derived from the chargers unless the main and backup AC supplies have failed.

(ii) **Source of Auxiliary Supply for Battery Charging**

The battery charger supplies are derived from the LVAC system installed within the substation which is described in Sect. 29.5.1.

(iii) **Separation of "Essential" and "Nonessential" Loads**

The separation of the "essential" loads from the "nonessential" loads in LVDC systems is not normally done in onshore substations, but may be achieved simply by having separate sections of LVDC boards connected by bus section switches. The physical design of the switchboard and isolation facilities must ensure that a fault in the bus section switch panel does not result in the unavailability of the "essential" section of the board.

(iv) **Abnormal LVDC Operation**

When the AC input to the chargers has failed, then the LVDC system should only supply the "essential" DC loads. The energy source (battery) is selected based on a number of criteria:

- Energy storage capacity required
- Type of storage batteries
- Location of storage batteries
- Voltages
- Other energy storage devices
- Relationship between DC and LVAC system

#### 29.5.2.4 Construction and Installation

(i) **LVDC Board Construction**

The configuration and construction of the LVDC system switchboard can have a significant impact on the overall availability of direct current auxiliary power supplies. In assessing the configuration and construction, the failure modes and consequences of the failure must be considered to achieve the performance.

(ii) **LVDC Cable Systems and Routing**

Wherever practicable, auxiliary power supplies supporting "redundant" functions should be segregated, using diverse cable routes to avoid a single incident taking out both supplies.

(iii) **Protection, Control, and Automation for the LVDC System**

The LVDC board and backup supply system need to be fully automated to ensure that a supply can be provided to "essential" loads at all times and must be coordinated with any local "supply changeover" arrangements.

#### 29.5.2.5 The DC Supplies Single-Line Diagram

To achieve high reliability for the DC supply system, a redundant two-battery system is required. The system consists of two equally rated batteries, the associated chargers, and the other equipment that is required for system operations and maintenance. Both battery systems are connected to the load via a diode system. A loss of any of the battery systems will not affect substation operation, since the load will be served by the un-faulted battery system. The above described system is represented by the single-line diagram shown below (Fig. 29.34).

### 29.5.3 Protection

#### 29.5.3.1 Statement of Requirements

The protection arrangements must be considered in the context of the cost and inconvenience of primary plant replacement in offshore substations and consideration given to systems which act to minimize the damage caused by faults.

The harsh environmental conditions experienced offshore must also be taken into account when selecting the protection equipment, its mounting and housing, and the microclimate into which it is to be installed. Where the protection system interfaces with the onshore substation, the relevant grid code needs to be considered to ensure that fault clearance times are compliant.

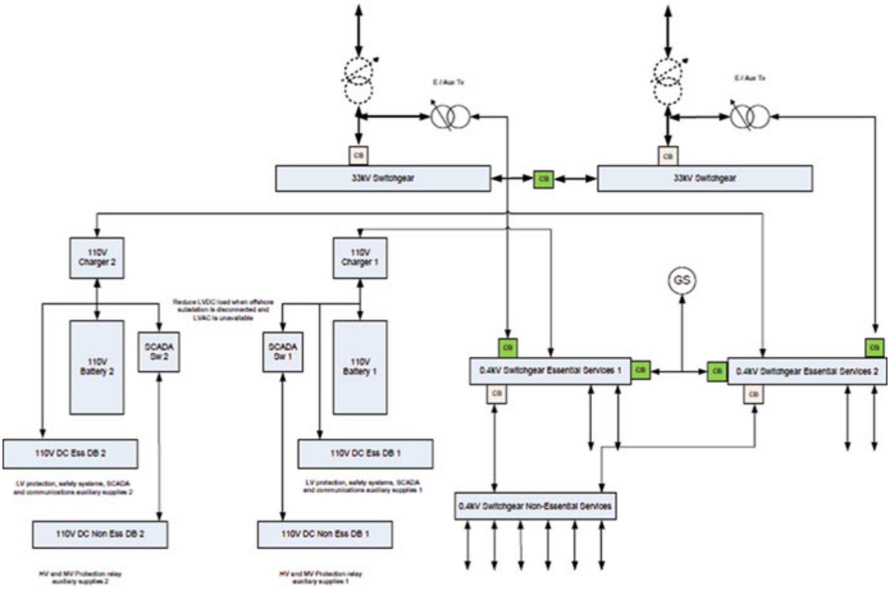



**Fig. 29.34** Fully redundant LVAC/LVDC system

### 29.5.3.2 Plant Protection

The protection systems installed on offshore substations are required to detect faults and initiate disconnection of faulted equipment across three subsystems:

- The transmission connection to the onshore substation
- The power collection system from the generators
- The auxiliary power system supplying the services of the platform

### 29.5.3.3 System Protection

In addition to the protection of equipment, the system should also provide for the detection of faults which put the main transmission system at risk, such as faults on the offshore substation which are not detected or cleared by protection and switchgear operations local to the faulted equipment. For this reason the following facilities also need to be considered:

- Circuit breaker fail
- Remote backup protection
- Protection signaling
- Remote non-unit protection

### 29.5.3.4 Operation with Degraded Communications

The protection will need to achieve fast clearance times and correct discrimination for faults, which will require the use of communications channels to the onshore substation. Should these communication channels become degraded or lost completely, the protection will still need to operate correctly, and not trip unnecessarily, and clear local faults as necessary.

#### 29.5.3.5 Particular Technical and Protection Application Issues for Offshore Connections

(i) **General Requirements for Protection**

Due to the high dependence of the substation on the availability and correct functioning of the protection systems together with the remote (sometimes inaccessible) location, the level of redundancy provided needs to be carefully considered.

A dual main scheme should ideally be implemented in two discrete devices utilizing alternate protection philosophies or implemented on different manufacturer platforms.

For transmission voltages and critical circuits, two separate and independent tripping channels, each with completely independent supervised power supplies, separate and independent trip circuits and separate and independent trip coils, i.e., on the associated circuit breakers, should be employed. The trip circuits should also be supervised in the CB open and closed positions, with supervision of the pre-closing circuit, i.e., full trip circuit continuity supervision. Failure of protection supplies, tripping supplies, or trip circuit continuity should be independently alarmed.

No single failure on the protection system, including auxiliary relay failure, supply circuit failure, trip circuit failure, etc., should prevent fault clearance.

(ii) **Protection Technology**

Wherever practical, protection relays should be of numerical design with continuous self-monitoring with alarm and diagnostic functions and which provide the option to utilize developed logic functions to help overcome the challenges presented by the setting problems with offshore wind power plants. They should also include instrumentation, disturbance recording, and event logging functions and have remote interrogation facilities to enable extraction of settings, measurement parameters, and disturbance records. It also allows for the remote adjustment of relay settings if required.

(iii) **Test and Isolation Facilities**

It is desirable that each functional protection relay is so arranged that operational and calibration checks can be carried out with the associated primary circuit(s) in service. The testing facilities should allow comprehensive testing to be performed in the minimum time with the minimum disturbance to connections or settings.

(iv) **Grouping and Accommodation of Protection**

It is recommended that protection and control cubicles should be of front access, swing-rack design, with glazed and sealed front doors through which necessary equipment indications can be observed. The protection and control equipment for several circuits may be accommodated within a common cubicle, but there should be proper segregation of wiring and terminal blocks to facilitate scheme testing and maintenance for one circuit without any risk of affecting scheme operation of other circuits while on load.

It is important that the installation design allows for the efficient replacement of the system.

(v) **Environmental Requirements**

For equipment installed in dedicated equipment rooms, protection equipment complying with IEC standards may be considered generally acceptable for offshore applications. The notable exception which may need to be considered is the ability of the equipment to withstand vibration and shock loads generated by weather, waves, and minor impact from docking vessels.

#### 29.5.3.6 Wind Power Plant Networks

The point of common coupling to the onshore network may be at either the transmission voltage such as 380/400 kV or at sub-transmission voltage typically 132/150 kV. Having an extra voltage level for the transmission-connected wind power plants may make the grading of the backup protection harder to achieve within the required timescales. The offshore substation will therefore for this section be considered as operating at a highest voltage of 145 (132 kV), having some sub-transmission switchgear which may or may not include a circuit breaker, one or more transformers from this voltage to 33 kV, a 36 kV switchboard system, and a number of 36 kV inter-array cable circuits. In order to understand and set the protection on the substation, it is necessary to consider the protection at the wind turbines and the onshore connection substation.

(i) **Main Protections**

Each independent protection group should be driven from independent current transformers and independent VT secondary circuits.

In general the main protections within the wind power plant network will be differential protections. For example, the 132 kV feeders will normally use numerical differential protection with fiber-optic communications. 132 kV busbar protection or connections may use conventional high- or low-impedance protection or directional blocking. The main power transformers will typically have biased differential protection.

Due to the remote location and difficulty of access, two fully independent main protection systems should be considered, operating in one out of two modes.

It is not practical or economic to provide differential protection for the WTG step-up transformers located in the transition piece, 36 kV collection array cables, and sometimes for the 36 kV busbar protection. For these circuits overcurrent and earth fault which may be either directional or nondirectional as required will be used as the main protection.

The protection systems should provide comprehensive records for trip and alarm conditions, with local indications of which element has initiated a trip or alarm and of voltage and current vector parameters at the time of trip initiation.

Voltage and current waveform disturbance recording and event logging should be included as part of the protection system.

(ii) **Backup Protection**

Backup protection will normally be achieved using overcurrent and earth fault protection or the plain distance elements integral within numerical differential protection. However, although the direction of real power flow is normally from the wind turbines to the grid, the protection grading is set to achieve coordination from the turbines to the grid connection point. Furthermore, the backup protection is also set to enable it to clear a fault in the event of failure of the protection on the next zone downstream item of the plant.

Each set of feeder protection should include remote backup protection for busbars to ensure that, in the event of busbar protection failure, a remote-end busbar fault will be cleared within the switchgear internal arcing fault withstand time.

#### 29.5.3.7 Unusual Settings Considerations

(i) **Normal Direction of Power Flow**

Unlike industrial applications where power flow is from the grid connection to the lower voltages and machines in a wind power plant, the real power will flow from the turbines toward the grid. The turbines however will not generate if they do not have a grid connection. Generally, the level of the fault current infeed is much greater from the grid than that from the WTGs depending upon the type of wind turbine generators being used. This fact can be used to achieve discrimination of the direction of the fault or can be used together with directional relays if required.

(ii) **Performance Similar to a Generator**

Within the grid codes in many countries, a wind power plant or power park module if it is greater in capacity than 100 MW has to perform in the same way as a generator. This puts a requirement on the generator to be able to ride through faults and remain connected to the grid. This fault ride through requirement means that all large wind power plants are required to aid system stability by remaining connected during disturbances and contributing to fault current.

(iii) **Possibility of Low Fault Currents**

Within the wind power plant, there are relatively long undersea cables both at the sub-transmission voltage (132 kV or 150 kV) and also at the generation collection voltage typically 36 kV. This may be exacerbated by the wind power plant being connected to the distribution network operator (DNO) networks. This can lead to the fault currents, particularly on the 36 kV network being very low, and these can in some cases even be less than the load current.

(iv) **Turbine Reactive Power Capabilities/Reactive Power Compensation**

The wind power plant will probably contain long export cables which generate reactive power which must be compensated. Most wind turbines have a broad reactive capability in steady state giving them the capability to both generate and absorb reactive power. In some wind power plant designs, use is made of this reactive power capability to minimize the amount of extra compensation plant to be connected to the network. This can lead to the direction of reactive power flow being the same as the direction of reactive fault current which at low fault currents can make it difficult to discriminate between the two.

(v) **Fault Clearance Time Required at the PCC**

The grid code or site-specific connection conditions may specify the maximum fault clearance times for backup protection at the connection point to be less than 1 s. Achieving this requirement while preserving coordination across the wind power plant is a challenge as there are many steps downstream.

(vi) **Turbine Transformer Protection and 33 kV Earth Faults**

Each individual WTG is connected to the collection array by a small step-up transformer. These transformers are typically 3–5MVA and 500–1000 V/33 kV with HV delta connected and LV star connected. On the HV side there is a circuit breaker which in many schemes is purely to protect for step-up transformer faults. The main protection for the transformer is provided by overcurrent and earth fault using a definite time characteristic. This protection will also provide backup for uncleared LV faults.

The delta winding acts as a zero sequence trap – hence LV earth faults can only be detected by HV overcurrent. If the LV earth fault levels are low, it may be necessary to add an additional earth fault element in the LV star point neutral.

Usually, the 36 kV system has delta-connected transformers on each wind turbine generator; also, the main infeed transformers from the grid also have delta windings on the 36 kV side. The 36 kV system is usually earthed through an earthing transformer which will be arranged to limit the earth fault current to approximately 750–1000 A.

Hence the values of earth fault current on the 36 kV system are low.

### 29.5.3.8 Collection Array Protection

The power from the individual WTGs is collected via string or tree connections at 36 kV. Typically six to ten turbines would be connected to one string. Fault passage indicators may be installed at the WTG locations to detect where in the string a fault has occurred. Some strings may be connected at their ends although they are not usually run as a ring. This can make the protection reach required for a string very long.

The main protection for the strings is usually provided by overcurrent and earth fault relays. However, the use of distance protection with fault locators is becoming more common (Fig. 29.35).

Often directional overcurrent and earth fault relays will be used although these may not provide the answer to all of the problems.

It is often necessary to use the negative sequence protection feature in the relays, or the relay may be equipped with some custom-designed logic to make it act as a voltage-controlled overcurrent. This enables it to distinguish between a low-level fault current and a load current.

Additionally 2nd harmonic blocking has to be employed on the relays to avoid tripping on transformer inrush currents.

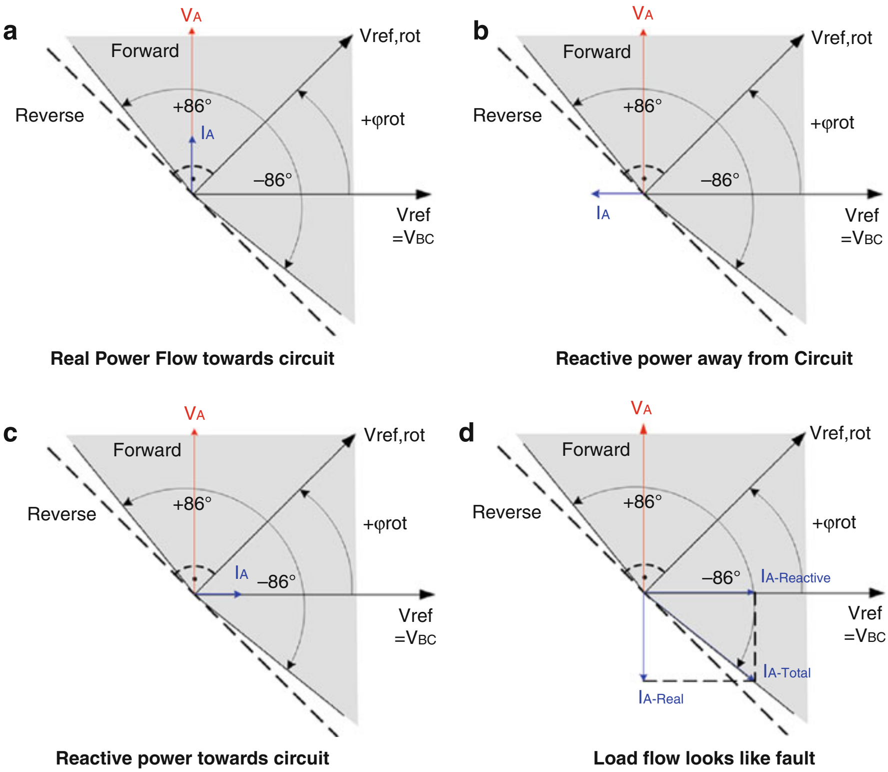



**Fig. 29.35** Reactive flows under load conditions may look like a fault

#### 29.5.3.9 36 kV Busbar Protection

Busbar protection must provide fast fault clearance for both phase and earth faults located on the busbar. As the earthing of the 36 kV network is via earthing transformers limiting the 36 kV earth faults to as low as 750 A. The limited earth fault current may mean that a traditional high-impedance circulating current protection may not be feasible due to the achievable minimum primary operating current being too high if there are a large number of strings connected to the busbars.

The options are a low-impedance protection scheme using numerical relays, but this is a little expensive or reverse interlocking busbar protection (RIBBP) which may be an economical answer.

#### 29.5.3.10 Platform Transformer Protection

The transformers used on the offshore platforms may be of either two-winding or three-winding design. For transformers in excess of 140MVA irrespective of whether they are two- and three-winding designs, two separate 36 kV switch panels will generally be required to accommodate the load current in excess of 2500 A. The transformers will be equipped with Buchholz gas, winding and oil temperature, and pressure relief protections which will operate in the same way as for any normal transformer. The transformers are equipped with HV REF which can be contained in the overall differential relay. LV REF is also used. For two-winding transformers, this can also be accommodated in the differential relay. For three-winding transformers, a separate restricted earth fault protection is required for each winding, and these will normally be accommodated in a stand-alone relay although numerical relays incorporating three REF elements are available. Each of the LV switch panels will be fitted with a directional overcurrent and earth fault relay. This relay may be an integral part of the RIBBP if utilized. This relay is also set to provide backup in the event of failure of the overcurrent protection on one of the strings or on a bus section or interconnector.

This relay can also be set with a definite time characteristic.

The backup protection on the HV side can be a two-stage IDMT overcurrent and high-set overcurrent (HSOC). Usually the stage 2 time delay is set to zero.

#### 29.5.3.11 Export Cable Protection

The main protection for the export cables will usually be a feeder differential protection. The key factor is the communications between the relays which uses fiber optics embedded in the submarine cables. For the normal operating condition, the relay uses fibers in an adjacent cable (assuming at least two export cables are used). If the normal channel is not available, then the backup channel using fibers in the protected cable is activated. This latter situation would be the normal case for a wind power plant with a single export cable. Alternatively a distance scheme could be utilized if an alternative fiber connection is not available. This could be a default operating mode provided by the differential protection following a loss of communications.

The backup protection is provided by overcurrent and earth fault located at the onshore end. This is due to the general approach of grading protections back from machines to the grid. Backup earth fault does not need to discriminate with any other devices as the earth fault reach is limited by the star/delta transformer connections. This enables short clearance times to be achieved which minimizes the fault duration on cable sheaths. The backup overcurrent must grade with the transformer HV backup. An IDMT characteristic may be applied. To minimize operation time, a curve graded at HVBU characteristic transition from IDMT to HSOC should be used.

#### 29.5.3.12 Breaker Fail Protection

Breaker fail protection tends to be applied to all circuit breakers from those in the 36 kV switchgear offshore right up to the onshore CBs. The operation of the CB fail protection is basically the same as applied on any transmission system. For failure of the last CB within the wind power plant system, intertripping of the CB by transmission operators will occur to clear the fault.

#### 29.5.3.13 Tripping Philosophy

As the WTGs cannot generate if they are not connected to a grid supply, then the loss of the grid supply will require reinstating the system. Consequently if a fault occurs on some upstream (HV) equipment, the tripping normally takes out all downstream (LV) plant to avoid this being left in the closed position when the voltage is restored at the HV end This downstream tripping may be effected from onshore to offshore using the intertripping facility built into the feeder differential protection relays.

#### 29.5.3.14 Interface with Operational Intertrip Schemes

In some countries, the connection agreements for some wind power plants may require the inclusion of operational intertripping schemes to trip the output of the wind power plant for certain grid system outage conditions. Although the simplest way to remove the output would be to trip the CB at the point of common coupling, in many cases it may be beneficial to trip the output at the offshore 36 kV busbars. This has two main advantages in that it does not require reenergization of the large offshore transformers with associated voltage dip on the network and it will leave any onshore compensation plant connected to the network to assist with voltage control. The intertripping can again be achieved using the facility in the differential relay.

An alternative approach is to provide fast curtailment of generation by interfacing directly to the WTG SCADA. This technique avoids the need for the tripping of CBs.

### 29.5.4 Control and Supervisory Control and Data Acquisition (SCADA) System Requirements

#### 29.5.4.1 Introduction

As the cost of keeping people in an offshore location is so high, the wind power plant will normally be designed for unmanned operation. This obviously puts large demands on the control and data acquisition system in order to perform this requirement. The substation naturally acts as a hub for the primary circuits, potentially owned by a number of different entities; it naturally follows that the substation also acts as a hub for communications, SCADA, and other data services such as asset management data. Traditionally, the manufacturers of wind turbine generators (WTG) have developed their own SCADA systems which have been totally dedicated to the needs of controlling the WTGs. This has led to there normally being at least two SCADA systems associated with offshore wind power plants, one to control the WTGs and the other to control the electrical system referred to as the HV SCADA system.

However, there may be a number of separate operating organizations requiring communication with and operational data from various elements of the "wind power plant complex," typically:

- Wind turbine operator(s)
- Collection system operator(s)
- Offshore transmission system operator (OFTO)

In the simplest case, there may be a willingness and commercial structure which allows the use of common systems with shared data, procedures, and communications controlled by password access, while in the most difficult circumstances, each of the stakeholders in the "wind power plant complex" may require fully independent data, communications, and procedures leading to the need for the HV SCADA system to be designed in two sections to allow the wind power plant SCADA and the OFTO SCADA systems to be separated, allowing them to be operated by different owners. It is important to ensure that these commercial and ownership issues are addressed very early in the substation design process to avoid any rework at a later date. The SCADA system needs to be designed so that the operation, maintenance, and any potential updates/modifications can be done independently without any undue effects on the availability and information in the other system.

The need for high availability of the SCADA systems is paramount. Often the SCADA system will have duplicated servers, communications, and power supplies and will have I/O segregated and/or duplicated so that the loss of any I/O card has a minimal effect on the wind power plant operability or availability.

The required level of information about the various systems offshore is an order of magnitude higher than that for onshore installations. In offshore applications the emphasis is on the remote collection of data to take operational decisions, identify failures, decide on repair strategies, and select replacement components to be taken by the correct repair team, when access can be arranged.

#### 29.5.4.2 Structure of the SCADA Systems

In this section, attention is concentrated on the SCADA system for the offshore substation itself rather than for other systems like the WTG SCADA or the collector system SCADA. The SCADA system for the offshore substation will usually be part of a common SCADA system with the onshore substation, and the servers will be located at the onshore substation.

As space is at a premium on the offshore substations, use should be made of the facilities provided in modern digital relays to provide the input/output for the SCADA system rather than providing lots of additional remote terminal units.

The intelligent electronic devices (IED) such as the protection relays and the RTUs can be arranged to run independently of the SCADA system such that in the event of a SCADA failure or communications failure, they will continue to function locally.

The communications will usually be designed as a redundant LAN topology to minimize the risk of path breakdowns. This will allow the SCADA servers located onshore to access the RTU/IEDs located offshore. Typically the protocols used for the SCADA systems will be IEC61850, IEC 60570-5-104, DNP3, Modbus TCP, OPC, etc. A typical SCADA configuration for an offshore wind power plant with two offshore substations is indicated in Fig. 29.36. This example incorporates the information from the WTG switchgear into the substation SCADA. A ring topology is used and redundant servers at the onshore substation. External access to the SCADA can be provided to enable:

- Remote monitoring of the plant by the offshore transmission operator
- Remote diagnosis of fault conditions by the maintenance staff to enable a more rapid and accurate response to site problems.

Different levels of redundancy can be selected and these are considered further in Brochure 483.

#### 29.5.4.3 Functionality of Each SCADA System

(i) **Wind Turbine SCADA**

The wind turbine SCADA system is not the subject of this document.

(ii) **Collection System SCADA**

If this system is separated from the Offshore System Operator SCADA system for reasons of ownership, then this system would typically control and provide status indications, alarms, and analogues for any switchgear located at each WTG together with any 36 kV or other equipment on the offshore substation platform, including protection equipment, and monitoring of power flows and voltages, of cable temperatures if using embedded optical fibers included for this purpose, of any battery/UPS systems including any on the WTGs, and of any security systems which are in the ownership of the generator. The features of this SCADA system would basically be the same as are described in the next section.

(iii) **Offshore Transmission System Operator SCADA**

This SCADA system will be the one which controls most of the plant on the offshore substation. It will provide control, status indications, alarms, and analogue information for the following items:

- HV switchgear
- Transformers (including tap change control and indication)

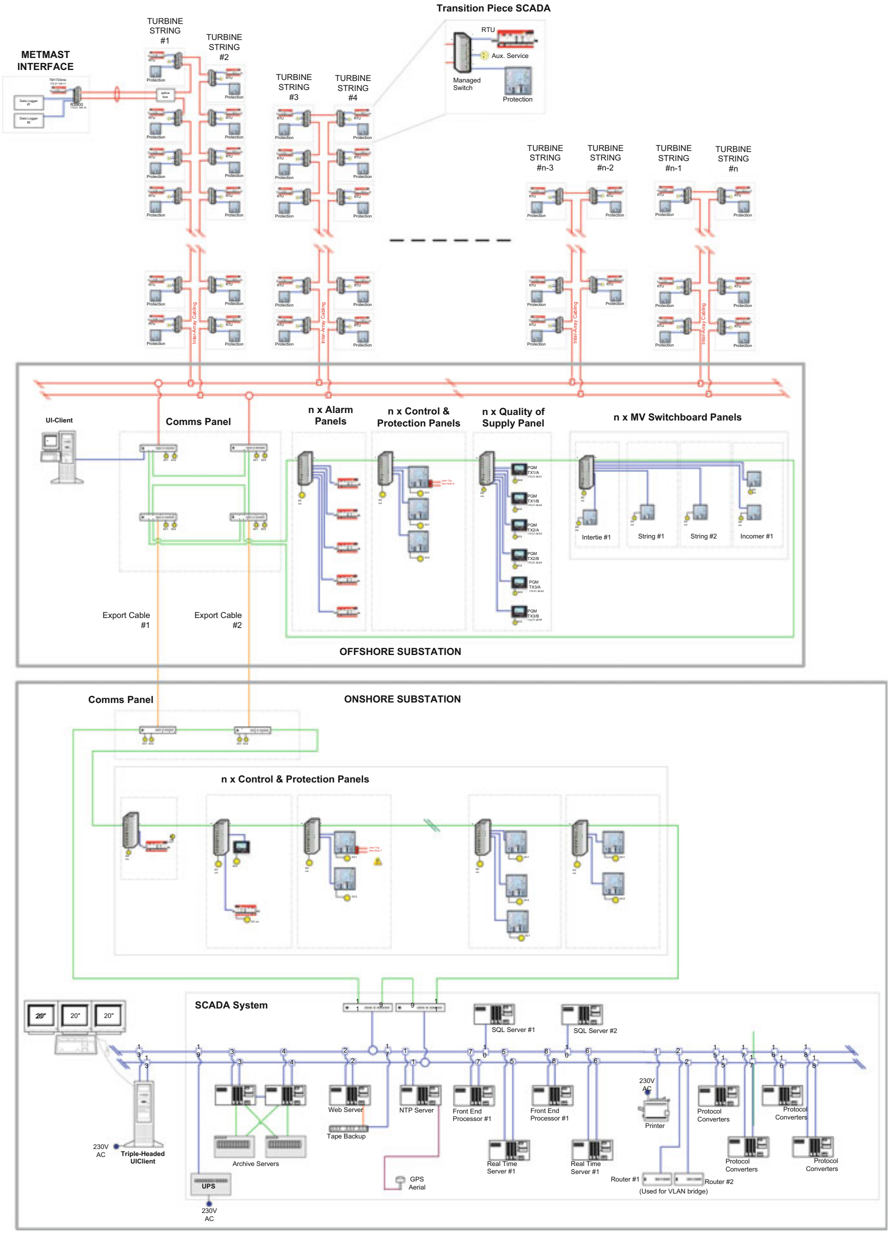



**Fig. 29.36** Typical SCADA configuration diagram

- 36 kV switchgear
- LVAC system
- DC system and batteries
- Diesel generator

- Protection systems
- Export cable temperatures (if using embedded optical fibers included for this purpose)
- Firefighting systems
- Platform building service functions such as air-conditioning, crane position and status and tank, sump and bund level monitoring, security and CCTV system alarms, etc.
- Navigation systems

Interlock conditions may be built-in if it is felt to be effective.

The SCADA system should also be designed to allow operation locally and remotely (at onshore substation, at customer's operating center, or other locations using broadband access). Each of these accesses can be controlled to limit who has authority to effect control.

Other functions which may be built into the SCADA are data processing and event and alarm processing.

#### 29.5.4.4 Use of SCADA for Maintenance Information

The SCADA system may be used as part of the maintenance regime of the wind power plant providing continuous remote condition monitoring and remote fault analysis and error correction. The data collected by the SCADA system can give the maintenance team information on sequence of events, analogue fault record charts, trend graphs, etc. to enable the maintenance team either to intervene remotely or to ensure that they have the personnel with the required skills and tools dispatched to the substation to deal with the problem. The SCADA system can have the capability to support predictive maintenance, preventive maintenance, and corrective maintenance.

#### 29.5.4.5 Interoperability of the Systems

Although the different SCADA systems may be owned and operated by different entities, there will be a need to communicate some information between the different systems usually between the main servers for the different systems located at the onshore substation. The communication may be by means of a protocol converter or in the worst case by hardwired connections between the two systems.

#### 29.5.4.6 Operation with Degraded Communications

The SCADA system is clearly vital to the successful operation and maintenance of the offshore substation. It is therefore important that the communications system is designed such that the failure of a single communication route does not cause the SCADA system to fail or become severely depleted. The communication routes from the shore to the platform should be duplicated and run in separate export cables such that loss of one route does not cause any interruption in the operation of the SCADA system. With regard to communications to the WTGs or their associated switchgear, ring systems will still be used but these may be run in the same cable. If the strings are tied to other strings at the end of their runs, then a complete SCADA ring system via different cables can be established.

Clearly any alarm indicating the failure of a communication route must be investigated swiftly to avoid the risk of a second failure losing the functionality of the system.

## 29.5.5 CCTV and Security Systems

### 29.5.5.1 Statement of Requirements

In order to allow remote monitoring of the substation and personnel for safety and security reasons, the use of CCTV and an associated security system is sometimes required to provide support to other systems of detection. The design of the system to provide safety monitoring will need to comply with legislation enacted by the appropriate statutory authority responsible for offshore installations. CCTV systems can be equipped with time-lapse video recording allowing images to be recorded at appropriate intervals. The time period that is saved before being overwritten needs to be defined. The system needs to have facilities to copy images onto removable media for long-term retention.

The system may also be configured to monitor the approach and docking of vessels to the platform and be arranged to provide warning of the close approach of vessels to the substation platform.

In the design and construction of the surveillance system, the reliability and availability should be carefully considered as under certain climatic conditions, the monitoring of activities may be totally dependent on the system.

In case of a substation equipment failure, the surveillance and monitoring system may be able to aid fault tracing and damage assessment prior to repair teams being dispatched.

### 29.5.5.2 Alarm System

An alarm system incorporating audible and visual annunciation capable of alerting all personnel in any accessible location is required. The system should also provide for two-way voice communications.

### 29.5.5.3 CCTV System

The CCTV system provides three distinct functions:

(i) **Personnel Surveillance**

The monitoring of staff working offshore by control center staff so that their safety and well-being is monitored.

(ii) **Security Surveillance**

Monitoring of vessels approaching the platform by both substation and remote control center staff to determine if the approach is planned, unplanned but acceptable, or a possible threat to the substation.

(iii) **Plant Surveillance**

Monitoring of equipment by control center staff so that abnormal plant behavior can be identified allowing early intervention. The cameras should be capable of remote control to cover defined areas of the plant, have sufficient zoom capability to provide detailed views, and operate in the visible light spectrum and infrared spectrum (for thermal imaging of the equipment).

### 29.5.6 Navigation Aids

#### 29.5.6.1 Statement of Requirements

In order to comply with statutory regulations, the substation needs to be identified and equipped with the necessary navigation aids to minimize the risk of collisions with any airborne or seaborne traffic. The substation navigation aids and markings should comply with all relevant international and local standards and coordinated for the whole power plant.

#### 29.5.6.2 Navigation Aid Power Supplies

All navigation aid systems are required to have two independent supplies of power with the physical arrangement of the supplies such that a fire, a fault, or a mechanical damage at any one point will not render both systems inoperative.

The supply system is to include automatic switchover between the two supplies in case of failure of one of them and initiate an alarm on the supervisory control system.

#### 29.5.6.3 Lamps

The construction and installation of the navigation lights used in the system should be suitable for the application and should comply with the appropriate legislation. All lamps should be individually supplied by a discrete circuit from a dedicated navigation lighting panel designed to provide secure supplies and lighting circuit monitoring/alarms. Main and standby lamps of identical type (usage) may be supplied via a single cable with two independent circuits provided that individual lamp isolation is provided.

#### 29.5.6.4 Light Panel

The navigation lights are to be controlled and supervised from a dedicated navigation light panel, and no other systems may take supplies from the panel. For every lamp the panel is to be fitted with a device which indicates or signals the extinction of a lamp. All alarms originating at the navigation light panel monitoring systems are to be repeated to the supervisory control system and recorded.

#### 29.5.6.5 Foghorn

When required by the local authorities, an audible warning device “foghorn” is to be provided for the substation platform complying with appropriate legislation. The warning system is required to have fully duplicated supplies with automatic changeover to the second supply and fault monitoring/alarm facilities giving local and supervisory alarms.

### 29.5.7 Communications

#### 29.5.7.1 Statement of Requirements

There are two main communications systems which may be considered suitable to provide the required bandwidth IP/SDH fiber-optic communications and IP/SDH satellite communications.

Depending on the overall structure of the power supply system, it may be that a fully redundant fiber system (most common currently in service) or a combination of fiber, microwave radio, and satellite is used.

In addition to substation to shore communications, the substation will require radio communication for use with supply boats, helicopters, and rescue services which are fully compliant with the statutory requirements for the jurisdiction in which the substation platform is located.

#### 29.5.7.2 Communication Routes and Usage

The communications system provided is required to support the following routes and functions:

(i) **Routes**

- Substation to shore – for voice and data communications into onshore corporate and public networks
- Substation to shore – for connection to onshore protection systems
- Substation to wind turbines – for voice and data communications into the substation systems for use at the substation or onward transmission to shore
- Internal within the substation – between locations on the platform for operation
- General “public address” broadcast system covering the entire substation
- Substation to supply or maintenance vessels for coordination
- Substation to emergency services and rescue teams – secure system

(ii) **Functions**

- Voice frequency for all verbal communications
- Data communications for e-mail, remote document access, Internet/intranet browsing, etc.
- Measurement and metering data
- Video surveillance for plant monitoring and personnel security
- Engineering tools – for accessing engineering data for remote analysis, e.g., fault records and remote adjustments to platform subsystems, e.g., protection settings
- High-speed communications such as protection signaling, differential current data, intertripping, and blocking

#### 29.5.7.3 Interfaces

The communications system will be required to interface to a number of equipments:

- Direct optical connection for protection relays, typically to IEEE C37.94 TM *(IEEE C37.94 is an optical standard for interfacing to PDH/SDH equipment. This would only be required if the protection relay data was multiplexed with other data on the same fiber.)*
- ITU-T G.821 V.35, G.703, X.21
- IEC 60870-5-10x
- DNP 3.0

#### 29.5.7.4 Communications Technology

The types of technology which may be employed include:

- SDH communications using optical fiber links
- SDH communications using leased satellite links
- SDH communications using point to point microwave links
- Radio systems for voice communications
- Backup satellite phone or mobile phone systems for voice communications

#### 29.5.7.5 Communications System Monitoring and Maintenance

It is essential that the monitoring, remote diagnostic systems, and remote repair facilities are designed to minimize site access requirements.

More detailed information on communications systems can be found in Brochure 483.

### 29.5.8 Equipment Accommodation and Environmental Management

#### 29.5.8.1 Statement of Requirements

Unless special requirements are specified, secondary systems are designed to operate over a well-defined but limited range of environmental conditions. If standard equipment, without special design or protective treatments, is to be used, the installation environment will need to be managed to provide the conditions required.

#### 29.5.8.2 Constructional Requirements and Equipment Accommodation

To achieve the required reliability, the overall construction system will need to be considered including:

- The accommodation room
- Position of the room
- Access doors
- Construction of the room
- Heating and ventilation systems

- Position for replacement equipment and or spares
- Cubicle and kiosk housing system components
- Physical construction
- Sealing
- Lighting, heating, and ventilation
- Protection function segregation
- Minimizing access requirements
- Major components
- Additional anti-corrosion measures
- Selection of high-specification long-life components
- Wiring, cabling, and other connection systems
- Corrosion-resistant connectors and terminals
- Tracking-resistant terminal blocks
- Cable glanding and sealing of gland plates

### 29.5.9 Maintenance Management

By designing and selecting equipment for low maintenance and making provision for simple testing, the number of personnel visits required and thus the time spent by staff at the substation is kept to a minimum.

Staff used for maintenance of offshore installations do not only need to be competent technically in their particular field but also have to be qualified to work in offshore locations. This is likely to limit the availability of and increase the cost of such staff. The number of different personnel required providing the specialist skill sets necessary may be directly related to the number of equipment types used within a substation. Incorporating standardization and redundancy in the design of secondary systems:

- Minimizes the number of visits
- Allows visits to be deferred until safe conditions for travel exist
- Reduces diagnostic and repair times
- Facilitates correct selection of spare parts to be taken to the substation
- Minimizes the number of special tools, equipment, and spares to be held at the substation

### 29.5.10 Metering

The wind power plant generation networks are connected through the offshore substation to supply power to the main transmission system. To measure the power delivered to the system, it is necessary to install tariff metering. The exact location for the metering will be dependent upon the location of the ownership boundary. In many countries an offshore transmission system operator has been established, and consequently this has led to the installation of tariff metering at the offshore substation.

The exact location for this metering may vary from one system to another. The common locations are at 36 kV on each array cable, at 36 kV on the LV side of the step-up transformers to the transmission voltage, or at the HV side of the step-up transformers.

If the metering is installed on the array cables, then this requires a large number of meters and current transformers to be installed. However the current and voltage transformer performance requirements tend to be less onerous.

Tariff metering normally requires two sets of metering known as main and check. Typically at load levels less than 100 MW, the main and check meters can be connected to the same high accuracy CT core and the same high accuracy VT winding.

If the metering is connected to the LV or HV side of the step-up transformer, then this will require fewer meters than for the arrays, but the current and voltage transformer performance requirements are more onerous. At higher load levels, the main metering must be connected to a dedicated high accuracy CT core and VT winding. The check metering can be connected to a second high accuracy CT core and VT winding but in this case other loads can be connected to these windings.

It should be noted however that if the metering is connected on the LV side of the step-up transformer and two circuit breakers are connected in parallel to achieve the rating, then each circuit breaker will need to be equipped with its own set of tariff meters as the summation of the CT signals will not be acceptable to meet the high accuracy requirements.

## 29.6 Special Considerations When Connected by HVDC Link

As offshore wind power plants (OWPP) grow in terms of rated power and continue to be located further from the coast (and the existing transmission networks), the rationale for using HVDC to transmit the generated wind power schemes increases. There may be several reasons for using HVDC instead of HVAC in the case of long-distance transmission. The most obvious ones are of course to overcome the large amount of reactive power generated by long high-voltage AC cables and the fact that an HVDC link becomes more cost competitive above a certain transmission distance. The use of HVDC to facilitate the connection to shore opens up new design possibilities for the AC collector system(s). This creates a number of options and challenges that are not encountered in “traditional” AC systems.

When reference is made to HVDC, this is a voltage source converter (VSC)-based HVDC as grid integration of large offshore wind plants will be based predominantly on VSC technology.

This section examines the special requirements that need to be considered during the design of an offshore AC collector substation that is connected to an HVDC link in comparison to a substation that is connected directly to the onshore site by means of AC export cables. The latter is treated in the earlier sections of this Chapter.

It also aims to identify issues and opportunities and to provide guidance on how to optimize the design of these collector systems and substations. The use of HVDC links means that AC collector substations are decoupled from voltage, frequency, short circuit contribution, and control of the onshore transmission system, which opens up the opportunity for optimization and harmonization of requirements and design, e.g., sharing of control efforts with the HVDC hubs. This means that operational conditions, requirements, and design of such AC collector substations will differ from those of the collector stations which are directly grid-connected by means of conventional AC export cables.

Specific design relevant issues are:

- **System Design**
  - Is there an optimal number of AC collector substations to be connected to a single, or multiple, HVDC hub(s)? What needs to be considered?
  - At which *frequency* should the offshore network operate? As the HVDC link provides a distinct separation from the onshore network, one may consider moving away from a standard frequency of 50 or 60 Hz. Shall the offshore AC networks operate at a standard onshore frequency of 50 or 60 Hz or utilize another fixed or variable frequency?
  - How to choose and standardize voltage of the offshore collection network for cost reduction? What *voltage* should the collector AC network operate at? It does not need to be related to the onshore voltage. Will standardization of the offshore AC network voltages lead to cost reductions and easy future expansion of the offshore network? How to choose and standardize voltage of the offshore collection network for cost reduction?
  - How to determine the right transformer impedance when connected to an HVDC substation with limited short circuit capacity?
- **Grid Codes**
  - How to achieve, harmonize, and standardize grid code requirements, such as fault ride through (FRT), reactive power compensation, and control of the wind turbines and those of the offshore HVDC station?
  - Fault ride through
    How is fault ride through of the wind turbine generators (WTGs) achieved, coordinated, and harmonized with that of the offshore HVDC converter?
- **Power Quality**
  - How to secure delivery of high quality power, minimize harmonics, avoid downtime of equipment, reduce maintenance cost, and enhance lifetime of the equipment, which is grid-connected via an HVDC link?
- **Recommended Studies**
  - Which studies should be carried out for AC and HVDC connections of wind power plants?
- **Protection, Control, and Communication**
  - How to detect a short circuit and choose an effective protection philosophy?
  - Protection philosophies
    - Will the protection philosophies differ as compared to AC-connected transmission links?
  - Communications systems
    - Are there any specific aspects with regard to communications systems that need to be considered?

## 29.6.1 System Design

### 29.6.1.1 Overall System Topology

An AC collector substation in this context is defined as an offshore HVAC platform with all the necessary electrical equipment to collect power from the MVAC (medium-voltage) array cables connected to wind turbines and step up the voltage to HVAC in order to provide connection to one or more offshore HVDC stations, so-called HVDC hubs. The link from these HVDC hubs to the onshore transmission system is made via HVDC links. The HVDC scheme may include one or more offshore HVDC hubs connecting one or more AC collector substations of the offshore wind power plants (OWPPs).

The design of the topology to be used to connect a WPP to an HVDC platform is influenced by the following parameters:

- WPP power rating and footprint (size and shape)
- Number and power rating of the wind turbine generators (WTGs)
- The maximum number of WTGs per cable string which is determined by the voltage and current ratings of the cables, the output voltage of the WTG step-up transformer, short-circuit levels and reliability, and installation considerations
- The maximum number of feeders and the characteristics of the cables entering the platform
- Environmental or topographical conditions along the cable routing
- System availability and reliability of the components
- Regulatory issues such as grid code requirements, rules and regulations from authorities, etc.
- Ownership boundaries
- Installation cost of network assets
- Presence and proximity of neighboring WPPs (for option of interlinking)
- Lifting capacity determining the size of platforms and equipment on them

The selection of topology, voltage, and frequency of the AC collector substations becomes critical for securing cost efficiency, interoperability, and future expansion of the offshore network.

The offshore AC collector substations can be arranged in different network configurations which are illustrated in Fig. 29.37, ranging from simple to complex configurations:

radial networks (see Fig. 29.37 1a), where one or more AC collector substations are connected by their HVAC (and/or MVAC) cables to their HVDC hubs with no interconnection between the stations and no interconnection between the hubs.

The number of AC collector platforms and power capacity per platform depends on the total power capacity and layout of the OWPP, i.e., physical size and shape, the voltage level of the collecting network, the maximum current of the AC switchgear, and maximum power rating of the AC transformers. Platform foundations, lifting capacities of installation vessels, mechanical restrictions on the platforms, and contractual strategies can result in lower-power capacities per platform. In fact, the

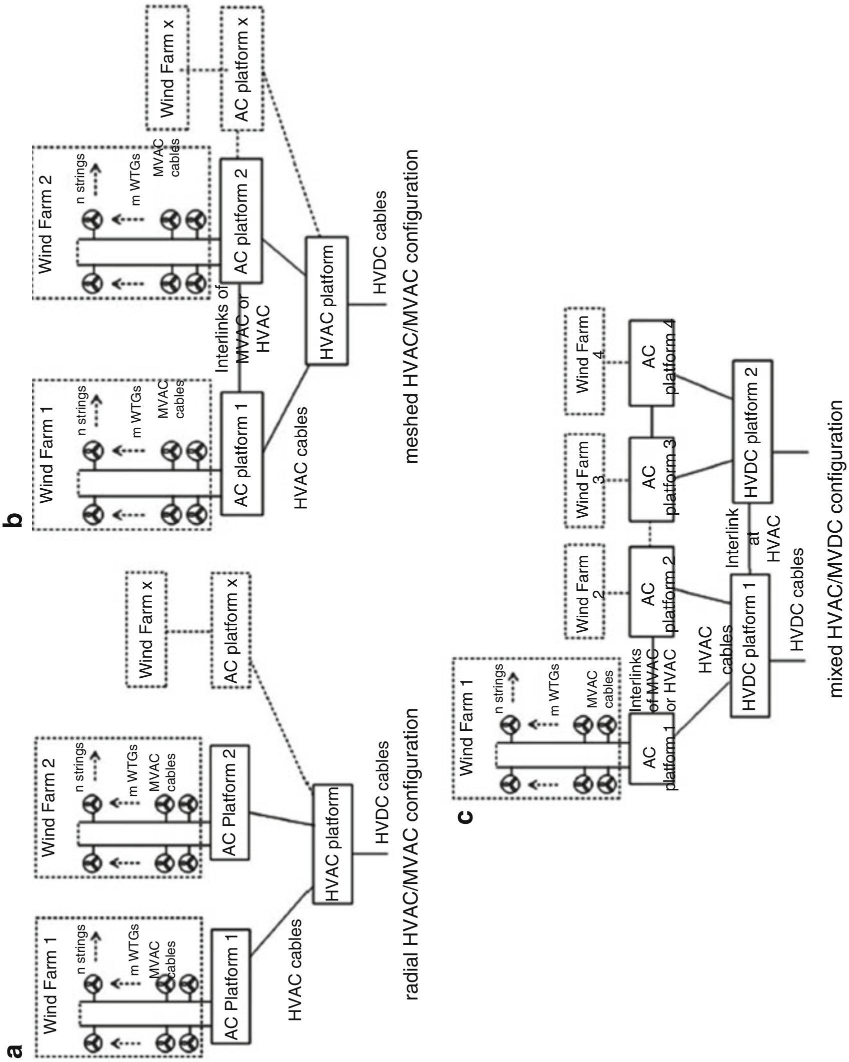



**Fig. 29.37** Network topologies

number of platforms and power capacity per platform is the result of optimization between the abovementioned electrical and physical key parameters and regulations. There are practical limits influencing the number and size of offshore equipment items, e.g., transformer ratings. Typically, secondary currents higher than 5 kA are impractical since this would exceed the maximum normal circuit breaker rating of two bays. Hence, in practice the maximum transformer ratings on the low-voltage windings are 280 MVA for 33 kV array voltage and 560 MVA for 66 kV array voltage.

Another topology is a meshed network (see Fig. 29.37 1b), where AC collector substations are connected by their HVAC (and/or MVAC) cables to the HVDC hubs and between each other, but there is no interconnection between the hubs. Although such a topology increases commissioning and operation and maintenance (O&M) costs, it can offer an increased degree of operational flexibility. This is especially important offshore where access for maintenance and repair may often be an issue. An interlink at MVAC will be cheaper and can provide an alternative supply route for the WTG auxiliaries if the normal supply route is disrupted by a planned or faulted outage of a transformer on the AC collector substation or an HVAC cable from one AC collector substation to the HVDC platform. MVAC is less suitable for the provision of an alternative export route as only a limited proportion of the power generated at the WPP can still be exported via the other platform, depending on the number of interlinking cables and their rating. Additionally, losses will be relatively high due to the high currents at this voltage level.

Interlinking at HVAC can also provide an alternative supply route for WTG auxiliaries in the case of an HVAC cable outage but not in the case of a transformer outage. HVAC can however provide higher power capacity, so would be more suitable for the purpose of providing an alternative route for export of wind power, but adds higher cost.

Similar considerations apply when AC interlinks are introduced between one HVDC platform and another should they be located at a reasonable proximity. Such a mixed HVAC and HVDC network is shown in Fig. 29.37 1c, where in addition to or instead of having an HVAC connection between HVDC platform 1 and 2, it is also possible to interlink at MVAC or HVAC between AC collector substations connected to different HVDC schemes, i.e., platform 2 and 3.

Note that all interlinks discussed here can be operated as normally closed or normally open if fault levels become excessive.

Interlinks should be planned and installed such as to minimize the risk that a single point of failure will affect both the primary transmission path as well as the backup (interlink). For example, cable routes of interlinks should if possible be separated from main cable trace, J-tube position different from main cable J-tubes, etc.

Interconnection costs must be balanced against the potential revenue gained (or lost) based upon the generation level possible and the frequency of occurrence of possible contingencies. With an HVDC connection of approximately 1GW, for example, the loss of generation can be significant. This must however be assessed against the cost of a fully, or partially, rated interconnection.

If a WPP is relatively close to the HVDC platform, then it may be cost-effective to connect WTGs directly to the HVDC platform, via MVAC cables linked to the

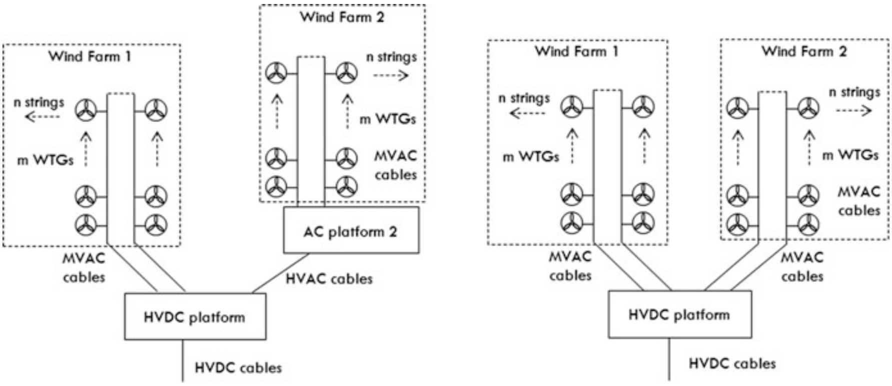



**Fig. 29.38** WPPs connected directly to HVDC platform via MVAC cables

converter transformer (stepping up from MVAC to HVAC) of the HVDC link (see Fig. 29.38). Removing one sub-transmission HVAC voltage level could result in cost savings because there is one less transformation stage, so less equipment (transformers and switchgear) is needed offshore. However, the main savings are probably on the platform side as fewer or no AC collector substations are needed. The cost for the HVDC platform may possibly increase somewhat as there would be more medium-voltage cables and MVAC switchgear. On the other hand, this solution would not require any incoming HVAC switchgear.

Omitting this transformation stage will also result in reduction of the overall maintenance costs and higher reliability as there are fewer components (transformers and switchgear) to fail and may also reduce power losses.

Whether overall system losses are reduced depends also on the cable losses, which in turn depends on the distance between the WTGs and the HVDC platform. Further expandability via direct HVAC connections between the existing and future HVDC platforms should also be included into the considerations of which HVAC voltage to choose in the offshore substations (needs of standardized HVAC voltage level). Drawing conclusions on the lowest power losses and overall HVAC systems design optimization requires long-term considerations (expandability of solutions) and economic and technical calculations (such as load flow, losses, and short circuit calculations) using the wind power production forecasts and plans for the offshore area development. At present, such evaluations must be conducted individually for each project.

The option to interconnect can also be used to address the intermittency of wind where the additional transmission capability that will result will increase the efficiency of transmission of available energy.

The North Seas Countries Offshore Grid Initiative (NSCOGI) and the wider European Super Grid will likely play a key role in building up a grid infrastructure on the regional transmission system level that may in turn have an influence on how the WPPs will be configured.

#### 29.6.1.2 Voltage and Power Ratings

The nominal HVAC and MVAC voltages that at present are applied or considered for OWPP are 132–220 kV and 33–66 kV, respectively. Current experience refers mostly to direct HVAC connection that utilizes one or more HVAC cables with voltages of 132 kV, 150 kV, and 220 kV. At present the only HVDC-connected OWPP is located in the German Bight and utilizes 155 kV HVAC cables to the HVDC hubs. These and other voltage levels, i.e., 132 kV and 220 kV, are also considered for connection of AC collector substations with HVDC hubs of future OWPPs.

A higher voltage level on the one hand has a higher power capacity per cable and reduces the number of export cables to the HVDC hub. It reduces also power losses and may allow connection over a longer distance.

On the other hand, increasing the voltage increases size, weight, and cost of the transformers and switchgear bays that may influence the size, weight, and cost of the entire AC collector substation. The cable charging current increases which in turn increases reactive compensation needs. Consequently, selection of the voltage level is decided on techno-economical evaluations, e.g., mapping of present experience from completed projects, possible risks and potential showstoppers, and a cost-benefit analysis.

The selection of MVAC for the wind turbine strings and power transport to the AC collector substations is a key design parameter. 33 kV has become the default MVAC voltage level, which is being challenged by the possible utilization of 66 kV for connection of larger rated wind turbines, typically greater than 5 MW, in strings with larger power capacities. The strings are arranged by MVAC cable sections with different cross sections. The thickest sections are at the end of the strings closest to the platform and will access the AC collector substations through J-tubes. This may restrict how thick these end sections can be.

The present experience is that many OWPPs use 33 kV cable strings with the thickest conductor cross sections of 630 $mm^2$. The next step is to use cables with 800 $mm^2$ conductor cross sections (and larger cross sections have been announced as well), which is deemed feasible but used in a limited number of projects so far. The usage of such larger cross sections can be challenging due to needs of larger bending radii when accessing J-tubes.

Higher power capacity can be accomplished either by more wind turbines (larger field) or higher-rated wind turbines. The latter would mean a lower number of wind turbines per 33 kV string and hence, in both cases, more J-tubes and switchgear bays on the AC collector substations. Experience from Denmark indicates that for wind turbine power capacities above 5 MW, 66 kV becomes more competitive than 33 kV resulting in fewer MVAC strings, reduced power losses, as well as reduced size, weight, and cost of the MVAC equipment on the AC collector substations.

The 66 kV cables generate more reactive power than the 33 kV cables. This can help to fulfill the reactive power capability (PQ) requirements of the grid codes in low-voltage conditions. However, the 66 kV cables will need more reactive compensation, which also includes no-load situations in the MVAC collecting network. This may also have implications on voltage regulation during light load conditions.

The implementation of a 66 kV MVAC collection grid could enable direct power transfer to the HVDC hubs without the need for high-voltage level transformation and hence AC collector substations. Such 66 kV connections can be competitive over shorter distances and worth including in the cost-benefit analysis of the AC collector substations. Using the 66 kV voltage level will also open up the opportunity for the possibility to interconnect OWPPs and AC collector substations on the MV side.

#### 29.6.1.3 Frequency

Decoupling the OWPP from the onshore transmission system by means of the HVDC links means that the frequency of the AC collector substations does not necessarily need to be the standardized 50 or 60 Hz used in the onshore systems. Furthermore, frequency synchronization with the onshore system is not required. The frequency of the offshore AC network is determined by power electronics of the HVDC converter. Hence, the frequency can be selected as either fixed or variable. It can be totally decoupled from the onshore system or, potentially, mirrored to it in order to get proper frequency response from the OWPP for frequency stabilization of the onshore system and coordinated between the frequency control of the HVDC hub and that of the OWPPs. Nevertheless, the same frequency scheme must apply within the entire interconnected (offshore) AC network.

The use of fixed frequencies above the standard 50 or 60 Hz may allow utilization of smaller and lighter offshore components, such as transformers and reactors. In contrast fixed frequencies below standard 50 or 60 Hz will reduce the reactive power charging of the cables and so reduce the requirement regarding reactive power compensation of them.

Variable-frequency applications already exist in modern wind turbines that decouple variable-frequency generators from the fixed-frequency grids by power electronic converters. This optimizes the energy capture below certain wind speeds, reducing mechanical stress and wear of gearboxes and achieving fault ride through (FRT) by means of power electronic converters. At the network level, a variable-frequency scheme would potentially become advantageous if such variable-frequency generators would be directly connected to the AC collector substations, i.e., without individual converters.

Scaling up the concept from a single wind turbine to an entire offshore network hosting numerous wind turbines will be challenging. For example:

- If the instant (variable) frequency value is kept the same through all AC-interconnected generators, the optimization of the energy capture from the OWPP (as a generation unit) and mechanical stress reduction of the wind turbines become less efficient due to unequal wind distribution over the OWPP area.
- Novel power frequency control schemes would need to be developed and implemented because the conventional schemes interpreting frequency deviations as power imbalances do not apply in variable-frequency regimes.

Both variable-frequency and nonstandard fixed-frequency schemes present further technical challenges:

- HVAC and MVAC cables can operate in a wide frequency range. However, the power transport efficiency is derated in a higher-frequency range due to larger reactive power generation in the cables and an increase of power losses.
- Redesign and suitability tests of protection schemes are needed, especially for operation in a lower-frequency regime. Lower frequency will introduce longer fault clearance times.
- Since the recovery voltage across the circuit breaker contacts rises more rapidly in higher-frequency regimes, interrupting duty of small capacitive currents becomes severe and risk of re-strike increases. Development of faster opening breakers or usage of two (or more) circuit breakers in series can be needed.
- Equipment, such as transformers, ancillaries, and diesel generators, should be designed and suitability tested for operation at a nonstandard frequency or in a wide frequency range. Some ancillaries may need additional frequency converters if not suitable with the applied frequency scheme.
- Lower-frequency regimes call for transformers with larger and heavier cores, but decrease the core loss and noise and the load loss. Higher-frequency regimes increase such loss and noise. Furthermore, the frequency regime affects the transformer impedance, which can be either an advantage or a disadvantage, according to design.

The adoption of a nonstandard frequency regime introduces a number of commercial problems:

- Specially designed equipment for nonstandard conditions is likely to increase the cost.
- Small supply chain capacity and limited competition between equipment suppliers.
- A challenge to future expandability if two offshore systems with different frequency regimes should be AC-interconnected.

In the consideration of operation with a frequency above or below standard 50/60 Hz, it was noted that a move to a different frequency would be a move away from standardization of the grid components and their type testing and certification.

However there is a significant amount of equipment which has been tested and certified at both 50 Hz and 60 Hz for Europe and America, respectively. Consequently the system designer in an area which has 50 Hz onshore may wish to consider the use of 60 Hz offshore if obtaining a smaller and lighter transformer is of significant value. Conversely, a designer in an area with 60 Hz may wish to consider the use of 50 Hz offshore if the VAR generation from cables is a significant problem.

#### 29.6.1.4 Availability and Reliability

For onshore transmission systems, (N-1) and (N-2) redundancy levels are frequently used onshore. Generation connectors, such as transformers and transmission lines to power plant generators, are made with (N-0) redundancy. Since the HVAC or MVAC connections from the AC collector substations to the HVDC hubs and the HVDC links from the hubs to the onshore transmission system are generation connectors, these can be designed for (N-0) redundancy.

However, the MVAC collection networks of the OWPP, voltage step-up transformers, and auxiliaries in the AC collector substation are normally designed with a higher redundancy level which is based on the cost of assets compared against the capitalized value of lost generation or on requirements of a governmental body. For example, the UK regulations require that a minimum of two transformers are installed per platform, each rated at a minimum of 50% of rated power. The HVAC connections from the AC collector substations to the hubs can also be designed for a higher redundancy, under consideration of the lifetime cost of the OWPP, regulatory requirements, impact of the loss of power on assets (maintaining emergency supplies), and consideration of high-impact low-probability (HILP) events.

Also alternative ways to access the platforms should be evaluated, e.g., using either boats or helicopters or both options.

CIGRE Brochure 612 provides methods for evaluation of such parameters and measures in connection to advanced design, contracting, and maintenance needs of the HVAC and HVDC platforms.

#### 29.6.1.5 Auxiliary Power

Different fault scenarios can force the complete offshore network into islanded operation. During islanded operation essential loads including safety systems, navigation systems, etc. must be supported to ensure the integrity of the AC collector substation and that the WTGs are supplied with auxiliary power.

The auxiliary power supply has been typically provided by one or more diesel generator sets located on the AC offshore platform designed only to support the AC collector substation. These generator sets could be designed to also supply the consumers of WTGs, in which case they must be able to provide the necessary active and reactive power to all auxiliary loads (including wind turbines) during steady-state and transient conditions.

Emergency diesel generator sets have a considerable influence in the AC collector substation design and cost (e.g., size and weight of diesel generator components, diesel tank, and fire hazard). Therefore robustly designed and low-maintenance equipment should be pursued when considering diesel generator sets. Special considerations may be necessary if the connection to shore is not yet available and the diesel generator set will be used to provide power to the WTGs during the erection of the WPP.

Challenges when designing the diesel generator and the auxiliary power concept are:

- Inrush currents during energization procedure of the MV radials and the wind turbine transformer.
- Fatigue and lifetime reduction can occur when operating prime mover on light load (less than 30–35% of its rated loading) for extended periods of time (wet stacking).
- Maximum and minimum number of wind turbines that the diesel generator should deliver auxiliary power to at any given time.
- Split of functionality between provision of the WTG auxiliary power supply and platform power supply (to give platform a stable and "clean" power supply).
- Furthermore due to the capacitive nature of the islanded offshore MV network, providing auxiliary power through diesel generators could require medium-voltage reactors to compensate the MV cables. This adds extra costs in terms of equipment and platform space and weight.

Due to the numerous challenges associated with providing auxiliary power to an islanded offshore MV network and the wind turbines, other options may be worth considering. A list of such options is given below:

- HVAC or MVAC interconnection to other HVDC or AC platforms
- Multiterminal DC interconnection
- Energization through the HVDC connector from the onshore system
- Wind turbine black start capability, so that a selected number of WTGs are able to provide auxiliary power to the rest of the MV network, including platform auxiliaries (requires the turbine converter system to be designed for black start mode)
- Small diesel units established at a selected number of WTGs

#### 29.6.1.6 Implications of Split in Ownership

The owner of a technical system can adapt its design to their needs. Based on technical and economical evaluations, the asset will finally be optimized.

At the interface point the two neighboring systems have to act jointly. In order to enable a stable operation of the two systems together, technical rules, e.g., grid codes, are defined which must be fulfilled by both parties. These rules are universal and reflect a wide range of technical circumstances which are not adapted to the present situation. Therefore the independent design of both systems will not be as optimized as they would have been if they had been treated as one complete system. Hence, technical systems belonging to different owners may not be optimized and may require additional technical efforts by the owners.

The location of split of ownership may have major implications on the final technical properties of the AC collector system and hence on its design, e.g., on the reactive and active power control of the AC collector system.

In case of one owner only, e.g., the TSO, there are greater opportunities to design for optimized solutions considering the whole asset as one system, integrating the WPP into the onshore grid.

If the transmission operator only owns the HVDC link, the AC collector system will have to fulfill all grid connection requirements at the interface between the two parties. This might result in additional efforts such as:

- Static reactors on the AC collector platform for medium- and high-voltage cable compensation
- Strong cooperation of the WTGs in the delivery and consumption of reactive power in steady-state conditions and fault situations
- Fixed-frequency behavior of the AC collector system (the WTGs will have to act accordingly)

If the HVDC link is owned by the generating company (split of ownership onshore), the technical properties required to provide a stable offshore grid under all circumstances can be optimized and split between all involved grid components. For example, the HVDC converter can be used to consume the reactive power of the AC collector system, and WTGs will just contribute in reactive power control if this gives major advantages in the design of the HVDC converter. Or, the WTGs do not contribute in voltage support during faults; the HVDC link itself stabilizes the grid. This benefits the WTGs but requires more efforts on the HVDC side.

As the WTGs are developed by the manufacturers to serve a wide market, most of the available WTGs are able (at least partly) to fulfill grid code requirements. On the other hand (even though harmonization and standardization of components and HVDC systems have been started), the HVDC systems design is unique and adapted for each specific project. In order to optimize the design of the offshore grid, the technical properties of the WTGs and the requirements of the HVDC system must be coordinated.

#### 29.6.1.7 Transformer Impedance and Voltage Control

The HVDC hub will provide a relatively small fault current, i.e., the short circuit power on the HV terminals is low.

Table 29.6 shows the impact achieved by decreasing the transformer short circuit impedance, in terms of short circuit current, MV busbar voltage drop, and reactive power "absorbed" by the transformer leakage reactance.

The results show that to cut by half the transformer short circuit impedance doesn't significantly impact the MV short circuit level. On the other hand the voltage drop and the reactive power are drastically reduced. Therefore, the transformer

**Table 29.6** Influence of decrease of short circuit impedance

| | $V_{cc\,\%} = 15\%$ | $V_{cc\,\%} = 13\%$ | $V_{cc\,\%} = 11\%$ | $V_{cc\,\%} = 9\%$ | $V_{cc\,\%} = 7\%$ |
|---|---|---|---|---|---|
| MV short circuit current [kA] | 6.387 | 6.957 | 7.656 | 8.103 | 8.533 |
| Voltage drop [%] | 1.25 | 0.96 | 0.71 | 0.49 | 0.31 |
| Transformer reactive power [MVAR] | 21.25 | 18.42 | 15.59 | 12.76 | 9.93 |

impedance should be chosen to be sufficiently low to secure proper functionality of the protection system. However, when there are several OWPPs connected to the same HVDC hub or there are several interconnected HVDC hubs at the transformer HV terminals, the short circuit capacity at the HV terminals will be larger. In such cases a higher impedance may be necessary, especially when parallel operation of transformers is required.

The transformer impedance should be determined by calculations based on realistic operational conditions on the AC collector substations, including the impact of the HVDC hubs and OWPPs. The possibility of any future expansion of the grid must be considered and included in the transformer impedance specification.

The HVAC/MVAC transformers can be specified with tap changers to maintain the MVAC network voltage within required ranges. The usage of tap changers can be justified in configurations with many long MVAC radials and with lack of sufficient voltage and reactive power control from the wind turbines, e.g., in no-wind conditions where the wind turbines are not obliged to control reactive power. The specification and design of tap changers should be evaluated through cost-benefit analysis where potential benefits of the transformers with tap changers and their extra cost and maintenance are compared to utilization of other reactive power control equipment and transformers with fixed tap positions. The cost should include reduced availability and increased maintenance due to moving parts. The tap-changing control should minimize the amount of tapping events.

Refer to CIGRE Brochure 612 for more considerations associated with the choice of tap changers.

### 29.6.2 Grid Code Compliance

Most TSOs have formulated grid codes (GCs), i.e., a minimum set of technical requirements, which the electricity-producing wind turbines shall comply with in order to be granted connection to the grid. Since its publication in 2012, the ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators (NC RfG) [C] has been in comitology. Once comitology is completed, the ENTSO-E NC RfG may become the European-level GC and replace national GCs for wind turbines.

With regard to HVDC in Europe, there have been no national-level GCs for HVDC connections. Technical requirements for HVDC connections have been specified by the customers, e.g., relevant TSOs, and negotiated with the vendors. The technical requirements have been based on specific technical and economical preconditions of the HVDC connections and of the adjacent AC grids. ENTSO-E has prepared the (draft) Network Code on High-Voltage Direct Current Connections and DC-Connected Power Park Modules (NC HVDC) [D]. Once the public consultation stage is completed, the NC HVDC will be in the comitology for adoption by the European TSOs.

Based on earlier draft versions of the aforementioned Network Code and on various published material, ENTSO-E has a vision for the potential EHV offshore

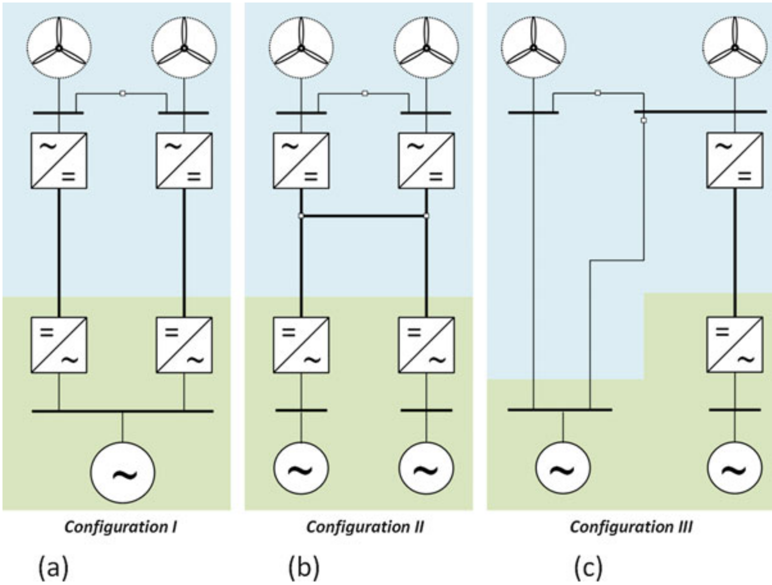



**Fig. 29.39** ENTSO-E categorization of offshore grid connection systems with HVDC

grid connection topologies, which are categorized into six fundamental AC, DC, and hybrid EHV configurations. Those within the scope of this section (HVDC connection and AC collection) are:

I. DC connection to single onshore point with AC collection: One or more offshore WPPs interconnected through an offshore AC collector system, which is connected to the mainland grid through one or more DC connections. This is illustrated in Fig. 29.39a.
II. Meshed multiterminal DC connection with AC collection: A number of offshore WPPs are interconnected through an offshore AC collector system, which is connected to the mainland grid through multiple DC connections (may be combined in a multiterminal system) at two or more grid interconnection locations. This is illustrated in Fig. 29.39b.
III. Meshed hybrid AC/DC connections with AC collection: A number of offshore WPPs are interconnected through an offshore AC collector system, which is connected to the mainland grid through AC and DC connections at two or more grid interconnection locations. This is illustrated in Fig. 29.39c.

Modern wind turbines utilize power electronic converters, which can be fully converter-interfaced or doubly fed (induction) generators. There are similarities between technical requirements to and controllability of the HVDC converter stations and those of the converter-interfaced/converter-controlled wind turbines:

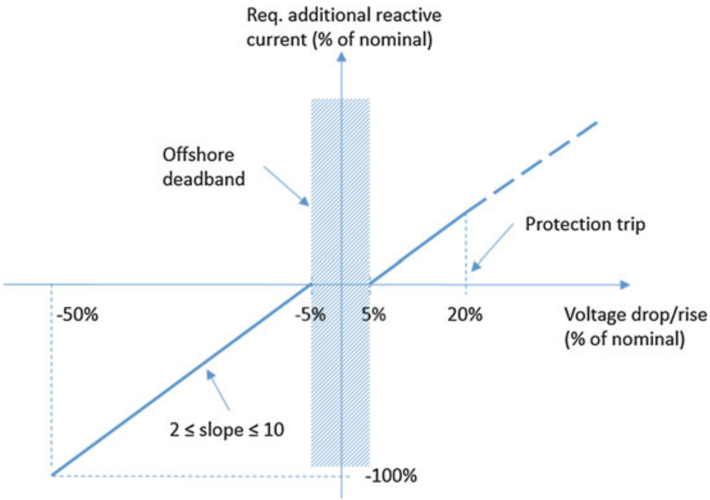



**Fig. 29.40** Principle of the voltage support through each generating unit during grid failures. (Source: TenneT Germany)

- The technical requirements refer to the AC connection points of the HVDC connections and of the wind turbines. Usually, this is interpreted as the connection point in substations of the AC transmission systems.
- Frequency stability: capacity to control the active power within a specified range and specific set point in response to system frequency changes.
- Voltage stability: capacity to control the reactive power within a specified range and set point in response to voltage changes.
- Robustness: capability to maintain connection, exchange of active power with the AC system with no reduction, and the required PQ-chart, as long as voltage and frequency are within requested admission ranges.
- Low-voltage ride through (LVRT): avoid tripping from the grid during short circuit conditions in the AC transmission system, when voltage and frequency remain within specified ranges over specified periods. In LVRT conditions, either reactive current provision to support the voltage recovery or active current provision to support the frequency stability can be requested as the highest priority. Figure 29.40 illustrates the principle of voltage support through reactive current provision from electricity-producing wind turbines.

It should be underlined that similar and often redundant requirements are specified for both wind turbines and for HVDC hubs. For example, the requirement of LVRT and reactive current provision during and after short circuits will apply to both wind turbines and to the offshore HVDC converter as they both need to access the same offshore AC network of the relevant TSO.

Lack of coordination between the technical requirements may potentially lead to oversizing of equipment and implementation of redundant control systems. Several measures are proposed to optimize and harmonize the design requirements and controllability of the offshore system components. Such measures should result in cost-efficient and technically optimized solutions, which also consider the risk of control system hunting and network instability. Among the proposed measures are:

- HVDC converter stations will most likely have LVRT capability and sufficient controllability to support voltage and reactive power. The voltage and reactive power control may be shared and optimized between the HVDC hubs and the offshore wind turbines within the same AC collector network. When possible, control efforts of the wind turbines may be reduced in order to avoid unnecessary oversizing of the equipment and control.
- Wind turbines may be requested to control the MVAC network voltage instead of delivering the power factor control, including during no-wind conditions. This may reduce the control efforts and avoid potential oversizing of the HVDC hubs as well as avoiding the need for additional reactive compensation equipment in the AC collector substations.
- Utilize voltage control with variable set points to optimize the control and reduce power losses in the AC collector network.
- Coordinated voltage control between HVDC and OWPP using voltage/reactive power droops.
- Coordinated and harmonized settings of LVRT, e.g., applied voltage versus time profiles. The HVDC hub and the wind turbines stay grid-connected as long as necessary, and tripping sequence is coordinated (the hub does not trip before wind turbines).
- Attenuation of fast oscillations. Coordination of control loop timing constants to avoid hunting or interactions between different systems.
- Demonstration and testing programs to validate the correct operation of complex systems.

Such measures will require an integrated design and control philosophy to be developed and formalized between the TSO and the OWPP operator.

### 29.6.3 Power Quality

An important part of every transmission system operator's (TSO) mission is to provide and maintain a high quality of electricity supply to its customers. Good power quality is an essential part of efficient and reliable operation of equipment. Power disturbances such as transients and harmonics can destroy or shorten the lifetime of sensitive equipment resulting in expensive downtime, extra maintenance, and loss of revenue.

The different power quality issues to be managed in the design of the offshore network of an HVDC-connected WPP are quite similar to the offshore network of an AC-connected one. In this section some HVDC-connected issues are highlighted.

Some of the known potential issues are the following:

- Voltage variations
  Unlike the situation with AC-connected WPPs in which any changes to PCC voltage are propagated to the collector system instantaneously, the collector system of a DC-connected WPP is less susceptible to voltage variation at the PCC due to the dynamic voltage control functionality of HVDC converters.

  A number of methodologies have been proposed to minimize or mitigate voltage fluctuation. Some of these include:
  - Modified back-to-back converter control systems of the wind turbines
  - Use of STATCOMs or SVCs
  - Application of local voltage control mechanism
  - Limiting inrush currents (transformer energization or MSC energization)
  - Controlled energization (at lower voltage)
  - Coordinating switching operations

  The first two mitigation methodologies are primarily applicable to AC-connected WPPs. However in HVDC-connected WPPs, these functionalities can be incorporated into the HVDC control. In this way an HVDC-connected transmission system has a positive impact on systems design from the point of view of voltage variation.
- Resonance
  The extensive use of long HV and MV cables makes the offshore network prone to resonances. Furthermore, the possibility of a great number of steady-state switching configurations (especially when considering AC interconnection of two HVDC converter platforms) as well as the fact that the resonant frequencies may significantly shift depending on the number of cables and wind turbines in service aggravate and add complexity to the resonance phenomena in offshore networks. Therefore harmonic studies should be carried out at the earliest possible stage in the project.

  Mitigation of resonances with filters adds complexity and platform space costs. Low harmonic emission converter technologies should be considered for the HVDC transmission (i.e., VSC-based HVDC multilevel converters) and for the wind turbine converters as well, in order to minimize or eliminate the use of passive filters.
- Power quality measurement
  Power quality (PQ) measurement has become a major concern in the field of power generation and distribution both for transmission system and WPP operators.

  Potential stability and quality of supply issues can occur due to interactions. These problems can be caused by interactions between the controls of the HVDC converter and the connected wind turbines with their power electronic converters. They could also be caused by a high level of AC system distortion due to the harmonic emissions in combination with resonant frequencies in the AC system and fast transients. These problems may potentially occur for all offshore clusters with HVDC connections and offshore WPPs which are equipped with a large number of power electronics.

If PQ problems (e.g., harmonics, voltage distortion, flicker, fast transients, etc.) occur during the WPP operation, protection trips may lead to undesired disconnection of wind turbines or even the whole WPP. This may lead to extensive costs related to loss of power infeed.

In the case that the WPP operator is responsible for the PQ problems, a fast detection is essential to solve the problems and restore power as fast as possible. The most efficient way to speed up fault detection is to install PQ measurements at all MV cable feeding strings in addition to the measurements at the PCC. However, if the PQ measurements are only located at the HV side of the WPP transformer, the fault detection procedure and the related costs due to lost infeed can rise very quickly. If the PQ problems also affect the neighboring WPP, legal claims cannot be excluded.

To comply with the requirements of the TSO and to bring the WPP operator into the position to be informed about, react to, and solve electrical PQ problems, an evaluation of this should be made.

For assessment of these kinds of power quality problems, very detailed models of the WTG including the real controller code of the frequency converters are required. Additionally, studies require accurate component models (transformers, cables, etc.) up to a high frequency range.

- Transients

  In general, electromagnetic transients are either caused by a planned operating procedure or by a random event. Typical planned operating procedures are switching feeders on/off, energizing or de-energizing equipment, etc. Some of the random events are an equipment insulation failure with a short circuit established either between phases or by contact of any phase with ground.

  Transient properties are determined by many factors including collector system topology, cross section and length of cable feeders, type and size of compensation equipment if any, electrical characteristics of the power transformers, type and characteristics of circuit breakers, type and electrical characteristics of the transmission technology applied as an interface with the onshore grid, earthing methods, etc.

  These transients are well known and the methods of their analysis are well established. Typically, these analyses are done by computer modeling and simulation.

  In case of DC transmission, analyses and simulation of transients are likely to be more complex than in AC transmission. The main reason lies in the fact that DC transmission is a rather complex system functioning based on a specific equipment and specific set of controls. Malfunctioning of any of the two converters by itself would cause a certain transient and most likely would be followed by a shutdown of the entire system.

- Flicker

  One of the fundamental differences between a WPP connected with AC and one connected with HVDC transmission systems is that the latter are decoupled from the grid, whereas the former are directly coupled to the grid. This combined with the higher voltage connection typical of HVDC means that flicker is not really a problem.

## 29.6.4 Technical Studies

The studies required for AC-connected wind farms are detailed in Sect. 29.2.11.

Moreover, apart from the abovementioned studies, a group of investigations should be specially considered in case of DC connections, among them are:

- Offshore power transformer energization study, which investigates significant inrush current in relation to limited overcurrent capability of the VSC-based HVDC valves.
- Emergency power auxiliary diesel generator design and sizing
- Control system interactions study – this should assess in depth the applied control systems of the HVDC connector and those of the OWPP. Undesirable interactions may, for example, be expressed in hunting phenomena such as fast-acting control systems controlling the same electrical quantity. This is in most cases either voltage or current and may potentially jeopardize the entire system stability. This study requires detailed knowledge of the applied control systems. The goal is to avoid and efficiently eliminate such conflicts by coordinating the relevant controls, e.g., using droop, master-slave, or fast-slow control strategies in order to avoid control systems counteracting each other.

## 29.6.5 Protection, Control, and Communications

### 29.6.5.1 General Protection Philosophy

**Fault Levels**

Where the OWPP is directly connected to the AC grid, the fault levels are mainly affected by the short circuit contributions of the upstream grid. However when the AC collector systems are associated with an HVDC transmission technology, things are different. Principally the contribution from the upstream power network represented by the HVDC converters can vary between 0 and 1.2 pu of the load current, depending on the HVDC technology and control system philosophy. Therefore, for AC collector systems connected to the grid through an HVDC system, the fault level will be significantly lower than if directly connected to the AC grid, and hence, differentiating between a fault and heavy load condition becomes a challenge.

From studies reported in CIGRE Brochure 612, it is noted that the short circuit current at the HV busbars in the case of a HVDC-connected substation could be in the range of 10–15% of the typical short circuit levels experienced by the AC grid-connected substations. The steady-state short circuit fault levels on the inter-array section of the AC collector could be between 20% and 35% less for an HVDC-connected wind power plant as compared to the case of an AC grid-connected wind power plant. Furthermore, with HVDC-connected wind farms, the islanded condition is more important, and this must be considered with only the diesel generator connected being the most onerous condition for the protection. These considerations will lead to the need for overcurrent relays with switchable settings to suit the operating condition. In addition, more use of negative sequence protection, voltage controlled overcurrent, and distance protection on the array feeders at the substation end and possibly the use of differential protection on the array cables (with the consequent increase in cost) may be needed.

**Control and Protection Systems: The Future Scenario**
With the growing share of offshore WPPs in the future energy production in Europe, it becomes more important to implement intelligent and coordinated control and protection schemes, which ensure a high reliability of the whole system to avoid outages of a considerable amount of power generation at once. The most important features of such schemes could be:

- High degree of selectivity of protection in the offshore HV grid and the inner WF array (e.g., by use of differential relays)
- Partly redundant cable connections in the inner WPP array (loop connections) and the HV offshore grid (e.g., cable connections between different offshore AC substations)
- Automated control in the offshore grid and WPPs, to allow automatic switching sequences after equipment outages (e.g., cable failure with protection trip) to reduce downtime of healthy equipment and restore the maximum available power infeed in short term
- Control algorithms to allow the maximum power infeed considering equipment loading within system bottlenecks, e.g., during outage of transmission equipment (cable or transformer failure), possibly with real-time temperature monitoring to allow controlled temporary overloading

Such features could be part of future regulations to increase the offshore system reliability/availability and consequently contribute to enhanced overall power system stability. However care has to be exercised to avoid making the protection too complicated since this may lead to increased mal-operations. Moreover, the lifetime of secondary equipment is generally shorter than for the primary equipment, and hence, this equipment may potentially need replacement during the life of the WPP.

#### 29.6.5.2 SCADA and Communications

Fundamentally the SCADA and communication requirements are basically the same whether connected by AC or HVDC. These considerations are discussed in Sect. 29.5.4. Further detail can be obtained by reference to CIGRE Brochures 483 and 612.

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# Part F

# Secondary Systems

*John Finn, Ray Zhang, and Yang Ruoling*

# Secondary Systems: Introduction and Scope 30

John Finn and Adriaan Zomers

## Contents

30.1 Auxiliary Systems ........ 732
30.2 Protection ........ 732
30.3 Control and Automatic Switching ........ 732
30.4 Metering and Monitoring ........ 732
30.5 Communications ........ 733
30.6 Digital Equipment ........ 733
30.7 Equipment Considerations and Interfaces ........ 733
30.8 Management of Secondary Systems ........ 734
30.9 General Considerations and Requirements ........ 734
30.9.1 Secondary System Functions ........ 734
30.9.2 Economic Aspects ........ 737
30.9.3 Operational and Maintenance Requirements ........ 738
30.9.4 Environmental Requirements ........ 739
30.9.5 Use in Seismic Areas, Shocks, and Vibrations ........ 740
30.9.6 Electromagnetic Compatibility ........ 741
30.9.7 Ergonomic Requirements ........ 743

So far in this book we have concentrated on the primary plant which makes up a substation, whether it be air insulated, gas insulated, or mixed technology. However, without the secondary systems, the substation would simply be a store house of primary equipment. The secondary systems are the essential ingredients to protect,

Adriaan Zomers: deceased.

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

A. Zomers

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operate, and control the primary plant and the whole power system, which bring the substation to life.

In this chapter, the following systems and functions are described.

## 30.1 Auxiliary Systems

These consist of the low voltage AC and DC power supplies required to power all of the substation equipments. The LVAC supplies provide power for such things as the heating, lighting, battery chargers, transformer fans and pumps, while the DC supplies are used for the control and protection of the plant and the tripping of the circuit breakers to clear faults. These systems need careful design to ensure reliable operation of the substation and these are covered in ▶ Chap. 31.

## 30.2 Protection

Protection is essential to ensure that faults are detected and cleared discriminatively in a time which is fast enough to maintain power system stability and to minimize damage to plant. The different types of protection systems, including back up systems, are described in ▶ Chap. 32.

## 30.3 Control and Automatic Switching

In order to operate the substation effectively, a control system which indicates the status of all plant both locally and remotely, showing analogue values for the key parameters such as voltage, current, real power, and reactive power as well as providing digital outputs to close and open switchgear, raise and lower taps on transformers, etc., is required. In addition to the basic indications and controls, other functions such as synchronizing, voltage and/or reactive control, interlocking for both safety and operational reasons, load control to avoid frequency collapse, etc., may also be applied. Other functions such as automatic closing or reclosing to optimize the performance of the network may be needed and in some instances controlled switching, i.e., point on wave control of closing or opening certain plant such as reactors or capacitors, may be used to reduce switching transients on the network. These features are described in ▶ Chap. 33.

## 30.4 Metering and Monitoring

Metering can be largely divided into two categories: operational metering and settlement (or tariff) metering. The operational metering provides the measurement of analogue values such as voltage, current, frequency as well as active and reactive power for the purpose of system operations, while tariff metering is to ensure that the sale of electricity between different parties can be performed. These two categories of metering are normally provided by separate measurement transformers and subject to different legal and operational regulations. In addition to this, there are many other monitoring functions which may be applied to improve the performance of the system such as fault locators for overhead lines, fault recorders to give analogue traces of fault conditions to help in analysis of faults, and event recorders to understand the sequence of events upon the occurrence of faults. In addition to these functions, there is also the requirement for self-supervision of the devices, and specialized condition monitoring equipments to optimize maintenance and indicate incipient faults before they become full blown faults. Based on the measurement scanning frequency, these monitoring functions can be divided into three categories: plant performance monitoring, fault recording, and system dynamic monitoring, all of these aspects are described in ► Chap. 34.

## 30.5 Communications

The substation is part of an interconnected system for power system operations, and so there must be means of communicating to and from the substation. The types of information that need to be communicated are telephony for giving switching and permit information to the operators, data for providing the relevant information to the central control point and signaling to enable the correct operation of protection. The speed and security required for each of these functions may differ. The various aspects of substation communications are described in ► Chap. 35.

## 30.6 Digital Equipment

In recent years, virtually all secondary equipment has become digital. This has given rise to new problems with management of software and firmware as well as with interoperability, and this has led to the development of IEC61850. These issues are discussed in ► Chap. 36.

## 30.7 Equipment Considerations and Interfaces

► Chapter 37 discusses the specific requirements associated with the equipment, such as electrical parameters, ambient conditions, and housing and accessibility. This follows through to the substation layout and building civil requirements such as basements, false floors or ceilings, and trenches. The interface requirements between the secondary equipment and the primary equipment and specific requirements for such items as current transformers, voltage transformers, and circuit breakers and their connections are also discussed.

## 30.8 Management of Secondary Systems

Most people are aware of the significant asset management requirements of the primary aspects of a substation. However, effective management of the secondary systems is equally or even more important. One of the key issues is the lifetime of the secondary equipment which is usually less than half that of the primary equipment which immediately raises management issues for replacement. ► Chap. 38 takes the reader through the management aspects from the reliability, physical security requirements to maintenance and replacement. Other practical aspects such as wire and fiber identification and labeling and ensuring the security of electronic devices are discussed as well as the various tests on secondary equipment from type tests through factory acceptance tests to commissioning and maintenance tests including fault finding and recovery are also described.

## 30.9 General Considerations and Requirements

However, before going through all of the above aspects in some detail let us briefly review the general considerations and requirements related to secondary systems.

### 30.9.1 Secondary System Functions

Firstly, substation secondary systems consist of a number of subsystems as illustrated in Fig. 30.1. These can be categorized as follows.
Note: The system designations indicated in the [] brackets cross reference to the functional requirements and deployment shown in Fig. 30.1.

- **Protection schemes [P]**
  System protections [P1] (not shown in Fig. 30.1):
  - Wide area protection [P1.1]
  - Load shedding [P1.2 – activated at control center level]
  
  Substation protections [P2]:
  - Busbar protection (BBP) [P2.1]
  - Breaker failure protection (BFP) [P2.2]
  
  Bay protections [P3]:
  - Feeder (lines and cables) [P3.1]
  - Transformer and reactor bank [P3.2]
  - Bus-coupler/Bus-section [P3.3]
  - Shunt plant, e.g., capacitor banks, reactors [P3.4].
  - Series plant, e.g., series reactors, series capacitiors
  - SVCs or statcoms
- **Automation schemes [A]**
  Systems/network automation [A1]
  - System restoration [A1.1]

| Functions Designation | Function Importance | | | Range of Use | | | | Method of Realisation (Note 1) | | | | | | | | | | | | Place of Application | | | | Scope of Redundancy | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | Traditional Systems | | | | | | Numerical Systems | | | | | | | | | | | |
| | Extra high | High | Lower | Always | Usually | On request | Need extra analysis | Relays: Electro-mech, Electronic | | Conventional MMI | | Hardwired Circuits | | Relays | | Numerical IEDs | | Numerical related MMI | | Bay equipment/On site | Local/Substation | | Remote/RCC | Appropriate | Not necessary |
| | | | | | | | | b | c | b | c | b | c | b | c | b | c | b | c | | b | c | | | |
| P2.1 | X | | | X | Note 2 | | | | X | | | | | | | | X | | | | | X | | | X |
| P2.2 | | X | | X | | | | | | | | X | | | | | X | | | | | X | | | X |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| P3.1 | X | | | X | | | | X | | | | | | X | | | | | | | X | | | X | Note 3 |
| P3.2 | X | | | X | | | | X | | | | | | X | | | | | | | X | | | X | |
| P3.3 | X | | | X | | | | X | | | | | | X | | | | | | | X | | | X | |
| P3.4 | | X | | X | | | | X | | | | | | X | | | | | | | X | | | X | |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| A1.1 | | X | | | | | X | X | | | | | | | | | X | | | | | X | X | | X |
| A1.2 | | X | | | | X | | X | | | | | | | | | X | | | | | X | X | | X |
| A1.3 | | | X | | | X | | X | | | | | | | | | X | | | | | X | X | | X |
| A1.4 | | X | | | | | X | X | | | | | | | | | X | | | | | X | X | | X |
| A1.5 | | | X | | | | X | X | | | | | | | | | X | | | | | X | X | | X |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| A2.1 | | | X | | | X | | | | | | X | | | | | X | | | | | X | X | | X |
| A2.2 | | X | | | | X | | X | | | | | | | | | X | | | | | X | X | | X |
| A2.3 | | X | | X | | | | X | | | | | | | | | X | | | | | X | | | X |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| A3.1 | X | | | X | | | | X | | | | | | | | X | | | | | X | | | | X |
| A3.2 | X | | | X | | | | X | | | | | | | | X | | | | | X | | | | X |
| A3.3 | | X | | X | | | | X | | | | | | | | X | | | | X | X | | | | X |
| A3.4 | X | | | | | X | X | | | | | | | | | | X | | | | | X | X | | X |
| A3.5 | | X | | | X | | | X | | | | | | | | | X | | | | | X | X | | X |
| A3.6 | | X | | | X | | | X | | | | | | | | | X | | | | | X | X | | X |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| CO1 | X | | | X | | | | | | X | | | | | | X | | X | | X | X | X | X | | X |
| CO2 | X | | | X | | | | | | | | X | | | | X | | | | | X | | | | X |
| CO3 | X | | | X | | | | | | | | | X | | | | X | | | | | X | | | X |
| | | | | | | | | | | | | | | | | | | | | | | | | | |
| CM1 | | X | | X | | | | | | X | | | | | | X | | | X | | X | X | X | | X |
| CM2 | X | | | X | | | | | | X | X | | | | | X | | | X | | X | X | X* | | X |
| CM3 | | X | | X | | | | | | X | | | | | | X | | | X | | X | X | X* | | X |
| CM4 | | X | | | X | | | X | X | | | | | | | X | X | | | | X | X | X | | X |
| CM5 | | | X | | | X | | | | | X | | | | | X | | | X | | | X | X | | X |
| CM6 | | X | | | X | | | | | | | X | | | | X | | | X | | X | | X | | X |
| CM7 | | X | | | X | | | X | | | | | | X | | | | | | | X | | | | X |
| CM8 | | X | | | X | | | X | | | | | | X | | | | | | | X | | | | X |

Notes: 1. The b, c designations indicate whether realization is in bay or control room related equipment.

2. Excluding ring type busbar arrangements.

3. Main protection recommended; back-up optional

*4. The volume of items in RCC usually reduced.

**Fig. 30.1** Functional requirements and deployment of substation secondary systems: protection, automation, and control

  - Load shedding (frequency and/or voltage control) [A1.2]
  - Ripple control (scheduled time order instruction) [A1.3]
  - Network splitting (islanding) [A1.4]
  - Load restoration (after ripple control or load shedding) [A1.5]

  Substation automation [A2]
  - Sequential switching [A2.1]
  - Automatic Switching including load transfer for transformers, switching-in of hot stand-by transformers [A2.2]
  - Control of parallel operation of transformers [A2.3]

  Bay automation [A3]
  - Auto-reclosing [A3.1]
  - Synchronization [A3.2]
  - Tap-changer control (voltage regulation) [A3.3]
  - Change of relay setting [A3.4]
  - Capacitor bank control [A3.5]
  - Reactor bank control [A3.6]
- **Control/operation [CO]**
  - Operating (switch-on, switch-off, tap change, etc.) [CO1]
  - Bay interlocking [CO2]
  - Substation interlocking [CO3]
- **Control/Indications [CM]**
  - Position (status) indications [CM1]
  - Alarms and annunciations [CM2]
  - Measurement/load monitoring – I, U, P, Q, t, f, synchronizing [CM3]
  - Metering (energy measurement) [CM4]
  - Reports [CM5]
  - Event recording [CM6]
  - Disturbance recording [CM7]
  - Fault location [CM8]
- **AC and DC auxiliaries**
- **Fire-fighting**
- **Heating, ventilation, and air conditioning (HVAC)**

Each of the above subsystems is interconnected with wiring/cabling. Secondary system functions are not necessarily associated with physically discrete pieces of equipment.

The functional requirements of the secondary subsystems (protection, automation, and control), as illustrated in Fig. 30.1 can, also be categorized by way of:

- Grade of functions
- Range of use (always, usually, on request, needs extra analysis)
- Method of application (conventional, computer based)
- Place of application (equipment – on site, bay substation, remote control center – RCC)

- Scope of redundancy requirements (essential appropriate, recommended, not necessary)

Tasks of AC and DC auxiliary subsystems (See ▶ Chap. 31):
- Generation, conversion, transmission, supply to power substation equipment

Tasks of fire-fighting subsystem:
- Fire detection
- Fire extinguishing

Air conditioning/ventilation
- Required by indoor equipment and/or human requirements

### 30.9.2 Economic Aspects

Economic considerations are very important in relation to secondary systems. To get the total life cycle cost of a secondary system, the following component parts have to be summated:

- Initial investment costs including design, equipment, installation, and commissioning costs
- Cost of operation, maintenance
- Cost of postdelivery support and repair
- Cost of personnel training
- Cost of extending the system at a later date

For secondary systems, it is recommended that a standard configuration be developed with detailed specifications for the different functions and for all important system parameters and interfaces. The benefits for the user are obvious:

- Less engineering for substation design
- Use of CAD
- Shorter erection and commissioning times
- Easier maintenance, repair, and extension
- Less spare parts to be stored
- Less errors/risks
- Better control of system costs

Today's secondary systems have to be evaluated from a completely different economic perspective to the conventional ones of the past. A shorter life cycle – of the order of 10/15 years as compared to the 30/35 year life cycle of previous "conventional" systems – combined with rapidly changing technology mean that complete replacement of the secondary system hardware has to be considered at shorter intervals.

The architecture of the system including precisely defined and coordinated interfaces plays an important role and can have a significant influence on the economic assessment. The flexibility of software and its customization to the user's requirements makes estimating cost difficult; to a large extent these requirements are interdependent. The only way to achieve acceptable costs of software is to use standardized products. Software cost estimates must still be approached with caution.

The major economic consideration in relation to the application of digital control systems is the issue of the shortened life cycle.

The need to replace systems after a 10/15-year life span with the consequent cost implications together with the outage time for installation and testing is still presenting problems to many utilities.

### 30.9.3 Operational and Maintenance Requirements

The important operational and maintenance requirements are listed below:

- Safety of personnel and security of operational functions
- Speed, selectivity, and sensitivity of operation (e.g., protection equipment)
- Reliability/availability
- Meet environmental conditions
- Long life time
- Easy to isolate
- Easy to operate
- Easy to maintain
- Easy to repair
- Easy to get spare parts (over the life time of the system)
- Easy to extend (over the life time of the system)
- Easy on-site testing

The older conventional secondary equipment had high quality standards. It met functional requirements, was reliable, and had a simple structure and a long life expectancy. Periodic tests on control and protection equipment in a defined sequence could verify reliability of function.

Today's new technology should at least match the operational requirements of conventional equipment, i.e., not show any disadvantage. However, the additional features are welcome such as higher flexibility and the possibility of achieving more intelligent decisions at all hierarchical levels in response to operation or network disturbance.

As regards maintenance effort, the availability of self-check (self-supervision) facilities (on-line diagnosis for hard and software) should lead to less preventive maintenance work and favors predictive maintenance. Periodic tests will decrease due to improved system reliability. Consequently, maintenance intervals are expected to increase.

Defective components (cards) can easily be changed by the maintenance staff, but in this new technology test equipment is needed to monitor the security functions (interlocking) without interruption of operation. However, the maintenance staff now need more knowledge and skills to deal with these modern multifunction relays.

#### 30.9.3.1 Influence of System Architecture

Decentralized architecture operating on the bay level tends to be the favored solution today. This means that control and protection functions have to be implemented at bay level as well as data integrity. The central processor unit performs data registration and evaluation, event monitoring, and facilitates remote control coupling.

In GIS and small substations, architecture at bay level is usually implemented in a central control building; large plants favor additional relay kiosks located in the HV-plant bays. It does not seem to be possible to operate the sensitive digital equipment mounted in traditional noninsulated kiosks as used for conventional secondary equipments mainly because of temperature and humidity problems. The ambient temperature has a remarkable influence on the life span and the failure behavior of digital equipment. A 10 °C rise in temperature can double the frequency of component malfunction. To ensure high availability of the equipment, the average temperature at the installation site should therefore be kept low.

The advantages of a decentralized architecture are obvious:

- Independent items at bay level
- Limited influence of central processor unit outage

#### 30.9.3.2 Organization/Training

The organizational arrangement of operation and maintenance functions is structured differently for different utilities. However, the arrangements as they were for conventional equipment may not always suit the requirements of the digital technology. Applications which were traditionally functionally separate are now integrated into the same item of electronic hardware. This has had implications for organizational structures and for staff training.

### 30.9.4 Environmental Requirements

Different environmental conditions can affect the ratings and the performance of electrical plant and equipment. Accurate knowledge of the environmental factors involved is particularly important for designers and suppliers of substations.

**Climatic Conditions Are the Most Important of the Many Environmental Influences**

Climate, as a factor affecting the performance of electrical equipment, is the main physical and chemical condition of the atmosphere in the open air or indoors, including daily and seasonal changes.

Climate thus involves natural factors such as air pressure, temperature, temperature variations, humidity, etc., as well as environmental effects such as pollution by dust, salts, and gases. The two factors must never be treated separately since as far as technical equipment is concerned, they usually appear in combination.

The basic natural climatic components are air temperature and air humidity. However, to determine the overall effect of climatic stresses, additional components such as daily and seasonal temperature changes, site altitude, and, in some cases, direct solar radiation, precipitation, thunderstorms, and wind must be taken into consideration. In addition to natural and civilization-related climatic parameters, various other environmental factors may have an important influence. These may include adverse soil conditions, the effects of flora and fauna, risk of seismic activity, etc.

For more details on climatic aspects, please refer to CIGRE Technical Brochure 88.

### 30.9.5 Use in Seismic Areas, Shocks, and Vibrations

Horizontal and vertical forces transmitted to the support structures by the ground during earthquake may cause extremely high mechanical stresses to all substation components. The risk of unwanted switching operations exists as the result of acceleration forces developed in switchgear and/or electrical relays.

The components of a secondary system have to be capable of proper operation during and after earthquakes. In regions with seismic activity, special measures are necessary to ensure proper operation.

Users of substations should provide information to the manufacturer that will adequately describe the seismic environment that the equipment will be expected to withstand. Any condition that may be of consequence during a seismic event should be described.

Characteristics of the expected earthquakes in a certain area can be obtained from recorded earthquakes in the past. Seismic zone maps are readily available, for all regions of the world.

The following earthquake characteristics are of major concern:

- Maximum acceleration (horizontal and vertical)
- Frequency spectrum
- Duration

The components or systems are divided into Class A and Class B:

- Class A: Any component or system whose failure, malfunction, or need for repair prevents the proper operation of the substation during or after the design earthquake.

- Class B: Any component or system whose failure, malfunction, or need for repair does not prevent the operation of the substation during or after the design earthquake.

Please refer to Brochure 88 for more details.

### 30.9.6 Electromagnetic Compatibility

Electromagnetic interference due to different noise sources in AIS and GIS may cause maloperation or even damage to the equipment. In the past, this subject has created much interest in CIGRE, IEC, and national working groups. Various specifications have been developed.

Today, the noise sources and the coupling mechanisms are well understood for AIS but less so for GIS.

The problem of EMC can be considered in three parts:

- To define the level of transient overvoltage at the terminations of secondary equipment
- To define the withstand capability of the secondary equipment and provide recommendations for test requirements
- To give recommendations for the complete layout of secondary circuits, including the earthing system in order to reduce the influence of transient overvoltages on secondary equipment

In existing specifications, it is common practice to divide substation secondary equipment into several classifications according to the amplitude of the interference signals to be expected. Classes are typically separated into severe categories, where the equipment is situated close to the switchgear and low level classes where the equipment is situated within control and equipment rooms and separated by a certain distance from the HV-equipment.

These classifications are not relevant in the case of GIS installations where the control room can be in the same building as the HV equipment. If atmospheric discharges are regarded as significant noise sources in an AIS, the resulting levels of transient overvoltages in the control room are comparable to those values observed in the control cubicles of GIS switchgear.

For GIS, only one value for the withstand capability of secondary equipment is recommended.

#### 30.9.6.1 Noise Sources in AIS and GIS

Noise sources in AIS and GIS causing transient overvoltages in secondary systems are:

- Switching in primary circuits – disconnectors or circuit breakers
- Atmospheric events – lightning strokes
- On-site tests – using impulse waveforms

- Earth faults – from switching overvoltages
- Switching in secondary circuits – de-energizing inductive loads
- Electrostatic discharge – from electrostatically charged people
- Radio transmitters (walkie-talkies) – high frequency field from devices

The noise sources mentioned affect the secondary circuits. One has to distinguish between interference by conductive (direct) inductive and capacitive coupling on the one hand (guided waves) and interference by radiated waves (interference fields) on the other hand. The influence of radiated waves on secondary circuits which act as an antenna becomes significant for high frequency events in the MHz-range.

Transient overvoltages in secondary system exist in the frequency range of about 100 kHz–100 MHz in GIS and of about 100 kHz–10 MHz in AIS.

Lightning strikes, switching of disconnectors in AIS, and switching in secondary systems generate transient overvoltage in the frequency range of up to 10 MHz.

As a result of disconnector switching in GIS and of flashovers due to site tests, very fast transient overvoltages with high steepness can be produced. In 123 kV GIS, the shortest front time of the first impulse of a VFT is of the order of 3–5 ns. This steep impulse can generate oscillations of up to 100 MHz in the secondary parts of CTs and VTs.

Transient overvoltage with frequencies of more than 50 MHz (up to 200 MHz) can be measured, superimposed on dominant voltages with frequencies up to 50 MHz. The amplitudes of the superimposed voltages normally are less than 20% of the dominant voltages.

More details concerning EMC are provided in Brochure 88; however, the main recommendations for minimizing the effects of EMC are detailed in the next subsection.

#### 30.9.6.2 Recommendations on How to Minimize EMC Problems

The most important measures to reduce the effects are:

- Exclusive adoption of screened secondary cables, if necessary with special screen construction; generally, it is advantageous to earth the screen at both ends
- Earthing conductors that are laid in parallel to cables in trenches to reduce screen current and to couple inductively the secondary system and the earthing system

**Additional measures specifically relating to GIS:**

- Connection of reinforcement steel to the earthing system at various points, especially in the floor
- Good screening at the GIS/air bushings by multiple connection between enclosure and wall (reinforcement, metallic wall) and additionally multiple connections between wall and earthing grid at ground level

- Galvanic connections between HV cable screens and GIS enclosure, if only single point earthing for the screens is allowed leave opposite end open
- Adequate design and test of secondary equipment in relation to amplitude, frequency, and energy content of interference stresses

### 30.9.7 Ergonomic Requirements

Conventional mimic diagrams as previously applied in substations have the advantage of good comprehensibility but from a technical point of view are not necessary when using digital control equipment. With digital systems, visual displays are usually used even in the case of large and complex substations. The technology of visual display units is continually undergoing development.

To maintain a reasonable legibility, it is necessary to limit the information presented on the visual display. Considerations of legibility dictate that the degree of filling of the screen should not exceed about 6%. On the other hand, this requirement may conflict with the desirability of minimizing the number of process displays.

A careful balance has to be struck. The way in which the information is presented on the display should meet certain ergonomic requirements. In fact, the design of Human-Machine Interfaces (HMI) requires a multidisciplinary approach because of its technical, ergonomic, and psychological aspects. The interface has to be designed in such a way that operator actions are minimized and that only relevant data is presented.

To meet ergonomic requirements, the arrangement and design of the system have to be adapted to match human capabilities:

- Information on displays or screen must be easily visible (readability) and logically classified (shape, color)
- Indication symbols and colors should follow the relevant national or international standards
- Screens, displays, and/or operation panel must be arranged properly for the operator to allow easy operation
- Rapid system response after operator action is necessary
- Ambience (light, temperature, humidity) should be comfortable

It may be advantageous to implement a preprogrammed test procedure and to standardize switching sequences (e.g., change of busbars) for operations, thereby providing support for the operator and minimizing the opportunities for operator error.

# Substation Auxiliary Systems

# 31

Mick Mackey

## Contents

31.1 Low-Voltage AC System ........ 745
31.2 Secure AC Auxiliary Supply Systems and Emergency Generation ........ 746
31.3 Batteries and DC Supply Systems ........ 747
31.4 Power System Interruption and "Black Start" Requirements ........ 752

Substation secondary equipment provides the interface to facilitate functional control, protection, and supervision of the primary plant and indeed the overall power system network. The auxiliary power supplies are sourced from the AC network and distributed as required:

- To AC loads over the substation low-voltage AC network
- Following rectification, to DC loads over the DC network

Both the AC and DC auxiliary systems should be designed to meet the immediate demand and likely future extension.

## 31.1 Low-Voltage AC System

AC substation supplies can be provided from a house transformer taking supply from the bulk supply or the tertiary of the inter-bus transformers or alternatively from the local distribution network operator (DNO). The possible need for a voltage stabilizer arises where supply is taken off the tertiary of an inter-bus transformer.

To cater for a total failure of auxiliary AC supply, diesel generators are provided in critical substations. These can either be permanent installations or a mobile unit.

M. Mackey (✉)
Power System Consultant Section, Dublin, Ireland
e-mail: mj.mackey@live.com

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In either case, they connect to the essential services board and also may provide some AC supplies that are required during erection and commissioning.

Both the active (kW) and reactive (kVAR) loads to be supplied must be established. This is particularly important when sizing the emergency generator.

Typically the supply is 400 V three phase. The acceptable tolerances are in the range $\pm 10\%$. The incoming supplies terminate on switchboards. Usually they consist of two – a general supply board and an essential supply board. The essential loads consist of:

- Battery charger
- Emergency lighting
- Switchgear operating mechanisms
- Tap-changer drives
- Numerical control/supervision equipment (where such equipment is AC supplied)
- Equipment heaters
- Fire services

All other services are supplied from the general services board. Typically these include transformer pump/fan drives, general services such as power sockets, air conditioning, ventilation, and general lighting.

All incomer feeds and outlets are arranged as radial circuits and are equipped with suitably rated miniature circuit breakers (MCB), molded case circuit breakers, and isolating links.

The design and construction of the AC system switchboard have a significant impact on the overall ability of the auxiliary power supplies. The following need to be considered when assessing potential failure modes:

- Number of busbar sections
- Position of standby supply incomer relative to the normal infeeds
- Bus section or interconnector
- Automation

In general the layout of AC distribution boards and associated incoming and outgoing cables should be arranged to maximize supply security and if deemed necessary duplicate supplies to each essential load.

## 31.2 Secure AC Auxiliary Supply Systems and Emergency Generation

The operational security of transmission substations is paramount and depends on the availability of auxiliary supplies. All auxiliary supplies in a substation are derived from a local AC source. These can be obtained either from:

- The main inter-bus transformers via either a step-down transformer or from a tertiary winding
- Incoming locally sourced AC supply (i.e., from the local distribution network operator) (DNO))

Both approaches have the disadvantage that a serious substation incident (e.g., transformer or major bus fault) or in the latter case a loss of the incoming distribution supply will result in a station totally dependent on the DC supply in standby mode. Two approaches are often considered to improve supply security.

- The two incoming supplies are sourced from different sectors of the distribution network. A changeover mechanism is provided to ensure that one of the incoming circuits is always connected to the AC distribution board. The changeover can be manual or automatic. To avoid inadvertent paralleling of the distribution supplies, the changeover action is interlocked so that only one supply can be connected at any time.
- The substation is equipped with a local generator, typically diesel or gas fired. This should be adequately rated to supply the essential services board. The diesel generator should be able to accept large block loads without stalling. Typically a diesel generator will only start against about 60% rated load, which may mean oversizing the generator or applying a sequencing system to the load application. The start-up and load transfer to the local generator should proceed automatically but interlocked to prevent inadvertent paralleling with other incoming supply sources.

Economic considerations of the relative importance of the substation influence the decision on the necessity for a diesel unit.

Power cables should be arranged to facilitate construction, testing, and maintenance and also to avoid common mode failures, e.g., due to a fire in a cable duct or tunnel. Incoming supplies should be segregated in different cable routes and/or ducts. Furthermore, power cables should be segregated from control cables. See also ► Sect. 37.4 in relation to cable installation.

## 31.3 Batteries and DC Supply Systems

The safety/security regulations and standards relating to the design, installation, and maintenance of battery systems vary between national jurisdictions. Prior to the design of the installation, familiarity should be gained with the issues involved and the particular regulations applying.

One of the most important loads on the AC supply is the battery charging system. The charger, depending on the required rating, may require a single- or three-phase supply. It should take its supply from the essential AC distribution board.

Substation secondary equipment must be powered by sources which are not subject to interruption at times of AC power faults. This requirement is met by the use of battery systems kept in a fully charged condition by battery chargers supplied from the AC network. Inverter systems operating from a battery give the same high level of security to equipment powered by AC.

Batteries constitute a relatively low-cost item in a substation but are key to successful plant performance as all protection, control, and supervision functions depend on the DC supply. Batteries are selected for essential operations (closing, tripping, protection, etc.) to ensure continuity in the event of AC supply failure. Also much of the normal load in a modern substation consists of supplying the power supply units in numerical relays and other numerical control/supervisory equipment.

Direct current delivered by a charger is obtained by rectification of an LVAC supply. Normally the battery takes a trickle charge from the charger which maintains it in a fully charged state. This rectified current contains AC components of different frequencies (50 or 60 Hz and harmonics). These components must be filtered by the rectifier to obtain levels (1% or less) compatible with the design specifications of secondary equipment. Furthermore, the life expectancy of a battery may be reduced if the rectified AC current component level is significant. This is one of the contributory factors to the reduction of the battery capacity.

The charger output, battery, and DC load are all connected in parallel. The charger output rating must be capable in the event of a battery discharge of:

- Supplying the normal continuous DC loads
- Recharging the battery

Effectively this ensures that under normal conditions, the charger supplies the normal DC load and the battery is available to provide peaking capacity or back up in the event of AC system failure. The latter is called *standby* mode. The standby period is determined by the particular requirement, but a typical value would be 6–10 h as this should give sufficient time for restoration from an AC supply failure. In substations not equipped with a standby generator, some utilities specify a much longer period of 12–20 h. Obviously, the standby period is critical when specifying the battery. The longer the period, the larger and more expensive will be the installation. The battery system should allow not only for immediate requirements but also for likely substation extension.

Nominal battery bank voltages in substations are typically 24 V, 30 V, 48 V, 60 V, 110 V, 125 V, and 220 V.

As well as the capacity to provide the standby load, batteries must also be capable of supplying very high short-duration demand as may occur, for instance, during multiple tripping following a busbar fault, at the end of its standby period. This means that to meet the required nominal voltage at equipment, the actual battery and charger output voltage may typically be 10–12% higher, e.g., it may be necessary to operate a 110 V battery at about 125 V.

While a single battery (e.g., 110 V) may be adequate on substations having a small physical footprint (110 kV or lower) where long control cable runs are required, two batteries are the norm, e.g., 220 V being applied for control and protection functions with a lower voltage such as 24 V or 48 V selected for alarm/

supervision. Furthermore, in AIS substations of 400 kV and above, it is usual to use distributed battery systems on a bay-by-bay basis. This is because of the enormous voltage drops if a centralized battery is used. Whether for control or supervision when selecting the battery voltage, the following must be considered:

- Power requirements of the connected equipment
- Voltage drop between battery location and connected equipment
- Availability of standby AC generator

Addressing these requirements determines the following:

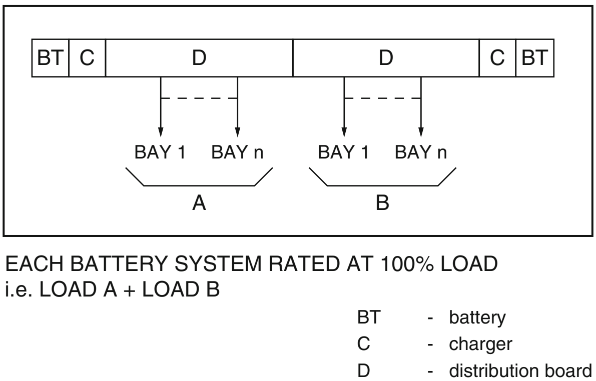
- Battery type
- Standby period
- Boost charging requirement
- Cable cross section
- Cable routing from battery to equipment

For important substations, typically 220 kV and higher, duplicate battery systems for the important control functions are frequently employed. This may simply consist of a second battery-charger system as a backup but more typically entails segregated circuitry to power duplicated functions such as protection systems and tripping circuits. For duplicated systems in EHV substations where the battery systems are deployed on a bay-by-bay basis, the second supply may be taken from an adjacent bay or a central backup or both. Furthermore, to allow for future extensions, the system should be capable of extension without requiring a DC shutdown. Various DC arrangements are illustrated in Figs. 31.1, 31.2, and 31.3

Batteries usually used in substations are of the lead-acid or nickel-cadmium type, the former being the most common. The advantages/disadvantages of the two types can be summarized as follows.

While more expensive, nickel-cadmium is more robust in terms of vibration sensitivity and if left discharged over long periods. They are suitable for higher

**Fig. 31.1** Example of substation with central DC system with duplicate batteries and chargers



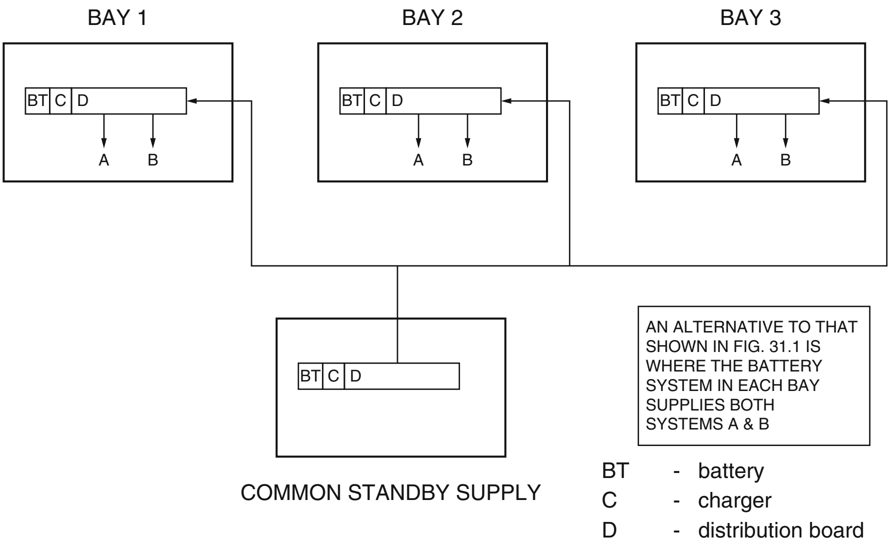



**Fig. 31.2** Example of distributed DC systems with central backup

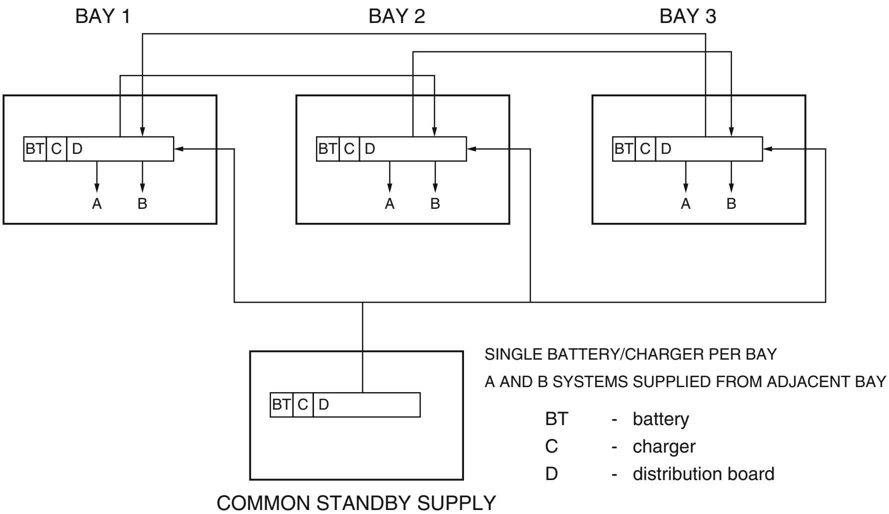



**Fig. 31.3** Example of distributed DC systems with interconnected and central backup

ambient temperatures, are more compact as they have a higher energy density, and are more suitable for higher discharge rates. Their expected lifetime is 25 years.

The flat-plate lead-acid type with a lifespan of about 12–15 years is most commonly used for substation application (with proper maintenance even longer lifespans can be expected). In the past, it also had some additional disadvantages:

water loss and flammable gas emission necessitating maintenance (water top-up) and special room isolated from electrical equipment to avoid the risk of explosion/fire. However, modern lead-acid designs consist of sealed gas recombining cells incorporating electrochemical features to facilitate recombination of any gases produced during charging, so there is neither water loss nor gas emission. This reduces the explosion/fire risk, removes the need for specially ventilated rooms and permits location adjacent to electrical and electronic equipment. A related advantage over the old conventional lead-acid types is that the necessity for an acid-proof floor is avoided. This is especially advantageous where the battery systems are deployed on a bay-by-bay basis. However, the expected lifespan of this modern design is currently about 10 years.

Battery capacity is defined in ampere-hours. Battery temperature should be maintained at above 5 °C as performance deteriorates at lower temperatures due to increasing internal resistance. Typically for lead-acid batteries, the capacity reduction is about 15% at 5 °C and 20% at 0 °C

**DC Distribution**

The battery and charger feed the DC distribution board in parallel. As mentioned already, this means that to allow for volt drop, the DC voltage applied to the loads is typically 10–12% higher than the nominal battery voltage, e.g., 110 V battery means 125 V normal approx. Also when on battery-only supply, the minimum voltage at the circuit breaker must be high enough to operate the trip coils. Typical tolerances are +10% and −20%. Therefore, the battery voltage must be at a level that ensures this.

The board consists of a busbar and a number of outlets to meet the immediate demand and likely future extension. Each outlet is equipped with a fuse or MCB plus an isolating link. Typically, on a single- or double-busbar substation, each substation bay takes a radial feed. Additional outlets also feed essential substation functions such as emergency lighting, common alarm systems, etc. It is common to provide some form of earth fault detection. A typical arrangement is to connect a high resistance in parallel with the battery terminals and connect the center point of the resistor to the ground through an earth current monitor. In this way, a single fault is easily detected before the more serious double fault and possible short circuit occur.

*Note* that when deciding on methods to earth the DC system consideration should be given at the design stage to the impact on cathodic protection systems provided to counteract corrosion on metallic structures. Impressed current cathodic protection (ICCP) systems utilize an injected (anode) current that may be subject to interference depending on the mode of battery earthing adopted.

As stated already, a substation may contain more than one DC system. Each system consists of a battery, charger, distribution board, and associated cabling. If sealed gas recombining cells are used, they may be located in the same room. This minimizes interconnecting cabling between battery charger and board and also simplifies maintenance. However, if hydrogen-releasing cells are employed, the batteries must be located in a separate room with fire-resistant door due to explosion risk. Also, the latter will require an acid-proof floor in the battery room.

**Table 31.1** Example of duplicated DC systems for EHV substations

| | System A | System B |
|---|---|---|
| Voltage level 1 | Prot group A<br>CB trip coil A<br>CB closing<br>Fault recorder | Prot group B<br>CB trip coil B |
| Voltage level 2 | Communication equipment A<br>Alarms<br>Control | Communication equipment B<br>Alarms<br>Control |

**DC Cabling**

Table 31.1 shows a typical application of duplicate DC systems as employed in substations of 220 kV and above. The system A and system B devices should be located in separate panels, and cabling thereto from the DC board should be mutually segregated. See also ► Sect. 37.4 regarding installation practice.

Cables should be selected with a cross section that ensures an acceptable battery-to-equipment voltage drop. In particular, the cabling associated with tripping circuits may require up to 25 or 35 mm$^2$ cable to achieve satisfactory voltages where trip circuit supervision is applied.

To reduce the risk of damage escalation in the event of fire, cables having flame-retardant-type insulation/covering are employed.

## 31.4 Power System Interruption and "Black Start" Requirements

A total shutdown of the power system although rare is nevertheless a possibility. Consequently system operators must have contingency plans in place for such an event. While system restoration primarily depends on selected generation plants, certain substations are frequently identified as essential to successful restoration. Under a blackout situation, the emergency generator in these substations may have to supply auxiliary loads for periods greater than those anticipated for the more typical "abnormal durations."

Therefore, when determining the essential supplies for these substations, any additional loads anticipated under black start conditions should be included.

# Substation Protection 32

Richard Adams

## Contents

32.1 Principles and Philosophies ... 753
32.1.1 Current-Operated Protection ... 754
32.1.2 Impedance Protection ... 756
32.1.3 Differential (Unit) Protection ... 758
32.1.4 Tripping Philosophies ... 761
32.1.5 Relay Settings ... 762
32.2 Protection: Commonly Used Schemes ... 762
32.2.1 Feeders ... 762
32.2.2 Transformers ... 765
32.2.3 Reactors ... 766
32.2.4 Busbars ... 767
32.3 Backup Protection Principles ... 767
32.3.1 High-Set Overcurrent ... 768
32.3.2 Circuit Breaker Fail ... 768
32.4 Protection: Safety Considerations ... 769
32.5 Fault Level Considerations ... 769
32.6 Power System Faults, Types, Categories, Consequences, and Arc Energy ... 770
32.7 Fuses HV and LV ... 771
References ... 772

## 32.1 Principles and Philosophies

The role of protection is not to prevent a fault from occurring but deal with it if one occurs and protect the power network as well as the primary equipment. Protection should detect and isolate the faulty equipment as quickly as possible in order to:

R. Adams (✉)
Power Systems, Ramboll, Newcastle upon Tyne, UK
e-mail: richard.adams@ramboll.co.uk

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- Minimize the risk of instability in the system including generators
- Minimize damage to the faulty item of equipment
- Minimize risk of damage to adjacent healthy equipment

Failure to clear a fault quickly can result in additional damage to the faulted item, other healthy equipment being subjected to high levels of fault current and possible loss of synchronism of generators or falling out of step, leading to a split in the system and subsequent wider loss of supply to customers.

Protection must be selective and discriminative in its operation – it should select and disconnect the minimum amount of equipment necessary to isolate the fault, thereby minimizing disruption to the wider network. In order to accomplish this, individual protections are applied to different items of equipment such as busbars, lines, transformers or connections, etc.

There are three main techniques for short circuit fault detection:

- Current
- Impedance (distance)
- Differential (unit) protection

And these will now be considered in turn.

### 32.1.1 Current-Operated Protection

This is possibly the most widely used and most basic form of protection. A current-operated relay will operate for any current flowing through it above its setting value, regardless of direction (though directional overcurrent relays are also available but also require a VT connection to create the directional element). A fuse is a simple current-operated protection, but these will be discussed separately a little later in this section. Drawbacks of simple current protections include the fact that they have no defined zone of protection and do not discriminate for faults on other circuits or parts of the network. In order to do this, time, current, or current and time grading are applied, to give the relay nearest the fault a chance to operate first, providing discrimination and selectivity.

Time-graded protection is only really suitable for simple radial circuits at distribution and lower voltages, where fault levels are lower and clearance times may be longer. Grading by time means that the relays furthest from the source have lowest operating time and those nearest the source have higher times, allowing those nearer the fault time to operate first, isolating as little as necessary to clear the fault.

Current-graded protection can be applied on the basis that the conductor of a circuit has impedance, and hence the fault level reduces along the circuit away from the source. Selecting settings based on this can achieve grading, but it is difficult to apply in practice and again is only really suitable for simple radial circuits at lower voltages. However, one area where this can work well is for the HV side of a transformer, since the relatively high impedance of the transformer means that it is possible to set a relay that will operate for faults at the HV terminals but will not operate for faults on the LV side.

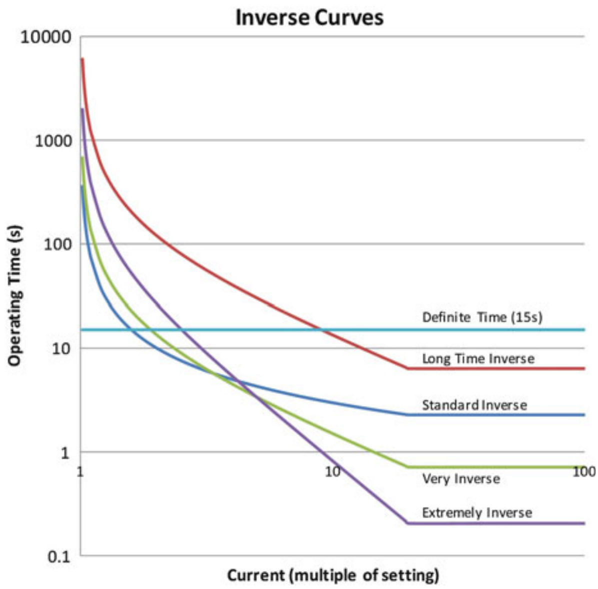
By combining current and time, it becomes easier to grade overcurrent relays on networks. While it is possible to apply fixed current settings and times (definite time, or DT operation), faster operation can be achieved by applying “inverse time”-type characteristics, whereby the relay operates faster for higher fault currents. In this case, a current setting and time-multiplier setting are applied to the relay.

Overcurrent relays generally have a choice of characteristic curves, conforming to IEC or IEEE standards, or maybe have user-defined curves. The curves are of the “inverse definite minimum time” (IDMT) type in that they have a minimum operating time, reached at a certain multiple of setting current (also sometimes referred to as Plug Setting Multiplier or PSM). Depending upon the actual relay, the minimum time usually occurs at a PSM of 20 or maybe 30 in some relays. Figure 32.1 below shows some typical standard IDMT curves and also includes a definite time setting of 15 s for comparison. The minimum time in this case is shown from a setting multiplier of 20.

The current axis is shown in terms of multiple of setting current. In the figure, a time multiplier of 1 is assumed for depicting the standard curves, but decreasing the time multiplier would lower the curve (reduce the operating times), and conversely increasing the time multiplier raises the curve and increases operating time. Changing the time multiplier or current setting does not change the shape of the curve but merely moves it in principle.

Overcurrent relays are widely used in transmission and distribution systems. The operating times achieved with IDMT-type curves and the meshed nature of the

**Fig. 32.1** Typical Inverse Curves



networks generally mean that these relays are used as backup protection in transmission networks, with faster main protections utilizing other measurement techniques. In distribution systems, with radial feeders or ring networks, IDMT-type overcurrent relays are widely used as the sole protection type in some circuits.

### 32.1.2 Impedance Protection

By using voltage and current measurement, it is possible for a relay to calculate impedance. The most popular form of such protection is distance protection used for feeder circuits. Distance protection is a non-unit type of main protection, but, when provided with a communication channel to another distance, relay at a remote end can be converted to a unit-type protection scheme.

Generally, for an overhead line, its impedance can be considered proportional to its length (there are exceptions, but these will be mentioned later), and hence measuring the impedance can be used to measure the distance. A distance relay is set to measure a specific impedance, termed its reach, and will then operate for faults up to that reach. In order to do this, it must measure the voltage and current flowing at the relaying point in order to establish if the calculated impedance to the fault is within its reach setting.

Distance protection relays have a number of zones to be able to measure a number of reaches, providing fast main protection for a particular circuit and additional time delayed backup protection for the protected line and beyond.

Looking at Fig. 32.2, zone 1 (e.g. $Z_{1AB}$) would be an instantaneous operating zone set to protect its line. While it should operate for a fault within the line, it should not operate for a fault beyond the line (possible loss of discrimination) and is hence typically set to 70–80% of the line impedance. The 20–30% safety margin allows for errors in the current and voltage transformers, in line impedance data, and in the relay itself. The second zone (zone 2) is a time-delayed zone set to protect the busbars at the remote end substation (as backup) and consequently protects the remaining 20–30% of the protected circuit not covered by zone 1. Typically zone 2 is set to 120–150% of the protected line or 100% of the protected line plus 50% of the shortest line from the remote end, with a time delay in the order of 200–500 ms. This time delay allows for discrimination with main protections on the outgoing circuits from the remote end (B). An additional time-delayed zone (zone 3) can be set to provide backup

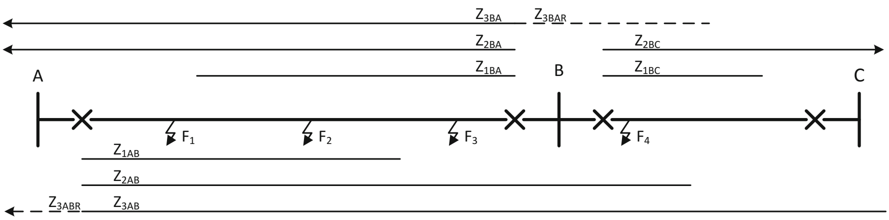



**Fig. 32.2** Typical distance protection zones

protection for faults on outgoing circuits from substation B. The zone 3 setting is dependent upon network configuration, and most utilities will have developed a setting policy specifically for their network. As an example, using Fig. 32.2, $Z_{3AB}$ could be set to the impedance of line AB plus BC (shortest line from substation B) plus say 50% of the next circuit or 120% of the impedance of line AB plus line BC. The time delay for this zone is typically 800–1000 ms. Zone 3 may also have a short reverse looking zone (say 20% of AB) to provide backup protection for busbar faults.

In order to give the relay directionality so that it only looks along the protected feeder, early distance relays had a mho characteristic. This was a circular characteristic, with the circumference passing through the origin on an admittance (resistance/reactance) diagram. The diameter of the circle representing each zone lies along the line, which is displaced from the resistance axis by the Relay Characteristic Angle (RCA). The further the reach, the larger is the diameter. One drawback is that for long reaches, they can approach or encroach on the normal load impedances if not careful. Figure 32.3 below shows an example of mho characteristic for zones 1 and 2 and an offset mho characteristic for zone 3 which provides a small reverse looking reach for backup coverage of busbar faults. It also shows typical load impedance and how zone 3 reach can come close to this – for clarity, load impedance is only shown for positive values of resistance; however there is a similar load characteristic on the negative side too.

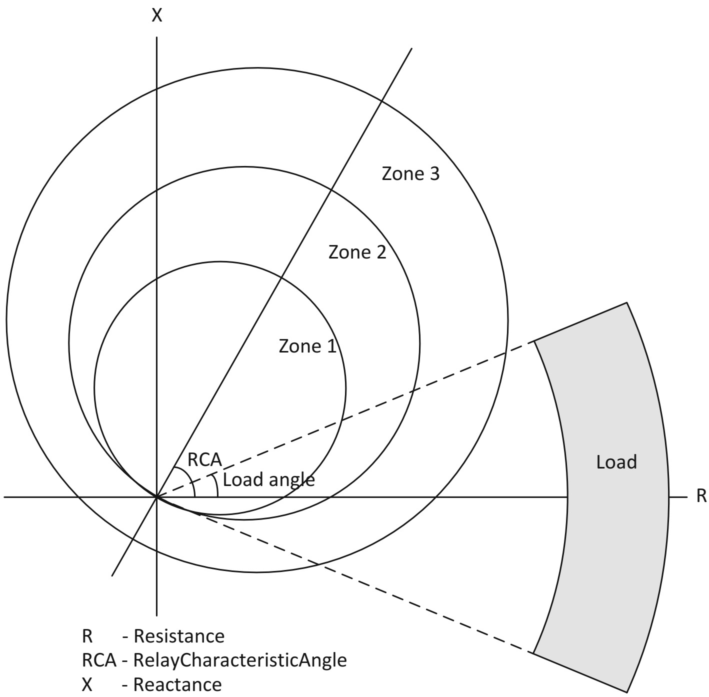



**Fig. 32.3** Typical mho/offset mho characteristic diagram

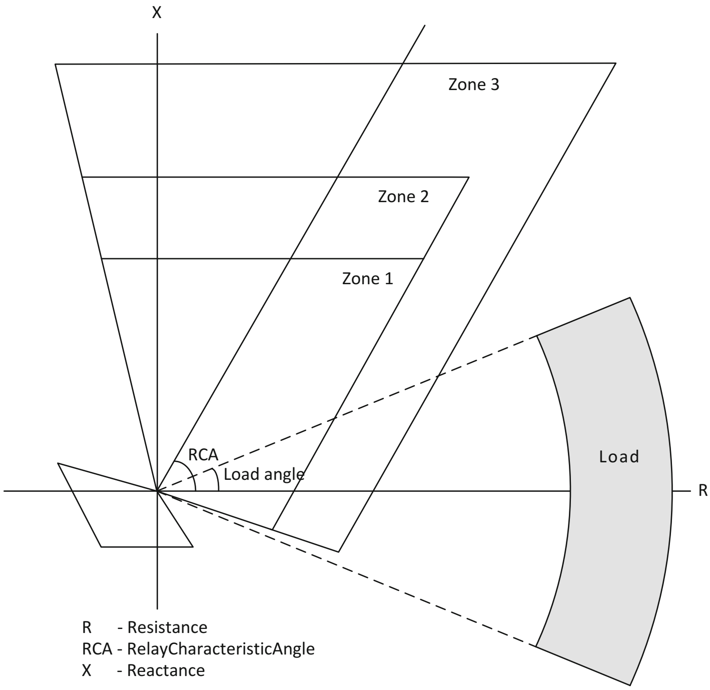



**Fig. 32.4** Example of a quadrilateral characteristic

Modern numeric relays tend to have an option to select the operating characteristic, and while the mho characteristic can still be an option, a quadrilateral (quad) characteristic tends to be more popular now, an example of which is shown in Fig. 32.4. With a quad characteristic, reactance and resistance settings for each zone are independently set, giving greater flexibility to avoid load impedance, especially with long circuits/reaches.

The application of distance protection to cable circuits or circuits with a mixture of overhead line and cable can be tricky if not impossible in some cases. Cables tend to have a much lower relative impedance than overhead line conductors, and hence it may not be possible to achieve suitable settings (within a particular relays' setting range) for short cables. Problems can also be encountered with earth-fault settings due to the cable sheath bonding.

Circuits with a mixture of overhead line and cable mean that the impedance is not linear along the entire length of the circuit, and this can also lead to difficulties in setting.

### 32.1.3 Differential (Unit) Protection

Based upon Kirchhoff's law, the current entering a circuit should be the same as that leaving, and if this is not the case, then there must be a fault, with current flowing out at

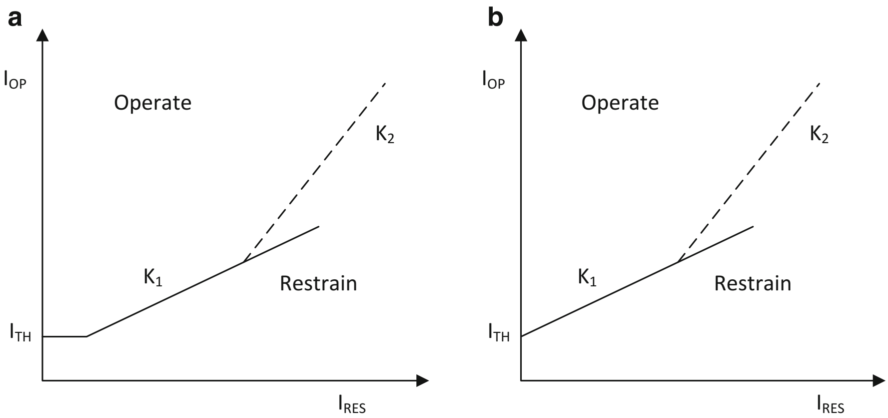



**Fig. 32.5** Typical biased differential characteristics

some other point within the protected circuit/zone. Differential protection can be applied to many, if not all, items of plant or equipment. It is commonly used for protection of feeders (overhead line and cable), busbars, transformers (and associated connections), reactors, etc. Modern differential protection relays for transformers are able to account for vector shifts in the primary and secondary currents due to the vector group of the transformer by applying the vector group in the relay settings, rather than using a separate interposing current transformer (I/P CT) which used to be the case. Energizing a transformer results in a potentially large inrush current, which has a high second harmonic content; by detecting these harmonics, the relays are able to distinguish inrush current and not maloperate during energization.

The most common operating principle is the bias current differential technique, which can be applied to lines, busbars, transformers, reactors, and generators. In its traditional form, the relay had two coils – a restraint coil in the current path and an operating coil in the residual connection. At lower values of circuit current (e.g., load) the spill current (due to differences in characteristics of the CTs, since they are not ideal) will be low, but at higher currents (such as inrush or through faults) the spill current can be much higher. The bias current principle allows an initial low threshold operating or bias setting ($I_{TH}$ in Fig. 32.5), making the relay sensitive, while at higher currents the bias setting is higher, making it less likely to maloperate. Depending upon a particular manufacturer's relay, the characteristic may have an initial horizontal threshold setting as in Fig. 32.5a or not as in (b). The characteristic may have a single slope $K_1$ or dual slope with a second steeper slope $K_2$ (shown dashed in Fig. 32.5) which aims to accommodate false differential current due to CT saturation under heavy through fault conditions.

The operating (differential) or bias current is the magnitude of the vector sum of the input currents, i.e.,

$$I_{OP} = | I_L + I_R |$$

where

- $I_L$ is the current measured by the local relay
- $I_R$ is the current measured by the remote relay

The restraint current can be obtained by any of the following:

$$I_{RES} = k \ | I_L - I_R |$$

$$I_{RES} = k \ (| I_L | + | I_R |)$$

$$I_{RES} = \text{Max} \ (| I_L |, | I_R |)$$

where k is a factor usually of 0.5 or 1.

Figure 32.6 below shows a simple example of different protection zones for a double busbar substation, but the principles remain the same for other arrangements. Note that protection zones should always overlap, to avoid a gap, however small, between zones, i.e., there should be an overlap at the connected CTs as below.

One form of differential protection widely used in the UK and UK-influenced networks but not found widely elsewhere is "high impedance protection" and is not to be confused with protection of high impedance faults on networks, which can provide their own challenges. The relays tend to be fairly simple in operation and present a high impedance to the (CT) secondary current circuit, hence the name. This

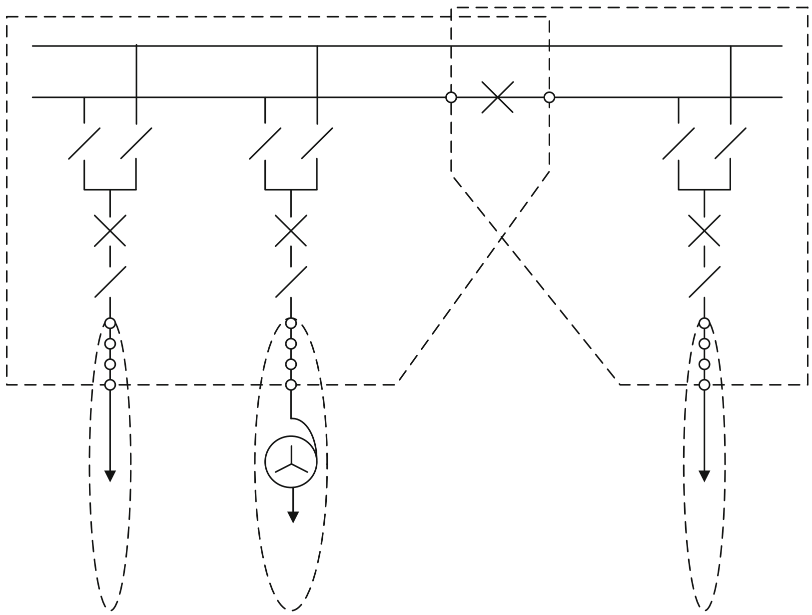


**Fig. 32.6** Example of protection zones

form of protection uses Class PX type CTs and caters for the scenario where one of its connected CTs might saturate under external fault conditions, but the protection still remains stable and does not maloperate. In order to complete the scheme, shunt or series resistors are often applied, along with a nonlinear shunt resistor (metrosil) to protect the relay circuit. The onerous conditions for matching CTs, along with additional components and relatively simple relays which do not tend to have self-monitoring, may have contributed to the decline in use of this type of protection.

### 32.1.4 Tripping Philosophies

In most cases where there is more than one protection for a piece of equipment (main and backup, first and second main, etc.), any one protection that detects a fault will initiate a trip. For instance, if a feeder circuit has two main protections, but only one detects a fault (the other may be faulty), then it will initiate tripping of the respective circuit breaker without any further delay. This is termed “1 out of 2” (or more) tripping. However, in some cases, such as busbar protection or circuit breaker fail, where a trip command can result in the tripping of several circuit breakers, “2 out of 2” tripping provides more of a safeguard against maloperation of one relay. For example, it is common for busbar protection to have several discriminating zones and an overall check zone, requiring at least one discriminating zone *and* the check zone to operate in order to issue trip commands.

The term intertripping or transfer trip applies to cases where a trip signal is sent also to another circuit breaker. This could be from the HV side of a transformer to the LV side circuit breaker but more commonly refers to remote ends on feeder circuits. Some protection relays signal between each other at opposite ends of a feeder to assess the location of a fault and trip faster than would otherwise occur (see Sect. 32.2), but regardless of whether this is the case or not, it is usual for an intertrip (transfer trip) signal to be sent to the remote end when tripping of the local CB occurs. These intertrip or transfer trip commands can be direct or permissive.

*Direct transfer trip (DTT)*, as the name suggests, is a signal from a local end trip relay (via a communication path) to a trip receive relay at the remote end which then initiates tripping of the remote CB without any further qualification of the command. A common application of this may be from a busbar protection trip relay, for a feeder which has its own dedicated CB at the remote end – if the busbar protection trips, then a transfer trip may be sent to the remote end to trip that CB to ensure that any possibility of remote infeed is also tripped. In this case, tripping of that remote end CB should cause no additional loss of supply to any other plant.

*Permissive Transfer Trip* is when the transfer trip signal is qualified by another signal or contact prior to tripping, i.e., not directly issued. For example, this conditioning could be after a CB fail timer so that a transfer trip is only sent after a trip relay and the CB fail timer have operated. Permissive transfer tripping may be selected for a teed (three-ended feeder) or a feeder where the remote end is a mesh corner with another circuit (e.g., feeder or transformer) connected, and tripping of the remote end CB(s) would cause loss of supply to additional equipment.

### 32.1.5 Relay Settings

The importance of correct relay settings cannot be overstated – it is all well and good applying the correct protection systems to a circuit, but if the settings are incorrect, then a CB may not trip for a fault or nonselective tripping may occur, isolating more plant than is necessary. The applied settings to any devices should be in accordance with the end user setting policy – it is usually the responsibility of the end user (often a utility) to define and manage a setting policy, defining and governing the settings to be applied for any particular item of equipment. However, modern numeric protection devices generally have a large number of settings and also multiple setting groups. While a policy will define the settings that should be applied, any unused settings must be disabled or set to a value that would not operate under normal circuit or system operating conditions. For example, if a particular unused overcurrent function cannot be disabled, then this could mean that it should be set to maximum to avoid unwanted tripping. Such unused settings, if incorrectly set, could remain undetected within the device for weeks, months, or years and may only be discovered under particular operating conditions. In order to help to avoid this, an additional "load test" can be carried out during commissioning by injecting the relay with secondary load current (and voltage if applicable) for a few minutes and checking that there is no unwanted/unexpected operation.

## 32.2 Protection: Commonly Used Schemes

The amount or number of protections provided for a particular situation or equipment depends upon a number of factors including the system security standard, voltage level, and the utility/asset owner. Generally, the higher the voltage level, the greater the consequences of maloperation or amount of power affected, and the more protection is applied. At transmission voltages of above 132 kV, there tends to be two main protections and backup but at 132 kV and lower distribution voltages maybe one main protection and backup. At lower voltages still, overcurrent/earth fault may be the only protections. Some utilities application policy requirements might be more onerous than this, and the decision ultimately rests with them as the asset owner to define their needs, so there is no hard and fast rule as to the exact requirements.

### 32.2.1 Feeders

Other than for lower voltage distribution feeders, where an overcurrent relay may be applied, generally differential and/or distance protection is applied as the main (fast-acting) protection.

In Sect. 32.1.2, it was mentioned how operation for faults beyond the zone 1 reach in a circuit is time delayed (zone 2 time). This can be overcome by the use of communications between the relays at each end, thus creating a scheme where the relays at each end communicate the relative position of a fault to each other and trip accordingly. Traditionally, power line carrier, using the primary conductors themselves to transmit the signal, was common, along with rented telephone pilot circuits, but fiber-optic networks, or dedicated fibers within an overhead earth wire (or buried alongside a power cable), are now the popular forms of communication. Common communication schemes are:

***Direct transfer trip (DTT)*** – The zone 1 element of the relay at one end initiates tripping of the local CB and also sends a signal to the other end to initiate a trip, regardless of the fact that the remote end relay only sees the fault in zone 2. That is, using Fig. 32.2, a fault at F3 would be detected by the zone 1 element at end B, and its output trips the CB at "B" but also sends a transfer trip signal to trip the CB at "A." Should the relay/signaling equipment send a signal erroneously, mal-tripping of the remote end CB will occur. If, however, the CB at end "A" is closed but that at "B" is open, fast tripping will not occur at "A" since no current flows through the relay at "B" to initiate the intertrip.

***Permissive under-reach transfer trip (PUTT) scheme*** – This is a distance protection with an improvement of the direct transfer trip scheme, made by conditioning the signal received from the remote end by an instantaneous zone 2 element contact, i.e., using Fig. 32.2 again, the fault at F3 would be detected by the zone 1 element at end B, and its output trips the CB at "B" and sends a transfer trip signal to end "A." Since the relay at "A" will have also detected the fault in zone 2, fast tripping of the CB at "A" will take place (without waiting for Z2 time delay). Similarly to the DTT scheme, fast tripping at "A" will not occur if end "B" is already open when the fault is detected.

***Permissive overreach transfer tripping (POTT) scheme*** – In this scheme, a zone 2 (looking beyond the remote end or overreaching) rather than zone 1 contact is used to send a signal to the remote end. The received signal is again conditioned by an instantaneous receiving end zone 2 element (to ensure operation only for faults within the protected feeder). That is, referring to Fig. 32.2 again, the fault at F3 would be detected by the zone 1 element at end B, and its output trips the CB at "B." This time it is the instantaneous zone 2 element (which has also detected the fault within the line) which sends the signal to end "A." Since the zone 2 element at B can also detect faults behind "A," the received signal is conditioned by an instantaneous zone 2 element at "A" (ensuring that a trip only occurs for faults within the protected line) before a trip signal is issued to the CB at "A." Effectively by ensuring that the fault lies within the zone 2 reach at both ends, it is effectively acting as a directional protection to ensure that the fault lies within the protected line. As before, fast tripping at "A" will not occur if end "B" is already open when the fault is detected.

***Blocking scheme*** – Whereas the previous mentioned schemes use a signaling channel to send a tripping command, a blocking scheme uses the reverse reach, and signaling is only used for external faults, detected by reverse looking zone 3 elements. If no signal is received, then fast tripping occurs by the overreaching zone 2 elements. Considering Fig. 32.2 again, a fault F2 would be detected by zone 1 elements at each end, and fast tripping would take place. A fault F3 would be detected by the relay at end "B" in zone 1 and the relay at end "A" in zone 2, and again fast tripping would occur. For a fault F4, the relay at end "A" will detect it in zone 2; however, the relay at end "B" will see this in the reverse zone 3 and send a blocking signal to end "A," preventing it tripping for a fault external to the line. The reverse zone 3 reach must be longer than the remote end zone 2 to ensure it does not see an external fault which cannot be blocked by the reverse zone 3.

With the transfer trip type schemes above, failure of the signaling channel means that a fault beyond zone 1 reach would take longer to clear (tripping would be in zone 2 time). In the case of the blocking scheme, failure of the signaling should cause the protection to revert to a plain distance scheme unless the signaling failure was coincident with the fault and then tripping of the protected line would occur for a fault outside of the line.

Direct transfer trip and blocking schemes may be described as "trip happy," in that they require no further qualification to cause a trip once the signal is initiated. Conversely, permissive schemes may be described as "trip shy" since they require not only receipt of the trip signal from the remote end but also a locally initiated signal in order that tripping of the CB occurs.

Figure 32.7 below shows a simplified basic typical protection arrangement for a sub-transmission (<300 kV) feeder. The main protection may be distance or unit protection, while backup could be an earth-fault relay. Typically, the main and backup relays would be separate devices, just in case one device fails and then the other should still be functional in the event of a fault.

Figure 32.8 below shows a simplified basic typical protection arrangement for a transmission (>300 kV) feeder. Two main protections are now provided, usually one

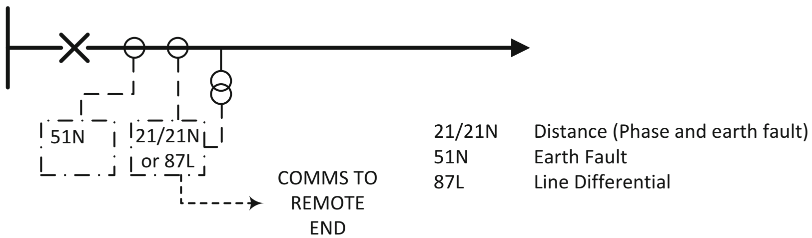



**Fig. 32.7** Typical basic protection for sub-transmission feeder

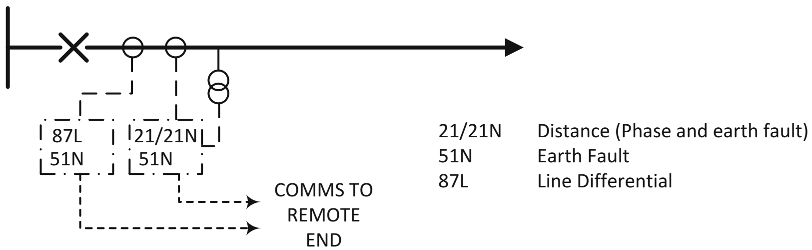



**Fig. 32.8** Typical basic protection for transmission feeder

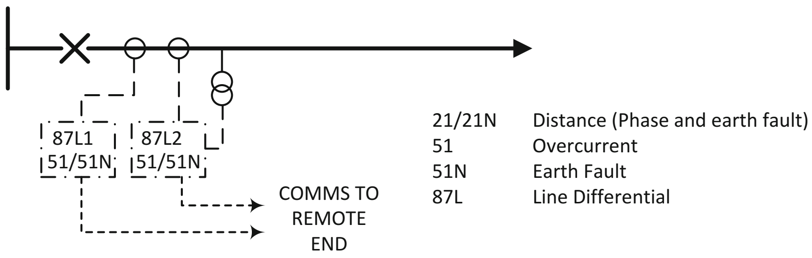



**Fig. 32.9** Typical basic protection for a short transmission feeder

distance and one unit type. With the multifunction capabilities of modern numeric relays, the backup earth-fault functionality can be integrated into the main protections but should be included in both in case one device is out of service and then there are still main and backup functions active.

Figure 32.9 below shows a typical basic protection for a very short overhead line or a cable transmission feeder. Duplicate unit protections are now used owing to difficulties with setting distance protection. Since distance protection provides an inherent backup function due to its multiple zones, but unit protection does not, overcurrent functionality is usually provided to supplement the earth-fault protection for backup. Furthermore, it is usual to use differential relays from different manufacturers or using different algorithms.

### 32.2.2 Transformers

As the voltage levels of transformers on a system increase, so do their costs/value and also the inconvenience should one require replacement as the result of a fault.

At very low voltages, transformers may simply be provided with overcurrent and earth-fault protection. A faster more comprehensive protection is unit protection. For autotransformers, there is no vector group shift between the HV and LV sides, and hence the unit protection can simply be a circulating current protection comparing HV, LV, and neutral currents to monitor that no current is leaving the protected zone between the CTs. Conventional double wound transformers may have star and delta windings and a consequent vector shift between the HV and LV sides, which must be considered when comparing the respective currents. A star winding may also be provided with restricted earth-fault protection comparing the phase and neutral currents. This can provide an additional protection to the unit protection but may in fact be incorporated within the unit protection relay. At transmission voltages, unit and backup protection are usually applied (by different relays) given the large value of the transformer itself and the fact that any uncleared fault could cause irreparable damage. Replacement of such a transformer could take some considerable time, even if a spare is held elsewhere by the owner.

In addition to electrical protection, mechanical protection, such as Buchholz (gas-operated relay), will normally be used which arguably is the most effective

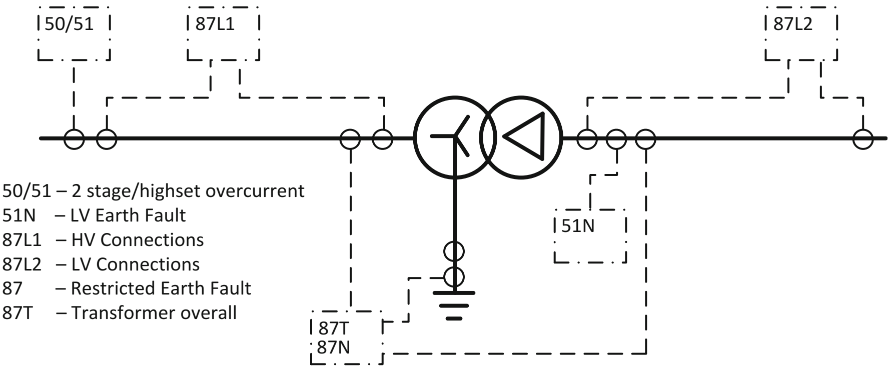



**Fig. 32.10** Typical transformer protection

protection of all. Also winding and oil temperature devices will protect against overloads.

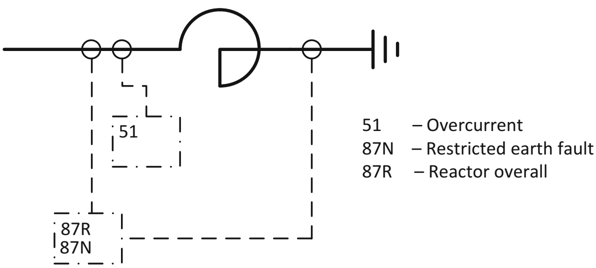
If the transformer has reasonable length connections on either the HV or LV (or both) sides (say longer than 50 m), then it may be desirable to use separate differential protections to protect these connections, rather than use the transformer protection to cover the connection and transformer. In this manner, it is possible to better ascertain the location of the fault when a fault occurs. For example, without separate unit protection, cables may also need to be inspected as well as the transformer for a protection operation.

Figure 32.10 below shows typical protection for a double wound transformer (but could also be applied to an autotransformer), with separate HV and LV connections protections.

### 32.2.3 Reactors

Figure 32.11 below shows typical protection applied to a shunt reactor but could equally apply to a series reactor. Similar to transformers, mechanical protections will normally also be used for oil-filled reactors.

**Fig. 32.11** Typical reactor protection



### 32.2.4 Busbars

The security of busbars at a substation is very important from a protection point of view; failure to operate for a fault can render the connected circuits out of service until any damage is repaired, but conversely the maloperation of their protection can disconnect many circuits unnecessarily. For this reason, substations at voltages of around 132 kV and above will almost certainly, or should, be fitted with their own busbar unit protection. At transmission voltages, two unit protections may be applied by some utilities, given the importance. Modern numeric busbar protections may be "centralized" or "distributed" type systems, depending upon the manufacturer. A centralized system tends to be a single unit (for small substations) or a number of main units (possibly phase segregated for larger substations) in a centrally located cubicle and to which CTs from all circuits are connected. A distributed system comprises a centrally located main unit and then a number of bay or field units, typically one for each circuit or set of connected CTs (bus sections and bus couplers may require two bay units if they have two sets of CTs). Connection between the bay units and main unit is via fiber optic. Each bay unit may be located in a circuit's protection panel or control cubicle near to its associated CTs, or alternatively they may all be located together in cubicles adjacent to that containing the main unit; however this would still be termed a distributed system by virtue of the fact that there is a main unit and bay units. It is common for busbar protection to be split into a number of (discriminating) zones, bounded by bus sections or couplers, enabling tripping of only the faulted zone and allowing circuits to remain connected to a healthy busbar. Additionally, a check zone covering the whole substation is often also used. In this case, operation of the check zone or one discriminating zone alone is not sufficient to cause tripping of the busbar, but both a discriminating *and* the check zone must detect a fault and operate, for so-called "two out of two" operation principle, providing additional security. With numeric busbar protections, the additional check provided by the check zone in high impedance schemes is replaced by ensuring that multiple algorithms are used to detect faults.

## 32.3 Backup Protection Principles

Backup protection, as its name suggests, backs up any main protection, should that main protection fail for any reason. It is effectively the last line of defense to discriminatively clear a fault on a particular circuit or plant item, and its operating times tend to be longer, to give main protections a chance to provide fast discriminative fault clearance first. In this situation, backup protection is still expected to clear a fault with discrimination or minimum disruption to other parts of a network. In the case where a main protection is a unit protection, backup protection also provides fault coverage for parts of the system outside of the protected zone (see Sect. 32.1). Non-unit protections such as distance protection inherently possess backup protection functionality, i.e., a distance protection relay does not have a remote end (reach) point defined by a CT in the same way that unit protection does –

its reaches are defined only by impedance, and some zones can (and should) be well in excess of the protected circuit for that reason.

The other common form of backup protection is simple overcurrent or earth-fault protection which responds to fault currents above their setting, regardless of position (as previously discussed in Sect. 32.1.1).

### 32.3.1 High-Set Overcurrent

High-set overcurrent (HSOC) is an instantaneous/fast-acting backup protection that can be effectively applied to transformers due to their inherent large impedance, which means that it can be set to definitely operate for a fault at the HV terminals under minimum system fault conditions but not operate for a fault at the LV side under maximum system fault conditions.

### 32.3.2 Circuit Breaker Fail

At voltages typically above 132 kV, it is common to apply circuit breaker fail (CBF) protection, in case any circuit breaker fails to trip and open following a trip command. Its use at lower voltages is not precluded but often not applied, depending upon customer requirements.

When any protection relay on a given circuit operates, as well as sending a trip to the respective CB to open, a command to initiate the CB fail function is also given. The CB fail relay (or function in a numerical relay) then monitors current (current check) for a preset time. If current above setting is still observed after the time delay has elapsed, then the CB must still be closed, and a trip signal is given to “backtrip” other CBs at the substation which are capable of contributing to the fault. An intertrip signal is also sent to the remote end if the CB is on a feeder to ensure that it is tripped, if it has not already done so via its own protection. At busbar substations, it is common to use the busbar tripping system to effect the CBF trip, since this already has tripping connections to all of the other circuits.

Some CB fail systems have two stages of timer, initiating a re-trip signal to the failed CB after the first time delay, in a further attempt to correctly clear the fault with discrimination, and then initiating a trip to all infeeding CBs after the second time delay.

The current check setting can be quite low (a few hundred amps) and below load current since the function only becomes operative following a trip signal. In order to correctly ensure that the CB has failed to trip and that it is not still in the process of opening, the CB fail timer setting must consider:

- Operating times of the main protections and any associated trip relays
- Circuit breaker arc extinction time
- Pickup time of the current check element
- Reset time of the current check element
- A safety margin (to account for errors in operating times, etc.)

Typical CB fail timer settings are in the region of 130–180 ms, with fault clearance usually less than 300 ms.

## 32.4 Protection: Safety Considerations

The main aim of protection is to protect the network from losing stability and the associated equipment from being damaged, rather than protect personnel – should any person come into contact with transmission or distribution system voltages, then the protection and equipment cannot be expected to operate fast enough to save them from serious injury or worse. However, failure to clear a fault fast enough or at all can put personnel or public at risk. For example, sustained fault current could cause equipment such as transformers to explode, releasing the insulating oil, and subsequent fire. A broken overhead conductor may fall to the ground or on to vegetation resulting in a high resistance fault due to poor connection to earth, and failure to detect such an incident could result in people being in proximity/contact with a live conductor which would normally be well out of harm's way.

## 32.5 Fault Level Considerations

The fault level of a power system (short circuit fault power) depends upon the amount of generation or sources of infeed which it contains. The fault level at any given point can vary due to circuit impedances and connected loads and generation, and hence minimum and maximum system conditions can be defined/quantified. In addition to its load rating or capability, each item of switchgear will have a fault level rating with an associated duration, i.e., how much fault current it can withstand at rated voltage for a specified time. Generally, as system voltage levels increase, so do the fault levels, and the quicker faults must be cleared in order to minimize damage and preserve system stability. Common examples of fault currents are 63 kA for 1 s at 400 kV or 40 kA for 3 s at 132 kV.

While primary system configuration should ensure that the fault level at any particular point does not exceed the rating of the primary equipment, the protection must be able to correctly detect and clear a fault. Unit protections should be stable for any fault outside of the protected zone, under maximum fault levels, to allow correct discrimination, but must correctly detect internal faults under minimum expected fault levels. Overcurrent protections should be set to grade with other similar protections on adjacent circuits, again to provide correct discrimination.

The protection relay type, setting, and coordination will depend on the transient and steady fault analysis of maximum and minimum fault current. The DC component of the transient maximum fault current is used for setting the minimum delay time of a protective relay. This has to be compared with the DC component of the rated short circuit breaking current of the associated circuit breaker. The relay current setting should always be lower than the minimum steady fault current.

Generally, from a setting's point of view, the protection should be set above normal load values but lower than the minimum expected fault current, under minimum fault level or plant conditions, by a reasonable margin. As a result, protection settings are often no higher than 50% of the minimum expected fault current, to ensure sufficient margin to guarantee correct operation.

Traditional thermal generation power stations (such as coal, oil, gas, nuclear, etc.) can provide very high fault levels from their generators (synchronous machines), which can be advantageous to the setting of protection (can be set above normal load conditions). Conversely, modern wind turbine generators (non-synchronous) and HVDC links to systems provide very low currents under fault conditions, generally only marginally above load currents, which can pose problems for protection settings, but nevertheless need to be disconnected from a faulted section. This may sometimes require conditional signals to distinguish between fault and maximum loads, for example, voltage-regulated overcurrent protection or possibly use negative sequence protection.

## 32.6 Power System Faults, Types, Categories, Consequences, and Arc Energy

A fault can be considered as an abnormal operating condition of the power system as a result of a reduction in the insulation between conductors or to earth and is usually accompanied by a significant increase of current above normal load levels. However, it is also possible to encounter broken conductors (with or without a connection to earth), which may not produce an increased current but would present an unbalanced condition in a three-phase network. This type of fault is most likely to be encountered with an overhead line.

The main types of faults which can affect power systems are:

- Three phase (with or without a connection to earth)
- Phase to phase, also known as two phase
- Phase to earth or single phase
- Phase to phase to earth (also known as two phase to earth or double phase to earth)

Other than the three-phase fault (with or without connection to earth), the other types present unbalanced conditions to the three-phase network. Analysis of these conditions traditionally involved using symmetrical components.

The above types of fault could be encountered on all kinds of plant in the system including cables, overhead lines, transformers, generators, motors, etc. Additionally, plant with windings such as transformers, generators, and motors could be subject to "interturn" faults, short circuit between turns on the same winding.

The reduction of insulation leading to a fault may develop over time and may not be discovered until a fault actually occurs. For example, buildup of pollution snow or ice on insulators in open terminal substations or overhead line insulator strings which gradually decreases the insulation until a flashover occurs, producing a detectable fault due to increased current flow.

Not all faults may be permanent in nature – the breakdown of a cable sheath would be a permanent fault, requiring remedial action, but faults on open terminal switchgear or overhead lines in particular may be transient. Among the causes of such transient faults are lightning strikes, foliage from shrubbery growing too close to a line, or debris being blown into close proximity. It would be anticipated that auto-reclosing after a trip due to such faults would restore the power system to its previous state (please refer to ▶ Chap. 33 for more detail regarding auto-reclosing).

It is also possible to encounter “nonsystem” faults, i.e., those that result in tripping of circuit breakers but without an actual fault on the power system (protection maloperation). Common causes of such faults would be faulty or wrong connections in the secondary wiring, incorrect protection settings, human error, or maintenance activities, though correct procedures and practices should help to avoid these.

Faults can release a large amount of energy, since they have the capacity of a network or system (governed by the amount of generation) to provide fault current which could be significant (e.g., 43 MVA or 63 kA in a 400 kV transmission system). Such levels of energy can cause significant damage, melting conductors if not cleared in time.

## 32.7 Fuses HV and LV

A fuse may be defined as a device which protects a circuit against overload (and consequently plant damage) by opening the circuit due to the melting of its fuse element (whereas a relay works in conjunction with a circuit breaker to open the circuit). A fuse element may be defined as the replaceable part of the fuse designed to melt and break the circuit and is normally housed in a fuse link. At lower voltages, the fuse link may be inserted into a carrier, which in turn is fitted into a base. The term fuse is taken to be the complete unit, encompassing element, holder, base, etc. The larger the current through a fuse, the quicker the element melts, and the current is interrupted. Fuses can in fact operate faster than circuit breakers (~5 ms), operating before fault current reaches its peak value. Fuses are much cheaper than circuit breakers and maintenance is less; however, once operated, a fuse must be replaced in order to restore power to the circuit, and hence reclosing is not possible.

Fuses have been commonly used in the secondary wiring in the past, but miniature circuit breakers (mcb) are being increasingly used, since an auxiliary contact can be fitted to indicate when a mcb has tripped. Fuses are categorized as either high voltage (>1000 V) or low voltage (<1000 V) by IEC standards 60282 and 60269, respectively.

Fuses can be applied in a variety of applications, for protection of networks, capacitors, transformers, and motors, with characteristics available for particular applications (to withstand motor starting current or transformer inrush as applicable) and different types are available:

**Table 32.1** Typical advantages and disadvantages of fuses

| Advantages | Disadvantages |
|---|---|
| Relatively cheap | Take time to replace and restore circuit |
| Do not require maintenance like circuit breakers do | Limited to distribution voltages (typically <33 kV) |
| Current limiting fuses limit short circuit current and may avoid/defer replacement of switchgear with that of a higher rating | Expulsion fuses can operate violently due to expulsion of gases and need adequate clearances |
| HRC fuse ratings can be changed within the range of the size of the fuse carrier size | Do not provide any indication of failure other than breaking the circuit |
| Variety of ratings/characteristics available | |

- ***Expulsion type*** – primarily mounted upon poles in distribution circuits, they consist of a tube with the fuse element inside. Operation results in melting/vaporizing of the fuse element, with the gas being expelled from the tube, assisting with extinguishing of the arc. This breakage of the element also releases a spring mechanism causing the top contact of the tube to disengage, and the tube falls around the lower contact/hinge point, making operation easier to spot on subsequent investigation.
- ***Current limiting type*** – has the benefit of protecting equipment against fault levels which could be greater than the existing switchgear capability by their ability to operate very quickly and before the current reaches its peak.
- ***High rupture capacity*** **(HRC)** – often found in a cartridge style, they are able to provide rapid clearance of faults with very high fault levels (tens of kA).
- ***Capacitor protection*** – capacitor units for use in series or shunt capacitor banks tend to comprise a number of individual capacitors and internal or external fuses allow continued operation of the bank by isolating individual faulted capacitors, subject to a limit specified by the manufacturer.

Table 32.1 above summarizes the main advantages and disadvantages of fuses.

## References

The following are not specifically referred in the previous section, nor meant to be an exhaustive list, but rather a possible source of further, more detailed information should the reader be interested. The E-CIGRE website is a very useful source of information published by the Study Committees of CIGRE

## Books

Baxter, H.W.: Electric Fuses. Edward Arnold, London (1950)

Electricity Training Association: Power System Protection 4 Volume Set. The Institution of Engineering and Technology, London (1995). ISBN: 978-0-85296-847-5

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TB 359 – Modern Distance Protection Functions and Applications, 2008

TB 431 – Modern Techniques for Protecting Busbars in HV Networks, 2010

TB 432 – Protection Relay Coordination, 2010

TB 463 – Modern Techniques for Protecting, controlling and monitoring power transformers, 2011

TB 465 – Modern Techniques for Protecting and Monitoring of Transmission Lines, 2011

TB 546 – Protection, Monitoring and Control of Shunt Reactors, 2013

TB 587 – Short Circuit Protection of Circuits with Mixed Conductor Technologies in Transmission Networks, 2014

TB 629 – Coordination of Protection and Automation for Future Networks, 2015

# Substation Control and Automatic Switching

# 33

John Finn

## Contents

33.1 Basic Control System ..... 776
33.1.1 Details of Conventional HMI ..... 776
33.1.2 Details of Computer-Based HMI ..... 778
33.1.3 Computer Performance Criteria ..... 779
33.1.4 Control from the Substation ..... 779
33.1.5 Control from a Network Control Center ..... 780
33.1.6 Architectures of Control Systems ..... 781
33.1.7 Extension and Modification Requirements ..... 781
33.1.8 Avoiding Unwanted Operations Within the Control System ..... 782
33.2 Interlocking ..... 782
33.3 Synchronizing ..... 784
33.4 Voltage Control ..... 786
33.4.1 Automatic Tap Change Control ..... 786
33.4.2 Automatic Reactive Switching ..... 788
33.5 Controlled Switching: Point on Wave Control ..... 790
33.6 Automatic Switching: Reclosing, Closing, and Operational Tripping ..... 792
33.6.1 Automatic Reclosing ..... 792
33.6.2 Automatic Closing ..... 794
33.6.3 Operational Tripping ..... 794
33.7 Frequency Control and Consumer Load Control ..... 795
33.7.1 Underfrequency Load Shedding ..... 795
33.7.2 Consumer Load Control ..... 795

In order to operate the substation effectively, a control system which indicates the status of all plant including alarms and indications of secondary system equipment; shows analogue values for the key parameters such as voltage, current, megawatts, and megavars; as well as provides digital outputs to close and open switchgear, raise

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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and lower taps on transformers, etc. is required. In addition to the basic indications and controls, other functions such as synchronizing, voltage and/or reactive control, interlocking for both safety and operational reasons, load control to avoid frequency collapse, etc. may also be applied. Other functions such as automatic closing or reclosing to optimize the performance of the network may be needed, and in some instances controlled switching, i.e., point on wave control of closing or opening, may be used to reduce switching transients on the network. These aspects will be covered in the following paragraphs.

## 33.1 Basic Control System

In most cases the substation control and monitoring system allows for three levels of supervision and control (or points of human machine interface HMI). However, the number of levels employed will be dependent on local practice and may be restricted to the first two levels of control.

- In the switchyard/switchgear buildings (bay control)
- At the substation control room (station control)
- From a central network control center (network control, remote control center, regional control center)

At any moment, only one control point shall be in service, and the rules to switch control points (control arbitration) are user-definable, but usually selection between bay or station control will be from the bay control point and may be on an individual equipment basis. Selection between station or network control will be from the station control point and may be on a per-circuit basis. The facilities at each point will vary in terms of the equipment being controlled, the indications, and the alarms available.

Alarms may be grouped for station and network control points to suit individual requirements. Generally, alarms and indications necessary for the safe and satisfactory operation of the substation should be provided at each control point. Special facilities, such as synchronizing, may be available at the station or bay control point.

Reference should be made to Fig. 33.1 which illustrates the type of equipment at the human machine interfaces.

With the continued increase in the use of equipment using digital technology, there is now a clear distinction between the conventional and the computer-based human machine interfaces. Computer-based HMI is commonly found at network control level but is becoming increasingly more common in station control rooms. However, there are still some conventional HMIs at the station level. HMI at bay level is often direct wire control and therefore conventional.

### 33.1.1 Details of Conventional HMI

HMI at bay level will comprise control switches, indicator lamps, and meters mounted on the equipment or in adjacent local control cubicles. Generally, these facilities are

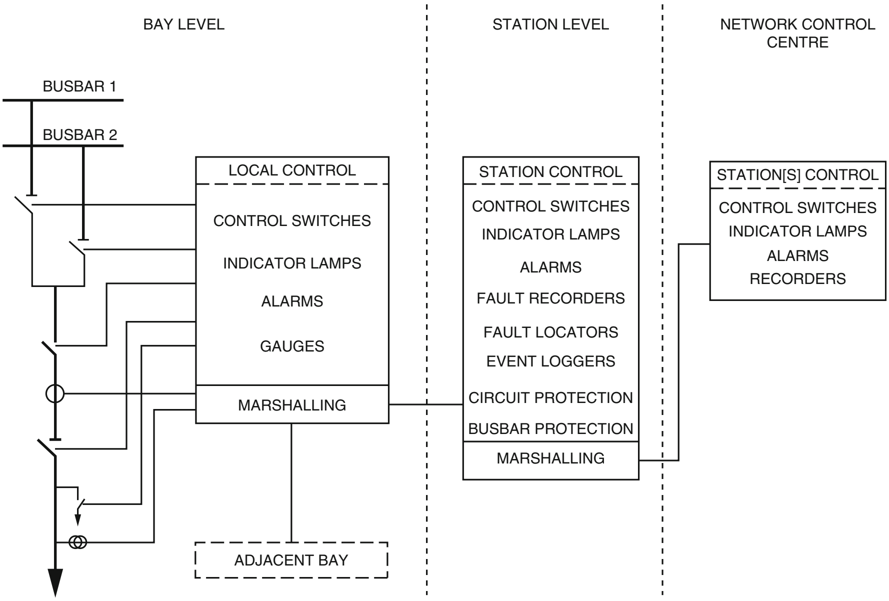


**Fig. 33.1** An example of human machine interface locations

used during maintenance of the controlled plant or as backup for use in the event of failure of the station level or central network control center. At the station level, control panels should be located in the main control room. The HMI equipment should be grouped on a per-circuit basis, and open and close switches should only control equipment on the same section of the substation as the control panel represents.

A mimic diagram representing the substation layout, usually in single-line diagram form, should be provided. The mimic board is intended to give operating personnel an overall view of the switchgear state. It may be made up from the individual circuit control panels mounted side by side. The arrangement should correspond to the primary equipment layout.

Alarm annunciation equipment should be mounted adjacent to the mimic diagram or form an integral part of the control panel. Operation of an alarm should cause the appropriate window to flash and sound an audible warning. Operation of an accept button will silence the audible warning, steady the flashing window, and prepare the annunciation to respond to subsequent initiation. A reset button should be provided to extinguish alarms which have reset.

A lamp test button is necessary which will initiate steady-state illumination of all alarm windows. Trip or protection initiated alarms should have windows distinct from others (e.g., red display instead of white or amber). Control and selector switches should be of approved types complying with accepted standards such as IEC 60337. Control switches will require two independent motions or two handed operation to effect operation. Indicating instruments should be of approved types complying with accepted standards such as IEC 60051.

### 33.1.2 Details of Computer-Based HMI

Computer-based human machine interfaces function through computer systems using distributed architectures. Such systems were commonly found at network level but only since the 1990s at substation control level. Remote terminal units (RTUs) form the interface with equipment and communicate information to the central system(s). RTUs will collect analogue and digital data and issue control commands.

The human machine interface may make use of the following items in varying quantities depending on the degree of redundancy required:

- Visual display unit (VDU)
- Alphanumeric keyboard
- Printer
- Plotter
- Trackball
- Joystick
- Special function panel
- Mouse

A mimic display either in the form of a board for large substations or VDU "pages" should be available.

Operator consoles capable of operating the substation (at substation level), or power system (network level), should be comprised of the required components from the above list. The console should be capable of operating in online, maintenance, training, and programming mode. Special software interlocks should prohibit two or more consoles working "online" simultaneously.

VDUs should be of the full graphic, multicolor type designed for 24 h a day continuous operation. The following information should be displayed:

- Static (fixed) information (e.g., substation single-line diagram)
- Operating parameters which may be changed
- Dynamic (real-time) variables

An operator's keyboard, which contains special function keys, should be provided at each console; this will allow execution of commands. The system keyboard is for data entry and general operation of the computer system and substation(s). In addition, an alphanumeric keyboard may also be required for system purposes.

When the substation is only manned occasionally, consideration should be given to the provision of a touch screen VDU or special function panel to simplify the task of the operator in controlling and monitoring the plant. The special function panel would only have a small number of dedicated push buttons and switches for plant control, selection of VDU pages, and acknowledgment of alarms. Two stage control (select-check-execute) is normally required for all the control commands to effect the operation from an HMI.

### 33.1.3 Computer Performance Criteria

The type and configuration of computer-based control equipment for substation secondary system applications should be such as to produce a system with the necessary reliability, functional availability, and ease of equipment maintenance.

**Master Station**

The master station computer system which supports the HMI should have a very high reliability with virtually continuous functional availability. The usual technique for fulfilling these requirements is to introduce hardware redundancy for critical major elements. The redundant elements are usually configured to function automatically on detecting failure of the online unit.

**Outstations**

Distributed data acquisition computer subsystems should have a very high reliability, but an occasional failure can normally be tolerated since it will usually only effect a small part of the overall system. Redundancy is not normally employed for reasons of economy, but component selection should be to a high standard to give long mean time between failures.

**Communications**

Distributed computer systems are reliant on communications. Where communication channel physical routing is not provided, a high degree of mechanical or electrical protection is required. Where the functions associated with an outstation are important, then main and standby channels should be provided over physically segregated routes. Otherwise the provision of a single channel normally gives satisfactory availability.

**Computer Loading**

While a power network is operating in a normal state, which it is for most of the time, computer-based control systems generally have no difficulty in performing all the tasks associated with updating telemetered data and supporting the HMI. During major network disturbances however, the volume of telemetered data and the processing associated with the HMI will both increase of the same order. During major disturbances, these requirements can be relaxed to some extent, but on no account should any data be lost.

### 33.1.4 Control from the Substation

In the past, HV substations were normally attended by resident staff and supervision, and control of the substation was carried out from the substation control room by local control.

The local control consists of a system for collecting data and a system for issuing commands (HMI). The data collection system gives information on the position of circuit breakers, disconnectors and earthing switches, line loading, transformer temperatures and loadings, voltage levels, relay functions, time tagged events, etc.

In the substation control room, this information is displayed on wall boards and mimic diagrams (in the case of conventional equipment) or on visual display units (in the case of computerized equipment). Control commands to circuit breakers, disconnectors, tap changers, etc. are issued from the substation control room, and thus it is possible from here to exercise full control of the substation by means of the HMI.

Should control from the substation control room fail, a backup control of circuit breakers, disconnectors and earth switches, etc. can be established from control cubicles located on, or adjacent to, the primary equipment.

### 33.1.5 Control from a Network Control Center

Nowadays, all utilities have introduced remote control, reducing the number of manned substations and thereby reducing the number of staff and the operational cost.

At present, substations are normally unmanned, and the control function is performed from an area control center that also receives information from and controls several other substations. This is done by means of a “supervisory control and data acquisition” system (SCADA system). A “remote terminal unit” (RTU) transmits from each substation to the area control center the information needed to draw a complete picture of the supervised network, and in the reverse direction, it transmits commands from the area control center to the substations.

In large networks with several area control centers, the procurement of energy and the optimal arrangement of the power transmission network are managed and monitored from a load dispatching center which in turn gets its information from power plants, area control centers, etc.

Local control in unmanned substations is still kept for standby purposes and for use during maintenance, but it is now generally of a simplified design. However, in newly built substations, the normal local control facility is frequently a display unit with keyboard. It can be based upon and integrated with the remote control equipment, provided there is a backup control facility at a lower level.

With the introduction of substation automation functions such as automatic switching between busbars and automatic switching-on of transformers and reactors, it is possible to reduce the amount of information transmitted to the regional control centers, thus relieving the control center staff. But besides being utilized for network control, information from the substations is essential for maintenance and for specialist relay staff in monitoring the relay protection; thus there is a need for increased transmission of information, but this may be devolved to different centers according to the category.

### 33.1.6 Architectures of Control Systems

When selecting the architecture for the control system, the following factors should be taken into consideration:

(a) Physical size and layout of substation, highest voltage, and ultimate development of substation:
   - Size/area
   - Indoor, outdoor
   - AIS, GIS

(b) Manning of substation
   - Manned
   - Unmanned

   Currently, most substations are planned as unmanned. Occasionally a utility may decide to operate a substation on a manned basis for a number of reasons such as:
   - Continuation of traditional utility practice
   - Specific technical reasons (i.e., unreliability of HV-equipment and/or remote control communication links)

(c) Choice of secondary systems functions to be implemented

(d) Technology of protection and control subsystems
   - Conventional
   - Computer-based

(e) Estimated life cycle cost which includes:
   - Investment
   - Training, education, and operation
   - Maintenance

The abovementioned aspects should be considered in detail together with the availability/reliability requirements of the transmission network and of the energy consumer. These considerations provide a basis for the selection of the architecture for the control system and associated protection.

### 33.1.7 Extension and Modification Requirements

Substation secondary systems may be extended or modified for any of the following reasons:

- Additional primary bays are required.
- The substation configuration is altered.
- Primary equipment is changed.
- Additional secondary equipment is installed (e.g., busbar protection or remote control).

In order to facilitate the extension of the control system in a substation, spare capacity should be incorporated in cable trenches ducts and tunnels and in the central control building at the initial design stage.

The standard control building consists of two distinct functional areas which can be categorized as being:

- The area independent of substation size (e.g., staff-related service areas)
- The area dependent on substation size (e.g., relay room)

The part which is dependent on substation size should have the capacity to accommodate any extensions or modifications that can reasonably be anticipated.

### 33.1.8 Avoiding Unwanted Operations Within the Control System

Traditionally the main concern with regard to unwanted operations was from electromagnetic interference. The EMC requirements are very important for all utilities. Nowadays the subject is well covered by international standards, and a lot of expertise has been developed in the field of screening of cables and earthing practice to reduce the risk of malfunctions as discussed in Sect. 30.9.6 Electromagnetic Compatibility. Furthermore, the increased use of fiber optic cables for inter-bay communication has further reduced this risk.

However, in this modern world, we are now facing another risk, namely, cyber-attack or "hackers" maliciously operating circuits and network controls without the authorization of the network operator. Instances of this happening on power networks have already been experienced in Ukraine in 2015. It is becoming more and more important that the control systems software is protected against invasion by "hackers."

## 33.2 Interlocking

Interlocking systems are used by many utilities to ensure that all disconnectors, fixed earthing switches, and where required circuit breakers are operated in the correct sequence so that operators do not compromise the integrity of the transmission system by incorrect or inadvertent operation of equipment.

The most common conditions covered by interlocking schemes are:

(a) Interlocking between disconnectors and circuit breakers to ensure that disconnectors do not make or break load currents.
(b) Interlocking between disconnectors and earth switches to ensure that earth switches cannot be closed onto locally energized circuits and conversely earth switches cannot be energized when closed by closing of a disconnector.

(c) Interlocking between disconnectors and adjacent earth switches to enable the disconnector to be operated for maintenance purposes when the earth switches either side are closed.
(d) To ensure correct sequence of on load transfer switching operations at multiple busbar substations and that a parallel path exists between the disconnectors connected to each bar. Some utilities block the tripping of a bus coupler or bus section which is providing the parallel path during bus transfer operation.
(e) To ensure that a bus coupler or bus section circuit breaker can only be closed when the disconnectors either side are both closed (operational condition) or both open (maintenance condition).
(f) To restrict access to areas of a substation where safety clearances may be infringed (e.g., filter equipment) unless appropriate safety measures have been taken such as isolation and earthing.

When the switching sequences involve only power operated switchgear, it is normal to effect the interlocking by electrical means. Ideally the correct interlocking status should be confirmed automatically on initiation of an operation whether that operation be by an operator or part of an automatic sequence. (Note: occasionally it may be necessary to bypass an interlock during an automatic switching scheme but this should be the exception rather than the rule). When the switching sequence involves manually operated plant, then the interlocking may be by electrical or mechanical means. The interlocking should be designed so that ideally it checks the interlocking status immediately before an operation. Where practicable, interlocking schemes should allow the maximum operational flexibility and not unnecessarily impose fixed operating sequences. The schemes should be inherently fail safe, and it should not be possible to defeat them except with the use of tools or by a purpose designed override facility. Such override facilities should normally be lockable with a unique lock. Interlocking should be effective for switching and operating sequences when they are being followed in either direction (e.g., if an earthing switch has to be closed before an access gate can be opened, then conversely the gate must be closed and locked before the earth switch can be opened). In some locations it may not be practicable to fully interlock a device. An example of this is the earth switch at a line entry, where it is not usually practicable to interlock it with the equipment at the remote end of the line unless it is a very short line. In such cases, it would be normal to provide a warning label indicating that the earth switch is not fully interlocked.

Mechanical interlocking is usually by means of key operated systems. The keys should be of a non-masterable design (that is to say there should not be any master key nor should it be possible to manufacture a master key). The differs (Note: differ is the term for the difference in a key which prevents it being interchangeable with another) should not be repeated at the same substation site. The interlocking keys are usually engraved with an identifying reference unique to the particular site. The identifier would often include the system number of the switching device where the key is usually located during normal operation, and the key locations are usually marked with the identifier of the associated key.

On more complicated interlocking schemes, it may be necessary to provide key exchange boxes, and these should be located at convenient points for the normal operation of the substation. Occasionally electromechanical key exchange boxes may be needed which provide a linking up of the electrical interlocking and the mechanical interlocking for a circuit.

Traditionally electrical interlocking has been done by using hardwired contact logic. With computerized control systems, the status of all of the plant is already known within the control system, and so it is possible to write some software logic to perform the interlocking function. Clearly this significantly reduces the amount of cabling required on the site, and it is very effective when applied to new Greenfield site substations; however, problems can be encountered when additions or modifications are required at the substation. Usually this will involve building a mimic of the entire revised substation in the factory to test the modified interlock software before loading it onto the actual computer system on site.

## 33.3 Synchronizing

Synchronizing is required on transmission networks to:

- Ensure retention of system stability
- Minimize damage to plant
- Facilitate the re-paralleling of a split system

If circuit breakers are closed when the systems either side are not in synchronism, then a shock load can be imposed on generators, and a large flow of synchronizing power will flow on the network.

On the transmission network, two types of synchronizing are usually employed, namely, check synchronizing and system synchronizing (refer to Fig. 33.2). Check

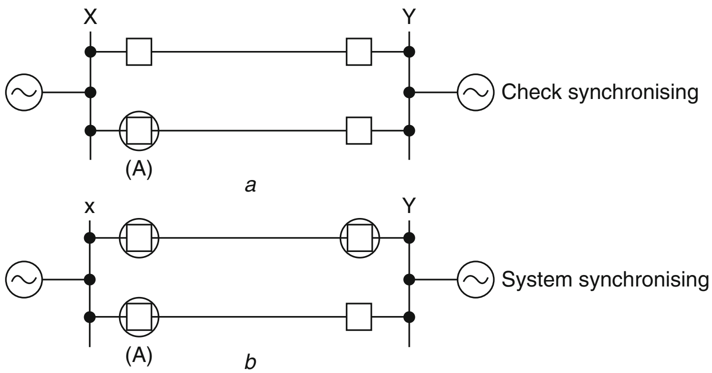


**Fig. 33.2** Example showing check synchronizing and system synchronizing (Note, the circled ones indicate the CBs are open)

synchronizing usually occurs when the circuit breaker being closed is within a solidly connected system, and system synchronizing occurs when the circuit breaker being closed is connecting two independent systems.

The conditions required for a synchronized close are:

- Same frequency on both sides of the CB (zero slip)
- Zero phase angle difference between the voltages on both sides of the CB
- Same voltage magnitude of approximately nominal value on both sides of the CB

The synchronizing relay will check that these conditions are met within a certain tolerance (refer to Fig. 33.3).

Normally there will not be any voltage transformer located on the busbars, and in order to obtain the voltage of the busbar to establish a "running" voltage, a voltage selection scheme will be required. It should be noted that the output of the voltage transformers should be monitored (e.g., by a MCB) as the lack of a voltage will be taken as a dead bar or a dead line. In the past, the synchronizing system consisted of a voltage selection scheme, an analogue synchronizing panel which would display the running voltage, the incoming voltage, and a synchroscope showing the instantaneous angle between the two voltages. Sometimes these instruments would be supplemented with lamps to allow a "lamps-lit" or "lamps-dark" form of synchronizing. Also, a synchronizing relay would be used to carry out a check on the voltages, angle, and slip and contacts of this relay connected in series into the

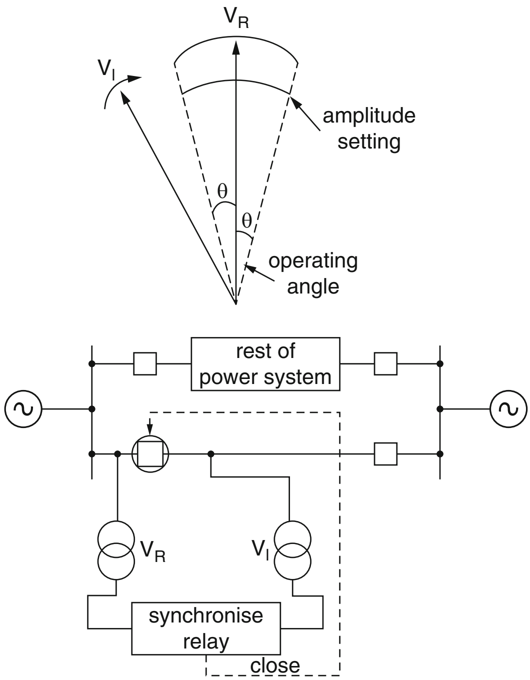


**Fig. 33.3** Synchronizing relay connections and comparison of incoming and running voltages for synchronizing

closing circuit of the circuit breaker. This synchronizing system would be used for checking synchronism for both manual and automatic switching.

With the development of computerized control systems, the need for a dedicated voltage selection scheme for synchronizing disappears as the computer control system "knows" all of the required information to select a suitable running voltage. Also by writing suitable software, all of the required checks can be carried out within the computer control system to enable manual closing of the circuit breakers. The closing of the circuit breaker will normally be enabled for any of the below conditions:

- Dead bar/dead line
- Live bar/dead line
- Dead bar/live line
- Live bar/live line (with check synchronizing or system synchronizing as appropriate)

For automatic closing (auto-reclosing), the synchronizing check facility is usually built into modern numerical auto-reclose relays.

## 33.4 Voltage Control

There are two main types of static voltage control applied within transmission substations, namely, automatic tap change (ATCC) control and automatic reactive switching (ARS).

### 33.4.1 Automatic Tap Change Control

Automatic tap change control is used to control the voltage on the low voltage side of transformers. This system works by detecting the busbar voltages on the low voltage side of the transformers which are outside of preset voltage limits (deadband) and then initiating the operation of the transformer on-load tap changers to bring the voltages within the specified limits (refer to Fig. 33.4). The timescales for this tapping has to be coordinated with other active voltage controls to avoid hunting.

Sometimes when a tighter control of the voltage is required, a device employing a double deadband will be used as illustrated in Fig. 33.5. As mentioned earlier the timing of the tap change operations has to be controlled to avoid hunting with other voltage control devices on the network; Fig. 33.6 shows how typically the tap change delay is achieved.

In more complicated substations, the ATCC equipment may need to be capable of controlling the voltages on a number of different busbars by controlling the tap changers on a number of different transformers. In order to do this, the ATCC equipment must automatically detect the topology of the low voltage substation and recognize the busbar grouping for transformer tap change control. In this

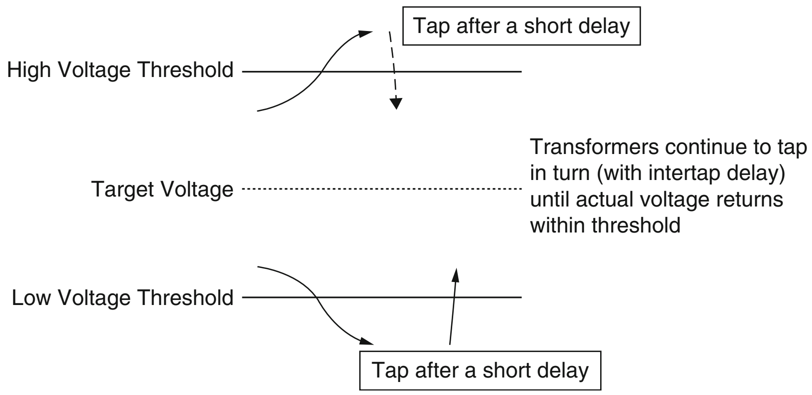


**Fig. 33.4** Illustration of control with a single deadband

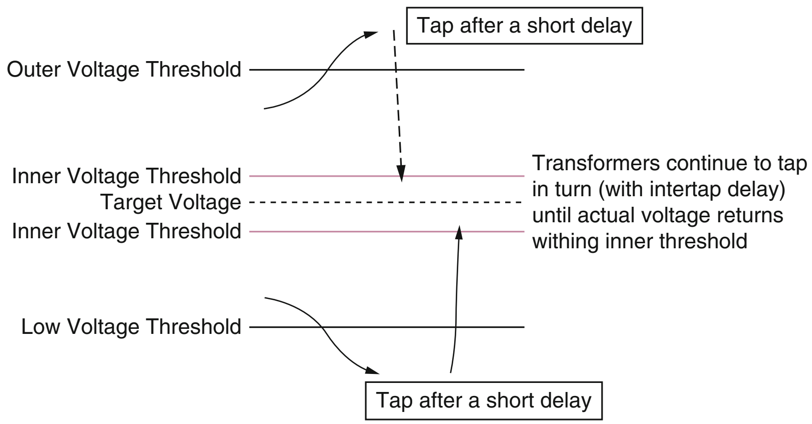


**Fig. 33.5** Illustration of control with a double deadband

situation, the controlled entity is the busbar voltage, and the controlling action is the initiation of the tap changers on the transformers connected to the controlled busbar. The scheme will usually ensure that the taps on parallel transformers connected between a pair of busbars are the same or within one tap of each other to avoid the circulation of reactive power between the parallel transformers.

Other features which can be built into the ATCC scheme are line drop compensation which enables the scheme to control the voltage of a busbar at the other end of a line by compensating for the voltage drop in the line. Furthermore, some ATCC schemes will have a choice of set voltages with say a nominal setting, a setting at 97% nominal and one at 94% nominal. When load shedding is required, then the ATCC set point can be selected to one of the lower voltages to effect load shedding.

ATCC was traditionally performed by dedicated schemes and relays. The schemes are needed to gather information on the status of the circuit breakers and

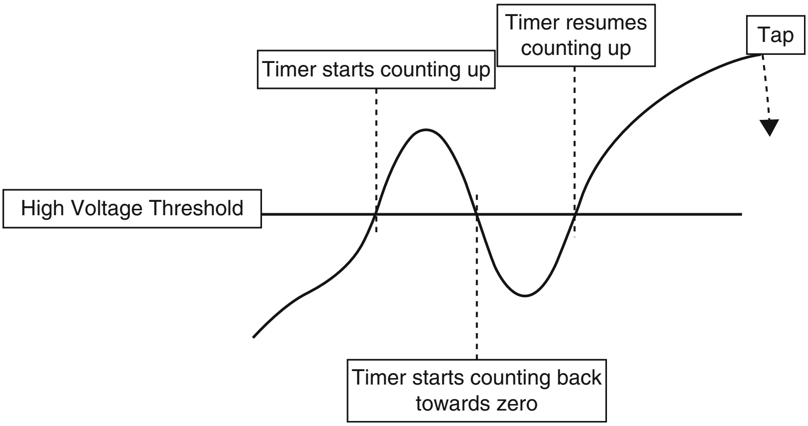


**Fig. 33.6** Illustration of the operation of a tap change delay

disconnectors associated with the transformers, bus couplers, and bus section switches in the substation. With the increasing use of computerized control systems, the ATCC function can be integrated into the control system by the use of suitable software, significantly reducing the amount of cabling on the site.

### 33.4.2 Automatic Reactive Switching

The way in which the voltage is normally controlled on a transmission network is by the dispatching of reactive power from generators connected to the network. Injecting more reactive power increases the system voltage, while reducing the injection or even absorbing reactive power reduces the voltage. As networks become more complex, it is increasingly becoming necessary to install additional reactive plant at substations remote from major generation sources in order to control the voltage. This reactive plant may be either of the dynamic type, such as static voltage compensators (SVC), or the static type such as shunt capacitors or shunt reactors. When both dynamic and static devices are connected, they should be coordinated such that the steady-state voltage control is carried out by the static devices and the dynamic plant is kept in reserve to respond to incidents on the network such as tripping of circuits or load rejection.

If we consider first the static devices, then these can be controlled by an automatic reactive switching scheme. This monitors the voltage at the HV busbars in the substation and controls it within specified preset limits (deadbands). If the voltage exceeds the upper limit, then any shunt capacitors will be switched out, or if none are in service, then a shunt reactor will be switched in. In a similar way if the voltage falls below the lower limit, then any shunt reactors will be switched out, or if none are in service, then a shunt capacitor will be switched in (refer to Fig. 33.7). The timing of these switching actions has to be coordinated with other voltage control

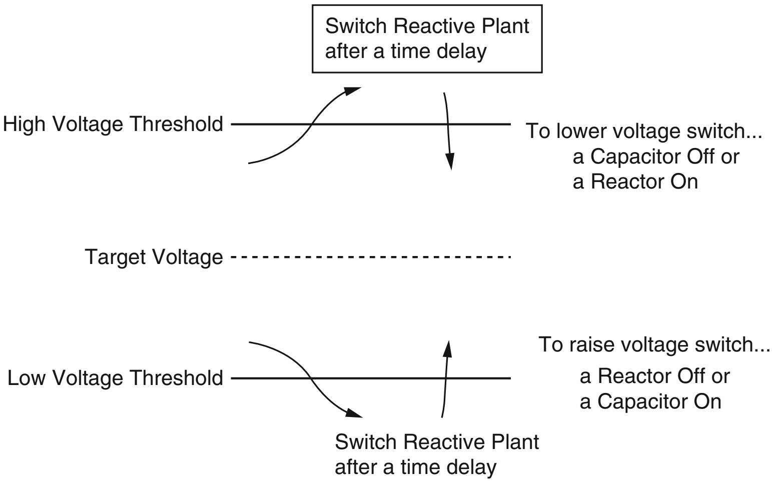


**Fig. 33.7** Control of system voltage with ARS control

devices such as the ATCC. Normally the high voltage system should be controlled after adjusting the lower voltages by tap change control; however under post fault situation, the ARS system will take actions first before ATCC. The information necessary for the ARS control includes the status information on many items of switchgear within both HV and LV substations. In the past, this information was gathered independently for the ARS scheme. However, with the growth of computerized control systems, this information is available within that system. The ARS can then be integrated into the control system by the use of suitable software, or as done by some utilities, a hybrid (IED) approach can be used. The hybrid approach uses the computer control system to gather the plant status information, and then this is fed by serial link to a dedicated ARS equipment (IED) which makes control decisions and sends back to the substation control system to execute the switching of reactive plant.

For rapid changes in voltage, these are usually controlled by dynamic voltage control devices such as SVCs or STATCOMs. These devices usually have a voltage set point and a slope setting. When the voltage is at the set point, then there will be no injection or absorption of reactive power. When the voltage exceeds the set point, then reactive power will be absorbed, and when the voltage falls below the set point, then reactive power will be injected. The amount of reactive power will be dependent upon the slope setting. For a small percentage slope, a small change in voltage will cause a large change in reactive power (i.e., a tighter control of voltage), while for a larger percentage slope, a larger change in voltage will be required to cause the change in reactive power (a slacker control of voltage). A typical operating diagram for a SVC is shown in Fig. 33.8. As the SVC uses power electronic components, its response time is very quick (of the order of tens of milliseconds) enabling it to assist in maintaining voltage stability on the

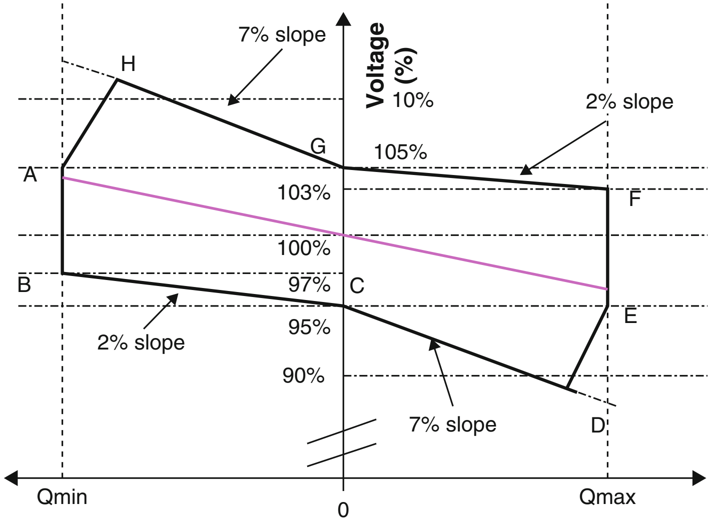


**Fig. 33.8** Example of typical SVC operating diagram

network. When both SVC and static switched components are being used, the controller for the SVC will normally become the master controller to ensure correct coordination in the operation of the devices.

## 33.5 Controlled Switching: Point on Wave Control

It is well known that transient surges can occur when closing or opening circuit breakers. The nature of the surges is being dependent upon the particular item of plant being switched. Some examples are:

- Surges when closing long lines or composite circuits (line/cable/transformer) due to reflected waves
- Surges when closing in capacitor banks
- Inrush when energizing large power transformers
- Induced voltages due to current chopping when de-energizing shunt reactors

The magnitude of many of these surges is dependent upon the specific point on the sine wave of either the voltage or the current at which the switching action occurs. For transformer energization it may also be useful to take into account remanent flux.

It therefore follows that if we can control the specific point on the wave that the actual switching action occurs then we can minimize the impact of the switching surge. For example, this control may be on voltage on closing for lines and capacitor banks or for current on opening for shunt reactors. As an example of energizing a

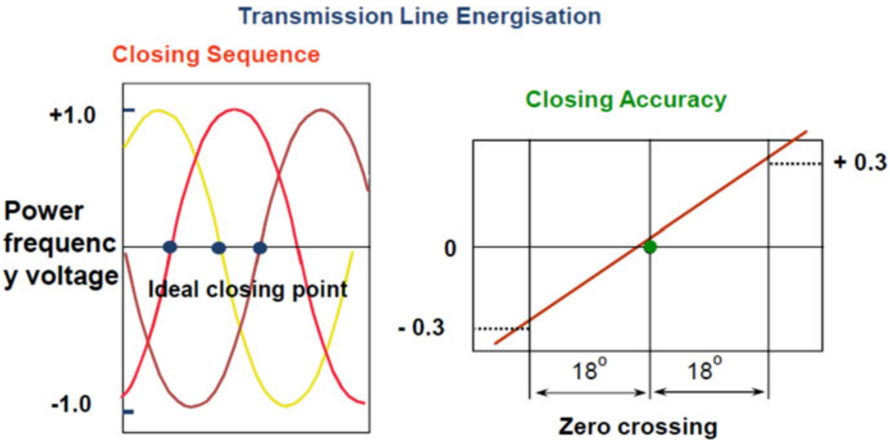


**Fig. 33.9** Diagrams showing ideal closing point for each phase and 1 ms accuracy impact

line, the voltage applied to the line will travel to the far end of the line and then be reflected, causing a voltage doubling. If the voltage at the point of energization is the peak voltage, then it is this voltage which will be doubled, while if the voltage at the point of energization was at the voltage zero, then theoretically there would be no voltage surge. So in this case, we may target closing the circuit at a voltage zero. In order to do this, we need to know accurately the effect on the circuit breaker operating time of certain parameters, for example, the ambient temperature, the close coil voltage, the oil pressure for hydraulic mechanism, etc. It is also very important that the circuit breaker has repeatable characteristics, that is, to say that for the same parameters the breaker will always take the same time to operate. As the voltage on all three phases are offset in time, then the closing signal to each phase has to be sent at the correct time for that particular phase (refer to Fig. 33.9). This usually means that separate mechanisms for each phase will be required, but some manufacturers claim to be able to achieve satisfactory accuracy (usually taken to be 1 ms) with a single mechanism employing a mechanical stagger between phases.

In order to know the precise point on the wave at which the signal has to be sent to the close coil, a special "point on wave" relay is required. This relay has to be linked with a specific circuit breaker and the precise parameters for that circuit breaker loaded into the relay. Based on the parameters at the time of switching, the relay will calculate the point on wave at which to issue the command to achieve the desired closing point. The relay is also usually adaptive so that it learns from each operation to improve its performance for the future. Other factors such as pre-arcing have to be taken into account because the actual voltage application will occur at the point of pre-arcing rather than at the point of contact close (refer to Fig. 33.10). As we try to design our systems to tighter tolerances and reduce the insulation requirements, the use of these fairly complicated controlled switching devices is increasing.

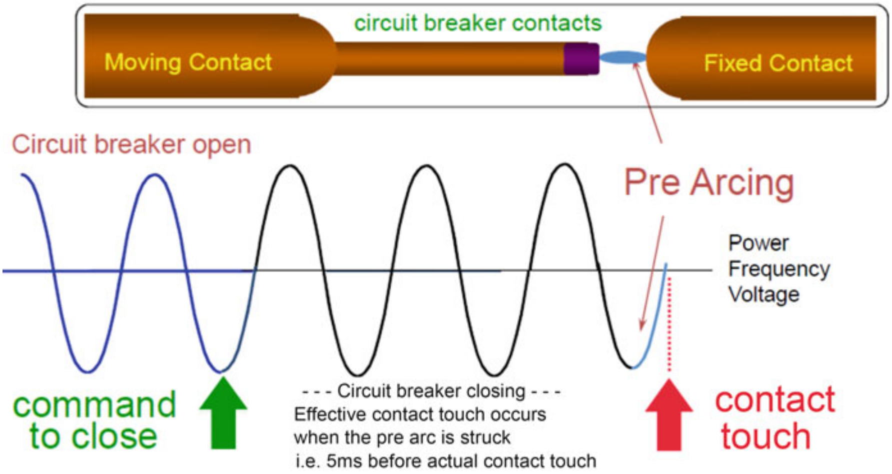


**Fig. 33.10** Effect of pre-arcing on timing of close pulse for transmission line closing

## 33.6 Automatic Switching: Reclosing, Closing, and Operational Tripping

As modern power systems become more complex, there is an increasing need for automatic switching to avoid untenable system conditions from arising.

### 33.6.1 Automatic Reclosing

The most common form of automatic switching is auto-reclosing applied to overhead line circuits. In the early days, operators soon realized that when an overhead line tripped out of service in the majority of cases the fault was transient in nature. If the circuit was reclosed, then the circuit would return to service without any need for intervention. This is because many of the faults which occur on overhead lines are caused by lightning, wind causing jumper loops to flashover to the tower legs, or farmers burning stubble in their fields. Once the fault arc has been extinguished and a short time allowed for the ionized air to clear from the fault vicinity, the insulation strength of the air is fully restored and satisfactory for service. In the early days, this reclosing of the circuit was carried out manually by the operator. It soon became apparent that it would be beneficial if this reclosing action was carried out automatically which enabled it to be much faster and so possible to assist in maintaining system stability under some fault conditions.

On distribution level circuits, multiple attempts to reclose the circuit are allowed, but on transmission circuits it is normal to only perform one auto-reclose. If the auto-reclose is unsuccessful, then the circuit will remain out of service. If however the reclosure is successful, then the auto-reclose relay resets and is available to reclose again on a later fault. Judging whether or not the reclosure was successful or not is usually done by seeing how long the circuit remains in service after being reclosed. This time is known as the reclaim time and is usually about 2 s.

There are several different types of auto-reclose as follows:

- Single pole – high speed
- Single pole – delayed
- Three pole – high speed
- Three pole – delayed

Single pole means that on the occurrence of a fault on one phase, only the faulty phase is tripped and the other two phases remain closed, and then the tripped phase is reclosed.

Three pole means that for a fault on one phase all three phases are tripped and then all three phases are reclosed.

High speed means that the reclosure will take place quickly, just giving enough time for the ionized air to clear away, typically less than 1 s.

Delayed means that the reclosure will be delayed by some time, typically in excess of 10 s. This enables the generators to recover from the first fault before being subjected to a second fault in the event that the fault was permanent and not transient.

Utilities use auto-reclosing for different reasons depending upon the strength of their network. For example, on developing or weak networks, single pole high speed reclosing will be used to assist in keeping system stability under fault conditions by maintaining synchronizing power through the two unfaulted phases. On well-developed networks with the majority of connections being double circuit, three pole delayed reclosing may be used to keep system security during severe storms by restoring the faulty circuit before the other circuit on the same towers trips. In complex substations (breaker and a half, e.g.), different types of auto-reclose may be used depending upon the conditions of the circuits.

Auto-reclosing in the event of a fault is specific to overhead line circuits; however, automatic switching of other circuits may be integrated into an auto-reclose sequence. For example, on a ring or mesh substation where a transformer may be banked onto the same mesh corner as an overhead line, then in the event of a fault on the transformer the whole circuit would be tripped, the transformer was automatically isolated by opening its disconnector, and then the overhead line circuit returned to service. Similarly for an unsuccessful auto-reclose of the line circuit, it may be automatically isolated, and then the transformer returned to service automatically.

During an auto-reclose sequence, circuit breakers may close under different conditions, for example, the first circuit breaker to close will normally be live bar, dead line closed. The circuit breaker at the other end of the overhead line would then close typically on check synchronizing. The synchronizing relay function tends to be built into modern numerical auto-reclose relays.

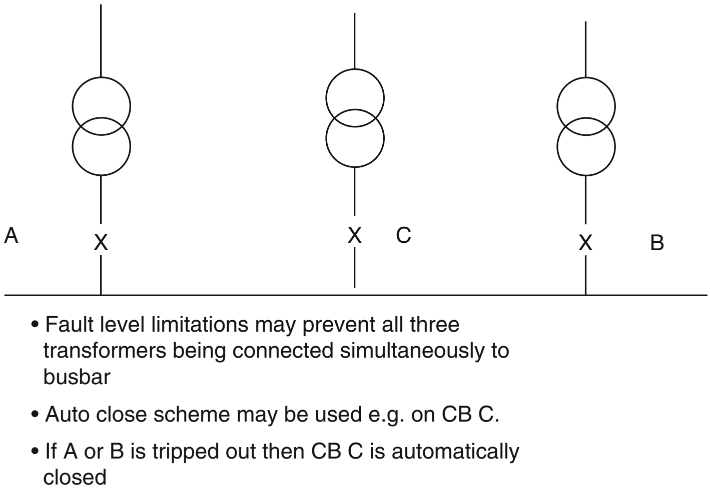


**Fig. 33.11** Example of simple autoclose scheme

### 33.6.2 Automatic Closing

This is the automatic closing of a circuit breaker when system conditions deem it is necessary. The simplest example is when a transformer is on hot standby (LV CB open but disconnector closed). Assume that there are three transformers connected to a busbar, but if more than two are in service, the fault level is exceeded, but two transformers are needed to meet the load demand (refer to Fig. 33.11). In this case transformers A and B are in service, and transformer C is on hot standby, i.e., energized but with the LV circuit breaker open. If either of transformers A or B trip out, then the autoclose scheme will close the LV circuit breaker on C to maintain two transformers in service. More complicated schemes may consider the status of several circuits in order to decide to automatically close the designated circuit breaker, such as bus sections/couplers.

### 33.6.3 Operational Tripping

As systems become more complex, it is becoming more necessary to put automatic schemes into service to avoid thermal overloading leading to cascade tripping or system instability due to excess load or infeed. As an example, if a large generating station is connected into the system via a limited number of circuits, then when some circuits are out of service, there is a danger that the remaining circuits may be overloaded leading to cascade tripping. When this condition arises, a trip signal is sent to a designated generator at the power station to trip it to reduce the power infeed from the station and reduce the loading on the remaining circuits. As this may mean the loss of a significant amount of power (500–1000 MW), the operational tripping scheme has to be very secure to avoid maloperation causing unnecessary tripping. When an operational tripping scheme is designed to avoid thermal overloading, the operating times can be of the order of minutes. However, some schemes have been installed to avoid instability by reducing the throughput of a HVDC link under certain operational conditions. With such an operational tripping scheme, the operation has to take place in less than a second with the same level of security.

## 33.7 Frequency Control and Consumer Load Control

At any instant in time, the power generated must equal the power consumed by the load for the frequency to remain constant. If the generation exceeds the load, then the frequency increases, and if the load exceeds the generation, the frequency decreases.

### 33.7.1 Underfrequency Load Shedding

Normally the frequency control is done by the governors on the generators which control the generator outputs to maintain the frequency constant. However, if there is not sufficient generation to achieve this, then the frequency will start to fall. In this instance, it is necessary to apply some load shedding. This may be done by using underfrequency relays to detect the problem. When the relays operate, they will initiate the tripping of designated circuits to reduce the load. The designated circuits will be the least important loads. A number of stages of underfrequency load shedding may be required with more important circuits being tripped at each stage. Another way of load shedding is to reduce the voltage, and this can be done by reducing the set point voltage in the ATCC scheme.

### 33.7.2 Consumer Load Control

As the load varies significantly during the day from light load through the night to heavy load during the working day, this gives rise to peaks and troughs in the generation required. It would obviously be beneficial if this variation could be smoothed out removing the need to have sufficient generation to meet the peak. Many ways of trying to achieve this have been tried. A simple way is to offer a reduced tariff for electricity used through the night (typically about one third of the cost during the day). This is achieved by fitting dual tariff meters in the consumer's premises. This works reasonably well, but the control of the load is in the hands of the consumer and not the utility. With the development of "smart" technology, it is possible to send signals through the power wires to consumer's premises which are then able to disconnect certain loads at their premises from the network. Usually the consumer will be offered a financial incentive for allowing some of their loads (usually the least essential loads) to be disconnected at any time by the utility. The big advantage of this type of scheme is that it puts the control of the loads in the hands of the utility to reduce the peaks and assist them in optimizing the generation output.

# Metering and Monitoring

# 34

John Finn

## Contents

34.1 Metering ........ 798
 34.1.1 Accuracy Class ........ 798
 34.1.2 Digital Measuring Equipment ........ 799
 34.1.3 Transducers ........ 799
 34.1.4 Digital Transducers ........ 799
34.2 Fault Locating ........ 799
34.3 Fault Recording and Event Recording ........ 800
34.4 Supervision and Alarms ........ 801
34.5 Monitoring ........ 802

In order to efficiently operate the substation, it is important to know the values of certain key parameters such as the voltage on the bus bars and the current in the circuits together with the values of real and reactive power flowing. Furthermore, it is necessary to know accurately the value of energy transmitted between one utility and another at the point of sale. When faults occur, then establishing the location of the fault may be needed. Additionally, analogue traces of currents and voltages linked to an accurate sequence of events can be very useful in analyzing the cause of the fault. In order to know that all of the equipment is operating correctly and not in need of maintenance, then supervision of the equipment together with suitable monitoring systems may be required. This section deals with these aspects.

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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## 34.1 Metering

Conventional circuit control panels, which are becoming less common these days, will include indicating and integrating meters to monitor and measure the primary conditions, e.g., amps, volts, watts, vars, temperature, tap position, frequency, and phase angle. The mounting height of the center of all indicating instruments should generally not exceed 2000 mm with the possible exception of certain common instrumentation, e.g., system frequency and system time clock. All instruments and meters should be fitted with glasses of low reflectivity which should not cause pointer deflection due to electrostatic charging through friction. All indicating instruments are generally of the flush mounted type with dust- and moisture-proof cases and are provided with readily accessible zero adjustment. The dials should, in general, be white with black markings and be of such material that no discoloration takes place. System voltmeters have expanded scales to display the nominal service voltage +20%. Wattmeters and varmeters should have linear positive and negative reading scales. Frequency meters should be of the pointer type and biased to swing to one end of the scale on loss of voltage. The user should provide electrical instrument and meter schedules to include manufacturer, type, current and voltage rating, accuracy class, and circuit designation. They should be of approved types complying with accepted standards such as IEC 60051.

### 34.1.1 Accuracy Class

Instruments are classified by the following accuracy classes:

- **0.05-0.1-0.2-0.5-1.0-1.5–2.0-2.5-5**

The accuracy is expressed as 100 times the quotient of the absolute error and the upper limit of the effective range (total scale length). The absolute error is the difference obtained by subtracting the true value of the quantity from its measured value.

Typical accuracy classes for measuring equipment would be:

- **Amps 1.0 Volts 1.0 Watts 1.5 Vars 1.5 Frequency 0.5 Phase Angle 2.5 Power Factor 2.5 kWatthour 2.0 kVarhour 2.0**

However, when the kWatthour or kVarhour meters are being used for tariff purposes at a point of sale, then the accuracy class will normally be 0.2 S. Furthermore, two sets of meters will normally be used, a main set and a check set. The main set of meters will normally be connected to CT cores and VT windings also with accuracy class of 0.2 S and dedicated solely to the supply of the meters. The check meters will also require CT cores and VT windings with accuracy class 0.2 S, but in this case, other equipment may be connected to the same cores and windings, though the burden imposed by the other equipment may affect and need to be taken into account when calibrating and commissioning the meters.

### 34.1.2 Digital Measuring Equipment

Typically, digital measuring equipment consists of a three-phase digital transducer which accepts signals from VT and CT secondaries and is able to digitally calculate three-phase volts, three-phase currents, three-phase summated watts, and three-phase summated vars and frequency. The digital measuring equipment output is normally via a port, such as RS232.

The main application of digital measuring equipment is in substations where a coordinated microprocessor control system is employed (which have now largely replaced the conventional control panels mentioned in Sect. 34.1).

### 34.1.3 Transducers

Transducers play an important role in the field of measurement and control. Instead of the movement of a pointer, the transducer output is a DC analogue current signal which is proportional to the input quantity to be measured. Used in conjunction with instruments and recorders, these units are convenient for local and remote indication. Installation costs are reduced due to a low burden on current transformers and where summation is required for power measurement, the elimination of a summation transformer. Microprocessor-based control and indication functions may require the use of suitable transducers for supervisory control and data acquisition (SCADA) systems, although more modern SCADA systems can take CT and VT inputs directly. Transducers when used should be of approved types complying with accepted standards such as IEC 60688.

### 34.1.4 Digital Transducers

Digital transducers measure an analogue input, such as current, and convert it into a digital voltage output.

This has the advantage that the transducer can be interfaced directly to a microprocessor-controlled system without the need for any supplementary signal conditioning equipment. Another advantage is that digital signals can be transmitted with a much better immunity to electrical noise and electromagnetic interference. Signal transmission can be by screened cable or by fiber-optic link.

## 34.2 Fault Locating

When a persistent fault occurs on an overhead line, then a line gang has to be dispatched to find the fault and repair it. As overhead lines may be tens or even hundreds of kilometers long, this can obviously be a long and time-consuming task. A fault locator is a device which is intended to be able to pinpoint the location of the fault to within, say two or three, spans. Many methods were used in the past including one using a very high-frequency signal (1 MHz or higher) injected onto the line. The reflections from this signal (similar to radar) are presented on a trace which becomes the characteristic trace for the line. When a fault occurs, a new reflection or blip occurs on the trace, and by measuring the distance of this blip from the terminals (line trap locations), the location of the fault could be established. However, nowadays the majority of fault locators work on an impedance measurement basis with special detailed representation of the overhead line parameters and so require CT and VT inputs for their operation. In countries which have very long lines and difficult terrain, fault locators using a traveling wave mechanism may be used, and these claim to be accurate to within one span.

Online traveling wave fault locators are also used for the location of underground cable faults and are able to pinpoint the fault to within 1% of the length irrespective of the earthing/bonding method of the cable.

## 34.3 Fault Recording and Event Recording

When faults occur on a system, it can be very helpful in analyzing the cause of the fault if analogue traces of the voltages and currents immediately preceding the fault (say 250 ms) are available for study. The device which makes this available is known as a fault recorder. In the early days, exotic names such as "oscilloperturbograph" were used, and the method of storing the prefault data was mechanical by scribing the analogue waveform on an inked drum. When a fault occurred, the recording paper was then applied to the drum approximately a quarter of a revolution later, thus imprinting the prefault traces onto the paper. Nowadays the memory is, of course, electronic. With the development of numerical relays, it is no longer necessary to purchase special separate fault recorders as the fault recording function can be built into the relays.

Fault recorders typically have 16 analogue channels for recording currents and voltages and 16 digital channels for recording protection relay operation or circuit breaker operation. The recorder can be triggered either by a level setting in the analogue channels such as current exceeding a certain amount or voltage falling below a predefined value or by operation of certain digital initiations.

Furthermore, when system faults occur, it can be very advantageous to have accurately timed information of such items as the operation of circuit breakers or other items of primary plant as well as the operation times of protection relays, auto-reclose actions, and alarms. This information is gathered by a sequence of events recorder (SER), which is a standard function with substation control systems. The accuracy of the time stamping of the information should be within 1ms and ideally synchronized accurately across different sites. This is particularly important when a system fault affecting a number of sites needs to be studied.

## 34.4 Supervision and Alarms

As the majority of secondary equipment may not operate for very long periods of time but then be required to operate within milliseconds to clear a fault, it is very important to know that the dormant equipment is healthy. In order to do this, supervision equipment is provided. Probably the most common form of supervision found in high-voltage substations is trip circuit supervision. This monitors that the supply voltage to the trip circuit is healthy and also checks the continuity of the complete trip circuit. This is usually effective for both the condition when the circuit breaker is closed and also the condition when the circuit breaker is open. The resistors allow for a very small current (much smaller than operating current) to flow through the trip coil, without causing its operation. The contacts of relay coil “C” are typically time delayed (around 400 ms) to avoid spurious alarms on operation of the CB and subsequent momentary operation of the contacts from relay coils “A” or “B.”

An example of such a scheme is shown in Fig. 34.1.

In the diagram below, the following symbols are used:

- PR – protection relay contact
- TC – circuit breaker trip coil
- 52a – normally open contact of circuit breaker
- R – resistors
- A – relay monitoring when circuit breaker is closed
- B – relay monitoring when circuit breaker is open
- C – relay energized when circuit is healthy with normally closed contact to give alarm when system is faulty

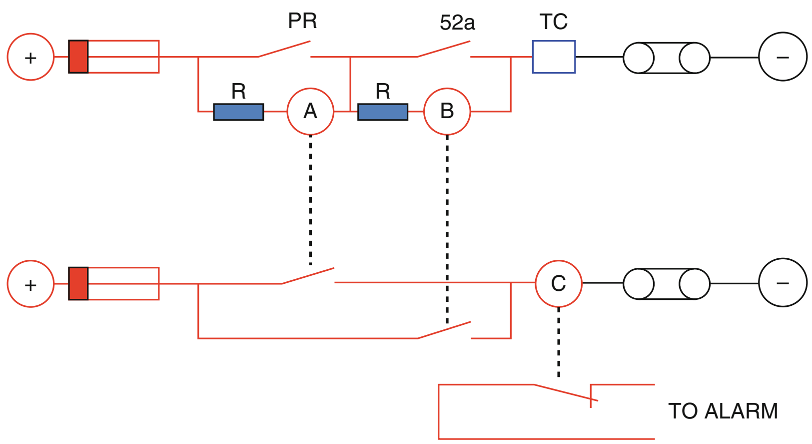


**Fig. 34.1** Trip circuit supervision scheme monitoring both closed and open circuit breaker condition

Such schemes would normally be applied to all trip coils of a circuit breaker.

It is also quite common to monitor the DC supplies to the various different protection circuits. This is usually a simple relay which is energized when the supply is healthy and drops off when the supply fails which initiates an alarm.

With the introduction of numerical relays, then these relays have self-supervision functions which advise the operators if there are any faults or problems with the relays. This should minimize the possibility of the devices failing to operate in the case of a fault, by enabling appropriate action to be taken to rectify the problem in advance.

It is usual in substations to provide information about the current health of the primary and secondary equipment. In the past, this information was displayed on alarm fascias, and the color of the windows would indicate the severity, e.g., white window for information, amber window for alarm conditions, and a red window for trip conditions. With computerized control systems, the alarms are usually produced as files of information stating exactly what the alarm condition is. The operator's attention is usually attracted by an audible sound. The full detail of the alarm condition is usually produced locally to the substation. Alarms which require urgent remote intervention will be forwarded to the control center individually. Alarms which do not need immediate intervention are frequently grouped into common headings, and an operator is sent to the site to investigate the exact alarm condition.

## 34.5 Monitoring

Monitoring of the substation both for the safe operation and also for determining when maintenance may be required has always been required. In the past, substations were usually manned, and the station operators would continually take readings and visually inspect the equipment to ensure that everything was in order. Nowadays, the vast majority of substations are unmanned, and so monitoring equipment may be needed to replace the useful task previously performed by the operators.

Some monitoring devices are able to advise the operator of the deterioration of an item of plant before a failure occurs. Examples of this are Buchholz gas collection for transformers and partial discharge monitors on GIS.

As the time available for circuit outages is becoming more critical, many utilities are considering moving away from time-based maintenance to condition-based maintenance. This requires the fitting of more sophisticated condition monitoring equipment. However, the monitoring equipment itself may be susceptible to failures, so careful consideration of the benefits and value of online condition monitoring needs to be considered. This subject is covered in some detail in ▶ Chap. 51 of this book.

# Substation Communications

# 35

John Finn

## Contents

35.1 Introduction .......... 804
35.2 Communications Within the Substation .......... 805
  35.2.1 Substation Automation with Electromechanical Relays .......... 806
  35.2.2 Substation Automation with Numerical Relays .......... 806
35.3 Communications Outside of the Substation .......... 808
  35.3.1 Information to Be Communicated .......... 809
  35.3.2 Multiplexing .......... 810
  35.3.3 Digital Hierarchies .......... 810
  35.3.4 PDH, SDH, and SONET .......... 810
35.4 Media .......... 814
  35.4.1 Pilot Wires .......... 815
  35.4.2 Power Line Carrier Communication (PLCC) .......... 815
  35.4.3 Microwave .......... 816
  35.4.4 Basic Communication Requirements for Protections .......... 817
References .......... 818

In recent years, the subject of communications, both within the substation and external to it namely between substations and between the substation and the control center, has become more and more important. The subject is so vast and changing so rapidly that in this book only a very brief introduction to the subject can be given to try to give the reader a basic understanding.

Reference has been made to Communications Technology for Protection Systems, PSRC, IEEE Special report by WG H9, 2013 in the preparation of this Chapter, which is an excellent reference for Protection engineers wishing to understand communications.

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

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## 35.1 Introduction

In today's environment, communications has become a consolidated activity as utilities increasingly invest in their own dedicated telecommunications infrastructure. Secure, reliable communications lie at the core of today's power delivery systems.

Through the years the need for reliable communications has become a major consideration in the design of protection and control systems. It is required for protection, control, energy management systems, and wide area monitoring as well as voice communications. Power system protection imposes the most stringent performance requirements upon a dedicated telecommunications system with the need to clear a fault in 80–100 ms requiring channel propagation times of the order of 5–10 ms. Furthermore, the network availability and integrity requirements are well beyond those of a mainstream telecommunications service and are continuing to become even more demanding. Inadequate communications can have drastic consequences for the power network.

Energy management systems and their SCADA need ever more bandwidth combined with high resilience and flexibility. In addition, it is common practice for utilities to implement back up control centers geographically remote from the main control facility. Transferring substation connections between control centers in the event of a major incident puts further demands on the communications network. More wide area applications using time synchronized measurements are being applied increasing the reliance on the telecommunications system.

With increasing demand for communications, digital communication technologies are being applied at an increasing rate. Electric utility applications are also increasing as the benefits of the various digital communication technologies are better understood.

The advancement of digital communication technology is driven by the telecommunications industry, and electric utilities have little influence on this. Consequently, electric utilities typically buy versions of telecommunications industry products with modifications made to make them suitable for the power sector, such as surge withstand capability, wide temperature variations, abnormal vibrations, and immunity to electromagnetic, electrostatic, and radio interference.

The changes over the last 25 years have been enormous with data rates increasing from 300 bps with serial communications to 1000 Mbps with Ethernet, and distances increasing from about 1.2 km with serial communications to in excess of 70 km using optical cables. In addition, there have been a variety of proprietary and open protocols developed culminating in the IEC 61850 whose objectives were

- A single protocol for the complete substation considering the modeling of the different data required for the substation
- Definition of basic services required to transfer data so that the entire mapping to communication protocol can be made future proof
- Promotion of high interoperability between systems from different vendors

- A common method format for storing complete data
- Define complete testing required for the equipment which conforms to the standard

It should be noted that IEC 61850 is being extended to cover the communications outside of the substation to the control center.

All of this has brought our substations into the digital world in which we now live.

## 35.2 Communications Within the Substation

Over the last 50 years the protection and control of substations has evolved. Originally, we had electromechanical relays and meters which were used to protect and monitor the power system. These devices were hard wired to current and voltage transformers, and their way of communicating was via a meter dial or auxiliary contacts, which were connected to other devices designed to provide the necessary audio/visual information. Such information was available locally via the meter dial or local annunciator and horn to attract the operator's attention. The operator was then responsible for communicating events to other stakeholders. This did not really change with the introduction of the "static" single function relays which followed.

The driving factor for the introduction of new technologies for the collection and transmission of data was the need for information in real time, to improve productivity and reduce operation costs. This led to the introduction of remote terminal units (RTU)s and programmable logic controllers (PLC)s to make the information available to other stakeholders.

A RTU is a microprocessor controlled electronic device which interfaces objects in the substation to a distributed control system or supervisory control and data acquisition (SCADA) system by transmitting telemetry data to the system and/or altering the state of connected equipment based on control messages received from the system.

A PLC is a digital computer used for automation of electromechanical processes. Unlike general purpose computers, they are designed for multiple inputs and outputs and designed for operation over extended temperature ranges, to be immune to electrical noise, and to be resistant to vibration and impact. Programs to control process operations are usually stored in battery backed or nonvolatile memory.

RTUs and PLCs are often fitted with interfacing equipments such as transducers and multiple inputs/outputs (I/O) to collect information, which is digitized and transmitted to remote locations such as control centers. Current and voltage signals are collected directly from the instrument transformers, and additional information such as trips and alarms are collected from the relays via the I/O cards (See Fig. 35.1).

RTUs and PLCs allow remote control centers, where the SCADA is located, to receive information via some means of communications link. With the introduction of RTUs and PLCs serial communications became the common communications

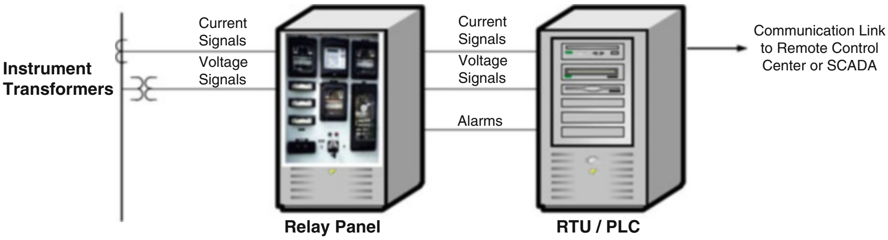


**Fig. 35.1** Introduction of RTUs/PLCs

technology with various protocols such as Modbus, Profibus, DeviceNet, ASCII, and proprietary protocols. The communications link to the control center which is discussed in Sect. 35.3 starts at the RTU or PLC.

### 35.2.1 Substation Automation with Electromechanical Relays

Where the substation is fitted with electromechanical or electronic relays which are not designed to communicate, an intermediate device such as an RTU or PLC as described above has to be installed to collect the relevant information such as:-

- Analog quantities – current, voltage, power, energy, frequency
- Relay alarms
- Breaker status
- Disconnector and earth switch status
- Transformer temperature
- Transformer oil levels
- On load tap changer position
- Breaker commands open/close
- Disconnector commands open/close
- Tap change raise/lower etc.

All of this information is collected in an analogue format, via transducers and I/O cards contained in the RTU or PLC, and is then digitized for transmission to the remote control center.

### 35.2.2 Substation Automation with Numerical Relays

Where the substation is fitted with numerical multifunction relays, also known as intelligent electronic devices (IED) which are capable of communicating either directly to a master computer or to a RTU, PLC, or gateway (Data Concentrator) there are different options dependent upon the type of communications used. Examples for RS 232 pure serial, RS 485 daisy chain, or Ethernet are shown in Figs. 35.2, 35.3, and 35.4, respectively.

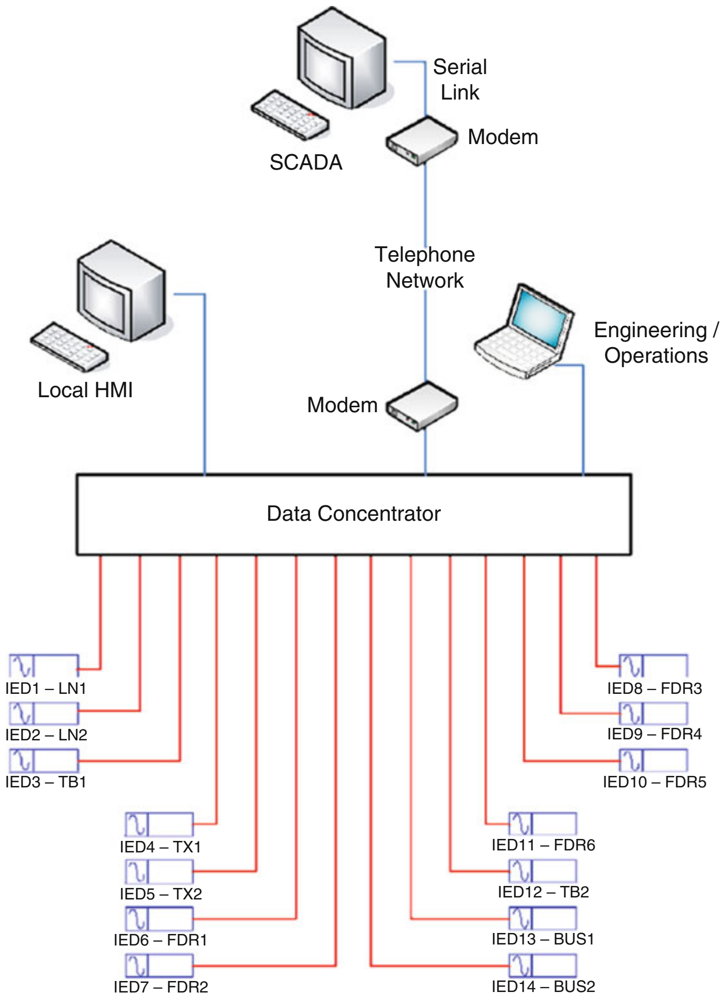


**Fig. 35.2** Serial communication using RS 232

In order to differentiate between communications taking place locally at the substation and communications between the substation and the remote control center, the local ones are called communications level 1 and the remote are called communications level 2.

In Fig. 35.2, the communications level 1 network is connected in star topology to the data concentrator and communications level 2 is also serial connected via a dial-up modem link.

In Fig. 35.3, the Level 1 network is connected via a daisy chain topology to the data concentrator; however, they are not in a single daisy chain. The number of IEDs per daisy chain is selected in order to expedite data polling based upon the baud rate

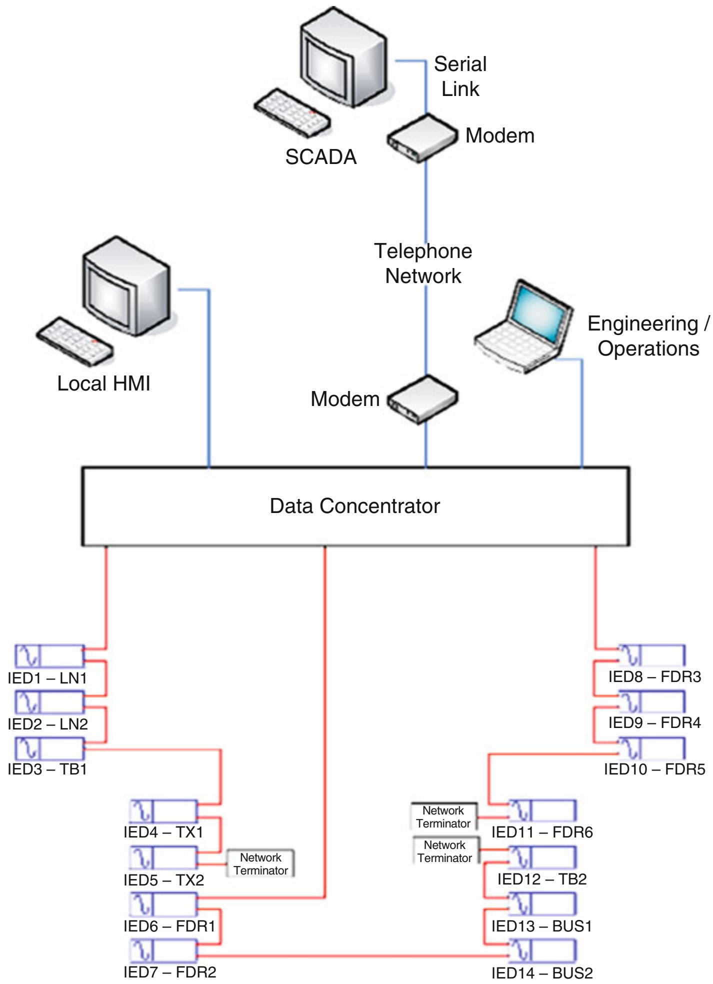


**Fig. 35.3** Serial communications using RS 485

and the amount of data to be collected from each IED. Also there is a limit on the maximum number of IEDs per chain typically 32.

In Fig. 35.4, the IEDs are connected to an Ethernet network, with Level 1 connected in star topology to two Ethernet switches. The Level 2 network starts at the second Ethernet switch to connect to the remote control center.

## 35.3 Communications Outside of the Substation

This section briefly discusses the aspects of the communications system outside the substation either between one substation and another or between the substation and the control center.

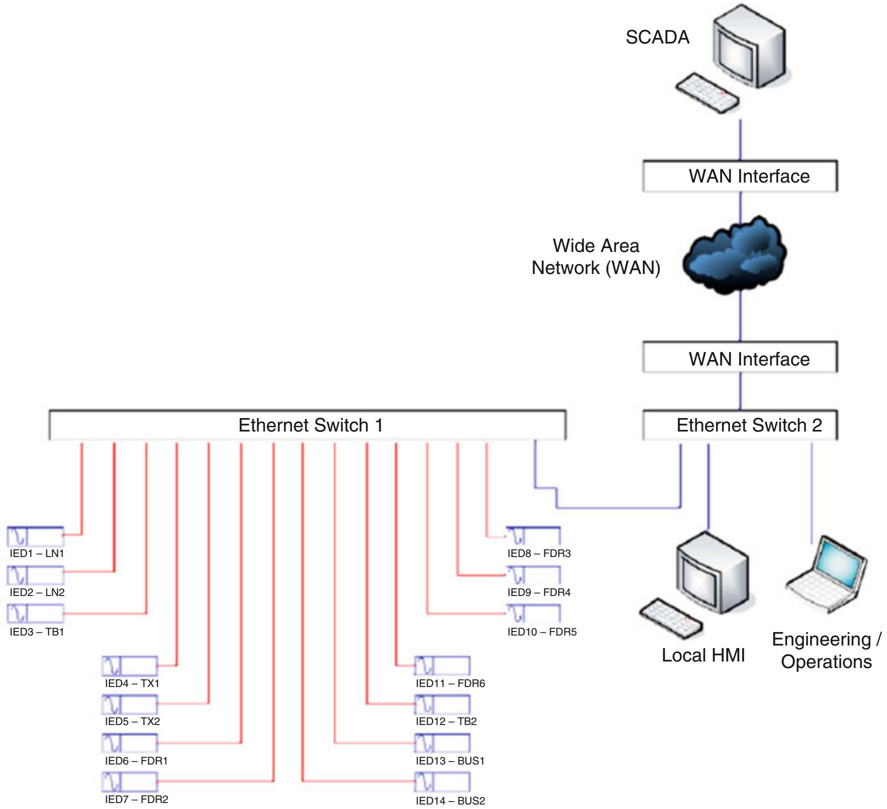


**Fig. 35.4** Communications using Ethernet

### 35.3.1 Information to Be Communicated

The information which has to be communicated outside of the substation is basically:

- Voice
- Data
- Signals as an essential part of a differential protection
- Protection signaling, e.g., distance protection signaling or direct transfer trip (intertripping)

These signals are all communicated via a communication system using one of the types of media described in Sect. 35.4.

In substations, there may be different types of telephone system available. For example, many substations will have a telephone connected to the national telecommunications system which may have a number published in the telephone directory which would enable members of the public to contact the staff in the substation.

Most utilities would not rely on an external telephone system and they will normally have a telephone PAX system of their own to provide secure internal communications. Some utilities may also have a dedicated telephone system for communication between the substation and the control system specifically for the purpose of issuing switching commands or information related to safety documentation such as permits for work, etc.

### 35.3.2 Multiplexing

With the ever-increasing amount of data to be transmitted, it is necessary to use multiplexing to maximize the capability of the physical links.

Multiplexing is the sharing of a communication medium by combining signals at a common point. When the multiplexed signal is received, it is necessary to extract the individual signals from the aggregate and this is called de-multiplexing. There are three main types of multiplexing, namely, frequency division multiplexing (FDM), time division multiplexing (TDM), and code division multiplexing (CDM). CDM is not usually used for protection and control purposes with substations. FDM is used with analogue systems with a special version of this wave division multiplexing (WDM) often being used with fiber optic cables. The system used with digital communications systems for substations is TDM with the version known as fixed TDM being most common for protection and control as it provides continuous data flow at a fixed bit rate without delay variations.

### 35.3.3 Digital Hierarchies

Digital transport systems are increasingly becoming the backbone of modern telecommunications networks or Wide Area Networks (WAN). With increasing demand for information transmission and increased level of traffic it became obvious that a larger number of channels needed to be bundled to fit within the available physical links. Hence, it became necessary to define further levels of multiplexing which are structured in digital hierarchies.

### 35.3.4 PDH, SDH, and SONET

Initially, digital telecommunication systems were based on the Plesiochronous Digital Hierarchy (PDH). These systems use "almost synchronous" channels in multiples of 64 kbps, which is the digital equivalent of an analogue channel. PDH has a number of disadvantages, for example, it is not possible to extract or insert individual channels without firstly de-multiplexing and then re-multiplexing. Furthermore, it does not support network management and performance monitoring. These disadvantages among others have led to the development of synchronous digital hierarchy (SDH) in Europe and synchronous optical network (SONET) in America.

The increased configuration flexibility and bandwidth of SONET/SDH provides significant advantages over the older PDH systems. These advantages include:

- Reduction in equipment requirements and an increase in network reliability
- Provision of overhead and payload bytes – overhead bytes permit management of the payload bytes on an individual basis and allow centralized fault sectionalization
- Definition of a synchronous multiplexing format for carrying lower level digital signals and a synchronous structure which simplifies the interface to digital switches and add-drop multiplexers
- Availability of a set of generic standards which enable products from different vendors to be connected
- Definition of a flexible architecture capable of accommodating future applications with a variety of transmission rates

SONET and SDH are similar but not identical with SONET having the broader scope.

A synchronous network will be more reliable than PDH due to both the increased reliability of individual elements and the more resilient nature of the whole network. SONET/SDH allows the development of network topologies which enable "network protection" to enable it to survive failures and to reconfigure, thus maintaining service by alternate means. Network protection can be achieved by the use of cross connect functionality to achieve restoration or the use of self-healing ring architectures.

There are two main types of synchronous ring architectures

- The 2 fiber unidirectional path switched ring (UPSR – SONET) and 2 fiber sub network connection protection ring (SNCP – SDH). This is a dedicated path switched ring which sends traffic both ways round the ring and uses a protection mechanism to select the alternate signal at the receive end if it detects a failure.
- The 2 or 4 fiber bidirectional line switched ring (BLSR – SONET) and 2 or 4 fiber multiplex section shared protection ring (MS-SPRing –SDH). This is a shared switched ring which is able to provide "shared" protection capacity which is reserved all around the ring. In the event of a failure, protection switches operate on both sides of the failure to route traffic through the reserved spare capacity (Table 35.1).

The following paragraphs and figures explain the UPSR topology.

Information entering the ring is bridged at the path circuit level and transmitted on both fibers in opposite directions. See Fig. 35.5.

The scheme uses one direction as the primary signal path and the other direction as the protected path. Switching from one path to the other is based on the health of the path at the point where it exits the ring. See Fig. 35.6.

**Table 35.1** Equivalence of the terminology between SONET and SDH

| SONET | SDH |
|---|---|
| 2-fiber Unidirectional Path Switched Ring (UPSR) | 2-fiber Sub-Network Connection Protection (SNCP) |
| 2-fiber Bidirectional Line Switched Ring (BLSR) | 2-fiber Multiplex Section Shared Protection ring (MS-SPRing) |
| 4-fiber Bidirectional Line Switched Ring (BLSR) | 4-fiber Multiplex Section Shared Protection ring (MS-SPRing) |

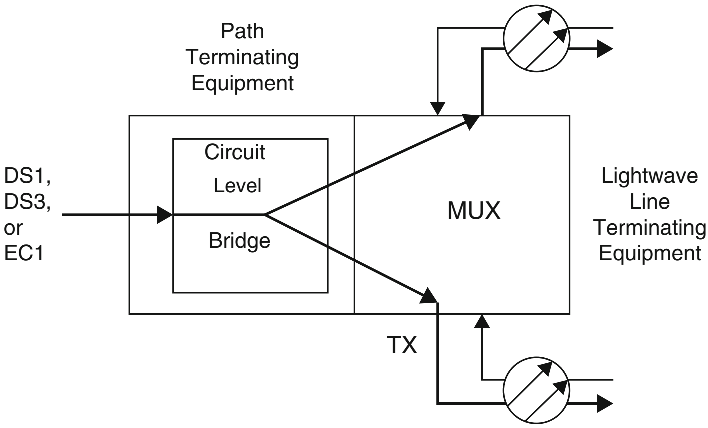


**Fig. 35.5** Path terminating equipment at circuit level entry

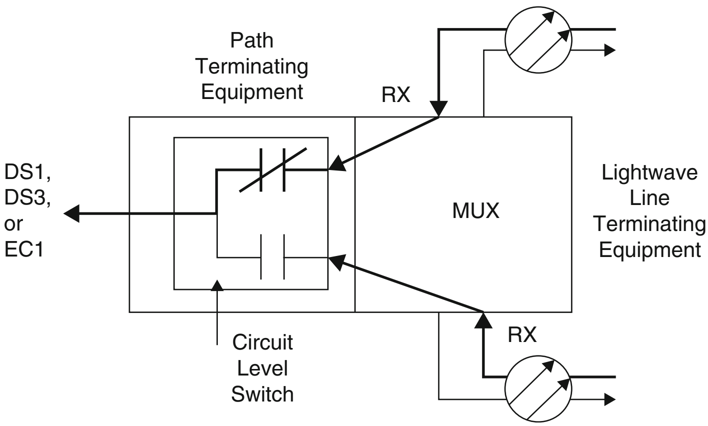


**Fig. 35.6** Path Terminating equipment at circuit level exit

In Fig. 35.7, a signal is entering a UPSR at node A and exiting at Node B with the primary path being the shortest route. If a failure occurs between Node A and Node B and this is detected at Node B, then switching to the protected route occurs as shown in Fig. 35.8.

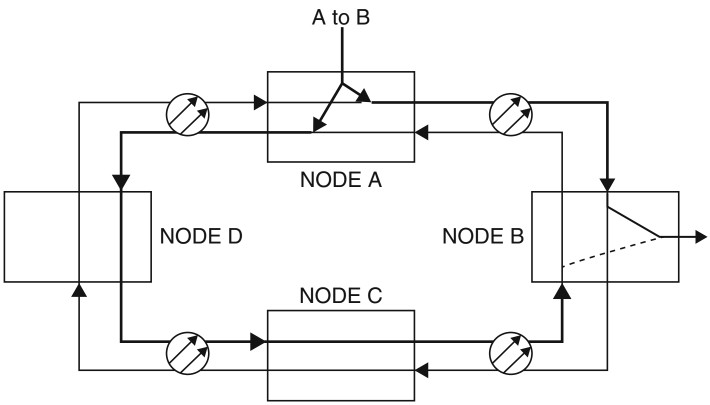


**Fig. 35.7** Normal flow in UPSR

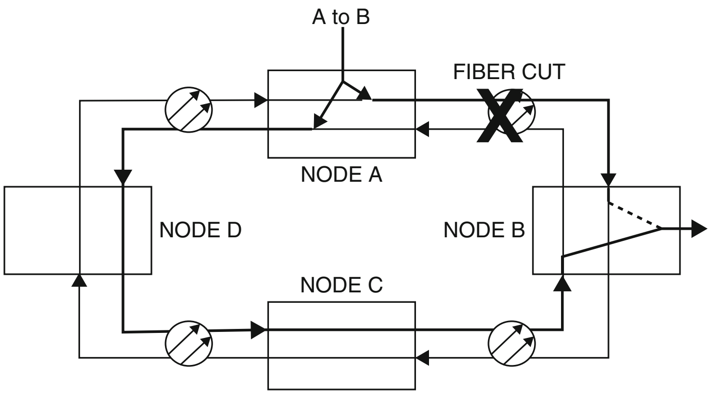


**Fig. 35.8** Protected flow in UPSR

However, as switching is determined at the receive end only it is possible that the path in one direction may switch over to the protected path while the other direction remains on the normal path, thus giving rise to unequal delays. See Fig. 35.9 which shows that Node A has switched to the protected route while Node B is still on normal. This can lead to problems with some differential protections.

In a BLSR topology, half of the bandwidth is reserved for protection. Both transmit and receive paths are mapped to take the same route in opposite directions and both switched together thus eliminating any differential delay although in the switched condition the delays around the ring are likely to be longer. See Fig. 35.10 for an example of BLSR. In normal mode, the route from A to B follows Service 1 S1 while the route from B to A follows S2. When a fault occurs A to B will follow P1 and B to A will follow P2.

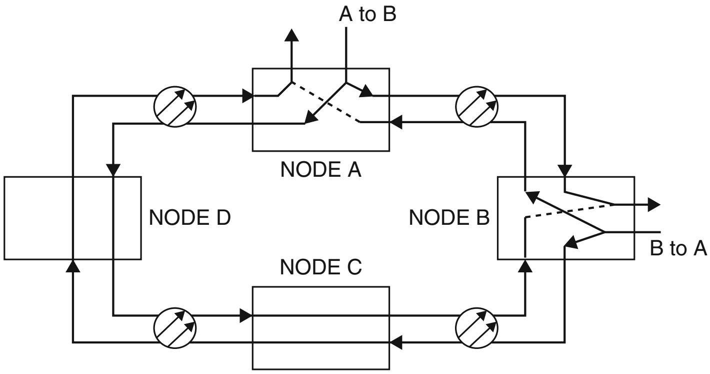


**Fig. 35.9** Example of unequal channel delay with UPSR

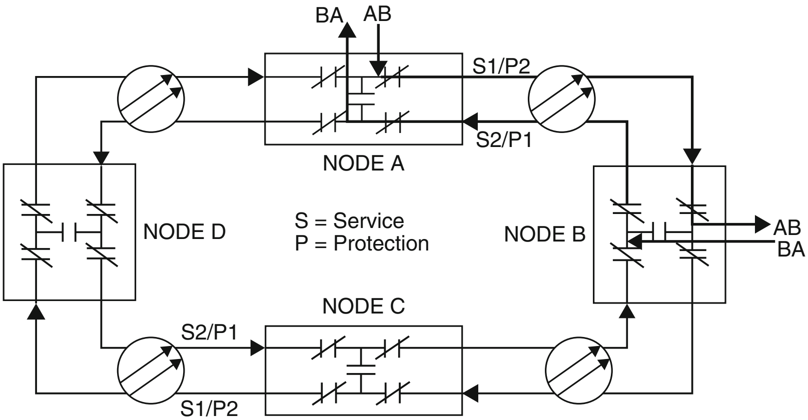


**Fig. 35.10** Example of BLSR in normal mode

## 35.4 Media

There are basically four different media which have been used over the years for communications from substations, namely:

- Pilots
- Power line carrier communications (PLCC)
- Microwave
- Fiber optic cable

These will be discussed in the next few paragraphs.

### 35.4.1 Pilot Wires

Pilot wires are often laid together with power cable circuits but less likely with overhead line circuits. In the past, it was possible and common practice to lease metallic pilots from the national telecommunications company. Many of the older pilot wire differential protections required continuous metallic pilots. However, 35–40 years ago, telecommunications companies said that they would no longer be able to lease metallic pilot wires and that pilots available would contain amplifiers, etc., in the line. This forced a change to pilot wire protection and many companies introduced voice frequency signaling built into their differential protection.

Leasing of pilot wires is still one of the media which is available to use today.

### 35.4.2 Power Line Carrier Communication (PLCC)

PLCC is communication using the power lines themselves. The frequency used for the carrier signal is usually in the range 20–700 kHz which falls within the frequency range used by civil aviation, time clock signals, and other public services, so interference needs to be carefully considered and minimized. Overhead lines have good high frequency transmission characteristics.

There are many different ways that the signal can be communicated over the power line, which may use one, two, or all three phases of the circuit. The cheapest and hence one of the more popular methods is to use single phase to ground, usually using the center phase. This only requires coupling capacitors and line traps in one phase. If a more reliable or lower loss system is required, then using two phases of the circuit the center phase and one outer phase (push/pull) is also often used. An alternative to this, frequently used on double circuit lines, is to use the center phase conductor on each of the two circuits. The lowest loss system is the Mode 1 coupling which signals out on the two outer phases and in on the center phase.

In simple terms, the information signal is used to modulate a carrier signal, usually a 4 kHz side band. The carrier signal is passed through the line tuner (LTU) and then coupled to the power line through a coupling capacitor (CC). It is very common practice to use the capacitance of a capacitor VT as the coupling capacitor for power line carrier. In order to prevent the high frequency signaling from going back into the substation a line trap sometimes called a wave trap (TRAP) is used. Basically, the line trap is a low pass filter which has negligible impedance to power frequency but very high impedance to the carrier frequency. The signal passes to the other end of the line where it cannot pass the line trap and so passes through the coupling capacitor to the LTU and the carrier equipment where the information is extracted (Fig. 35.11). This was a very common method of communication used on EHV systems although in many countries it is now being superseded by the use of optic fiber.

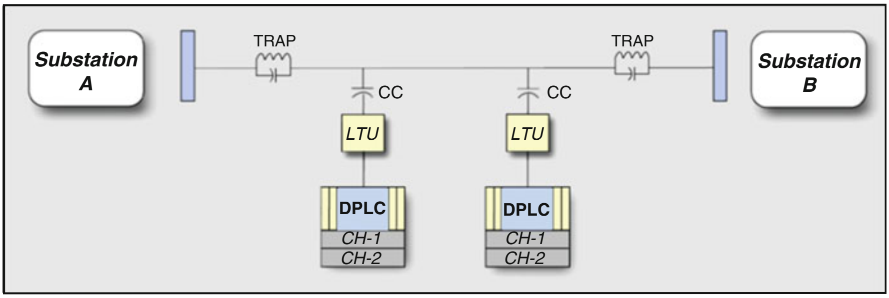


**Fig. 35.11** Power line carrier communications (PLCC) system diagram

### 35.4.3 Microwave

In the power industry, "microwave" is a type of communications used for transmitting and receiving signals from one location to another. It transmits and receives signals through the air with the use of radios and antenna. The radio frequency is in the range 300 MHz–300 GHz, and specific frequencies within this range are usually regulated and assigned to various users by a national governing organization.

Microwave has a large band width meaning that assigned frequencies can be allocated to more users. It can use highly directional and small antennae. Some other advantages are:

- It supports a wide variety of network requirements such as voice, data, and video.
- There are no leasing costs which would be incurred when leasing pilots.
- The restriction on rights of way is small as only the tower locations need permissions.
- The service and expansion of the microwave system is under the control of the utility.
- The path is not affected during power line faults as may occur with power line carrier.

However, it is restricted to relatively short "line of sight" communication paths. Therefore, repeater stations are required to communicate where there are mountains or other obstacles between the sending and receiving locations. Also the signal is vulnerable to increased loss under certain weather conditions such as fog, rain, or snow.

#### 35.4.3.1 Fiber Optic Cable

The use of this media has dramatically increased over the last 15–20 years and for many utilities is now their preferred media. This is due to a number of reasons including multi-vendor availability leading to lower purchase and installation costs. Optical fibers are integrated into the earth wires on all new overhead line routes and upgrades. Furthermore, it is possible to wrap fiber optic cable around existing earth wires or even around phase conductors. This is enabling utilities to build a very reliable communications backbone with a minimum of common mode failures. It also enables the utility to combine many communications needs such as telecommunications, SCADA, video, data, voice, etc.

There are two optical fiber categories, namely, multi-mode and single-mode fibers. The distance of the communication link usually decides which type of fiber is required. Multi-mode fiber is used for shorter distances of up to about 16 km. Optic connections are generally made within the substation using multi-mode fiber because of the lower cost.

For longer distances, single mode fiber is used with LED or laser optical transmitters. Laser provides a longer reach but at a higher cost. Distances in excess of 100 km can be achieved with 1550 nm fiber combined with a laser optical transmitter.

## 35.4.4 Basic Communication Requirements for Protections

This section briefly discusses the main aspects which are essential for communications associated with protection functions.

### 35.4.4.1 Speed/Delay

It is important to know the speed of the channel, namely, how many bits per second are communicated and the delay as much of the information associated with protection functions is time sensitive.

#### Speed

The speed of communications channels used for protection is normally 64 kbps suitable for full duplex operation.

#### Delays

**Propagation Delay**

The propagation delay is the delay for the signal to travel from one end to the other. It is dependent upon the number of different items of equipment in the route and the route length itself. Usually a delay time of about 6 ms or less is required for satisfactory operation. It is also important that the delay time is stable and not variable during normal operation. It will however change if the path is rerouted due to failure conditions.

**Differential Delay**

Differential delay is the difference in time of the path from A to B compared with the path from B to A. This aspect is very important with regard to differential protections where the typical maximum acceptable differential delay will be of the order of 400 μs.

**Table 35.2** Dependability and security requirements for teleprotection

| Scheme | Dependability | Security |
|---|---|---|
| Blocking (DCB) | $<10^{-3}$ | $<10^{-3}$ |
| Permissive underreach (PUTT) | $<10^{-2}$ | $<10^{-4}$ |
| Permissive overreach (POTT) | $<10^{-3}$ | $<10^{-3}$ |
| Intertripping (DTT) | $<1O^{-4}$ | $<10^{-6}$ |

#### Dependability and Security

As well as requiring high speed, constant data transfer, and protection relays have very high requirements on reliability. Reliability has two components, dependability and security.

#### Dependability

This is the aspect of reliability which relates to the assurance that a relay or relay system will respond correctly to faults or conditions within its intended zone of operation, i.e., it will trip when it is supposed to do.

#### Security

This is the aspect of reliability which relates to the assurance that a relay or relay system will restrain from faults which are outside of its intended zone of operation or other conditions, i.e., will not trip when it is not supposed to do.

When a digital communications system is used for teleprotection purposes both of the above aspects have to be considered. IEC 60834-1 (1999) provides some guidelines for acceptable levels of dependability and security (See Table 35.2).

### 35.4.4.2 Redundancy

Redundancy, which means that there is more than one means for performing a given function, inherently increases dependability but it will tend to decrease security as there are more devices which can mal-operate. However, it is normal practice to provide duplicated and separate routes for the first and second main protections on a circuit. These should normally be spatially separate (typically at least 5 m apart) and should not be subject to any common mode failure which could affect both links. Also, if a communication path fails, there will normally be a back up route which will automatically be switched into service (See Sect. 35.3.4).

## References

Communications Technology for Protection Systems, PSRC, IEEE Special report by WG H9 (2013)

# Substation Digital Equipment

# 36

Richard Adams

## Contents

36.1 Digital Systems Within Substations and IEC 61850 Impacts ........................... 820
36.2 Software and Firmware ............................................................. 824
References ............................................................................... 825

The majority of protection devices used in substations today are digital or numeric devices. Unlike older electromechanical devices that tended to only have one function, digital devices may have many functions, being able to perform several types of protection from the one device, including control functions, fault recording, and condition monitoring. Another benefit of these devices is that they can provide self-supervision and indication of failure should one occur, whereas many old electromechanical devices were unable to provide such indication and any failure would only be detected during maintenance or maloperation/non-operation during an actual fault. Digital devices tend to be smaller than their traditional counterparts, and their use means that fewer discrete relays are required, and hence less panel space, so the number of panels now required for a particular type of circuit is reduced. This mean that relay rooms may in turn be smaller, with consequential reductions in land and civil costs.

Since much of the electrical protection scheme logic now resides within the relays themselves, it is no longer possible to view a traditional electrical schematic drawing and follow the logic of the protection scheme in its entirety. The schematic diagrams largely show connections of inputs and outputs; however, the internal logic of the relay should also be understood in order to have the full picture of how the complete system works. In many cases the internal logic can also be changed or designed to suit a particular application, which can also lead to less wiring.

R. Adams (✉)
Power Systems, Ramboll, Newcastle upon Tyne, UK
e-mail: richard.adams@ramboll.co.uk

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These advantages also bring a number of challenges or considerations for the protection system designer and testing personnel. For instance, if a multifunction digital device is only used for one or two functions, the remaining ones should be switched off or disabled to prevent inadvertent operation. There are a far greater number of settings to be configured and managed and a greater possibility of errors unless due consideration is given. This has been mentioned earlier in ► Sect. 32.1.5.

Traditional large mimic-type control panels with discrete instruments, alarm annunciators, and control switches have also been replaced in most instances by digital control systems, with HMI (human-machine interface) computer-type monitors. Instead of the operator manually turning discrepancy control-type switches to operate switchgear, plant is now selected on a screen and operated by a mouse or other pointing devices and a keyboard. In fact it is becoming increasingly difficult to distinguish between protection and control devices within a substation. Since many devices can perform functions for both categories, terms such as Substation Automation Systems (SAS) rather than "protection and control" are now being used to refer to the secondary systems. The term IED (Intelligent Electronic Device) is now commonly used for devices, rather than just "relays," since the devices are capable of much more than purely relaying functions.

The above has an impact upon staff, since they should keep their knowledge up to date with the faster-moving technology but maintain knowledge to service any existing legacy equipment still on the network. It can also impact upon the operating structures within utility organizations; departments such as protection, control, and telecommunications which may have operated largely independently of each other in the past need to work closer together or possibly merge since the equipment now involves all of these disciplines. Indeed, over time, the roles and knowledge may merge too. With the complexity and number of functions of modern numeric devices, some utilities may outsource more work to suppliers/manufacturers who are deemed to know more detail about the devices, thus reducing the onus somewhat on the utility itself.

## 36.1 Digital Systems Within Substations and IEC 61850 Impacts

Substation automation systems have been applied by utilities since the 1980s, justified on the basis that engineering would be easier and operation and maintenance costs would be reduced. However, the lack of international standards resulted in the use of a range of proprietary solutions offered by manufacturers, but this restricted or complicated the application of devices from other manufacturers. The profusion of protocols and knowledge required by engineers meant that a non-proprietary standard would be the best solution, leading to the development of IEC 61850, thus replacing a number of incompatible protocols.

The IEC 61850 standard (Communication networks and systems in substations) is multipart and a global standard, intended to meet cost and performance requirements of utilities. It enables IEDs from different manufacturers to use and exchange information for their own functions, as well as support different philosophies. It supports free allocation of functions and can be applied to centralized or decentralized systems and is intended to be "future-proof," allowing progress in communication technology and evolving system requirements. The most important benefits to users are deemed to be:

- Lower installation and maintenance costs through self-describing devices that reduce manual configuration
- Reduction in engineering and commissioning with standardized object models and naming conventions for all devices eliminating manual configuration and mapping of I/O signals to power system variables
- Less time needed to configure and deploy new and updated devices through standardized configuration files
- Lower wiring costs while enabling more advanced protection capabilities via the use of peer-to-peer messaging for direct exchange of data between devices and a high-speed process bus that enables sharing of instrumentation signals between devices
- Lower communication infrastructure costs by using readily available TCP/IP and Ethernet technology
- A complete set of services for reporting, data access, event logging, and control sufficient for most applications
- Maximum flexibility for users to choose among an increasing number of compliant products to be used as interoperable system components
- Sampled value standards enabling the sharing of digitized analogues and reduction of the number of CTs and VTs required

It has facilitated the replacement of traditional copper wiring/cable connections with fiber optics, reducing cabling costs. This can reduce civil costs too if the numbers and sizes of cables are reduced and smaller ducts or trenches can be installed.

Figure 36.1 shows the three typical levels of control architecture in a substation. The station level contains the common equipment for the substation – the HMI, communications interfaces, etc. – while the bay level is more circuit specific and the equipment for each circuit (such as the protection relays and local control units) reside here. The primary equipment (such as instrument transformers and disconnectors and circuit breakers) is within the process level. While the connections between levels have traditionally been copper wiring, the application of substation communication buses led to a reduction of cabling. IEC 61850 now enables devices from different manufacturers to be connected to the same communication bus and share information in a truly interoperable way. Not only can devices from different manufacturers be applied, but status signals can be shared between devices, meaning that multiple connections of plant status signals, etc. are no longer necessary – once the signal is configured for one device, it can be shared to others connected to the network in the substation. However, all these interoperability and interchangeability features require a standard configuration specification.

In a further advancement, IEC 61850 has now enabled the copper wiring connections between the process and bay levels to be replaced by fiber optics with the so-called process bus, replacing analogue signals with digitized versions. To many,

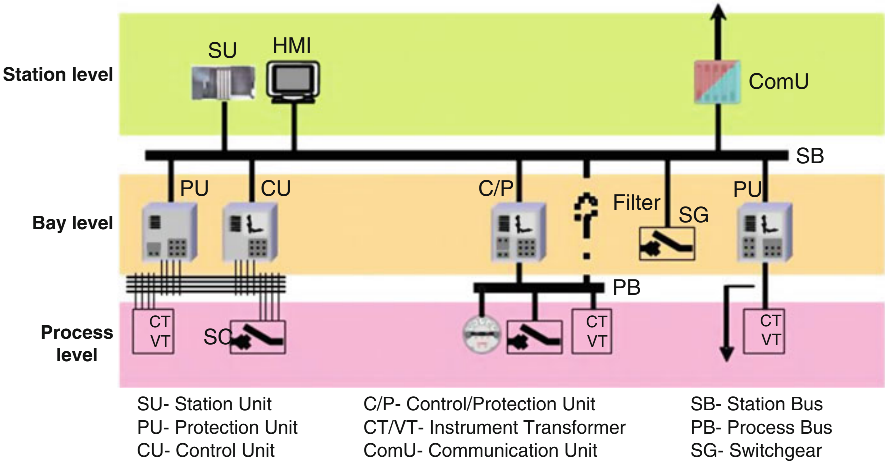



**Fig. 36.1** Three levels of communication within substations

this represents a significant change in philosophy with the fundamental signals to and from the plant no longer being hardwired in copper. Instrument transformer signals from conventional CTs and VTs can be digitized via merging units in the switchyard or modern nonconventional CTs using fiber optics and Faraday effect or voltage dividers to replace a VT, each with inherent analogue-to-digital conversion can be used.

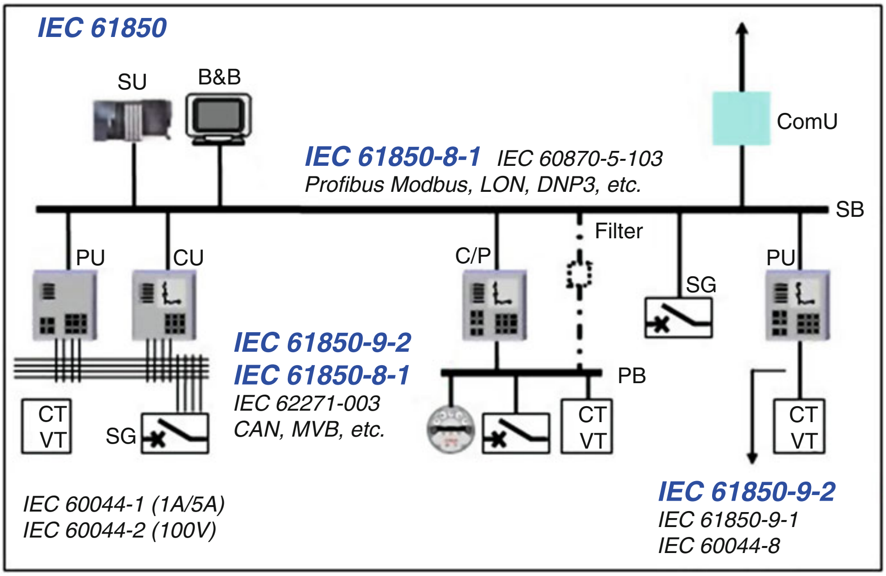
Tripping signals too can be issued via GOOSE (generic object-oriented system events) message over the network rather than conventional wiring, and a truly digital substation has become a possibility and reality.

Figure 36.2 shows some of the standards used in substations prior to the release of IEC 61850 and the comparable IEC 61850 parts. Note that while the substation bus and process bus are shown as being separate networks, they could in practice both be part of one single network. As implied by the diagram, it is possible to apply a substation bus while devices at the process level are still hardwired to bay level units, meaning that users can establish and adopt a degree of automation which they can comfortably manage and control.

Figure 36.3 shows a block diagram representation of a substation, the differing communication levels and possible connections between them.

As the substation automation equipment has become digital, so too has the commissioning and testing equipment. Modern test equipment can be programmed to run specific test sequences, reducing time and cost. Some test equipment is also IEC 61850 compatible and does not need to be connected directly to the device under test anymore but can be connected to the substation bus and "address" the device requiring testing. The use of process bus and "sampled values" of the primary current and voltages has also facilitated this.

An aspect of modern digital devices which also must be considered is their life span, which is generally much shorter than electromechanical devices. There are




| | | | | | |
|---|---|---|---|---|---|
| SU | Station Unit | C/P | Control/Protection Unit | SB | Station Bus |
| PU | Protection Unit | CT,VT | Instrument Transform | PB | Process Bus |
| CU | Control Unit | ComU | Communication Unit | SG | Switchgear |

**Fig. 36.2** Protocols in substations

many networks which still contain electromechanical relays in working order 40–50 years after installation. By contrast, digital devices have a lifetime nearer 10–15 years due to obsolescence of components and difficulty of continuing support by manufacturers. This means that during the typical 40-year life span of a substation, the substation automation system would be replaced at least once, if not twice, during the life of the primary equipment. This may at least in part be offset by the fact that the relative cost of digital equipment and the engineering tends to be lower than that for electromechanical devices. Ease of replacement of the secondary equipment is best considered during initial construction of the substation, to avoid potential problems later.

The use of IEC 61850 can assist with the upgrading of equipment – the reduction of copper connections and use of Ethernet-type connections instead mean that new devices can be connected to the substation bus, configured, and tested in the substation environment before replacing the older unit.

Modern digital devices and control systems are also able to provide and handle additional monitoring functions. In the digital substation, it is possible to monitor so much more than previously by gathering additional information regarding the status of the plant. Trend analysis is also possible, enabling condition-based maintenance rather than fixed time schedule maintenance.

Novel techniques such as dynamic line rating can also be applied by measuring wind speed to vary the current capacity of the line.

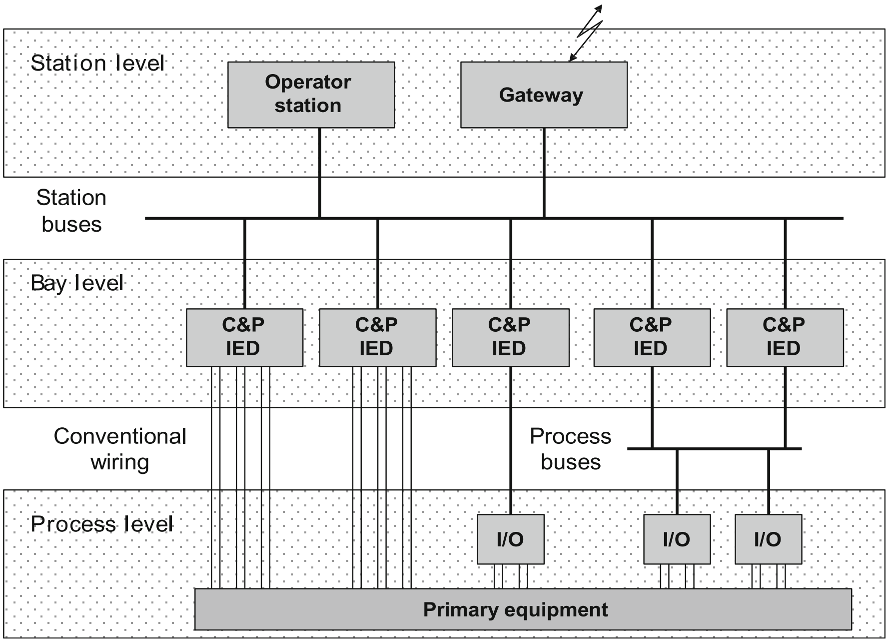



**Fig. 36.3** Substation terminology

## 36.2 Software and Firmware

These days, many devices from an individual supplier look identical, and it is hard to distinguish say a distance relay from a transformer relay at first glance. It is the applied firmware (software within the device itself) which establishes how the device will perform and what functions it will contain. While many digital devices contain a small display to be able to access or read settings, etc., they are usually configured with appropriate manufacturer's software, to allocate functions and operation to specific outputs, etc. and apply suitable protection settings. However, the management of firmware and software can present their own challenges, and certain versions may not be compatible with each other.

New versions of devices, which may include additional functions or modified setting ranges, etc., can be released by manufacturers by modifying the firmware, meaning that new versions can be issued more easily and frequently than older static or electromechanical relays. If not managed correctly, this can pose challenges to utilities and owners – they could end up with several versions of seemingly identical relays, but which may contain subtly different functions and setting ranges, resulting in logic or setting files that may not be compatible between devices. A way that some utilities overcome this is to approve a certain firmware/software version and then specify that particular firmware version only for any supply until such time as another version is approved by them. In this way they can be sure of the functionality of the device and its compatibility with their network and any spares which they may hold. If this is not done, then the owner must be sure of the functionality contained within the devices and the differences between different versions in order to minimize the risks of maloperation.

## References

The following are not specifically referred in the previous section, nor meant to be an exhaustive list, but rather a possible source of further, more detailed information should the reader be interested. The E-CIGRE website is a very useful source of information published by the Study Committees of CIGRE.

### CIGRE Publications


TB326 – The Introduction of IEC 61850 and its Impact on Protection and Automation Within Substations, 2007

TB401 – Functional Testing of IEC 61850 Based Systems, 2009

TB464 – Maintenance Strategies for Digital Substation Automation Systems, 2011

TB466 – Engineering Guidelines for IEC 61850 Based Digital SAS, 2011

TB540 – Applications of IEC 61850 Standard to Protection Schemes, 2013

TB628 – Documentation Requirements Throughout the Lifecycle of Digital Substation Automation Systems, 2015

TB637 – Acceptance, Commissioning and Field Testing Techniques for Protection and Automation Systems, 2015


### Standards


IEC 61850: Communication networks and systems in substations –

Part 1: Introduction and overview

Part 2: Glossary

Part 3: General requirements

Part 4: System and project management

Part 5: Communication requirements for functions and device models

Part 6: Configuration description language for communication in electrical substations related to IEDs

Part 7-1: Basic communication structure for substation and feeder equipment – Principles and models

Part 7-2: Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)

Part 7-3: Basic communication structure for substation and feeder equipment – Common data classes

Part 7-4: Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes

Part 7-410: Hydroelectric power plants – Communication for monitoring and control

Part 8-1: Specific Communication Service Mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3

Part 9-1: Specific Communication Service Mapping (SCSM) – Sampled values over serial unidirectional multidrop point to point link

Part 9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3

Part 10: Conformance testing

# Equipment Considerations and Interfaces for Substations 37

John Finn

## Contents


37.1 Equipment ........ 828
37.1.1 Circuit Breakers ........ 828
37.1.2 Current Transformers ........ 828
37.1.3 Voltage Transformers ........ 831
37.1.4 Other Plant ........ 833
37.2 Testing Associated with Primary Plant ........ 834
37.2.1 Circuit Breaker Interface Testing ........ 834
37.2.2 Primary Injection of Current Transformers ........ 834
37.3 Secondary System Isolation ........ 835
37.3.1 DC Voltage Isolation ........ 835
37.3.2 Trip Isolation ........ 836
37.3.3 Current Transformer Isolation ........ 836
37.3.4 Voltage Transformer Isolation ........ 836
37.4 Secondary Equipment Considerations ........ 836
37.4.1 Separation of Cubicles/Rooms ........ 837
37.4.2 DC Distribution ........ 837
37.4.3 Relay Rooms ........ 837
37.4.4 Cabling and Wiring ........ 838
37.4.5 Accommodation of Equipment and Ventilation ........ 838
37.4.6 Fire Detection and Extinguishing ........ 839
37.5 Earthing Practice ........ 841
37.5.1 Measures to Be Taken on Secondary Equipment ........ 842
37.5.2 Measures to Be Taken in the Installation ........ 842
37.5.3 Screening of Relay Rooms and Control Rooms ........ 843
References ........ 843



J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com



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As mentioned in the introduction to this part, the secondary equipment allows the substation to perform its intended functions. This section deals with the main interfaces between the secondary and primary equipment and also the interfaces with the buildings and the earthing system to ensure that the secondary equipment can perform satisfactorily.

## 37.1 Equipment

In this section, we take a brief look at the main interfaces between the secondary system and the primary plant. It is not intended to be an exhaustive list but basically to highlight some of the requirements.

### 37.1.1 Circuit Breakers

The interface of the secondary equipment with the circuit breakers is probably the most important interface as this enables the operator to close and trip the circuit breaker and also for the protection devices to automatically trip the circuit breaker. These interfaces are still mainly hardwired interfaces with a contact closing to apply voltage to the close coil or the trip coils. This may change in the future as the capability and confidence in the GOOSE message approach grows. At transmission voltages, there is usually one close coil and two trip coils. One trip coil is being used for each of the two separate protection systems. The interface is basically very simple; however it should be remembered that the trip coils can draw quite high operating currents. This means that the voltage drop in the cables from the battery to the coil can be large, and it is essential that the voltage delivered to the trip coil is high enough to trip the circuit breaker reliably at any point in the battery charging cycle or on loss of AC supply to the charger. This may require the use of a large cable cross section (say 25 or even 35 mm$^2$) to ensure adequate voltage is available even below nominal battery voltages.

The other interface with the circuit breakers is the auxiliary switches to indicate whether the circuit breaker is open or closed. This information may be needed for control, interlocking, protection, or autoreclose purposes.

### 37.1.2 Current Transformers

Many items of secondary equipment interface with current transformers (CT). Current transformers transform the very high currents in the primary circuits to values which can be handled by the instruments and relays. Usually the secondary current of a current transformer will be either 1 A or 5 A. However, when interfacing secondary equipment with current transformers, it is very important to understand the function of the secondary equipment in order to select the correct type and class of CT. Furthermore, reference should always be made to any requirements on CTs defined by the relay supplier. The following paragraphs discuss some of the more common types of CT.

#### 37.1.2.1 Metering CTs

When the CT is providing a signal to an instrument to indicate the current or power for control purposes or to a meter for tariff measurement, its accuracy at the normal values of current is important, but accurately measuring high currents which may occur under fault conditions is not. In fact, we do not want these high secondary currents which occur under fault conditions to damage instruments or meters, and so ideally metering CTs will saturate at relatively low values of current in order to protect the instruments.

In order to specify a metering CT, we would usually specify the following parameters:

- **Ratio** – this is a current ratio, e.g., 2000/1 meaning with 2000 A in the primary, we will get 1 A in the secondary.
- **Class** – this defines the accuracy of the CT at normal currents, e.g., Class 0.2 means it is accurate to within 0.2%.
- **Factor of Safety (Fs)** – this is the factor of safety to protect the instruments connected to the CT, e.g., if Fs is 5 then this means that the CT will saturate when five times the rated current flows through the CT with the rated burden connected. (It should be noted that if the CT does not have its rated burden connected, then the CT will not saturate until higher values of current are flowing.)
- **Burden** – this is the maximum burden which can be connected to the CT for it to still meet its performance requirements. The accuracy will be maintained between 25% and 100% of the rated burden. A typical burden may be 15 VA.

#### 37.1.2.2 Protection CTs

When the CT is feeding a current signal to a protection relay, it is obviously important that the CT will remain relatively accurate up to the high values of fault currents so that the protection can operate properly. Consequently, when specifying a CT for protection purposes, it is necessary to specify the following parameters:

- **Ratio –** This is a primary to secondary current ratio, e.g., 2000/1 meaning 2000 A in the primary will give 1 A in the secondary.
- **Class –** This defines the purpose and performance of the CT. For example, Class 5P20 means:
  - 5 – This is the percentage accuracy of the CT at the accuracy limit current.
  - P – This means the CT is for protection purposes,
  - 20 – This is known as the accuracy limit factor. This is the maximum multiple of the rated current for which the CT will retain its specified accuracy (i.e., not saturate) when the rated burden is connected. (Note that if the connected burden is less than the rated burden, the CT will remain accurate to higher multiples of the rated current.)

- **Burden** – This is the maximum burden which can be connected for the CT to retain its specified performance, e.g., 30 VA.

It should be noted that when connecting instruments to a CT which is also being used for protection purposes, then a saturating reactor should be connected into the circuit to protect the instruments.

#### 37.1.2.3 Special Protection CTs

There are some CTs which are designed with specific parameters for protection purposes. One of the most common of these types (particularly in the UK) is Class PX. These CTs were developed for use with high impedance circulating current protection but are also suitable for use with most other protection applications. In order to specify this type of CT, the following parameters have to be specified:

- **Ratio** – This is a turns ratio (not a current ratio), e.g., 1/2000 which means that the CT has a bar primary and 2000 turns on the secondary.
- **Class** – PX (formerly just X in BS3938).
- **Minimum knee-point voltage ($V_k$)** – This is the minimum value for the knee point of the CT (the knee point is the point at which a 10% increase in voltage gives rise to a 50% increase in magnetizing current).
- **Maximum value of secondary resistance ($R_{ct}$)** – This is the maximum value for the secondary resistance of the CT in ohms.
- **Magnetizing current at a specified point on the magnetizing curve ($I_e$)** – This is the magnetizing current of the CT at a point on the magnetizing curve which can be defined by the purchaser. The most common point to use is half of the knee-point voltage.

Note that for Class PX CTs there is no definition of any percentage accuracy.

#### 37.1.2.4 CTs for Defined Transient Performance

The IEC standard 61869-2 defines special types of CTs with defined transient performance. These types of CT are types TPX, TPY, and TPZ. All of the CTs discussed previously were high-remanence CTs. This means that the CT has a magnetic core without any air gaps and there is no limit set on the remanent flux and it can be in excess of 80% of the saturation flux. In IEC 61869-2 TPX is also a high-remanence CT but has specific transient error limits defined which usually results in a larger physical construction than other remanent flux CTs.

Type TPY is a low-remanence CT where the remanence is defined to be less than 10% of the saturation flux. This is achieved by having small air gaps in the core. This type of CT inherently has a higher error than Class TPX CTs, and the accuracy limit is defined by peak instantaneous error during the specified transient duty cycle. This type of CT is most commonly used for line protection with an associated autoreclose function.

Type TPZ is a non-remanence CT where the remanence is virtually zero. This is achieved by large air gaps in the CT core, which also significantly reduce the effect of the DC component of the primary fault current. However, this has an effect to reduce the accuracy in the unsaturated linear region of operation. These CTs are typically used for special applications such as differential protection of large generators with a high DC time constant.

#### 37.1.2.5 Nonconventional Current Measuring Devices

In recent years, many different types of current measuring devices have been developed using Rogowski coils, optical techniques, etc. With the increasing use of digital devices and the development of IEC 61850 and the process bus, it is likely that these types of device will be used more frequently in the future.

### 37.1.3 Voltage Transformers

Similar to the need for CTs to reduce the primary current to manageable levels, there is a need to reduce the primary voltage by the use of voltage transformers (VTs). The voltage transformer transforms the voltage from the primary figure to typically 110 V phase to phase or 63.5 V phase to neutral. Other voltages of similar magnitude may be used in some countries. There are two main constructions of VT, the more obvious one being an electromagnetic VT which simply has a primary winding and a secondary winding and the alternative type, which is much more common at the higher voltage levels, the capacitor voltage transformer (CVT).

#### 37.1.3.1 Electromagnetic Voltage Transformer

This type of voltage transformer is often used at distribution voltages and also in gas-insulated switchgear (GIS). At lower voltages, it is the most economic way to transform the voltage. However, at high transmission voltages, electromagnetic VTs are very expensive, and in many cases they are constructed as a number of transformers in series known as a cascade VT. The advantages of electromagnetic or wound-type VTs is that generally they can be made more accurate to provide high-accuracy inputs to tariff metering and also if specially designed to withstand the thermal and electromagnetic forces, can be used to rapidly discharge capacitor banks. Electromagnetic VTs are also used where transient performance is important such as supplying voltage reference signals for static VAR compensators (SVC) and similar equipment.

#### 37.1.3.2 Capacitor Voltage Transformers

A CVT is basically a capacitor divider which is used to step down the voltage from the transmission level to a typical distribution level such as 12 kV. The use of the capacitor divider is much more economical than a primary winding with lots of turns. The tapping from the capacitor divider at the distribution voltage level is then fed into a conventional electromagnetic VT to step the voltage down to the 110 V.

Another advantage of the CVT at transmission voltages is that the capacitance of the CVT can be used to couple high-frequency signals to the power line for use in power line carrier communications although this is becoming less common nowadays with the rapid increase of fiber optics for communication.

### 37.1.3.3 Specifying a Voltage Transformer

Before starting on the technical requirements, it is important to define if an electromagnetic or CVT is required. The key parameters after that are basically the same.

- **Ratio** – This is the ratio of the primary voltage to the secondary voltage, e.g., 132000/√3:110/√3 or 1200:1.
- **Class** – This will define the purpose and accuracy of the VT. If the VT is being used for metering purposes. then class is a number defining the percentage accuracy at the normal voltage range of 80–120% of nominal voltage, e.g., Class 0.5 means that the VT is accurate to 0.5% in the voltage range 80–120% of nominal voltage.

  If however the VT is being used for protection purposes such as distance protection, then it is important that the VT maintains a given accuracy down to the lowest voltages experienced during fault conditions. In this case, the letter P is introduced to indicate the protection requirement, and a number precedes this to indicate the percentage accuracy which must be maintained down to 5% of the rated voltage, e.g., 3P.
  Sometimes VTs are specified to be used for both protection and instrumentation purposes, and so a Class 3P/1.0 may be seen. This means that the VT will be accurate to within 3% down to 5% of rated voltages while having an accuracy of 1.0% in the voltage range 80–120% of the rated voltage.

- **Burden –** Finally the rated burden for the VT must be specified. This is the maximum burden for which the VT will maintain its specified performance, e.g., 50 VA. It should be noted that the accuracy is only guaranteed for burdens between 25% and 100% of the rated burden.

Voltage transformers can be provided with multiple secondary windings, and in some cases one of the secondary windings may be connected in open delta for use with directional earth fault protection.

Some utilities when ordering CVTs may specify the capacitance value to be used in the capacitor divider particularly if it is being used for power line carrier purposes.

### 37.1.3.4 Measuring Harmonic Voltages

Harmonics was an issue that in the past was mainly the concern of distribution networks as this was where loads which could be the source of harmonics were generally located. However with the increasing use of power electronic devices on the transmission network, for example, HVDC links, SVCs, wind farms, etc., the control and hence measurement of harmonics on transmission networks has become more important.

In general, CVTs cannot be considered as a reliable device for measuring harmonic voltages. Electromagnetic VTs are slightly better but for harmonics higher than the 17th, they also are not reliable.

The device which can accurately measure harmonic voltages is the resistor capacitor (RC) divider. However, these devices are better suited to being located in high-voltage laboratories than on a commercial network, and so they are expensive and need careful attention.

There are now patented devices which connect CTs at the neutral end of a CVT to measure the currents through the high-voltage capacitor and the low-voltage capacitor (the one in parallel with the electromagnetic unit) and use these current measurements to derive the voltages accurately for harmonics up to the 50th. These devices can be supplied complete with a CVT or retrofitted to an existing CVT.

#### 37.1.3.5 Nonconventional Voltage Transformers

Similar to CTs, new ways of measuring voltage are being developed which do not use conventional magnetic transformers. Some of these use Pockels effect and measure the change of polarized light which is proportional to the electric field and hence to the voltage. In the past such devices have always been hampered by being converted to an analogue signal for feeding to instruments or relays. It is hoped that with the development of IEC 61850 and particularly the process bus, these nonconventional devices will become more practical.

#### 37.1.3.6 Ferroresonance with VTs

Ferroresonance can cause problems with both CVTs and also magnetic VTs. With CVTs which are lightly loaded, ferroresonance can occur between the capacitance and the low-voltage magnetic VT. Usually this can be cured by loading the VT to a level in excess of half of its rated burden to damp out the resonance.

With electromagnetic VTs it is possible to observe ferroresonance between the grading capacitors on circuit breakers and the VT winding if the VT is on a short length of busbar. If the VT is connected to a reasonable length of overhead line or cable, then this will usually detune the resonance. However, when initially commissioning equipment and energizing it in a step-by-step fashion, it is possible to get the conditions for this type of ferroresonance, and before it is realized, the VT is destroyed. This is most common in GIS substations but can also occur in AIS substations as well. It is strongly recommended that when writing the switching programs for commissioning, this possibility is carefully looked at to avoid the risk of inadvertently causing ferroresonance during the process.

Depending upon the type of ferroresonance encountered, fundamental frequency, or sub-third harmonic, it may be possible to detune the ferroresonance by connecting a saturable reactor or damping resistor to the secondary winding, but the detail of these techniques is beyond the scope of this book.

### 37.1.4 Other Plant

The main other items of a plant which interface with the secondary equipment are the disconnectors and earth switches. This interface is similar to circuit breakers in that there will normally be hardwired control connections for closing and opening the devices and auxiliary switches for knowing the status of the disconnectors or earth switches. For some applications the relative timing of operation of the auxiliary switches compared to the operation of the primary contacts of the device can be important. An example of this is with disconnector contacts used in high-impedance busbar protection; some of the auxiliary contacts need to close just before the main contacts reach the pre-arcing distance to ensure that if a fault occurs during the operation of the disconnector, it will be correctly cleared.

Another special feature of auxiliary contacts used with high-impedance busbar protection is that the contacts used for switching the CT circuits will normally be silver plated to ensure effective connection.

## 37.2 Testing Associated with Primary Plant

When testing the control system and the interlocking, positive and negative operation tests (i.e., proving that the operation occurs positively when it should and that the operation is blocked when the required conditions are not fulfilled) will be required with virtually all of the primary plant. In this section however a little more information is given on the repetitive testing of the circuit breaker and the proving of the current transformers by the injection of current through the primary.

### 37.2.1 Circuit Breaker Interface Testing

When protection trip testing is being performed, this can result in a very large number of operations of the circuit breaker. If the circuit breaker is of the air blast type, then the resulting noise pollution will be very high and probably unacceptable if the substation is close to a residential area. To avoid this problem, some utilities use a "dummy breaker." This is a specially designed device which has similar current requirements for operation as the real breaker but is basically a relay so that its operation is clear to see. Usually if a large number of operations to trip the breaker are required, the first and last operations would be to the true breaker, and the large number of intermediate ones can be to the "dummy breaker." The "dummy breaker" is designed to be easily plugged into the trip circuit of the breaker without disturbing any wiring connections.

### 37.2.2 Primary Injection of Current Transformers

It is usual to prove the ratio of the current transformers in the field, particularly if the CT has multiple taps to ensure that the correct tap has been selected. In order to do this, heavy current leads (often portable earthing leads) are connected as close to either side of the primary of the CT to be tested as possible. A primary injection transformer will then be used to circulate the current through the primary of the CT. The primary injection transformer is basically a step-down transformer with the secondary rated to carry the high primary current for the test. Often the set will have different voltage settings, e.g., 2 V, 4 V, etc. The 2 V position will theoretically give the highest current output as the power of the device is limited by its rating. However, if there is too much impedance in the primary path, the theoretical output of the device will not be achieved, and under these conditions using a higher voltage tap can result in a higher injection current.

Whenever possible it is good practice to primary inject with enough current to achieve operation of the protection device connected to the secondary. When the current transformers are located in the turrets of power transformers, the impedance of the transformer will usually mean that very little current can be injected through these CTs through the actual primary connection. In such cases a test bar is often inserted through the center of the cores such that primary injection can be carried out. Some utilities require a test winding on the CT as it is not always possible to do primary injection. These windings are normally rated at 10 A and when injected with this value of current, produce the same output as the rated primary current passed through the primary winding, and most importantly the test winding must be open-circuited during normal operation of the CT. An alternative to primary injection is to carry out test tap injection where the secondary circuits are left intact and the injection current passed through other secondary taps. This enables lower levels of injection current and still effectively tests the CT secondary circuit through to the relay.

When carrying out primary injection of CTs located in GIS, the usual way to do this is to temporarily remove the connection of one of the earth switches located on one side of the CT under test. The "live" lead from the test set can then be connected to this point. Usually the earth switch connection will be insulated from the enclosure of the GIS to avoid the test voltage from being shorted out. To complete the test circuit, an earth switch on the other side of the CT under test will be closed. The output of the test set being connected with one end earthed and the other end connected as mentioned above.

## 37.3 Secondary System Isolation

During maintenance work, it will become necessary to isolate various parts of the secondary system to enable safe working. The more common isolation requirements are covered in the following paragraphs.

### 37.3.1 DC Voltage Isolation

When work is to be carried out on the secondary systems, it will usually be necessary to remove the DC voltage from the appropriate part of the secondary system. Usually separate supplies will be provided for the first and second main protection circuits as well as for backup protection. Each of the supplies will usually be fitted either with a fuse and link or a miniature circuit breaker. Isolation is achieved by removing the fuse and link or switching off the miniature circuit breaker. If the isolation is achieved by removing fuses and links, then a warning tape may be fixed across the fuse and link carriers warning not to replace the fuse and link until a permit has been cleared. If the isolation is achieved by a miniature circuit breaker, then it may be fitted with a lockable device to prevent it from being re-closed.

### 37.3.2 Trip Isolation

When carrying out work or testing of the secondary circuits, it may be necessary to ensure that the primary circuit is not inadvertently tripped. In order to be able to do this, it is common practice to provide trip isolation links. The detail and number of trip isolation links provided may vary from one utility to another and according to local design standards and practices.

### 37.3.3 Current Transformer Isolation

When working on the secondary equipment, it may be necessary to isolate the current transformer (CT) circuits. It is important to remember that if a CT secondary is left open circuit, then a very high voltage will be produced if any current flows in the primary circuit. For this reason it is common practice to provide shorting and isolating links on the secondary side of all CTs. These links are often arranged as double links so that one link can be moved to short-circuit the CT secondary before the second link is opened to isolate the CT from the secondary circuit.

The CT secondary circuits are earthed at only one point via a link. This earth link is removed for the purpose of insulation resistance testing of the circuits.

### 37.3.4 Voltage Transformer Isolation

The isolation of a voltage transformer is a very important safety consideration. If the voltage transformer secondary is not isolated and the voltage is applied to the secondary side as part of secondary equipment testing, then full primary voltage will be applied to the primary. It is therefore an important part of the isolation and earthing procedure before issuing a permit for work that secondary isolation links are removed to prevent any possibility of inadvertently back energizing the primary circuit. In many utilities these secondary isolation links will be locked away in a lockout box for the duration of the permit for work.

## 37.4 Secondary Equipment Considerations

This section discusses some of the aspects which need to be considered to ensure the effective performance of the secondary system.

### 37.4.1 Separation of Cubicles/Rooms

In a substation, the secondary equipment provides the functional interface for the control, supervision, and protection of the network. The equipment is organized into substation level or bay level depending on whether it operates on an overall substation basis or only for a single bay.

The secondary equipment can be located in different buildings or in separate rooms within a central building or in some cases, mounted directly adjacent to the switchgear.

The normal practice is to use a central area for metal-enclosed substations and open-air sub-transmission substations.

For high-voltage open-air substations and for high-security, metal-clad substations, the usual practice is to provide dispersed relay kiosks/rooms for bay-level equipment and a centralized control building for substation-level equipment.

### 37.4.2 DC Distribution

Substation secondary equipment must be powered by sources which are not subject to interruption at times of AC power faults. This requirement is met by the use of battery systems kept in a fully charged condition by battery chargers supplied from the AC network. Inverter systems operating from a battery give a similar level of security to equipment powered by AC.

Each DC system includes a battery, a charger, and a distribution board. They may be located in the same ventilated room, if sealed gas recombining cells are used. This has the effect of minimizing the length of cables between the battery, the charger, and the distribution board and also simplifies maintenance. Hydrogen-releasing batteries, due to the risk of explosion, must be located in a separate room closed by means of a self-closing door.

Duplicate DC systems are generally employed for substations rated 220 kV and above, to ensure availability, security, and reliability (see ► Sect. 31.3 for more details).

### 37.4.3 Relay Rooms

Protective and control equipment may be located in a central building and/or in dispersed relay kiosks/rooms (CIGRE SC 23 1982).

With GIS and AIS at lower voltages (or where the primary plant is erected indoors), distances between primary and secondary equipment are short and favor a centralized arrangement for the protection and control equipment.

When distances become long, especially with AIS for higher voltages (transmission substations), it can be advantageous to locate a larger part of the control and protection equipment in small relay kiosks/rooms close to the primary equipment and a smaller part in a central control house. The arrangement adopted depends in each case on such factors as:

- The physical size and layout of the HV plant (voltage level, AIS or GIS, etc.).
- The requirements for secure operation and maintenance and the risk of a common mode failure in case of fire.
- The type of control equipment employed (traditional or computer based) and type of internal connections (cables or optical fibers).
- The cabling from VT and CT to the secondary equipment. Lead burdens must be limited to values which permit the correct functioning of the equipment.
- Environmental conditions (adverse climatic conditions can make it desirable to group the secondary equipment within a common central building).
- The overall cost of installation.
- Building – cabling and wiring.
- Heating/cooling equipment – installation.

### 37.4.4 Cabling and Wiring

The wiring must be designed so as to simplify construction, testing, and maintenance and to allow for any subsequent revisions that may arise (CIGRE SC 23 1982).

**Simplification of Construction**

It is necessary to determine which part of the wiring is to be prepared in the factory and which part has to be carried out on-site.

Prefabrication can provide higher quality but requires a wiring design with a high degree of standardization. The degree of standardization to be adopted depends on the volume of construction work. With the benefits of prefabrication, the work on-site is restricted to final termination of cabling or the use of plug and socket arrangements simplifying the commissioning process in the field.

Over the life of a substation, extensions and modifications will take place which will necessitate the modification/reconnection of the secondary equipment. To facilitate these future changes with minimum cabling and remediation work, the use of interfacing cubicles may be recommended (e.g., cabling to HV equipment).

**Layout of Cables**

All the external cabling between one building and the external plant and between buildings is laid in pipes, conduits, or trenches, which should have adequate spare capacity for future extensions of the substation. Provision must be made for good access and to avoid the propagation of fire from generator set/transformers. Sand can be used to seal tubes. Cable entries into a building must be animal/vermin proof.

### 37.4.5 Accommodation of Equipment and Ventilation

The design of premises must take into account basic requirements, which include:

- Pollution, protection against the environment: both climatic and electrical.
- Adequate ventilation (particularly battery rooms).

- Facilities to simplify maintenance and repairs.
- Flexibility to allow future extensions and modifications with minimum space requirements.
- Ease of installation on-site.
- Safety of personnel.
- In some cases, two-stage air-conditioning settings are used to keep equipment within nominal temperature ranges when the room is unmanned and able to maintain more comfortable temperatures when manned for maintenance or testing purposes.

#### 37.4.5.1 Control and Protective Equipment

Secondary equipment is mounted either in traditional boards of sheet steel construction or in frames intended for 19″ rack mounting.

Two basic arrangements are in use:

- Accessible front and rear boards
- Cubicles accessible from the front only with a hinged door allowing access to the terminations and wiring on the rear surface or terminated in plugs that fit into cabling terminations mounted on the wall

Most control and protective equipment is available for 19″ rack mounting. Electronic equipment generally dissipates more heat than conventional relays. The heat must be dissipated by natural or forced ventilation. The use of open racks instead of cabinet-type enclosures may be a solution to this.

When some cooling is needed (hot environment), it is preferable to provide air-conditioning for the equipment room as a whole.

Anticondensation heating and lighting may be required in the panels.

### 37.4.6 Fire Detection and Extinguishing

General precautions for reducing fire risk include the following:

#### 37.4.6.1 Ventilation

A ventilation system must be designed:

(a) To keep passages free from smoke
(b) To limit the development of flashovers (ignition of material at a distance from the original fire source because of smoke pollution) and back draft (risk of an explosion caused by unburnt residues)

#### 37.4.6.2 Air Conditioning

The fire protection system when operated should shut down the central air-conditioning plant to alleviate the spread of fire.

#### 37.4.6.3 Segregation of Cables

Segregation means the installation of cables in different tunnels or physically separated by a fire-resistant barrier of an adequate rating to avoid common mode failures. Separation is usually taken to mean separated by a distance in air or by physical barriers.

(a) Power cables should be segregated from control cables where economically practicable or as a minimum should be separated by distance.
(b) External communications and important internal communication cables should be separated from other services.
(c) Main and backup protection should be independently cabled and routed.

#### 37.4.6.4 Materials

The use of combustible materials should be eliminated as far as it is practicable and economic.

#### 37.4.6.5 Building Construction

False floors or ceilings should be avoided if possible in areas where the risk of fire is high or the consequences of a fire are serious. However, if a false floor or ceiling has to be used to accommodate multiple cable runs, e.g., control room floors, fire detectors should be installed.

#### 37.4.6.6 Smoke Protection Zones

Smoke detection systems should have each alarm covering a relatively small hazard area. Due to possible false alarms, it is recommended that two different types of detectors are used and carefully located so that each will verify the other within their zone before the alarm actually initiates. Entrances to each area should have notices specifying the smoke detection zone.

#### 37.4.6.7 Fire Protection During Station Construction

There must be strict attention to cleanliness during construction so that no combustible rubbish is allowed to accumulate.

The capability of the firefighting service should be determined in periodic consultation with the local fire officers so that it is always commensurate with the growth of the fire risk on-site in terms of buildings and plant erected.

A temporary site fire alarm system consisting of special telephones should be provided for the site security staff to call the local fire brigade immediately upon receipt of an alarm, without awaiting an assessment of the severity of the fire.

#### 37.4.6.8 Permanent Equipment

The local fire authority should be consulted on the fire precautions to be provided. They should be requested to familiarize themselves with the facilities installed.

Built-in fire protection schemes must be operative on the commissioning date of the associated plant.

Personnel should be trained in the use, testing, and maintenance of all fire protective equipment.

#### 37.4.6.9 Factors in the Design of Fire Protection Systems

The detailed design of the fire protection equipment should comply with good design principles and practice of the utility and should meet the requirements of the local fire authority. Valves for manual operation should be of a quick-acting type and situated in sight of the fire risk but shielded from it for safe access by personnel.

In all fire-risk areas, fire detectors must initiate audible and visual local alarms for any staff in the area.

This must be repeated at the local control point and any appropriate remote central control point.

The reliability of automatic detectors, alarms, and extinguishers must be high. All automatic systems must be capable of manual initiation.

Full testing of the complete system is likely to be a frequent operational requirement.

## 37.5 Earthing Practice

Measures have to be taken in designing and installing secondary equipment to reduce the effects of electromagnetic interference to acceptable values consistent with the EMC capability of the equipment (Strnad 1985).

Sources of noise are the following:

- **Low frequency: 50 Hz – 10 kHz**
  - HV busbar current and earth faults inside or outside the substation
- **High frequency: 100 kHz – 50 MHz**
  (full amplitude) in GIS
  - **100 kHz – 10 MHz**
  (full amplitude) in AIS
  - Switching in primary circuits (CVT transmits more interference than VT due to the HF current flow through capacitors.)
    - Atmospheric events (lightning stroke)
    - Switching in secondary circuits
    - Electrostatic discharge
    - Radio transmitters (walkie-talkies)
  - **>50 MHz**
  Very high-frequency or high rate-of-rise interference is often characteristic during switching of GIS equipment, and measures to reduce the impact of this type of noise should be considered in GIS substations.

### 37.5.1 Measures to Be Taken on Secondary Equipment

- The various circuits incorporating devices having different degrees of interference level should be separated.
- The I/O signal circuits and the auxiliary supply should have a galvanic separation provided by isolating relays, optical diodes, transformers, and coupling condensers.
- Each secondary equipment must be earthed by means of low-impedance connections. The screen of the cables from the switch bay should be earthed at the bottom of the board/cabinet and not adjacent to unshielded circuits to avoid HF radiation from current flow in cable screens.
- Each part of a board/cabinet should be earthed to improve screen effect.
- The use of filters and transient suppressors.

### 37.5.2 Measures to Be Taken in the Installation

- Multiple interconnection of the various separate parts of the earthing system.
- Current flow circuits are arranged so that corresponding outward and return flow cores are located in the same cable.
- Control cables displaced from power supply cables and capacitor VTs.
- HV equipment should be located directly adjacent to a conductor of the earth grid.
- Network meshing strengthened in the area where the occurrence of high transient currents is more likely (e.g., lightning arrestors, VT, CVT, CT, spark gaps).
- Screened cables positioned as close as possible in order to benefit from their mutual screening effects.

The best system to reduce HF interference in circuits is the adoption of screened cables for all cabling entering and leaving control cubicles and buildings, earthed at both ends except for low-voltage signal cables. The practice is to use screened cables for control circuits positioned outside a building. In some cases, using only one earth for CT, VT, and CVT cables may be considered if double earthing is not required. Consideration should be given to the installation of large parallel earth cables, earthed at both ends in parallel with control cabling to reduce the effects of circulating current in double-earthed screened cable.

The reduction of interference at HF is mainly due to the copper screen effect that is more significant with twisted or rippled copper screens. This effect is of little importance at LF, as the screen has a low capability to reduce 50–60 Hz interference.

Therefore, the action of screened cables must be completed by the reduction of the size of the loop of wiring outside cubicles.

- Use a radial configuration for DC auxiliary supply or control cables in preference to a ring configuration so as to avoid the creation of circulating current in the event of an HV earth fault.

- Use screened telecommunication cables because these circuits offer a small loop to radiation. Their use, however, is limited by the resistance of the conductor.

### 37.5.3 Screening of Relay Rooms and Control Rooms

Relay room screening is generally only necessary when the secondary equipment does not have adequate withstand capability for the anticipated transient fields; however care should be taken to ensure all relay room metallic components are appropriately earthed. Protection equipment of the dedicated type with adequate interface circuits does not generally require particular precautions even if located near the HV equipment because of the screening effect of the building metallic structure and of the metallic cabinet/housing.

Control equipment is installed in the control building. When it is located distant from the HV equipment, the screening effect explained above is sufficient. But in the case of GIS which is in the same building as the control and protection equipment, then the latter should be located in rooms provided with earthing systems in the walls and roof.

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# Asset Management of Secondary Systems of Substations

# 38

Mick Mackey

## Contents

38.1 Design, Installation, and Building Requirements ........ 847
38.2 Reliability Impacts ........ 847
38.2.1 Reliability and Availability of Systems/Components ........ 847
38.2.2 Redundancy ........ 848
38.3 Plant Labelling ........ 851
38.3.1 Panel/Kiosk Labelling ........ 851
38.3.2 Wire and Fiber Identification ........ 851
38.4 Quality Assurance Requirements and Testing ........ 852
38.4.1 Quality Assurance: Introduction ........ 852
38.4.2 Quality Assurance: Manufacturer's Perspective ........ 855
38.4.3 Quality Assurance: Utility's Perspective ........ 857
38.4.4 Laboratory, Factory, and On-Site Tests ........ 859
38.4.5 Test of Software ........ 861
38.4.6 Test of Printed Circuit Boards ........ 863
38.4.7 Cost-Benefit ........ 865
38.5 Maintenance ........ 865
38.5.1 General ........ 865
38.5.2 Cause and Effects of Deterioration and Aging Factors ........ 866
38.5.3 Maintenance of Secondary Equipment ........ 867
38.5.4 Fault-Finding and Recovery: Influence on Design ........ 868
38.5.5 Conventional Equipment ........ 869
38.5.6 Microcomputer-Based Equipment ........ 869
38.5.7 Spare Parts ........ 874
38.5.8 Training of Staff ........ 874
38.6 Asset Lifetime Expectancy and Replacement ........ 875
38.6.1 General Considerations ........ 876
38.6.2 Updating of Secondary Systems with Computer-Based Systems ........ 879

M. Mackey (✉)
Power System Consultant Section, Dublin, Ireland
e-mail: mj.mackey@live.com

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38.7 Security of Electronic Systems ........ 880
38.7.1 Cyber-Induced Attacks ........ 881
38.7.2 Intentional Electromagnetic Interference ........ 889
38.8 Physical Security Requirements ........ 895
38.8.1 Site Access ........ 896
38.8.2 Alarm System ........ 896
38.8.3 CCTV and Intruder Alarm Systems ........ 896
References ........ 897

## Abbreviations

| | |
|---|---|
| AIS | Air insulated substation |
| BBP | Busbar protection |
| BFP | Breaker failure protection |
| CAD | Computer-aided design |
| CT | Current transformer |
| CVT | Capacitor voltage transformer |
| DACU | Data acquisition and control unit |
| EHV | Extra high voltage (170–800 kV) |
| EMC | Electromagnetic compatibility |
| EMI | Electromagnetic interference |
| GIS | Gas insulated substation |
| HF | High frequency |
| HV | High voltage |
| IED | Intelligent electronic device |
| LV | Low voltage |
| MMI | Man machine interface |
| MTBF | Mean time between failures |
| MTTR | Mean time to repair |
| MV | Medium voltage |
| P&C | Protection and control |
| RCC | Remote control center |
| SCADA | Supervisory control and data acquisition |
| SPU | Surge protection device |
| VDU | Visual display unit |
| VT | Voltage transformer |

The successful asset management of substation's secondary systems requires consideration of all aspects over the lifetime of the asset. This includes both technical and economic requirements.

Economic issues relate to costs:

- Design, development and initial investment
- Installation, commissioning
- Operation, maintenance, and repair
- Staff training
- System extension and decommissioning

In HV substations with a conventional secondary system, the initial investment cost of the complete secondary system will be in the range of 10–20% of the total cost of the substation. The life expectancy of the secondary system is equal to, or greater than, the life expectancy of the HV equipment. Modern secondary systems have to be evaluated from a completely different economic perspective. A shorter life cycle – of the order of 10 years as compared to the 30-/35-year life cycle of current "conventional" systems – combined with rapidly changing technology will mean that complete replacement of the secondary system hardware will have to be considered at shorter and shorter intervals.

The various activities associated with secondary systems that need to be considered for the management of these systems are discussed in this chapter. They may vary in some details from one geographic location or political jurisdiction to another but are fundamental to understanding the contributors to a successful exploitation of the secondary systems in a modern substation.

## 38.1 Design, Installation, and Building Requirements

The design, installation, and building requirements for secondary systems obviously have an influence on the effective management of the systems over the lifetime of the equipment. However, these aspects are covered in other chapters as follows:

- Design – ▶ Chaps. 33, ▶ 34, ▶ 35, ▶ 36, and ▶ 37 inclusive
- Installation – ▶ Chap. 37
- Building requirements – ▶ Chap. 37
- Further more detailed information on these aspects can be found in CIGRE Brochure 88.

## 38.2 Reliability Impacts

The reliability of secondary equipment will obviously depend on the quality of the component devices. Measures to ensuring quality are addressed in Sect. 38.4.

In terms of system management however, it is also essential to quantify the reliability using suitable indices. In this way performance can be benchmarked and particular areas targeted for improvement.

Where higher levels of reliability are required in the system, redundancy is frequently employed.

### 38.2.1 Reliability and Availability of Systems/Components

Availability is a combination of:

- Reliability (dependability, security) – maintainability
- Supportability

Availability is defined as the relation between the time in "healthy" state and total time and can be expressed as:

$$A = \frac{\mathrm{MTBF}}{\mathrm{MTBF} + \mathrm{MTTR}}$$

- MTBF = mean time between failures
- MTTR = mean time to repair

Availability of secondary systems depends on:

- Planning
- Design
- Erection and commissioning
- Quality of equipment/components and software
- Scope and type of redundancy
- Maintenance and self-supervision
- Ease of functional testing with appropriate test systems
- Protection against electrical interference (noise)
- Environmental conditions.

### 38.2.2 Redundancy

The reliability can be improved by duplicating the critical (highest grade) functions/equipment, i.e., so-called redundancy. Redundancy is an option, the extent of which should be decided during the planning phase.

Two types of redundancy can be applied:

- Parallel (systems operate independently of each other, i.e., one out of two)
- Series (function performed only if both systems have provided the same output, i.e., two out of two)

Relationships between dependability (function will be executed correctly when wanted) and security (function will not be performed when unwanted) for both types of redundancy are shown in Fig. 38.1.

It should be noted that self-supervision increases reliability, and therefore it is very important to incorporate such features. This is relatively easy to achieve by the use of digital technology (computer-based systems).

In the table below, the numerical values are compiled for a distance relay having an availability/reliability ratio of $p = 0.94$, a probability of non-operation of $Fp = 0.06$ (i.e., 1–0.94), and a probability of false tripping (security) of $Fs = 0.008$.

Unlike series connection, with parallel connection the two units/components must be completely separated.

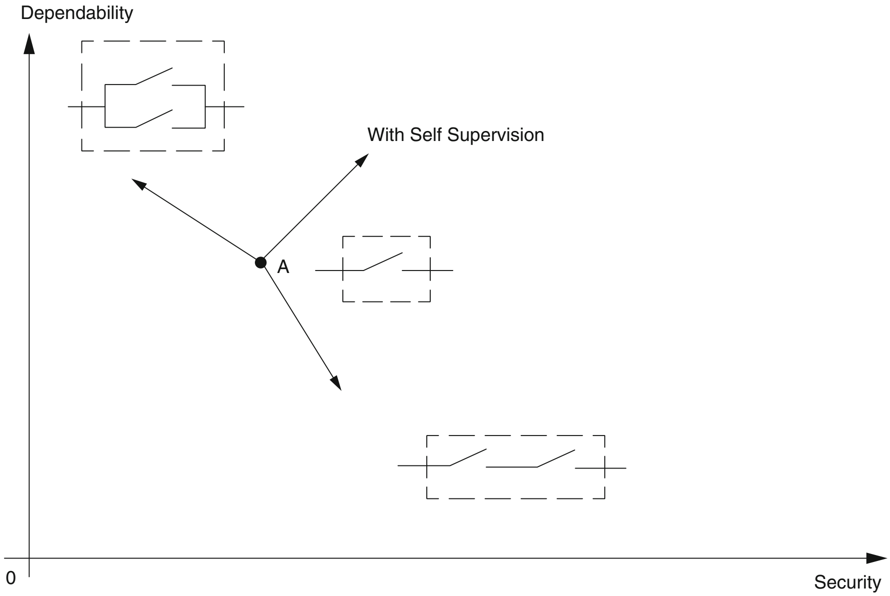


**Fig. 38.1** Relationship between parallel and series connections for dependability and security

**Table 38.1** Comparison of different redundancy arrangements

| | Availability/ reliability | Probability of non-operation | Security |
|---|---|---|---|
| One relay | $p = 0.94$ | Fp = 0.06 | Fs = $8{*}10^{-3}$ |
| One out of two | 0.9964 | 0.0036 | |
| Parallel arr. | ($2p$-$p^2$) | | (2Fs) |
| Two out of two series arr. | 088 | 0.12 | $6.4{*}10^{-5}$ |
| | ($p^2$) | | ($Fs^2$) |
| Two out of three | 0.99 | 0.01 | $19{*}10^{-5}$ |
| | [$p^2$(3-2p)] | | [$Fs^2$(3-2Fs)] |

If an equipment has n elements x of which are identical, and if all these elements are necessary (series arrangement), the availability of this equipment is:

$$A = \left(\frac{\text{MTBF}}{\text{MTBF} + \text{MTTR}}\right)^{n} = (Ax)^{n}$$

If an equipment has n elements x of which are identical, and if only one is necessary (parallel arrangement), the availability of this equipment is:

$$A = 1 - \left(\frac{\text{MTBR}}{\text{MTBF} + \text{MTTR}}\right)^{n} = 1 - (1 - Ax)^{n}$$

Parallel redundancy is used more frequently than series. Typical practical examples are:

- AC and DC supply equipment (i.e., battery, auxiliary transformer, etc.)
- Cabling and cable routing
- Protection systems (particularly bay protection) and trip coils of circuit breakers
- Power supply fed from separate circuits and/or dual supply units
- Communications (bus communications)
- Control/operation of equipment

There are also other types of redundancy that can be applied in computer-based equipment:

- Duplication of system components which operate in parallel but with one system (or system component) active and the other one automatically active if the active one has failed
- Processing of signals or commands in one system (or system component) to different algorithms or in different paths and output only if both of them provide the same result (decision two out of two)
- Serial redundancy by several repetitions of a signal in one system and verifying if all signals show the same result

The primary process determines the degree of reliability and safety necessary for secondary systems. Active or passive malfunctions restrict reliability or safety. An active malfunction is a malfunction where something operates which should not, and a passive malfunction is a malfunction where something fails to operate when it should.

Malfunctioning of secondary systems which give rise to dangerous conditions endangers safety. Malfunctioning of the secondary system which has only detrimental effects is not dangerous but restricts availability. Table 38.2 summarizes the impact of such events.

Redundant systems are essential to ensure the necessary degree of reliability and freedom from malfunction. Redundant systems must fulfil the following conditions:

**Table 38.2** General assessment of malfunctions

| | Active malfunction | Passive malfunction |
|---|---|---|
| Protection | Detrimental, e.g., maltripping of a CB | Dangerous, e.g., tripping of a CB not effected by fault |
| Control | Dangerous, e.g., disconnector operated under load | Detrimental, e.g., intended switching operation not effected |
| Position indication | Dangerous, e.g., release of interlocks due to faulty indication | Dangerous, e.g., release of interlocks due to missing indication |

- Failure of system components or parts of them must not endanger safety.
- Failure of system components or parts of them must not restrict availability.

The scope within which these conditions must be fulfilled will be dependent on the type and importance of the primary installation and should be determined at the design stage.

As a general key principle, no single failure should result in the total failure of a protection system.

## 38.3 Plant Labelling

To avoid incorrect plant operation or the incorrect selection by staff of plant for maintenance work, it is of the utmost importance that primary and secondary plants are uniquely identified. In this regard any identification systems chosen must be unambiguous.

### 38.3.1 Panel/Kiosk Labelling

The labelling of switchgear is not a standardized practice across the electrical power supply industry. Various systems are employed in different countries. However to ensure the safety of plant and personnel, there are important considerations when selecting an identification procedure.

- Primary plant is labelled in a systematic, consistent, logical fashion.
- All secondary equipment panels and cubicles/kiosks must be labelled in a way that clearly relates them to the primary plant with which they are associated.
- Labelling system is utility wide, i.e., all substations use the same systems and procedures, thus avoiding the risk of error by staff.

Some labelling systems, such as the German KKS system, go further than this by indicating plant location within the substation. However while widely used in power generation, it is often considered to be overly cumbersome for substations.

### 38.3.2 Wire and Fiber Identification

The need for a clear unambiguous method of identifying secondary system cabling to facilitate installation and subsequent maintenance or fault-finding activities is self-evident. Nevertheless, practices vary significantly across the industry. Some utilities simply attach labels at each end of a cable and use the internal core (or pair in case of telecom cables) marking as provided by the cable manufacturer. The cable connection diagram or table is retained as a record of all terminations for future reference. This approach does not give end-to-end identification of connections within the cubicle or kiosk, and some utilities apply uniquely labelled ferrules to the wire ends within the panels and kiosks to address this.

Another approach is to identify each connection by particular function and apply a wire ferrule for this purpose, e.g., each individual trip, control, signal, or instrument transformer connection would have a unique ferrule label. The British Energy Networks Association Standard ENA TS 50-19 (formerly BEBS S12) describes such a system.

Where the KKS system is adopted for plant identification, it can also be used to include cable identification.

## 38.4 Quality Assurance Requirements and Testing

A crucial factor in the performance of an organization is the quality of its products or services. Quality for the manufacturer means that its products or services should conform with client's requirements and expectations. For the client it means a high level of availability of the equipment supplied and optimal cost.

A program of testing is usually required to prove that the plant as installed meets functional requirements. Such tests form an integral component of a quality assurance system.

The quality system of an organization is influenced by its objectives, by the particular products or services, and by the specific practices of the organization. Thus, quality systems may vary from one organization to another. But the system adopted will influence if not determine the various test programs and maintenance strategy to be adopted. The following describes a generalized model based on general principles.

### 38.4.1 Quality Assurance: Introduction

**General**

To regulate the diverse quality systems applicable to the differing requirements of varying products and services, the following standards are relevant:

- ISO 9001 model for quality assurance in design/development, production, installation, and services
- ISO 9002 model for quality assurance in production and installation
- ISO 9003 model for quality assurance in final inspection and test

The corresponding numbers of the European Standard are EN 29001, EN 29002, and EN 29003.

When considering quality different levels apply:

- "Quality inspection" which consists of performing measurements and tests during the production of equipment with the purpose of evaluating conformity with the specifications

- "Quality control" which is the result of several inspections, comparing the measured values with the nominal ones and when necessary introducing improvements in the methods of manufacturing
- "Quality assurance" which is not only the test and inspection of manufacture but also the technical and organizational requirements to obtain the desired specifications for the equipment

Quality assurance programs arose from the need to implement major capital projects in accordance with specifications and within tight time scales. It was associated with the construction of nuclear power plants, submarines, and the space program.

The quality system is concerned with, and interacts with, all the activities pertinent to the quality of a product or service. It involves all phases from initial identification of the customers' needs to final satisfaction of requirements and customer expectations. This can be represented by the "quality loop" shown in Fig. 38.2.

All the activities related to the delivery of a product or service can be conceptualized as a chain that is only as strong as its weakest link. The final quality is dependent on every link in the chain.

The quality assurance is based on the following essential basic ideas:

- The job of the manufacturer is to demonstrate the correct quality of the product.
- The task of the client is to evaluate the quality assurance program of the manufacturer.

The goal is to create and convey confidence about the achievement of a certain level of quality. The functions are to ensure correct performance of the equipment and when necessary to introduce improvements in manufacturing methods.

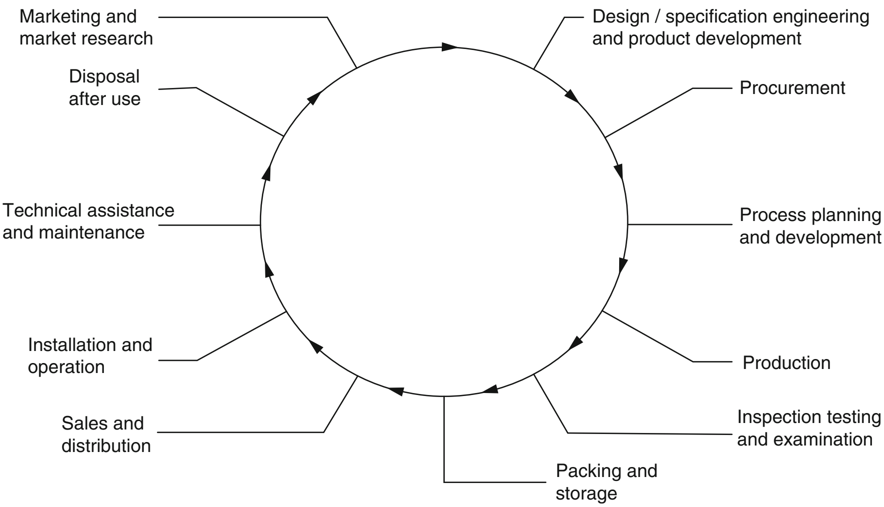


**Fig. 38.2** The quality loop

The methods are:

- Planning and scheduling
- Organization
- Control and inspection
- Identification of nonconformities
- Improvement process
- Audits

The final expected result is to eliminate shortcomings in the quality of products and to avoid the resulting cost implications. The advantages of implementing an effective quality assurance system can be summarized as:

For the client:

- Lower cost for the evaluation of the quality
- No major additional costs on the acquired product
- Improvements in scheduling
- Increased reliability

For the manufacturer:

- Optimal cost for a product or service involving manufacturing, installation, and operation
- Increased reliability
- Improvement of security aspects
- Decrease in the total cycle time
- Competitive prices
- Fewer after-sales problems

**Quality Costs**

The costs resulting from the activities involving the quality assurance system are classified as follows:

Prevention costs (related to the activities that contribute to preventing nonconformities)

- Preparation of procedures
- Planning of control methods
- Planning of inspection schedules
- Quality staff management
- Staff training

Inspection costs (related to the activities of quality verification)

- Incoming inspection
- In-process inspection

- Final inspection
- Calibration of measuring and test equipment

Nonconformance costs (related to the nonconformities)

- Internal failure: included are the costs of the scrap and of the repair of nonconforming products.
- External failure: included are the costs of the failures during the warranty period.

### 38.4.2 Quality Assurance: Manufacturer's Perspective

The manufacturer must define a quality policy. He is responsible for planning and developing a program to control the production process as well as the inspection and test verifications and corrective actions when necessary. This policy must be stated in written form and must be circulated to all personnel.

#### 38.4.2.1 Quality System Documents

- Quality assurance manual
- Quality assurance procedures
- Inspection and test plans
- Quality records

#### 38.4.2.2 Organizational Authority

- Organization chart of the company.
- Organization chart of each functional department in the life cycle of the product.
- Definition of the general and specific responsibilities for all personnel.
- Independent inspection must be performed by personnel who shall be other than those performing or directly supervising the work being accepted.

#### 38.4.2.3 System Functions

The manufacturer must have written documents that cover the following items:

**Contract Review**
The manufacturer must review the contract before acceptance in order to resolve differences from the tender.

**Design Assurance**
A design check is made to ensure that it reflects user's specifications and relevant standards and that everything is correctly translated into drawings, specifications, and work instructions.

**Document Control**
The responsibility and authority for preparing, reviewing, approving, and amending documents as well as for removing them when they are obsolete must be defined.

**Control of Measuring and Testing Equipment**
Measuring and testing equipment must have the necessary accuracy, and calibration records must exist to ensure that valid measurements are made. Calibration schedules and procedures are also required.

**Purchase Control**
The manufacturer must select his suppliers based on their ability to meet quality requirements. He must have a list of qualified suppliers and must assess their quality system.

**Incoming Inspection**
The manufacturer must inspect incoming products in accordance with inspection procedures, identify and hold nonconforming products, and initiate corrective action with suppliers when necessary.

**In-Process Inspection**
The manufacturer must inspect products in accordance with the requirements of the quality system, monitor special process methods, and identify and hold nonconforming products.

**Final Inspection**
The manufacturer must inspect the final products in accordance with inspection procedures, identify and hold nonconforming products, and make inspection and test records available to the customer before acceptance testing. He has to submit for acceptance only those products that meet specified requirements.

**Special Processes**
A special production process is one where conformance is assured by using evidence generated during the process. The manufacturer must assure that these processes are accomplished under controlled conditions by qualified personnel.

**Packaging, Storing, and Shipping**
The manufacturer inspects the final cleaning, packaging, and marking of the equipment and verifies the shipping operations to ensure that specified requirements are met.

**Quality Records**
The manufacturer must maintain quality records to prove that the quality assurance program meets the requirements of the relevant standards and that the product and documentation meet specified requirements.

**Control of Nonconformances**
The manufacturer is responsible for the issue of all nonconformances including those of sub-suppliers.

**Corrective Actions**
The manufacturer reviews and analyzes the cause of detected nonconformances and develops corrective actions to prevent recurrence.

### 38.4.3 Quality Assurance: Utility's Perspective

#### 38.4.3.1 Quality Policy
This is to design and manage the construction of substations while taking account of the following:

- Scheduled dates in the network development plan
- Requirements and needs of departments responsible for the operation and maintenance of substations
- Requirements related to service characteristics, safety, reliability, and expansion
- Highest quality at the lowest cost

#### 38.4.3.2 Organizational Authority
Considering the multiple functions of each department and their interconnections, it is necessary to establish an organizational chart and to define the activities, functions, and responsibilities of each organizational unit.

#### 38.4.3.3 System Functions

**Design Assurance**
In the scope of the design assurance, the written procedures of the appropriate project departments must assure that:

- The development of the project is in accordance with a well-defined sequence.
- The requirements of the customer are studied in order to ensure compliance.
- All standards and regulations are complied with.
- New projects are discussed with the appropriate departments.

**Document Control**
All documents (drawings, specifications, etc.) are registered and issued to all interested departments. The reviewing of approved drawings and specifications is handled in the same manner as for the originals. Obsolete documents and drawings are removed or stamped "obsolete."

**Purchasing Requirements**
All suppliers are selected for their ability to meet quality requirements. The suppliers are informed of all nonconformities found in their supplied items or rendered services. The results of the inspections and tests are periodically evaluated, and the results are used in the selection of suppliers.

**Inspections and Tests**

The inspections and tests are made by experts in accordance with procedures or approval tests. The results of inspections and tests are registered. The equipments with nonconformities are well identified and segregated. All nonconformities are registered and are communicated to the appropriate departments to avoid their repetition. All equipment is submitted to a final acceptance test before starting its industrial service.

**Measuring and Testing Equipment**

All the measuring and testing equipment is periodically calibrated. Calibration of instruments is made according to written procedures. Records of the periodic calibrations are kept. Equipment being well identified is a condition of the calibration procedure.

**Corrective Actions**

The nonconformities are studied and presented in a written document in order to eliminate their causes and to prevent recurrence. The responsible departments provide the necessary corrective actions.

**Handling and Storing**

When necessary, the equipment is provided with instructions concerning handling and storing. The equipment is well protected to prevent damage when stored or handled.

**Maintenance**

The equipment is provided with instructions concerning its maintenance. These instructions must cover the following points:

- Actions required
- Equipment necessary to execute the actions
- Maintenance interval or triggering criteria
- Relevant documentation

**Quality Records**

Every important piece of data relating to the quality is registered on adequate forms. Copies are distributed to the appropriate departments. The following quality records are filed for periods of 5–20 years:

- Nonconformity records
- Test records
- Test certificates.

**Internal Audits of Quality**

There are written procedures concerning quality assurance for all activities that influence the final quality of a substation. The quality control program is periodically audited in order to determine if it is complete, up to date, and being duly applied.

**Training**
The staff that controls the quality has adequate training and is familiar with the equipment and plant necessary for its examination.

### 38.4.4 Laboratory, Factory, and On-Site Tests

**Before commencing any test whether it be laboratory, factory, or site test, a clear specification and plan of the testing needs to be prepared and submitted to all parties involved in or witnessing the test.**

#### 38.4.4.1 Laboratory Tests/Type Test

The purpose of these tests is to qualify new equipment, systems, or solutions for use in the substation environment. Type tests are defined in order to establish the adequacy of the design of the equipment/solutions. These tests are concerned with:

- Electrical insulation
- Electrical characteristics with all the specified functions
- Mechanical endurance
- Climatic endurance
- Electrical interference (lightning)

As the description “type test” suggests, they are intended to generically demonstrate that the proposed equipment is capable of performing in accordance with the specification. Once type tests have been successfully performed on an item of equipment, repeat testing is not usually deemed necessary.

#### 38.4.4.2 Factory Tests/Routine Tests

The purpose of these tests is to establish that the equipment or a system/solution has been manufactured in accordance with the design specification for an application/project. They cover:

Verification that the equipment or a system/solution has been built with specified materials and components (visual inspection). These tests will be concerned with:

- Quality of materials and components
- Dimensions
- Protection grade
- Painting and final appearance
- Support structures
- Arrangement of the equipment
- Accessibility of the components
- Wiring and layout of cables
- Ground connections
- Labelling

To verify the functional characteristics (functional inspection), these tests must be made under conditions as near to the real situation as possible. Both measuring equipment and simulation equipment (sometimes based on computer technology) are required. The tests include:

- Measuring of power consumption
- Measuring of line voltage tolerance
- Test of short circuit protections
- Test of the equipment's reaction when inputs are applied
- Test of man machine interface
- Test of the system's reaction to operator's mistakes
- Test of the maintenance and extension dialogues

Electrical tests, no matter how comprehensive, cannot provide assurance of a quality product. Certain conditions can reveal themselves in the early stages of the in-service life cycle of the product which can lead to malfunctioning and failure. Test procedures can be devised which simulate in an accelerated manner the influence of such factors as:

- Temperature
- Voltage
- Vibration
- Humidity

These are the so-called "burn-in tests," for which temperature and humidity cycles must be defined and should normally be included as part of the type tests.

#### 38.4.4.3 On-Site Testing/Commissioning Testing

The design of the secondary system allows the equipment to be completely tested at the factory where the functional tests are however only simulated. The subsequent on-site tests include both visual inspection and functional tests.

The purpose of the visual inspection is to verify that no damage occurred during the transport and that the equipment is correctly installed.

The purpose of the functional tests is to verify the correct performance of the equipment when connected to the high voltage apparatus.

The functional tests include:

The checking of polarities

- To assure that there are no reversed polarities
- To assure that each function in the HV switchgear and in the protection relays are supplied with the correct polarity
- To assure that the voltage drops are within the allowable limits

The checking of the following circuits:

- Current circuits (to ensure continuity)
- Voltage circuits (to eliminate short circuit)
- Position-indication signals for:
  - Circuit breakers
  - Isolators
  - Transformer's tap positions
- Alarms for:
  - Circuit breakers
  - Isolators
  - Transformers
- Control circuits for:
  - Circuit breakers
  - Isolators
  - Tap changers
  - Cooling fans
  - Oil circulation pumps
- Interlocking circuits for HV switchgear
- Protection circuits:
  - Tripping circuits
  - Reclosing circuits
  - Alarm circuits
- Drive mechanism circuits for:
  - Circuit breakers
  - Isolators
- Heating elements for outdoor cubicles

The checking of the following functions:

- Individual controls of HV switchgear
- Sequential controls of HV switchgear
- Protection relays settings

### 38.4.5 Test of Software

#### 38.4.5.1 General

Any quality assurance methods used must take account of certain characteristics which are inherent features of software:

- Software has no physical form. There is no physical law that allows us to test some components and assume a linear behavior.
- There is no degradation in the performance of software with use. An error is a singular event.

#### 38.4.5.2 Software Failure Modes

Software errors can arise from:

- The specification:
  - The software specification must cover all the input conditions and output requirements.
  - There is no place for ambiguities, inconsistencies, or incomplete statements.
  - There is no safety margin.
- The design:
  - In the software system design, errors can occur from incorrect interpretation of the specification or from incorrect logic.
  - It is at the design stage that the response of the program to error conditions is defined. Care must be taken to ensure that a highly "robust" program is produced.
- The coding process; typical errors of code generation are:
  - Typographical errors
  - Incorrect numerical values
  - Omission of symbols
  - Inclusion of expressions which can become indeterminate.

#### 38.4.5.3 Programming Style

**Structure**

Structured programs require the use of control structures which have a single entry and a single exit. Structured programming leads to fewer errors and results in clearer and more easily maintained software which is much easier to understand and inspect.

**Modularity**

Modular programming consists of breaking down the overall program into separate smaller separate programs or modules, each one of which can be separately specified, written, and tested. Each module is easier to understand, thus reducing the probability of errors and assisting in the task of checking.

**Remarks**

The use of remark statements to explain the program assists in its testing.

**Defensive Programming**

Defensive programming consists of introducing routines to check for errors and allowing the program to indicate the source of the error.

#### 38.4.5.4 Software Checking

In general, a new program must undergo a long development and debugging phase before all errors are eliminated.

To verify compliance with the specification, the program must be checked against each requirement of the specification. Checking is made much easier if the program is structured into well-specified modules.

Some functions of the program can only be checked in a "line-by-line check" of the program listing. A test schedule which stipulates the tests required to demonstrate compliance with specification must be prepared.

### 38.4.6 Test of Printed Circuit Boards

In electronic equipment, the printed circuit boards are the type of prevailing assembly, with a set of associated technologies, which influence in a very strong way the quality and the reliability of the system in which they are inserted.

#### 38.4.6.1 Principles of Good Printed Circuit Board Design

These are:

- Simplicity
- Accessibility
- Ease of fault-finding
- Ease of replacement
- Impossibility of incorrect assembly
- Minimal adjusting
- Ease of production

The printed circuit boards must be manufactured and tested individually before being integrated into the whole equipment.

#### 38.4.6.2 Tests of Printed Circuit Boards Before Assembly

**Visual Inspection**

In this test we must verify:

- Type and quantity of holes
- Uniformity of metallic deposits
- Short circuits and open circuits
- Dimensions
- Wrapping
- Correct fit of solder resist and silk screen

**Test of Physical Characteristics**

- Thickness measurement
- Flexibility tests

- Measurement of surface resistance
- Measurement of insulation resistance

These tests are only made on a sample batch of printed circuit boards, for approval of total production run.

**Test of Components**
- Environmental tests
- Mechanical tests
- Electrical tests
- Burn-in tests

### 38.4.6.3 Tests of Printed Circuit Boards after Assembly

**Solder Inspection**
The solder points must have:

- Metallic brightness
- Flat surface of board
- Convex surface of solder
- Small contact angle

**Tests of Assembly**
The following points must be considered:

- Missing components
- Incorrect components
- Incorrectly assembled components
- Mislocated components
- Unidentified components
- Damaged components

**Functional Tests**
With these tests we can detect:

- Open circuits
- Short circuits
- Incorrect assembly of components
- Missing components
- Incorrect components
- Components with parameters out of limits
- Incorrect performance of the circuits

The purpose of the functional tests is to verify the correct performance of the equipment for the high voltage apparatus.

### 38.4.7 Cost-Benefit

The implementation of a quality system and associated quality proving and testing procedures in accordance with the relevant national and international standards will almost certainly involve additional costs. In the medium and long term, however, these costs should be compensated by reduced nonconformance costs and by the benefits which will accrue to the manufacturer by its improved image in the market place. The client will benefit by improved system reliability and by an enhanced quality of service.

## 38.5 Maintenance

Maintenance policy and practice relates to the activities which are necessary to ensure that equipment and installations continue functioning over their lifetime in accordance with specification. Preventive maintenance means that the maintenance of the equipment will be carried out in such a way that acute failures can be prevented as far as possible.

### 38.5.1 General

The efforts to obtain a high availability by minimizing failure rates start at the specification stage and continue by including the design and production stages in a quality assurance program that continues through to commissioning (Sect. 38.4 refers).

During commissioning a complete test report will be prepared with all relevant measured values, relay parameter settings, etc. This report will be part of a comprehensive "as built" documentation for use by the operation and maintenance staff. In addition, a maintenance program should be prepared well in advance of commissioning.

The performance of the secondary equipment is influenced by many factors. Some are caused by inherent defects, e.g., stochastic faults in components due to manufacture, aging factors such as wear and tear, deterioration of insulation, etc.

Replacement of equipment for secondary systems today generally takes place before the end of the real lifetime because:

1. The components become obsolete with respect to their technical function.
2. The components have gone out of production and it is very difficult to get spare parts.

Present day maintenance mainly concentrates on diagnostic tests including the periodic testing of protection equipment with respect to preventive maintenance and modifications, supported by self-checking facilities.

The depth or thoroughness of maintenance will depend upon many factors, and, accordingly, it is difficult to give general guidelines. Issues such as whether the whole scheme should be checked fully at each maintenance period should be considered by the utility. For instance, there is a great deal of difference in time (and cost) between testing a distance relay for correct operation at characteristic angle and testing a whole distance scheme including full polar diagrams, end-to-end test to check the signalling, doing trip checks, and checking all the auxiliary relays included in the scheme.

In future, more and more self-checking facilities will detect malfunctions or defects without fixed maintenance intervals, i.e., the occurrence of defects in secondary systems will be detected by online diagnostic facilities. Therefore, for many components of secondary systems, the regular maintenance interval will be extended to several years. The faulty components will then be repaired or replaced as needed or the functions automatically switched over to redundant components.

### 38.5.2 Cause and Effects of Deterioration and Aging Factors

Electrical:

- Slow destruction (insulation aging, contact pressure, and wear)
- Direct effects (insulation breakdown or flashover caused by overvoltages)

Mechanical:

- Vibration (bearing play of relays and meters)
- Rotation (leaking and sealing)
- Pollution (dust, humidity, rust, mice, spiders)
- Attrition on contacts

Chemical:

- Life cycle of special components (battery Pb or NiCd/average life of electrolytic capacitor)
- Environmental influence

Thermal:

- Short-term overload
- Long-term overload
- Influence of environmental temperature

Technical:

- Not according to actual standards
- Inefficient
- Inaccurate

- Slow reaction time (relays)
- Polluting
- Wrong setting
- Operating errors

Economic:

- Uneconomic service conditions

### 38.5.3 Maintenance of Secondary Equipment

Maintenance can be divided into the following items:

- Inspection
- Periodic tests
- Self-checking with diagnostics
- Overhauling due to maintenance program
- Repairs of acute faults
- Fault reporting and registration

An alternative approach to maintenance of protection relays is to increasingly use diagnostic testing. The complete diagnostic testing of all equipment in a substation gives a broad cross section also of secondary equipment installed on the system. The diagnostic results should also give a good indication of the integrity of this equipment and similar equipment installed elsewhere on the system. In the event of a particular type of equipment demonstrating a high failure rate, a more comprehensive diagnostic testing program could then be put into place to test all similar equipment wherever installed.

#### 38.5.3.1 Periodic Tests

Periodic tests shall be carried out for the preventive checking of protective, control, and annunciation equipment in order to verify safety of function after a defined operating time. Periodic testing should be done continually in a clearly defined sequence.
Manual test:

- Lamp test
- Go-no-go test by switch (qualitative)

Functional check of scheme (quantitative):

- With meters, test units according to test description and test sheets

Automatic testing:

- Automatic testing equipment (mostly additional equipment) is initiated by a clock or manually (testing once a day or week); up to 60% can be checked by these systems.
- Self-checking systems detect inherent faults and initiate alarm signals; after repair of the respective system component, safety of function is to be verified by a periodic test; periodic tests can be reduced (3–6 years) if the self-checking feature incorporates both initiation and tripping circuits for the protective devices as well.

Frequency of periodic maintenance depends on the component in question and will be stated in the maintenance program.

#### 38.5.3.2 Self-Checking Facilities

If wear and tear can take place on very important equipment, such as protective schemes in transformer and busbar protection, computer, or control systems, self-checking facilities should be installed.

On new systems with microcomputers and other new technologies, maintenance often seems to be very complex, but it does not have to be. Modern systems are programed with continuous checks to diagnose their own state of health. Error codes indicate clearly what is going wrong. These checks have no influence on the actual operating time.

Continuous supervision:

- In solid-state protection, voltage levels are continuously checked.
- Simultaneous presence of signals (Io, Uo) or summation signals are checked.

Extensive self-monitoring:

- Check of system faults and incorrect setting

### 38.5.4 Fault-Finding and Recovery: Influence on Design

#### 38.5.4.1 Repairs of Acute Faults

The consumers of electrical energy expect a high reliability of supply. Repair of equipment has to be carried out according to economical and technical considerations while fulfilling all safety rules for staff.

If an acute fault occurs, the utility's own staff may be able to cope with the necessary troubleshooting and repair work. In other cases, the fault may be of such a character that specialists from the factory will be needed. It is therefore recommended to set up an on-call service plan together with the manufacturer so that the proper measures can be taken for urgent troubleshooting. Faulty parts will be repaired on the spot as far as possible by taking the most suitable measures, while those which cannot be repaired on the spot will be carried back to the factory for shop repair after being replaced with spares.

#### 38.5.4.2 Fault Reporting and Documentation

It is important that every fault or defect in the secondary system, whether identified during commissioning or during maintenance activity, is described in a fault report which will be part of the fault statistics and also feed into the design activity as part of the "continuous development" process.

By modifications and changes, it is also important that the "as-built" documentation is subsequently corrected so that the documentation is always up to date. This requires a strong discipline within the utility and should form an integral part of the utilities quality assurance system.

All maintenance tests have to be recorded in a similar manner to the original commissioning tests. The documentation and evaluation of maintenance results are recommended to be handled by computer systems to allow for a better analysis and to optimize future planning.

#### 38.5.4.3 Maintenance Programs

Every utility has some sort of maintenance practice. A maintenance program is a list of the various maintenance activities with a description of the works that have to be done and a time when they have to be done.

The program can either be a simple manual system or a more advanced computer-based system. The latter has obtained a wider acceptance in recent years especially in large utilities (Table 38.3).

### 38.5.5 Conventional Equipment

Table 38.3 shows the main components in a conventional installation and typical periodic test schedules for preventive maintenance in unmanned substations.

**Battery and Battery Charger**

The DC supply, without the battery connected, has to be within limits for ripple content as required by the electronic equipment.

DC/DC converters can produce dangerous overvoltages if a battery charger is supplying an AC voltage superimposed on the DC level.

The battery chargers are practically maintenance free, but they have to be checked during weekly inspection for abnormal noise and smell. Batteries have to be kept clean and the level of electrolyte has to be checked once a month. The change of the electrolyte depends on prevailing operating conditions but may be useful after a period of approximately 5 years (NiCd).

### 38.5.6 Microcomputer-Based Equipment

This equipment performs the protection and control system functions on a digital basis by means of microcomputers. The information exchange between the various units is realized by serial digital communication. Equipment based on microcomputers

**Table 38.3** A typical maintenance schedule for conventional secondary equipment

| Equipment | Visual inspection | Periodic check | Comments |
|---|---|---|---|
| Rectifiers | Monthly | 1–3 years | |
| DC distribution | Monthly | 1–3 years | |
| Inverters, UPS | Monthly | 1–3 years | |
| Power supply units | | 1–3 years | |
| Fire detection | | 1 year | |
| Air conditioning | | 1 year | |
| Control equipment | | | |
| Mimic diagrams: weekly | Weekly | | |
| Instruments, indicating | | | |
| Instruments, recording | Weekly | 3–5 years | |
| Meters | | | |
| Protection relays | Weekly | 5–10 years | |
| | | 5–10 years | |
| Fault recorders | | | Mech. Parts see 38.5.2 |
| Event recorders | Flags-weekly | 3–5 years | |
| Remote terminal units | | | Mech. Parts see 38.5.2 |
| Signalling devices (alarms) | | | Mech. Parts see 38.5.2 |
| Interlocking devices | Monthly | 2–3 years | |
| Communication units | Monthly | 2–3 years | |
| | | 2–3 years | |
| | Weekly | 2–3 years | |
| | | 2–3 years | |
| | | 2–3 years | |

makes it feasible to integrate different functions that were previously performed by separate functional units in conventional equipment. It consists functionally of data acquisition, data transmission, data storage, and data processing. It has both hardware and software (or firmware) to maintain.

#### 38.5.6.1 Hardware Maintenance

The equipment is mainly composed of the following units:

- Visual display units
- Keyboards
- Printers and plotters
- Input/output units
- Processing units
- Storage units
- Communication units

Although more complicated than conventional equipment, computer-based equipment has built-in features of self-checking routines for detecting inherent faults combined with a precise indication of the defective component or sub-unit. This will reduce maintenance of the hardware to replacing defective sub-units. Preventive maintenance will be reduced, except for the mechanical parts in plotters and printers and other parts subject to wear and tear. Computer systems need periodic inspection and attention. It is difficult to be specific about the nature and content of the work and the time required for its execution as it depends on the system configuration and operational condition. Table 38.4 is recommended as a guideline.

**Yearly Regular Inspection**
The functional tests of the system itself, the design life check, the replacement of worn out parts, the operational tests for error detection mechanism, etc. and the operation margin tests will be executed. In performing these tests, the service history and the error data are taken into account (Table 38.4).

**Three-Monthly Regular Inspection**
Lubrication, cleaning, inspection, and investigation and the replacement of worn out parts will be executed periodically, mainly for the mechanically operating parts of the peripheral devices to lengthen the remaining serviceable life of those devices and to prevent problems occurring. The 3-month regular inspection will be included in the 1-year regular inspection.

**Weekly Inspection**
It is recommended to execute weekly inspections on the environmental management of the computer installation workplace: cleanliness, servicing, operating condition check, and data arrangement.

**Overhaul**
For I/O devices with moving parts, stable operation over a long period can only be achieved through a program of regular inspections combined with a regular regime of lubrication, cleaning, and adjustment.

**Table 38.4** A typical maintenance schedule for computer-based equipment

| Inspection | Interval | Description |
|---|---|---|
| Yearly | Once per year | Minute inspection of complete computerized system |
| 3-monthly regular | Once per quarter | Inspection focused on peripheral devices |
| Weekly regular | Each week | Inspection under operating conditions |
| Overhaul | Occasionally | Dismantle system, inspect wear of mechanical parts, replace if necessary, and perform cleaning, lubricating, reassembling, and readjusting |

The long-term planning and control of overhauls would be more effective to improve the operational efficiency and to maintain the system reliability. Taking this into account and also the intention to prevent the occurrence of problems, a plan for the overhaul should be worked out in cooperation with the manufacturer. The execution can be agreed to take place at the working location or perhaps by carrying the system or parts of the system back to the factory for overhaul.

The preventive maintenance activities mentioned above are illustrated in Fig. 38.3 and shown in comparison with a failure rate curve (bathtub curve). Theoretically, the bathtub curve is valid for all types of equipment. Here it is shown for electronic parts.

As indicated above, overhauling is a scheme to lengthen the service life of the system which is undertaken at fixed periods. The main work is the replacement and readjustment of life parts which may then have no safety margin to maintain their reliability.

Those parts that will deteriorate in performance and reliability throughout the course of service life and which finally become inadequate are generally called "life parts."

The categories of life parts and non-life parts are indicated in the following table (Table 38.5):

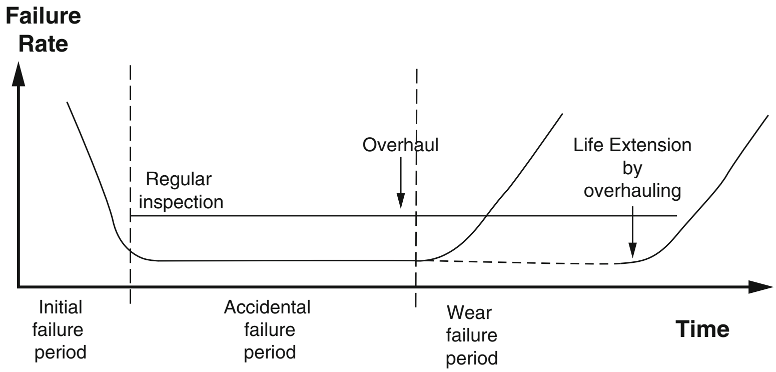


**Fig. 38.3** Failure rate curve (bath tub curve)

**Table 38.5** Categorizing life parts and non-life parts

| Component type | Life parts | Non-life parts |
|---|---|---|
| Electrical components | CRT, fuse, aluminum electrolytic capacitor | IC, LSI, other logic forming elements |
| | | Resistor, transistor, capacitor (except aluminum electrolytic capacitor) |
| Mechanical | Bearings, rotating parts accessories, packing, filter, belt, cooling fan | Static components |

The lives of the parts are determined by the life tests (accelerated life test, forced deterioration test, etc.) which are conducted as part of the reliability tests at the production stage (also by estimating the period of time during which the prescribed performance will be maintained).

For an overhaul of the system, the execution interval is established on the basis of the life determined as above. Particularly, with mechanical life parts, regular inspections have difficulties in the determination of fatigue, wear, and aging, compared with electrical parts. So, they seem to cause unplanned problems due to fatigue limits.

#### 38.5.6.2 Software Maintenance

The software can be divided into areas covering:

- System functions
- Application functions

**System Functions**

These are defined and tested in the system design and will not undergo major alterations during the system lifetime. Modifications and troubleshooting in this part of the software will normally require the assistance of the manufacturer.

**Application Functions**

These will normally be implemented initially by the manufacturer. However, the utility engineers (protection, control, metering engineers) must be familiar with the application software covering their fields.

After initial implementation and testing of the application software, it is very unlikely that faults will occur. Application software will be altered and modified, however, due to the operational requirements of the primary system. These might be the changing of relay parameter settings, change of automatic sequences, addition of new bays, etc. These tasks may be handled by the utility staff.

In addition, there may be modifications and/or adaptations caused by:

- Reform of statutory regulations, by new standards and/or by changes of organization
- Further development of electronic data processing (EDP) methods, e.g., supply of a new software version with more user-oriented operating methods (such as macro commands, menu-controlled operation, window techniques, etc.). Such modifications may have influence on the total concept of electronic data processing. Therefore, it has to be determined that in such cases the management must be informed.
- Where the modifications of the software did not have their origin with the users, the timing of the modification and the necessary training has to be agreed with the users.

### 38.5.7 Spare Parts

For *conventional* equipment, consisting of separate functional units, both the utilities and the manufacturers normally have a good idea of what is needed for spare parts, and these are normally provided from a central stock. This guarantees short delivery and quick repair as conventional techniques have no serious problems with interfaces. The amount of spare parts in store at the utility will depend on:

- How critical the part is
- Delivery time from the manufacturer
- Capability of repair within the utility

For computer-based equipment, where several functions are integrated in the same units, it is very important to have a sufficient amount of spare parts in order to minimize downtime. On the other hand, this equipment is composed of many identical sub-units that will reduce the necessary amount of spare parts. Another aspect of spare parts for computer-based equipment is the very fast rate of change of products from the manufacturers. From the date of obsolescence of a product, 10 year's field support should normally be achieved by the manufacturer by delivery of the same product or a compatible product with the same function or a replacement component based upon updated technology while covering the required functions.

An alternative could be to negotiate a contract with the manufacturer where he guarantees:

1. Delivery of spare parts within the lifetime of the system and a maximum repair time
2. The failure rate of the system and of important parts of it

### 38.5.8 Training of Staff

The training of staff for maintenance of secondary equipment varies from utility to utility.

Large utilities which may also design, build, install, and maintain the equipment themselves can afford to have specialists in each discipline. On the other hand, small utilities where each engineer has to undertake a variety of tasks will normally only be able to maintain their equipment up to a certain level and beyond that will have to rely on the services of the manufacturer. Accordingly, the training of staff will vary depending on the level of maintenance which utilities find economically justifiable to provide from their own resources.

For conventional equipment, utility engineers traditionally are grouped by professional specialization:

- Protection/relay engineers
- Control engineers

- Instruments/metering engineers
- Primary equipment engineers, etc.

The distinctions between these fields of activity are well defined for conventional equipment where each function is generally handled by one or more dedicated units.

The training of staff is a continuous process of learning and of acquiring knowledge on new equipment being installed within the utility. Normally this training will be acquired by attending specialist courses arranged by the manufacturer, and this should be part of the terms when new equipment is purchased.

Basically, these distinctions between the professions will also be upheld when computer-based equipment is introduced either as single items or as whole systems because the professions reflect the various functions to be performed. These functions will be the same, but it will now be the software or the firmware that dictates how they will be performed.

The fundamental difference is that in order to change, modify, or extend functions, the utility engineer has to communicate with the equipment with the assistance of visual display units and keyboards. The manufacturers make great efforts to make this human-machine-communication user-friendly, knowing well that the acceptance of the new technology by the customers will depend upon this.

The transition to computer-based equipment was a gradual process, and utility engineers must master both systems for some years to come.

This might be achieved by selecting persons with solid basic experience who will be trained to get an all-round knowledge of the systems hardware and software and become what we can call systems engineers.

In addition, the established professions such as relay, control engineers, etc. have had to be "upgraded" so that they master the communication with the equipment and are able to express and implement their respective functions through software instead of hardware components.

As the technology continues to develop so rapidly, the best way of acquiring training is to attend specialist courses provided by manufacturers.

It is important that the staff obtain practice in handling the equipment. If maintenance work is rarely required because of the small number of substations, it may be difficult to maintain the necessary skill levels of the maintenance staff. An alternative may be to hand over the maintenance activity to the supplier or to another utility.

The extent to which utilities are willing to go in the maintenance, modification, or even the design and manufacture of new systems is a question of company policy.

## 38.6 Asset Lifetime Expectancy and Replacement

The lifetime assigned to an asset can have a number of functions, whether it is financial, physical, or reliability based. This can also vary dramatically, from a few years for modern light current equipment up to half a century for primary plant. This scenario makes justifying whole scale asset replacement of a substation, or even a bay, complex and ever more subject to economic scrutiny.

Primary equipment is expected to last typically up to 40 years for switchgear and possibly longer for power transformers. On the other hand, secondary systems are complex, with short lifetimes for microprocessor components (5–6 years), while relays, control boxes, and telecoms should last for at least 15 years. The utility needs to determine an economic lifetime for secondary systems, which takes into account, refurbishment and spares availability before equipment becomes obsolete and unobtainable.

### 38.6.1 General Considerations

A key consideration at the outset is to manage electronic interfaces with the switchgear and establish the overall economic lifetime, since the component lifetimes do not match and the equipment will need to be refurbished at some stage during the switchgear lifetime. However secondary system replacement in isolation of overall system requirements may not be the most prudent approach to substation upgrading. This section describes the systematic approach to asset replacement within overall asset management.

For substation asset replacement decisions, it is necessary to adopt a general point of view, as all infrastructures (e.g., HV plant, secondary systems, support structures, buildings, etc.) should be included in the overall assessment. It is therefore necessary to evaluate not only the status of the secondary equipment but also to assess the overall condition of substation infrastructure. Replacement of an individual asset (such as secondary equipment) is often postponed using possibly temporary solutions, although replacement could possibly imply cost savings; however, as soon as a project is initiated due to, e.g., the capacity plan, the context changes. The capacity plan results from middle- and long-term grid planning and investigates situations beyond “business as usual. In this respect, the capacity plan has a strong influence on asset replacement decisions.

The integral nature of the decision process results from the consideration of both the maintenance needs of existing assets (due to aging), as well as of the requirements of the capacity plan (due to grid enlargement or structural changes). This integral approach to substation asset replacement is necessary so as to ensure that high-level, general business drivers are systematically applied to all levels of individual replacement projects.

The proposed decision process for asset replacement is organized into ten steps, as shown in Fig. 38.4.

**Step 1: Business Drivers**

Business drivers address the values that a power utility wants to put in the foreground. Unless business drivers serve as starting point for further decisions, it will not be possible to integrate asset replacement within the overall business of a utility.

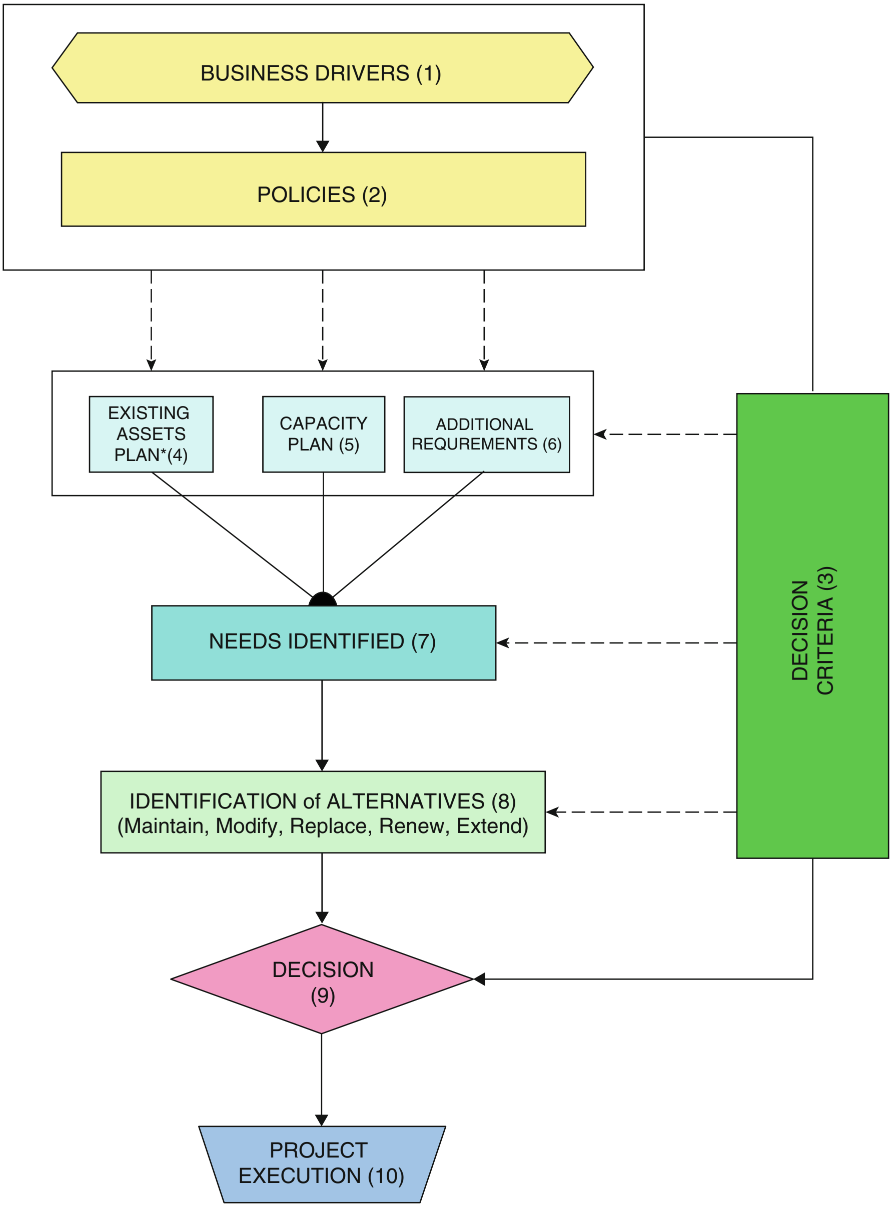


**Fig. 38.4** Decision process for asset replacement

Therefore, business drivers have to be clearly identified first. Examples for common business drivers of power utilities include personal safety, legal compliance, security of supply, power quality, financial and socioeconomic issues, reputation, environmental care, and sustainability.

**Step 2: Policies**
Once the aforementioned general business drivers have been identified, appropriate asset replacement policies will have to be established. Such policies involve existing know-how of a utility and define a general perspective for asset replacement decisions, which usually comprises of standard decision-making procedures. Well-defined policies provide general guidelines which ensure consistent decision-making.

**Step 3: Decision Criteria**
For the assessment of decision alternatives on asset replacement, decision criteria are necessary. Such criteria evaluate and quantify the performance of the alternatives with respect to the general business drivers. In this context, risk indicators are proposed as decision criteria: for example, personal safety is measured by the risk of personal injury.

**Step 4: Existing Asset Plan**
The existing asset plan (renewal, replacement, long overhauls, etc.) comprises all investigations, decisions, and processes with a view to maintaining assets already installed. In a sense, it might be viewed as a "business as usual" scenario. Although it mainly results from the technical condition of the equipment in the grid, the power utility's ability to maintain existing assets also plays an important role. The latter is influenced by factors such as technical obsolescence or general in-house technical competence regarding training, maintenance skills, and workforce developments. However, asset condition is still the main driver behind an existing asset plan. In order to provide information on asset condition, a systematic, up to date register containing data about installed assets regarding ratings and operating and maintenance history has to be maintained. See also Sect. 38.5.

Appropriate diagnostic techniques and respective interpretation schemes should further be applied in accordance with the specific asset type.

**Step 5: Capacity Plan**
Integration of the capacity plan into asset replacement decisions is an important feature of the proposed decision process. The most obvious impact of changed capacity requirements is on equipment ratings: higher short circuit capacity of circuit breakers or higher rated power of transformers are typical examples of drivers for asset replacement due to increased capacity requirements. However in terms of numerical or computer-based devices, availability of superior functionality to support overall grid and asset management processes or procedures can also be a driver for replacement.

**Step 6: Additional Requirements**
Additional requirements can also act as external drivers for asset replacement in substations. One example of such additional requirements is infrastructure work (e.g., construction of a new highway) affecting an existing substation.

**Step 7: Identifying Needs**

The next step in the decision process is the identification of individual needs of each asset as per both the maintenance and the capacity plan as well as any additional requirements. In order to ensure transparency of all risks within the utility, an easily accessible, systematic register of needs should be designed and kept up to date.

**Step 8: Identifying Alternatives**

The aforementioned register of needs forms the basis for the development of decision alternatives by the engineering asset management department. Each alternative should be defined as a project with a clear scope and budget along with assumptions made.

**Step 9: Decision-Making**

Prior to decision-making, the performance of each alternative with regard to the decision criteria has to be evaluated. Comparing the respective risk indicators with and without project execution demonstrates the compliance of an alternative with the general business drivers. Moreover, risk exposure due to postponement of decision-making should be taken into account in order to identify urgency.

In order to ensure that the decision process is always followed, decisions on asset replacement should be well documented and approved by an entity with sufficient authority within the utility. The documentation should include all considered alternatives along with their performance indices.

**Step 10: Project Execution**

After a decision on asset replacement has been made, the project should be assigned to a team for execution. This team should oversee all aspects from conception through completion. The project leader is usually responsible both for budget planning and for technical supervision. It is also advisable for a utility to implement a planning and control system for the development phase, for the annual plans, and for any internal contracting mechanisms (service level agreements).

The replacement of secondary equipment is frequently undertaken as part of a larger substation replacement/upgrading project. In some instances due to numerical device obsolescence or malfunction, it may involve the replacement of electromechanical or analogue-based systems with numerical devices. The integrated process described here adequately caters for such eventualities. However the introduction of computer-based systems has implications extending beyond the substation as outlined in the next section.

### 38.6.2 Updating of Secondary Systems with Computer-Based Systems

The transition to the enhanced functionality available with the numerical equipment introduces wider system-related considerations. Consequently, renewal of the secondary systems is usually implemented in conjunction with:

- Renewal of the regional control center (RCC) and related new functional requirements
- Substation extension requirements or the replacement of HV plant
- Obsolescence of the existing secondary systems rendering them economically and technically obsolete (increasing failure rates and excessive maintenance costs)

It may be beneficial to undertake the replacement of the secondary systems in all substations controlled by the same RCC – or at least a number of the more important ones. This should be implemented as a coordinated project as part of an overall strategy. In this way standardization of hardware and software is achieved, facilitating both staff training and system maintenance.

Standard protocols for communication between substation and control center (long distance communication) and inside the substation (local communication) should be applied. They will permit the association of equipment from different sources for use within or outside the substation. They will also facilitate the extension or modification of the digital system and its replacement in the future.

To achieve the most advantageous return on investment over the economic lifetime of digitally based equipment, the capital expenditure should be completed over a relatively short period. (A prolonged project schedule risks hardware and software compatibility issues arising between equipment during earlier and later stages of the project.)

The new systems should be installed and commissioned in the traditional manner. The systems should first be proved in the factory and retested on-site as part of the commissioning process.

## 38.7 Security of Electronic Systems

In the past, substation control and protection schemes typically consisted of single function devices that were mainly hardwired interconnected. However, over the decades, taking advantage of the multifunction intelligent electronic devices (IEDs), it became possible to increase the functionalities and hence reduce the number of devices. Furthermore substation control has introduced local area networks (LAN) for station and bay control replacing the traditional hardwired solution. More recently the International Electrotechnical Commission (IEC) has published a number of communication standards including IEC 61850 which is becoming the dominant basis of protection and automation systems not only within substations but also between substations and between substations and other remote locations such as control centers.

However this deployment of electronic devices renders substation secondary systems vulnerable to malicious interference or attack from two sources:

- Cyber-induced attacks
- Intentional electromagnetic interference (IEMI)

### 38.7.1 Cyber-Induced Attacks

One feature of IEC 61850 is its strong emphasis on interoperability between intelligent electronic devices (IEDs) manufactured by different vendors. Another strong feature is the open publication of the IED data dictionary and communication services supported for most protection and automation functions. Furthermore, IEC 61850 and other communication standards include the specifications for peer-to-peer operation over high-speed communication channels using the Internet Protocol (IP) as shown in Fig. 38.5. This raises significant cyber security concerns. Therefore, there is a need to introduce requirements for prevention against unauthorized cyber-based access to and use of IEDs (Fig. 38.5).

Cyberattacks can be grouped into four categories as defined in CIGRE Technical Brochure 603 *Application and Management of Cybersensitivity Measures for Protection and Control Systems*.

**Gathering attacks** involve skimming or tampering with substation automation data, eavesdropping (listening and recording communication between P&C IEDs and authorized users), and performing traffic analysis of repeated patterns of communication.

**Imitation attacks** such as spoofing, cloning, and replay to impersonate legitimate access to substation IEDs, and between substation IEDs, to obtain authorized access.

**Blocking attacks** designed to deplete substation IED resources and network resources or interfere with communications using tactics such as denial of service, jamming, and malware.

**Privacy attacks** designed to disclose sensitive information about legitimate protection and control (P&C) users or groups.

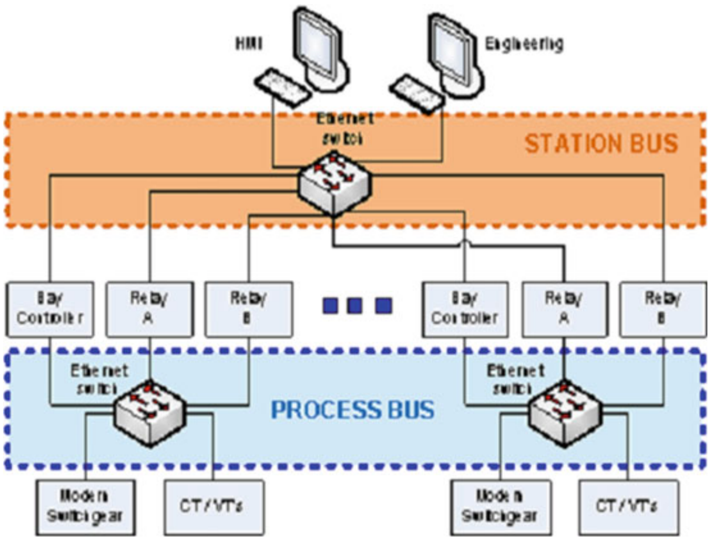


**Fig. 38.5** Typical IEC 61850 architecture

Prerequisites to successful cyber defense are:

- Clear unambiguous utility security policies and procedures
- Robust and reliable security mechanism provided in the substation devices and services

#### 38.7.1.1 Cybersecurity Threats to Substation Systems

**Vulnerabilities Introduced During Development**
Vulnerabilities introduced into the hardware and software by protection and control system manufacturers are typically difficult for the utility substation engineers to discover and patch.

The most common cybersecurity flaw is a vulnerability that provides the means to inject malicious code into the system software.

This can allow an individual to bypass the access control restrictions set by the developer or utility engineer, for instance, to gain complete control of a protection relay from a remote location or to escalate user privileges to "administrator" on a protection relay. Typically, administrator privilege includes the capability to change the privileges of other users.

Code injection attacks can be realized as binary code injection attacks or source code injection attacks. A binary code injection attack involves insertion of malicious code in a binary program to alter how the program behaves. Source code injection attacks involve interaction with protection and control system applications written in programming languages that do not require compilation, e.g., JavaScript, Hypertext (PHP), and Structured Query Language (SQL). Consequently, this attack type primarily concerns web applications. Common vulnerabilities of this category include cross-site scripting (XSS) and SQL injection. XSS involves adding malicious JavaScript code to existing web applications which then enables any visitor (or visitor specified by the attacker) access to the particular application.

**Deployment and Maintenance Vulnerabilities**
A common type of vulnerability concerns enabled software services that are either not utilized or are unknown to the engineers responsible for the security of the protection and control system. These types of services are often vulnerable because no one is concerned about them. An example of a service often employed, but seldom used in systems, is Window's file sharing, which is enabled per default on modern Windows operating systems. Another example of a service unknown to the utility engineer could be a file transfer protocol (FTP) server that is enabled to allow remote data access to system files for a user, without consent from the utility engineer.

**Firewall Configuration Errors**
Assuming that the firewall within the substation is in a gateway or local area network (LAN) routers, appropriately configuring a firewall is a difficult task for the substation engineer due to the complexity of the firewall rules. However, the engineer must

be confident that the firewall configuration is correct because of the trust invested in its security. To gain this confidence, SAT and maintenance testing should always include verification that the firewall configuration is correct. Regardless of where the firewall is located, frequent misconfigurations provide the means for an attacker to reach vulnerable P&C system components and their data.

**Online Password Guessing**

For system software using passwords, a back-off function should be in place that limits the number of password attempts allowed (typically a maximum of three tries). If the software does not have a back-off function, attackers can brute-force the authentication mechanism to gain entry. If the password is weak, the vulnerability is serious because using a dictionary of common words the attacker can easily guess the password.

**Off-Line Password Guessing**

Sometimes it is possible for an attacker to retrieve whole databases of substation system user credentials, for example, from active directory servers. If the information is poorly encrypted (or not at all), of low entropy (i.e., easy to guess), then the attacker can simply extract the information from the database.

For this reason, protection and control engineering managers must strictly enforce applicable cybersecurity policies and organizational directives.

**Inadequate Access Controls**

Poorly specified access controls can result in giving a system user too many or too fewprivileges, for example, providing administrator access to an individual or to a group of individuals who should have read-only access. Overly restrictive access control can also result in problems due to services not properly shutdown or sensitive credentials shared among personnel. Protection and control system engineers should routinely review who has what access control privileges and ensure that they properly align with those privileges associated with their job role and responsibilities.

**Network Traffic Analysis and Manipulation**

An attacker that is able to listen to and record data in transit has the potential capability to conduct a number of different attacks, e.g., the attacker could replay previously sent messages and thus fool the system operators regarding the state of the power system. Intercepting passwords sent in clear text is not difficult. Simply adding a randomly selected encryption mechanism is not enough to prevent an attacker from listening to and recording the message traffic. Although applicable to both wired and wireless communications, special attention to deployment of wireless communications is advisable. For example, utilities that have in operation Wired Equivalent Privacy (WEP) for IEEE 802.11 wireless networks whose encryption mechanisms can be easily broken. Protection and control system engineers should review all wireless remote access to the automation system. Depreciate wireless access using WEP encryption and their interface to the P&C system network declared “untrusted.”

#### 38.7.1.2 Practical Cybersecurity Solutions

Figure 38.6 shows the global vulnerabilities management process indicating the responsibilities of the various entities involved in the provision of the system.

- P1: Vendor protection and control engineer
- P2: Third-party service provider
- P3: Protection and control system integrator
- P4: Electrical power utility (EPU) protection and control engineer

Vendors need to have in place a well-defined cybersecurity threat-survey process to address the vulnerability issues in a timely manner. This survey process requires up-to-date information about cybersecurity problems coming from various third-party components providers (e.g., Microsoft, Sybase, etc.) as well as entities like CERT (computer emergency response team).

**Collaboration Efforts**

Practical solutions for implementing cybersecurity require a cooperative effort between protection and control engineers, network engineers, and others with specialized skills. For example, managing network devices (router, switches, firewall, etc.) are usually the responsibility of the network engineer. However, the P&C engineer must work with the network engineer to ensure that configuration settings for the network devices do not impact P&C systems performance, reliability, and availability.

**Physical Security for Protection and Control Systems**

Physical security involves many different aspects from locked gates and doors allowing access to the IEDs to prevention of unauthorized access to the automation systems. The access security for the IEDs is the role-based access control (RBAC) involving password and user permission levels. The utility should keep a database of permissible functions by personnel that links to the password for that person. For the many different aspects of RBAC, see CIGRE Technical Brochure 427 *The Impact of Implementing Cyber Security Requirements using IEC 61850*.

**Endpoint Security of Protection and Control Systems**

**Common Malware Issues**

Sophisticated malware is proliferating, especially at the endpoints that connect protection and control networks to unprotected devices. Ponemon Institute, an independent research organization, reported that their surveys identified the most frequently encountered network incidents as malware attacks, botnet attacks, and SQL injections. The most challenging types of incidents were zero-day attacks, SQL injections, and the exploitation of software vulnerabilities more than 3 months old. The greatest concern is related to employees working from remote locations,

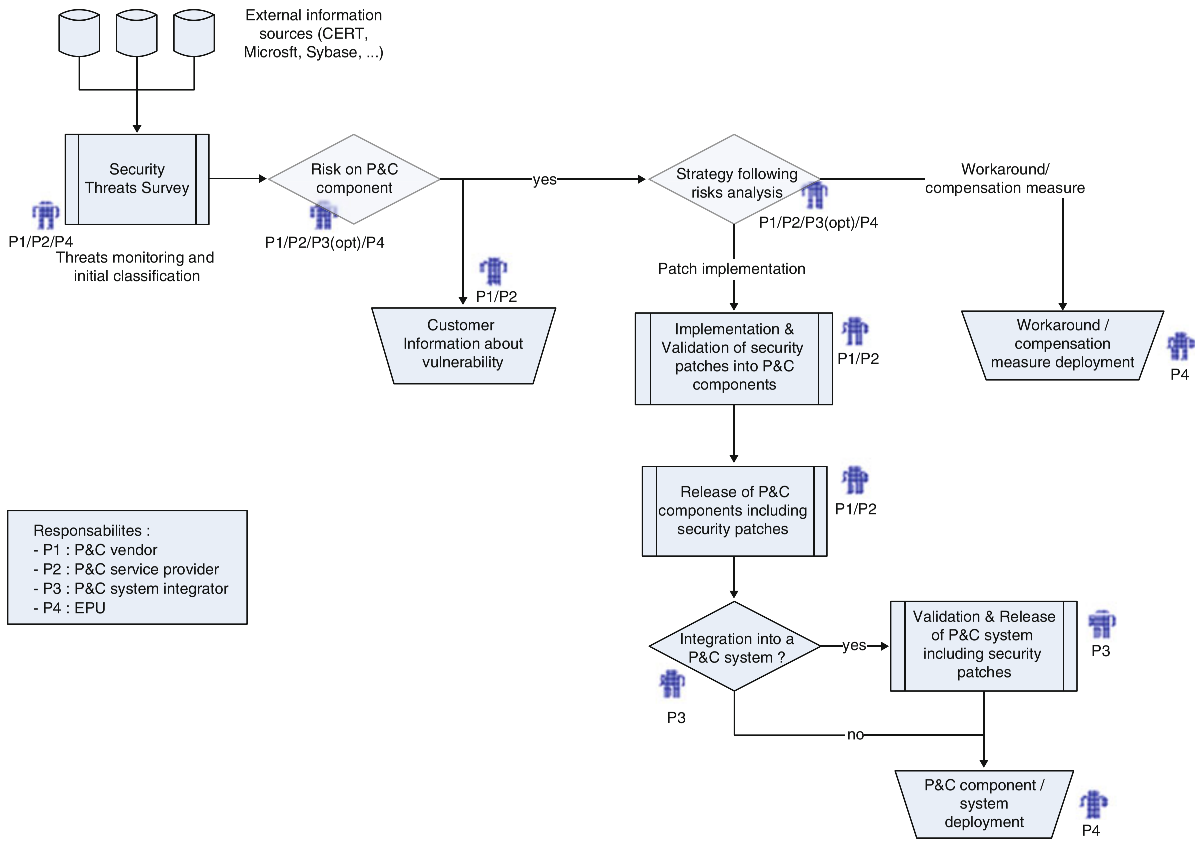


**Fig. 38.6** Vulnerability management process

downloading unfamiliar third-party apps, and increasing the threat of destructive, hard-to-detect malware attacks. According to Verizon's 2010 Data Breach Investigations Report, the most common attack pathways are web applications, remote access and control services and software, and backdoor or control channel.

**Emerging Endpoint Security Stack**

An emerging solution is the creation of an endpoint security stack. This places patch and configuration management at the center and then surrounds it with layers of coordinated application control, device control, and antivirus. Protection and control engineers should consider the following strategies and tactics:

- Improve patch management: IEC 62443-2-3 offers an improved patch management approach that should be considered.
- Put antivirus in place.
- Whitelist protection and control apps: these allow only approved applications to execute and block everything else; by default, it protects the network – including against "zero-day" attacks – as it does not need to wait for the latest vulnerability patch or antivirus definition.

Engineers understand patch management and antivirus perimeter defenses. They need a better understanding of whitelisting management procedures.

**Network Security Control of Protection and Control Systems**

Network security is an important building block to achieve a layered defense for automation systems. In addition, it is an essential part of the notional architecture (see Fig. 38.7). It affects the communication aspects of the main use cases: substation automation, substation-to-substation, substation-to-control center, as well as remote engineering. In general, network security fulfils the following security functions:

- Access control – strong identity mechanisms for all elements of a protection and control system connected to a network: users, devices, and applications.
- Data confidentiality and integrity – encryption is optional, except where requirements and regulations mandate data confidentiality.
- Threat detection and mitigation – the objective is to protect critical assets against cyberattacks and insider threats.
- Device and platform integrity – device protection against compromise must be resistant to cyber-induced attacks.

Inherent network capabilities relating to QoS (quality of services) provide the capability of functions to detect traffic abnormalities and offer denial-of-services (DoS) as a prevention. QoS deployment in protection and control systems is an essential measure to control and protect the installation against a various number of attack scenarios such as external, internal, technical failure, and misconfiguration. It controls resources and facilitates coexistence of several traffic types.

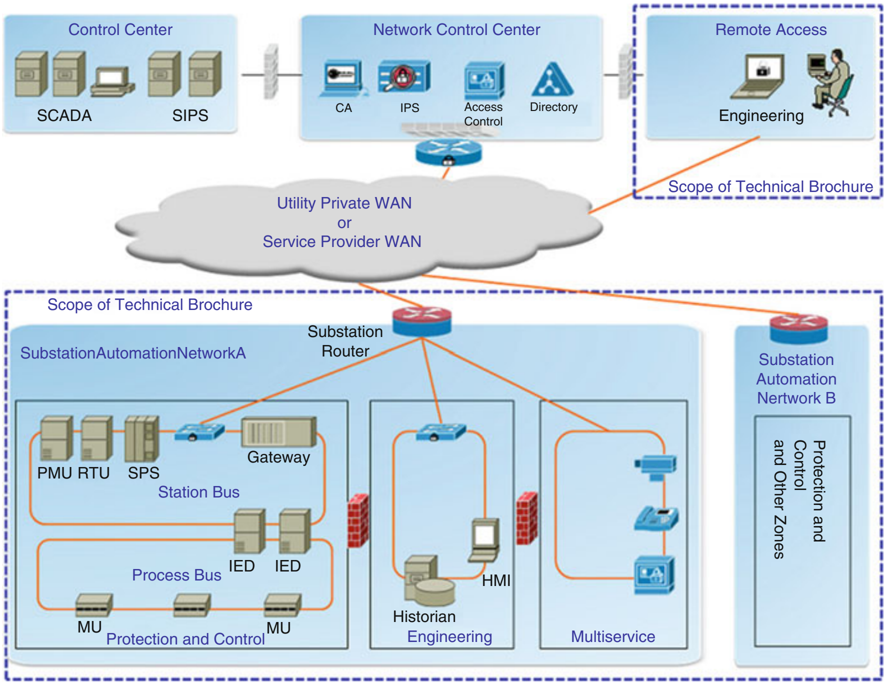


**Fig. 38.7** Notional architecture used for this section

- Network traffic analysis to evaluate deviations from the norm to detect cyber-induced attacks on the protection and control system.
- Performance management monitors and maintains the performance of the network.
- Fault detection and notification of all protection and control network components and associated IEDs attached to the network.
- In terms of network architecture, topology, and hardware, a correct and use case driven network design regarding capacity, bandwidth, and QoS as well as a proper selection and configuration of routers and switches including redundancy aspects are essential preconditions.

**Operational Constraints: Enabling Trusted Access to Substation Automation Assets**

There is a clear need relating to substation automation systems for the comprehensive management of role-based access control. This must include various independent entities required for substation operations such as support contractors and regulatory agencies that have legitimate needs for access to and control of substation assets. Some situations require access on-site and others require access from remote locations. In either case, the protection and control engineer's view is to declare those requiring access to protection and control assets as untrusted. To warrant trusted access and use of substation assets, use digital certificates to vet and control access privileges and user privileges. Further details on access enabling mechanisms for key management life cycle are described in CIGRE Technical Brochure 603, *Application and Management of Cybersensitivity Measures for Protection and Control, Annex M*.

**Maximizing the Use of Compensating Security Mechanisms**
Protection and control engineers recognize three reasons to provide compensating security controls to protect critical assets and functions. First, legacy systems, subsystems, and components have inadequate security mechanisms and must rely on perimeter defense systems for protection. Second, many new protection and control components do not have adequate memory or computing resources to embed security mechanisms. Third, response time for power system protection cannot afford either the communication latency or processing time to perform complex tasks such as encryption and decryption to protect the confidentiality and data integrity of information exchanged. For these reasons, protection and control engineers need to insist on maximizing their first line of defense, specifically, substation LAN access control from interfaces that are declared "untrusted." The second line of defense is comprised of multiple security mechanisms that enforce use control (e.g., read/write privileges specified in digital certificates), restricted data flow managed by substation network routers, and management of network resources embedded in all P&C IEDs.

#### 38.7.1.3 Action Summary for Substation Automation Engineers to Counter Cyber-Induced Attacks

The important actions are summarized as follows:

- Protection and control engineers (and IT engineers) should review and approve the factory acceptance and site acceptance test plans and procedures, including test scripts, to ensure they adequately include consideration of cybersecurity mitigation requirements.
- Although antivirus is helpless against zero-day attacks, protection and control engineers should ensure that up-to-date patches are installed for perimeter defense of the protection and control network to block known threats.
- Protection and control engineers should use security scanners to obtain an objective assessment of the state of cybersecurity vulnerabilities. They should periodically selectively scan individual sites and mission critical applications. They should perform automated penetration testing and system audits to support compliance management policies, procedures, and organizational directives.
- In addition to antivirus perimeter defense, engineers should implement a strong whitelisting policy to protect access to the protection and control network and components.
- Engineers should periodically review all wireless remote access to the protection and control system. Wireless access using Wired Equivalent Privacy (WEP) encryption should be depreciated and their interface to the system declared "untrusted."

- Role-based access control requires effective key management to protect access control and user control privileges specified in the digital certificate issued to users. Key management is not the sole responsibility of the protection and control engineers. However, these engineers should be part of the key management team with the responsibility to influence the design and operation of key management support functions that directly relate to the substation automation systems, subsystems, and components that use keying material for security protection.

CIGRE Technical Brochure 603, *Application and Management of Cybersensitivity Measures for Protection and Control* describes ten important points to be considered:

1. The scope and level of cybersecurity protection should be specific and appropriate to the protection and control assets at risk. One approach does not fit all; risk-based tailoring provides the proper context that is responsive to organizational structures and policies.
2. Cybersecurity mechanisms must be pervasive, simple, scalable, and easy to manage by protection and control engineers as part of their normal duties.
3. Where applicable, based on the utility's risk assessment, IEDs and applications must communicate using open, secure protocols such as those described in IEC 62351.
4. All protection and control devices must be capable of maintaining their own cybersecurity policy (or provided compensating protection) on an untrusted network.
5. All protection and control engineers, technicians, and managers, including the processes they control and the cybersecurity technology they use, must have declared and transparent levels of trust for any exchange of data to take place.
6. IEDs must be capable of appropriate levels of (mutual) authentication for accessing systems and data.
7. Outside of the area of control specific to protection and control, authentication, authorization, and accountability requires careful attention to the trustworthiness of external interfaces.
8. In accordance with the attributes in IEC 62351, access to protection and control data is controlled.
9. Data privacy (and the cybersecurity of any asset of sufficiently high value) requires a segregation of duties and privileges enforced by strong role-based access control (RBAC) mechanisms.
10. When stored, in transit or in use, by default, enabling security mechanisms protects protection and control data.

### 38.7.2 Intentional Electromagnetic Interference

Intentional electromagnetic interference (IEMI) has been defined as the "Intentional malicious generation of electromagnetic energy introducing noise or signals into electric and electronic systems, thus disrupting, confusing or damaging these systems for terrorist or criminal purposes.” The topic is discussed in detail in CIGRE Technical Brochure 600 *Protection of high voltage control electronics against intentional electromagnetic interference*.

IEMI involves the use of various electromagnetic weapons that can create either narrowband or broadband time waveforms. The range of frequencies that can be created is shown in Fig. 38.8 and compared to those associated with lightning and early-time high-altitude electromagnetic pulse (HEMP fields). These electric fields reach peak values in the kV range for 10 s with pulse widths of the order of 100 ps.

Most substations are unlikely to be subjected to IEMI. However in response to the concern that a building could be an IEMI target, an assessment should be made of the vulnerability of the facility. Here it is assumed the dominant concern is EM coupling to internal cabling, which leads to adverse effects on the attached equipment, such as computers, process controllers, or communication gear. The IEMI evaluation can be reduced to a sequence of questions and the calculations that follow.

- What are the EM threat environments from possible EM weapons?
- How close can the attacker get to the building (standoff distances)?
- What EM shielding does the building itself provide?
- What interfering EM signal levels could then be induced on the internal cabling?
- What EM disturbance levels are needed to cause adverse effects to the equipment?
- What level of EM protection is required to prevent interference?

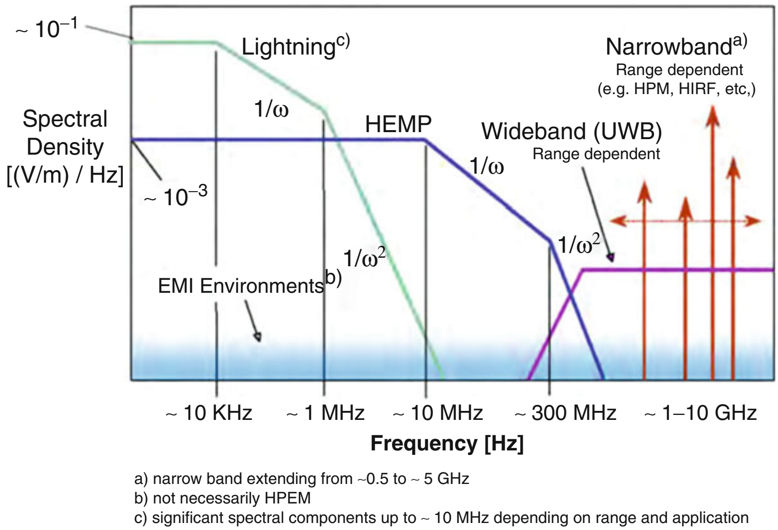


**Fig. 38.8** Comparison of several high power EM environments, including the IEMI wideband and narrowband environments. (**a**) Narrowband extending from ~0,5 to ~5 Ghz. (**b**) Not necessarily HPEM. (**c**) Significant spectral components up to ~10 MHz depending on range and application

**Generic IEMI Mitigation Methods**

The basic IEMI problem for a power substation involves the radiated IEMI fields illuminating the high voltage yard and the substation control building itself. For the sensor and control cables that run to and from the control building, the main issue is to develop a high-frequency grounding system to bleed off the common mode currents coupled to the cables to ensure they do not propagate directly to the electronics equipment. Several options for mitigation include:

**Increase the possible standoff distances using physical security**, such as fencing, to keep assailants far away, in order to take advantage of the 1/R falloff in electric field from an antenna.

**Use electromagnetic (EM) alarms to monitor the EM environment**. Watch for the start and the continuation of an IEMI attack (and also to document that a high-level EM environment had occurred). While not all equipment may respond to the fast rising IEMI environment, there will be some equipment that could be impacted. Situational awareness is important even if to understand why malfunctions occurred after the fact. These sensors are still under development but should be available in the future.

**Better electromagnetic building shielding**. Increase the quality of the shielding effectiveness of the building in the frequency range of importance. For example, windows are leaky to high-frequency EM fields and should be covered over with metal sheeting or well-grounded screen mesh. The use of metal doors is recommended.

Depending on the strength of the IEMI weapon and its location relative to the control building electronics, it is conceivable that the external peak electromagnetic fields will be greater than 10 kV/m. These fields may not be attenuated very much in the range of 1 MHz–5 GHz, depending on the natural shielding provided by typical construction materials. Table 38.6 shows the results of measurements performed at power system substation buildings and control centers. It is clear that there is a strong

**Table 38.6** Comparing the shielding effectiveness measurements for various power system buildings and rooms

| Shielding measurements | | |
|---|---|---|
| Nominal shielding, dB | Room | Shielding, dB |
| 0 | All wooden bldg | 2 |
| 5 | Room under wood roof | 4 |
| | Wood bldg-room 1 | 4 |
| | Conc – no rebar | 5 |
| | Wood bldg-room 2 | 6 |
| 10 | Conc.+rebar-room 1 | 7 |
| | Conc.+rebar-room 2 | 11 |
| | Conc.+rebar-room 3 | 11 |
| 20 | Conc.+rebar-room 4 | 18 |
| 30 | Metal bldg | 26 |
| | Conc.+rebar-well prot.room | 29 |

variation in attenuation. The far right column indicates the measurement values obtained, while the first column represents an attempt to place the measurements into categories. The intention is to determine if there is a pattern in the expected attenuation depending on construction quality. It is clear that an all wooden building or a room under a wooden roof provides very little protection from electromagnetic fields. Also concrete without rebar (or brick) appears to be in the 5 dB category. When the building is constructed of concrete with rebar, then the attenuation increases substantially; however there can still be variations in shielding depending on the location of the room within the building. Typically rooms that do not share an outside wall provide the best attenuation. Finally metal buildings (even without welded seams) are the best, although as noted in Table 38.6 below a concrete/rebar building with a room isolated from the outside walls can be nearly as good. This latter room was a control room (not a substation control building) and was in a large building that had many offices around it. It was well isolated from the outside walls of the building. For substation control buildings, the usual situation is a single large room.

There are two approaches in dealing with the shielding of an existing building:

- Shielding effectiveness could be improved by covering open windows if present.
- Covering the external surfaces of the building with metallic material, adding metallic materials to the internal walls of the building, or replacing the existing building with an all metal building.

The latter approach will be the best and may be cost effective if the substation building is scheduled for an upgrade in the near future. In addition, irrespective of the approach taken, the external sensor and control cables must be grounded with low-inductance techniques to the metallic building.

**Reduction of Cable Coupling**

If high levels of IEMI fields can penetrate into the building and couple to network cabling, then an effort must be made to either reduce the coupling to the cables or restrict the effects of the coupled signals.

**Cable Layout**

High-level IEMI-conducted transients are coupled onto metallic cables in "common mode," and while such signals do not propagate well on building wiring, they are still a concern. However, there are some aspects of common mode signal propagation and coupling that can be used to advantage in IEMI mitigation. In general, the longer the cable run, the more the coupling. However, for practical purposes, given the main frequency content of IEMI is above 100 MHz, the pulse field coupling tends to maximize on cable lengths between 3 and 10 m in length. Another obvious factor is the cable length exposed to the IEMI fields. Running cables in metal cable conduits, troughs, or under raised floors is very helpful – when it is metal that surrounds the cabling. This helps shield the cables from the IEMI fields. Even if not completely enclosed by metal, coupling to the RF fields is significantly reduced if the cables are run very close to metal walls or structures. This also applies to grouping many cables together in a tight bundle – as some of the cables will tend to have lower coupling, especially the innermost ones. Such approaches should not be overlooked, but it can be difficult to characterize the amount of protection provided. Also, for some of these mitigation approaches, it should be ensured that they are not "undone" in some future maintenance.

**Shielded Cables**

Shielded cables have been used extensively for "everyday" EMI mitigation in the past. The concept is simple, as the IEMI signals are still induced on the cabling but on the external cable shield, not on the inner wires that connect to the sensitive electronics. The shield is an EM barrier, protecting the inner wires. Significant concerns for all cables, but especially Ethernet cables, are the quality of the terminations at the ends of the shielded cables. Typically shielded RJ-45 plugs do not form a 360° bond around the inner wires, which is desired at high frequencies. Furthermore, even this type of low-quality shield termination is only possible if the electronic equipment itself has shielded receptacles, but many do not.

**Ferrites**

Ferrites are often used to suppress EMI on cables. Split ferrite beads can be snapped onto cables without interrupting normal operations. Thus, it is possible that they might be of use to mitigate IEMI. In this case, the bead acts as a series resistance to the common mode signal, with a negligible effect on the normal differential mode signals of the network communications. An important issue with ferrites is that there is a strong frequency dependence. Unfortunately IEMI can cover a wide range of frequencies. It is possible that multiple ferrites, with a spread in frequencies of the absorption peak, might be used, although this will make the application of ferrites difficult as the number of cables increases. Tests have been performed for different types of ferrites. Ferrites were added to a cable, and the reductions in current on the shield, and for the inner wires, were recorded. Tests were performed with variations in the number of ferrites of the same type used. Figure 38.9 shows the results for nine different ferrites from one manufacturer illustrating samples of peak pulse attenuation versus the number of ferrites for nine different types of snap-on cable ferrites. The top plot (a) is for the total cable current (mostly shield current), and the bottom (b) is for the total current on the inner wires. It is important to match the frequency characteristics of ferrites to the transient frequency content that is to be reduced, although it is clear that the amount of total reduction achievable is limited.

**Surge Protection Devices**

Surge protection devices (SPD) are generally designed for lightning, power faults, or interference from malfunctioning equipment. Such devices are common for phone and AC power lines and may be found on AC power strips or UPSs (backup power). In some cases surge protectors for network lines might be included. SPDs usually react in a nonlinear fashion; they short out or open the lines when they sense a signal that is too high (Fig. 38.10).

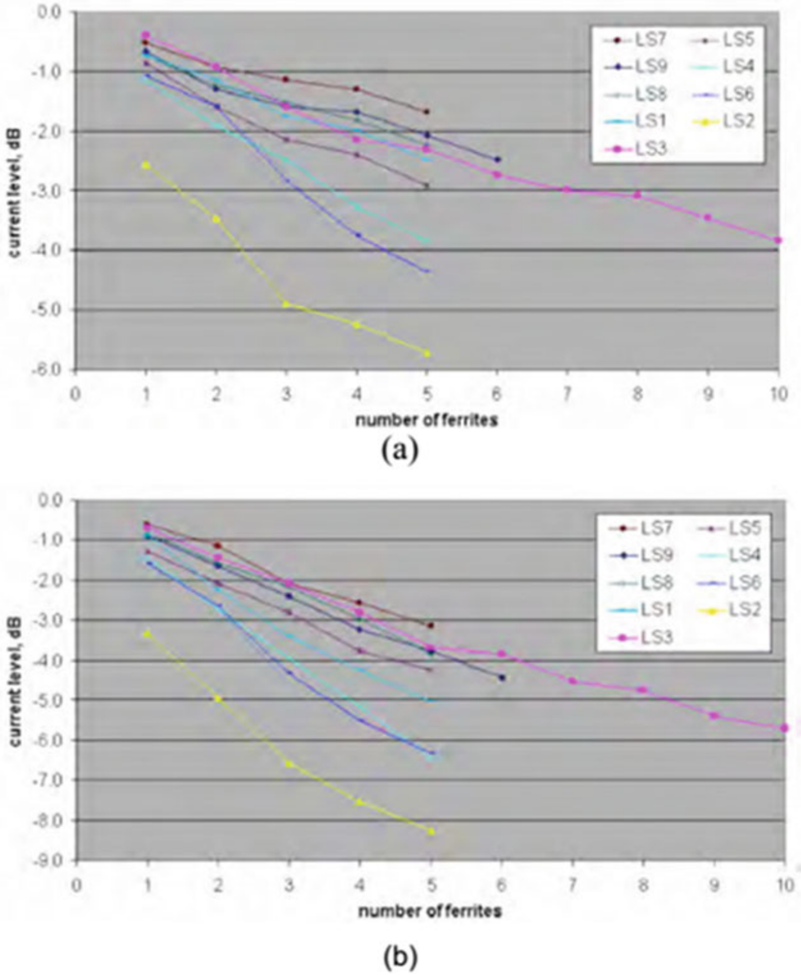


**Fig. 38.9** Samples of peak pulse attenuation versus the number of ferrites for nine different types of snap-on cable ferrites. The top plot (**a**) is for the total cable current (mostly shield current), and the bottom (**b**) is for the total current on the inner wires

Among the important operational parameters are how much energy the protector can handle (especially important for lightning) and how fast the protection can "turn on" in response to a transient (especially important for IEMI). Surge protectors for Ethernet cables are available, examples of which are shown in the diagram. They are placed in series with the network lines; the incoming cable connects to one side of the SPD, and the other side connects by a short jumper into the RJ-45 plug on the protected equipment. The jumper needs to be short, since it is again a network line that can pick up IEMI signals.

**Fig. 38.10** Samples of network cable surge protectors

It is unclear how well the typical advertised network surge protectors would work for fast-rising pulses. A few network protectors have been found that advertise protection from high-altitude electromagnetic pulse (HEMP) and so might be useful for IEMI too. Additional effort may be necessary to ensure that selected devices will be appropriate for IEMI protection purposes.

**Optical Cabling**
An ideal solution to the IEMI cable-coupling problem is known from normal EMI case studies – replace metallic lines with fiber optic lines. As long as the fiber lines have no metal (some have metal for strengthening), there can be no RF coupling or propagation to connected equipment. All components are readily available, and conversion from metallic to fiber is straightforward. One difficulty is that the equipment to be connected must possess optical connectors, which may not be the case for older electronic equipment.

## 38.8 Physical Security Requirements

It is of paramount importance that a substation has security measures in place that are adequate to ensure the following:

- Safe and secure working conditions for on-site staff
- Prevention of accidental or intentional access by unauthorized personnel
- Preventing damage to equipment by intruders

### 38.8.1 Site Access

To prevent unauthorized access, the substation should be located in a secure building, or in the case of AIS where the primary plant is outdoors, the site should be enclosed by walls or fencing sufficiently high to prevent intruder access. Gates and doors should normally be equipped with robust locks and key access controlled as part of the utilities security/control procedures. Gates and doors should be constructed to prevent their easy removal or damage by vandalism. Windows should not be provided in buildings that are adjacent to and overlook public areas, but where this is the case, steel shutters or burglar bars should be fitted. For more details on the subject of fences and walls, refer to ► Sect. 11.13.

Relay panels, kiosks, and switchgear cubicles should be securely locked at all times except for maintenance work or inspections. Issuing of keys for access to such plant should be controlled under an appropriate "permit to work" procedure.

### 38.8.2 Alarm System

The alarm system should detect any abnormal conditions arising within the substation that constitute a danger to staff or equipment. The system must be capable of alerting staff irrespective of their location whether on-site or accessible remotely, e.g., control center.

The system should be capable of both manual and automatic activation as appropriate for the particular condition arising in the substation. As a minimum it should include:

- Smoke/gas detection
- Fire protection operated
- Plant failure
- Protections operated
- Staff assembly/attention required
- Intruder system activation

The system should initiate an alarm that is audible throughout the site and also provide visible annunciators having identifying signals that indicate the alarm cause. To avoid a confusing proliferation of signals, alarms should be grouped in a relatively small number.

### 38.8.3 CCTV and Intruder Alarm Systems

Intruder alarm systems have been used for some years to counter unauthorized access, burglary, vandalism, etc. Such systems consist of activating devices provided on doors and windows augmented by motion detectors within the site. The system is connected to the alarm system and possibly, if required, to a local police or security authority.

Suitably located CCTV cameras as well as monitoring planned or unwanted approaches or entry to the substation also allow for plant monitoring. This is particularly useful for locations that are difficult to access due to remoteness. CCTV cameras permit the monitoring of plant that is behaving abnormally enabling early intervention for the equipment to be identified and engineering/operational data collected. This also facilitates the prompt switching out, if necessary, of equipment at risk.

## References

Much of the material in this section is based on some of the following publications. They are also a possible source of further, more detailed information should the reader be interested. The E-CIGRE website is a very useful source of information published by the Study Committees of CIGRE

TB 88 – Design AND Maintenance Practice for Substation Secondary systems

TB 124 – Guide on EMC in Power Plants and Substations

TB 252 – Functional Specification and Evaluation of Substations

TB 300 – Guide to an Optimised Approach to the Renewal of Existing Air Insulated Substations

TB 318 – WIFI Protected for Protection and Automation

TB 329 – Guidelines for the Specification and Evaluation of Substation Automation Systems

TB 380 – The Impact of New Functionalities on Substation Design

TB 427 – The Impact of Implementing Cyber Security Requirements using IEC 61850

TB 448 – Refurbishment Strategies based on Life Cycle Cost and Technical Constraints

TB 464 – Maintenance Strategies for Digital Substation Automation Systems

TB 532 – Substation Uprating and Upgrading

TB 535 – EMC within Power Plants and Substations

TB 600 – Protection of High Voltage Power Network Control Electronics Against Intentional Electromagnetic Interference (IEMI)

TB 603 – Application and Management of Cybersecurity Measures for Protection and Control

TB 628 – Documentation Requirements Throughout the Lifecycle of Digital Substation Automation Systems

TB 637 – Acceptance, Commissioning and Field Testing Techniques for Protection and Automation Systems

# Part G

# Environmental Impact of and on Substations

*Jarmo Elovaara*

# Introduction to the Environmental Impact of and on Substations 39

Jarmo Elovaara

The environment is a key consideration in the design and lifetime management of substations. The environment affects the substation and the substation the environment. The effects can be in both cases immediate or develop in time. In case of the environment effects, it is usually a question about how the substation or its equipment will work under the environment in question. Examples of these kinds of effects of the environment on the substation and on substation equipment are such daily phenomena as ambient conditions to which temperature, solar radiation, wind, rain, snow, and accumulation of pollution on insulator surfaces belong. On the other hand, some of the environmental effects can occur much more sporadically but be very severe and cause significant damage and/or disruption. Examples of these are hurricanes, floods, wildfires, earthquakes, and volcanic eruptions. Already the given examples reveal that the effects can be very site specific and vary from one site to the next within a country or within the substations belonging to a single grid owner/operator. We have learned to know best the effects of the environment on substations and their equipment in case of outdoor conditions. Consequently, an essential part of the design guides and different (technical) equipment specifications deals with the question of how the environment has to be taken into account already in the design phase of the substation and equipment selection. In indoor substations, the variation range of environmental factors is usually smaller than those for otherwise equivalent outdoor substations.

Over the last decades, it has been noticed that some effects of the environment have started to become more severe than observed previously. Especially the number of events with extreme characteristics has increased. The quite commonly accepted opinion is that the basic reason for this development is climate change associated

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

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with global warming. The old design philosophies and requirements may not necessarily be any more relevant as such. This “large-scale change” sets harder requirements on the electricity transmission and distribution system by impairing the reliability of supply. At the same time, more people than earlier are affected by the consequences of these kinds of extreme situations. This in turn is caused by the fact that electricity is now an absolutely necessary commodity to almost all people on Earth. Potentially catastrophic consequences may be expected, if the modern industrialized society loses the electricity supply for a longer period of time.

When the effects of a substation on the environment are discussed, usually only such things are considered which spoil or damage the original condition of the environment. Such factors are especially the chemical pollution; land area consumption, noise, visual impact of the substation and the electromagnetic fields created by lines, feeders, bus bars, and equipment; and even the direct contribution of the substation to global warming of the atmosphere. Lately making more effective use of the waste has become a topic, too. The field effects and the effects of $SF_6$ are examples where electricity or technology has been used already for a long time before people have become aware of their possible risks to the environment and of their possible health effects. At this stage it is already extremely difficult and/or expensive to improve the situation. In both cases a major factor has also been that the development of the technology has been so rapid that all environmental risks have not been identified before the practical use of the new technology has already become very extensive. The overwhelming advantages of electricity-based technologies are now known to all, and it is not possible to maintain the present standard of living without electricity. So the transmission and distribution facilities as well as consumption devices need to be made safer. The gas $SF_6$, in turn, has excellent dielectric withstand and arc quenching properties compared to other substances known so far, but it is also, as we know now, a very powerful greenhouse gas with a global warming potential (GWP) of 23900. In this case the only alternatives are the reduction of the $SF_6$ leakages to the atmosphere and development of a new gas with lower environmental risks.

CIGRE SC B3 (substations) and its precursor SC 23 have contributed not only to the technical development of substation technology but also to the environmental effects of the technology. However, when the organization of CIGRE was updated at the turn of the millennium, the topics dealing with environmental matters were partly removed to SC C3 (System Environmental Performance). Consequently, questions related with the field effects belong now to the environment committee, but the $SF_6$ subject has remained under the control of SC B3, because it is largely a manufacturer- and user-centered topic. This chapter provides a review of the main environmental questions, based upon CIGRE’s technical brochures, electra articles, and session papers.

# Impact of Ambient Conditions on Substations

# 40

Jarmo Elovaara and Angela Klepac

## Contents


40.1 Normal Ambient Conditions ........ 904
40.2 Polluted Conditions ........ 906
40.3 Abnormal Ambient Conditions ........ 907
40.3.1 Heavy Wind and Storms ........ 907
40.3.2 Winter Conditions ........ 909
40.3.3 Substations in Very Hot and Dry Conditions ........ 910
40.3.4 Earthquakes ........ 912
40.4 Substations under Special Conditions ........ 913
40.5 Effects of Wild Life ........ 913


External insulation of equipment installed outdoors is directly affected by the external ambient conditions. Installing devices indoors reduces the number of the ambient factors affecting the equipment but does not remove them completely, because indoor installation does not necessarily mean that the system is hermetically sealed and fully protected from all the effects of variation of ambient conditions.

Ambient conditions usually include the pressure, density, and humidity of the ambient air. These influence especially on the dielectric strength of air gaps and insulators surrounded by air. However, ambient temperature and solar radiation are important also when the thermal stresses of the substation equipment as well as the sag of the busbars made by conductor bundles are considered. Further, wind has to be taken into account because it causes mechanical loads to the substation equipment and can induce fatal vibrations, for example, in tubular busbars if this risk is ignored.

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

A. Klepac
Zinfra, Sydney, Australia
e-mail: Angela.Klepac@Zinfra.com.au

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In addition the lightning flash density (number of lightning strokes per km$^2$ and year) or the keraunic level (number of annual thunder days) plays a role, because it impacts on the application of shielding wires above the substation or on the use of lightning masts in the substation. Former CIGRE SC 33 has published in 1991 the brochure TB 63, where statistical properties of the lightning flashes have been presented on the basis of measurements made with the help of tall constructions (masts, buildings). Later, SC C4 has updated this publication on the basis of data obtained with the help of lightning direction finder networks.

Standards usually cover the most common variations of external ambient conditions. However, in the northern hemisphere, the temperatures can reach lower values than what is taken into account, for example, in IEC standards. Different equipment standards and IEC standards 60071-1 and 60072-2 cover the dielectric withstand values to be used in case of external installations and equipment in temperature range −40 °C to +30 °C.

## 40.1 Normal Ambient Conditions

In case of external insulation of outdoor installations, ambient conditions mean the status of the external ambient air. The dielectric withstand of air gaps has not been a research item for SC B3, but in 2015 B3 prepared Technical Brochure TB 614 concerning the design of air-insulated substations for severe climatic conditions, including a summary of how the withstand capability of air gaps is dependent on atmospheric conditions. A short summary is given here.

It has been known for a long time that the dielectric properties of air gaps depend not only on the shape of the electrodes and the length of the gap but also on the pressure ($p$) and temperature ($T$), i.e., on the density ($\rho \sim p/T$) of the air, as well as on the humidity of the air, height of the installation site ($H$), and number and type of impurities in the air. The TC 42 of IEC has studied (with the help of CIGRE SC D2 and earlier SC 33) the effect of the variation of atmospheric parameters on the dielectric strength of air gaps and has published in international standards the methods by which the results measured in a laboratory can be transformed to results valid in standard conditions (and vice versa). Some refinement to these correction formulae continues to take place because more is still being learned about the physics of the discharges in air gaps.

In short air gaps (up to the length of about 2 m), electrical breakdown is controlled by streamer discharge, which is affected by the relative air density (ratio of densities in local and standard conditions – 293 K and 1013 mbar). In longer air gaps, the electric field distribution is less homogeneous, and due to the longer length, successive streamers are formed. They join together and form a conducting channel which is called a leader. On the tip of the leader, there is a streamer ionizing the air in the gap. The leader grows – propagates – in the direction of the highest electric field. Finally a jump to the opposite electrode takes place, and the whole gap is short-circuited by the conductive channel. A breakdown takes place. The combined streamer-leader process governs the breakdown in longer air gaps. The essential thing is that the relative air density has less effect on the leader process than on the streamer process. More is still being learned about this, and therefore in large air gaps with inhomogeneous field distributions, the climatic correction factor, especially the power to which the relative air density is raised, is still developing.

Pure water molecules are slightly electronegative and they try to attach free electrons to them. This is why the dielectric strength of a pure air gap increases with the humidity of the air until the dew point is reached. When local impurities (like dust or pollution) are present, the humidity can condense around these and form small water droplets. On insulator surfaces there is usually some external pollution which can become conductive due to the water or the high humidity. The outcome is usually that a conductive layer is formed on the insulator surfaces. This increases the leakage current over insulation. This in turn can lead to the formation of dry bands on the surfaces. In fact, this means that the length of the path measured along the insulator surface (the creepage distance) has been reduced, and this can lead to a pollution flashover of the external insulation. CIGRE SC 23 also actively studied this flashover mechanism and contributed strongly on the formulation of the present standardized rain test and pollution tests requirements.

The laws according to which the dielectric strength of an air gap increases with the humidity have been developed experimentally for different test voltage forms. The mathematical models describing withstand of insulators or insulator surfaces with or without pollution are still developing.

Rain affects the dielectric strength of an air gap very little. However, if an insulator in air is under rain, its dielectric strength is reduced. The resulting strength depends both on the characteristics of the rain and those of the insulator. Rain parameters which have an influence are, e.g., strength of the rain, size of the rain drops, and inclination of the rain as regards the insulator as well as the conductivity and the surface tension of the water. In the insulator the critical items are the structure, material, surface, and its condition, especially the pollution and its type (e.g., industrial or salt pollution). Certain dielectric type tests have to be done under artificial laboratory rain which is quite intense compared to normal rain at temperate latitudes. International standards are available as far as artificial rain tests are concerned. Also tests on polluted insulators have a special testing standard. Rain is used also in these tests, but the rain must not be so intense that it washes pollution away from the insulator surfaces.

There are still also conditions which are not yet covered by standards. An example is a lightly polluted ceramic or glass insulator under heavy humidity. Unexpected flashovers can take place on outdoor insulations especially early in the morning when the humidity is high. However, this happens more seldom in substations than in overhead lines because the latter often have a lower design withstand strength than the substation equipment. As an explanation two alternatives are given, light pollution combined with high humidity and excrement of birds.

Snow and ice do not normally reduce the withstand strengths of insulators. However, melting ice and snow can form a very critical condition, especially if the melting material has been strongly polluted. However, the accumulation of ice on the conductors in a substation affects the mechanical design of the busbar systems because it increases the effective dead weight of the conductors and also increases the effective cross section of the conductors and supports, thus increasing the wind loading.

The wind does not affect the breakdown process but it can reduce the clearances. Busbars made of metallic conductor ropes can swing (even if V-strings are used) and end up in a movement toward each other reducing the clearance between the phases so that a breakdown takes place. When tubular busbars are used, a transversal wind can cause such vibrations in the tubes which without proper damping can cause the fixing systems to be damaged. This may lead to a busbar fault. Usually enough damping is obtained by installing a wire rope fixed at one end only inside each tubular busbar (see ► Sect. 11.5.3 for more detail). The mechanical design has to take account of the wind pressure on the busbars, insulators, and structures. This force can be very significant in areas of high wind speed, and it is usually added to the short circuit force.

The atmospheric pressure and the density of the air decrease with increasing altitude. The decrease is about 1% for each 100 m above sea level. This means that the dielectric strength of the air decreases with increasing altitude by 1% per 100 m. In IEC standards the general approach is that withstand value~~s~~ $U_0$ measured at sea level are valid as such up to the altitude 1000 m. If the limit 1000 m is exceeded, withstand and length of the external insulation have to be derated roughly by the amount +1% per each 100 m. At slow-front overvoltages, this means a length increase about 1.2–1.8% (lower values correspond to the smaller operating voltages). Hence, the air gaps at high altitude have to be longer than at sea level. This can lead to strange situations, if a device with both internal and external insulation is mounted at high altitude but tested in the sea level laboratory. Due to the final site, the external air clearances have to be so long that withstand at sea level exceeds clearly the withstand of the internal insulation, which does not need any derating. The solution is to make a dummy for the tests of external insulation only.

## 40.2 Polluted Conditions

The effect of the external pollution on the dielectric strength of the external insulation was mentioned already above. Normally humidity or wetting of the polluted insulator surface is needed to cause a pollution flashover. Due to the operational experience, it is known that one and the same insulator might behave differently under different pollution conditions. The former WG 33.04 of SC 33 (Overvoltages and Insulation Coordination) studied the different representative pollution testing methodologies in the 1970s and 1980s, and two methods have reached such maturity that they were also introduced in the international standardization by IEC (salt-fog method and solid-layer method). As already the first name reveals, the salt of the seawater and also the salt of the desert sand can cause operational difficulties under heavy humidity or normal rain on lines which are located near coastal zones or cross over a desert (heavy rain might wash the pollution away from the insulator surfaces and thus improve the behavior of the insulator). Also salt used to keep roads free of ice during the winter can cause problems on insulators which are located very near busy roads. This salt pollution is normally a light pollution, but it can cause failures of line insulation under high humidity conditions, too. Therefore it is better to have the mid-span at the road crossing. The test base on solid-layer method better describes pollution caused by industrial and agricultural activities.

Greasing of insulators was studied as a method to prevent pollution flashovers, but the complication related with this method is that after a certain time, the grease might become saturated by the pollution particles and then the greasing does not help anymore. The user should then clean the insulators and grease them again. Also live line washing methods have been developed. Fortunately composite types of insulators with glass fiber-based core and outer shed made of silicon rubber are light and strong, have nowadays also competitive price, and are very tolerant in polluted conditions. Their use is now very common in challenging installation sites.

There have been relatively few CIGRE Brochures on the topic of pollution testing. The most relevant information on the effect of pollution and testing is published in IEC standards. WG C4.303 has published TB 361 (Outdoor Insulation in Polluted Conditions: Guidelines for Selection and Dimensioning – Part 1: General Principles and the AC Case) and in 2012 the TB 518 (Outdoor Insulation in Polluted Conditions: Guidelines for Selection and Dimensioning – Part 2: The DC Case). The newer publications naturally include also valid older results.

## 40.3 Abnormal Ambient Conditions

### 40.3.1 Heavy Wind and Storms

Mainly due to the heavy storm events combined with freezing rain in Canada in 1998 and in France in 1999, SC B2 (Overhead Lines) published in 2008 the TB 344 "Big storm events: What have we learned." During the preparation of the Brochure, it became evident that two separate event types should be defined on the basis of the severity and area: (a) widespread big storm events including European windstorms and tropical cyclones and (b) localized high-intensity winds, such as small-scale downdrafts and tornadoes. Because the Brochure is based on an international questionnaire, it is able to collect and compare worldwide information on big storm events in order to share experience in adaptation strategy and emergency preparedness. It also provides some additional recommendations which are useful also in the case of substations. Such are:

- Taking immediate photos and videos before clearing the damaged structures (for assessment of the origin of direct and indirect failures and to allow designers to distinguish between the primary and secondary failures).
- Collecting all available meteorological data to analyze and understand the storm event.
- Performing failure analyses, understanding the relation between the climatic load and the strength of components.

- Developing strategies and policies for increasing structural and electrical reliability and improving availability and continuity of service as well as for taking actions to reduce secondary failures and cascades.
- Finding a good balance between corrective measures to be taken after an unexpected storm event and preventive measures taken before possible storm events.
- Improving basic understanding and knowledge about climate features, their changes, and their impact on electrical transmission and distribution system.
- Facilitating transfer from deterministic to reliability-based design methods. For example, when loads and strengths are recognized as random variables, a value of wind or ice load can be associated for any selected climatic return period or reliability level.

References report thoroughly the design against severe climatic conditions. In this category severe heat, drought, dust, severe flooding, severe rain and humidity, severe cold, snow and ice, as well as severe wind are encountered. A questionnaire was created and circulated to prepare the Brochure, and 43 replies were received from experts from 19 countries worldwide. The coverage of the questionnaire was perhaps not as good as was wished because only one or no replies at all were received from utilities, engineering companies, consulting companies, and academia from Africa, South America, and Asia. However, the coverage over the industrialized countries was quite good. The reader gets in any case a good overview on the available mitigation techniques and experiences. Here mainly reference to the Brochure TB 344 is made without going into details. Some exceptions are made in cases where the Brochure has not stressed enough certain unexpected consequences of abnormal ambient conditions.

It is not necessary that storm is of the hurricane type for severe outcomes to occur. In Nordic countries storms are typical every autumn, and they can cause long and wide area outages. Usually outages occur only in the distribution grids and they originate from the overhead lines. The reason is that distribution lines are no longer constructed with such broad right-of-ways that trees cannot fall on to an overhead line. However, the transmission companies still follow the old policy and limit the height of the trees in the neighborhood of the right-of-ways so that trees cannot fall on the lines.

Due to environmental pressures, different types of compact line designs have been applied especially by the distribution companies. At low voltages, aerial bunched cables (self-supported aerial cables) are very widely used. Also in medium voltage grids ($U_m$ = 24 kV), the so-called covered conductors have been taken into use, because they do usually not cause an earth fault if a tree falls on the line. The conductor area can be quite large in present conditions, too, and in addition, single wooden poles are normally used as line pylons. It has turned out that this kind of design is not necessarily good under severe weather conditions. During heavy storms so many trees can fall on the line that instead of the conductors, poles have broken. This leads to much longer outage times than previously. Long outages have caused so much irritation among the clients that the legislation has been changed in some countries so that the clients have to get a right to compensation from the grid company, if the outage time exceeds 12–24 h. As a result, two relatively large changes are taking place:

- Lines are removed away from the forests to go beside the roads, because the access to the possible fault place is then easy and also repair works are easier and cheaper to perform.
- Application of underground cables has become more general in distribution grids even in sparsely populated areas.

In substations, the consequences of this development are related to the increase of the earth-fault current levels. The relay protection systems have to be replaced or modified, and special measures are needed to limit the magnitude of earth-fault currents (e.g., use Petersen coils). In addition, the local grounding systems have to be redesigned because the present earthing mats designed for lower earth-fault currents do not necessarily guarantee low enough earth-potential rises and hazard as well as interfering voltages.

### 40.3.2 Winter Conditions

In Northern countries, the air-insulated outdoor substations need to be designed so that a reliable and safe operation is possible during severe winter conditions. For example, the metallic supports of outdoor equipment have to be so high that snowdrifts cannot make the clearances to the live parts too short. Local conditions (e.g., depth of snow in winter) determine the size of the extra margins that have to be added to the standardized minimum clearances between phase and earth.

Also the temperature in winter can be lower than the minimum ambient air temperature specified in different equipment standards of IEC. It has to be possible to operate the devices with an external temperature of −50 °C. Further, excessive ice can be gathered, e.g., over the contacts of the disconnectors. Consequently, excessive ice-breaking capability may be required from the operating mechanism of disconnectors. This latter problem disappears when disconnecting breakers are used. Earlier also the humidity freezing in the valves of the pressurized air operating mechanisms of breakers and disconnectors could cause problems which had to be taken care of by applying extra efforts to keep the air dry. Now pressurized air systems are replaced with hydraulic and motor spring mechanisms which has resulted in a lower failure rate according to TB 510 and TB 511. Presently $SF_6$ breakers are mainly installed in the HV grid, but at Northern latitudes condensation of the pressurized gas at temperatures below −30 °C has to be avoided. For this purpose, gas mixtures $SF_6/N_2$ or $SF_6/CF_4$ are used. This sets new requirements for the maintenance of the breakers.

Due to the very low winter temperatures, it may be necessary to specify different temperature ranges for different areas of the same network. For example, Finland is divided in two parts so that in the Northern part, the minimum ambient temperature is specified as −50 °C, whereas in the southern part of the country, the value is −40 °C.

Although the winter days in a country can be very cold, the summer days can be quite hot. In the sunshine in the summer, the metallic flanges even in temperate regions can reach a temperature of 35–40 °C so that the variation range of the surface temperature within a year can reach the value 75–80 K. This makes the sealing of the equipment very difficult. Direct material requirements can be given, and as a security measure, double seals might be required in the most demanding conditions.

### 40.3.3 Substations in Very Hot and Dry Conditions

Heat, drought, and dust are usually combined with very hot and dry conditions, and they cause different phenomena and problem to the affected substations.

(a) **Heat**

Heat is produced by natural sources such as the sun and also by electrical losses from transmission and switching. Heat is a prime enemy of electrical equipment. Elevated heat levels, above nameplate temperatures, can cause premature failure of the electrical transmission and distribution network increasing maintenance and operational cost to the utility. Elevated temperatures from natural sources are prone in desert and equatorial regions of the world.

Areas other than these can see elevated temperatures during abnormal environmental cycles creating heating conditions that are detrimental to the correct operation of electrical equipment and the electrical utility.

Equipment manufacturers and engineers consider the heat generated from losses when designing equipment and provide the required cooling for these applications. In special applications where elevated heat levels exist, alternate or additional methods of heat dissipation can be applied.

Generally, when there is increased or severe heat conditions, the affected equipment will be less efficient. Some potential problems associated with severe heat include:

- Transformer temperature increases
- Mal-operation of digital devices
- Transformer overload
- Hydraulic leaks
- Operation of additional motors
- Insufficient cooling fan capacity
- Changes in $SF_6$ pressure causing alarms or incorrect operation of the equipment

High temperature could cause derating of transformers, to prevent oil and hot spot temperatures exceeding upper limits. Periods of high temperature are normally accompanied by high solar radiation (UV) levels, which have detrimental effects on most PVC and polymer products used in insulation over the long term.

Additional cooling systems such as forced or conditioned air units are alternatives to increasing cooling effectiveness. For most situations this application is not practical. Forced air requires the use of electric fan motors to circulate the surrounding air. In some instances the external air temperature may be high enough to endanger the electrical equipment requiring heat removal. For most applications the additional forced air motors would be mounted on the equipment it serves.

Conditioned or cooled air requires the use of an additional unit used to cool or chill the circulating air.

Depending upon the amount of dissipation required, this unit may be mounted adjacent to or near the equipment it services and will require routine maintenance to ensure optimized utilization.

A reflective coating on the exterior of electrical equipment is an additional solution to reduce the effects of natural or sun-generated heating. This involves the use of a reflective material such as glass chips or other materials to combat the effects of external heat sources. This coating can be applied during the electrical equipment manufacturing process.

Some other solutions to reduce the effects of severe heat are:

- Providing a sunshade or pergola roof over transformers, other equipment, and even cables
- Operate transformers at reduced rating
- Specify additional requirements for radiators
- Provide temporary cooling fans
- Provide permanent air-conditioned enclosures
- Uprating of transformers for overload operation
- Use of indoor equipment
- In addition to adding fans, spraying radiators with water during adverse temperature conditions

(b) **Drought**

Drought is often associated with heat; however, the effect on the substation is quite different.

Bushfires (or wildfires) are one of potential issues to be considered. Australian experience shows that bushfires have limited impact on high-voltage substations but may still occur due to extreme weather conditions. The key to protecting the assets is to ensure that the vegetation management around the substation is well maintained and areas surrounding the substation from the perimeter fence are always kept cleared.

Other design areas to consider are:

- Timber pole structures can and will burn and can fail either during fires or subsequently as result of fire damage. The preference is to use either concrete poles or steel poles or gantries in areas where there is a high risk of bushfires.
- During a bushfire arcing and flashover impacts are common due to ionized air or the presence of carbonized products such as ash, soot, and smoke in the air as fires

pass near an in service substation. Flashovers and faults might potentially occur, generally as the fire front passes but can be quite intense also, when there is a strong wind present that may force the fire flames across and in the direction of the energized substation. The high heat intensity from the fire may cause conductor strand damage, and insulator tracking can result from flashovers.
- Ash and soot buildup on insulators can cause flashovers either during the fire or subsequently. Inspection of the substation, post a fire event, can identify the need to replace or wash the insulators. This is recommended irrespectively of a flashover event when a bushfire comes in close proximity to substation assets.
- A detailed inspection of the substation should be undertaken following the route of a bushfire to assess the damage and impacts, with particular attention being applied to pole structures, insulators, and any nonmetallic elements.

Other potential issues resulting from drought include:

- Cracks in the ground, causing ground movement affecting settlement of direct buried cables and trench foundations
- Drying out of the soil reducing the effectiveness of ground grids

Some of the solutions to reduce the effects of severe drought are:

- Condition monitoring of ground settlement/movement
- Micro-pile countermeasures for dislodged equipment foundations

(c) **Dust**

Heat and drought environments will create more dust. Some of the potential issues caused by dust include:

- Dust mixed with grease may reduce the effectiveness of grease applied to devices such as disconnecting switches, etc.
- Dust particles if mixed with corrosive materials may cause corrosion.
- Dust with contaminants may reduce insulation strength and creepage distance.

Some of the solutions to reduce the effects of dust are:

- Upgrading the IP protection to IP5X or IP6X
- Providing pressurized ventilation or air-conditioning system to rooms or equipment cabinets/enclosures in order to keep the dust out
- Regular cleaning and greasing of equipment

### 40.3.4 Earthquakes

For substations located in earthquake areas, please refer to ► Sect. 11.11.

## 40.4 Substations under Special Conditions

Electrical installations of offshore wind farms and oil platforms are subject to the same kind of environmental stresses. CIGRE has recently published a technical brochure (TB 483, Guidelines for the Design and Construction of AC Offshore Substations for Wind Power Plants) about offshore substations, and therefore the subject is not treated more closely here. A special question might be offshore wind power plants in sea areas which can get ice covering during the winter. Strong winds can move even large ice coverings which stress heavily the foundations of the offshore platforms. Special solutions are needed but also known to cover even these kinds of events.

Special requirements have to be met also in mines, because high humidity and dust might cause difficulties but otherwise the conditions correspond to those in indoor substations. In addition, these grids belong usually to the category of distribution grids. Necessary special solutions are usually well-known among the specialized designers. The equipment needed in these special conditions are normally commercially available, and there is no need to treat the subject in more detail here.

## 40.5 Effects of Wild Life

Animal-related stresses and troubles met in substation do not occur systematically in every substation. Their occurrence is much more common in overhead lines than in substations, and they can take place practically everywhere in the world being caused in different regions by different types of animals. Typically, they are caused by small rodents and predators which are able to penetrate into the substation through the external fences or by certain medium-sized or large birds.

Rodents cause troubles mostly in medium voltage systems where they are able to cause earth faults and short circuits due to their size, especially in busbar systems or on the transformer tank. The most effective way to get rid of faults caused by wild rodents is to enclose the busbar system inside a cage in which the rodents cannot make access. The use of insulated cables might also help, if they have an external metallic protective screening.

Birds (e.g., white storks, herons) most often cause trouble by constructing nests on lattice structures which locate above energized conductors. Twigs/sticks can fall from the nest and cause short circuits. Because destroying of the nests might not be a good policy for the transmission/distribution company, special poles with constructions on top making the nest building easy can be erected farther away from the energized constructions, if the substation turns out to be a popular place among the birds. Birds also pollute insulator units of I-strings with their excrements. The negative effect of bird excrements might be avoided by applying V-strings, by using nail mats, etc. on lattice structures which prevent the sitting of the birds above the insulator chains. Another alternative is to equip the topmost insulator unit with a collar/sleeve which has a larger diameter than the insulator units. Then the excrements fall directly to the ground without touching the insulator.

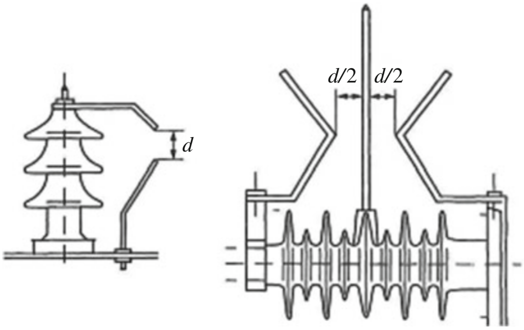


**Fig. 40.1** Spark gaps used to protect small 20/0.4 kV pole-mounted distribution transformers. In the right the gap is equipped with a rod preventing birds to sit and short-circuit the gap

**Fig. 40.2** Extreme bird damage of a composite insulator (Australia)

When spark gaps were used as overvoltage protection means at small pole-mounted distribution transformers, birds (e.g., crows) sitting on the horizontal gap caused frequently earth faults. These were avoided by installing an extra rod-type electrode transversally over the air gap (Fig. 40.1). Now the problem has probably disappeared because an operation of the spark gap always causes the tripping of the feeder and in the modern present society, these interruptions no longer tolerated. This has caused that majority of protective gaps have been replaced with gap-less surge arresters.

The use of composite insulators can cause very special problems in certain areas. There are, namely, birds which like to use the soft sheds of insulators as a "chewing gum." For example, certain parrots have strong beaks that grow continuously throughout their life. The beak should grow and "be worn" down at an equal rate, and the birds realize the latter action by nibbling and/or chewing the silicon rubber. Figure 40.2 shows an extreme example from Australia how birds have destroyed a composite insulator.

Birds are damaging composite insulators most frequently when the asset is de-energized or under construction or maintenance activities, but bird damages take place also while the asset is energized. In the former case, the solution is to place a protective sleeve over the composite insulator during installation that can easily be removed by pulling a cord at ground level and releasing the protective sleeve from the insulator just before energization. In the latter case, it is a lot more difficult to prevent the damages to occur. The electric field does not either help in repelling the birds from insulators because at the earthed end of the insulator, the field is relatively weak. The bird damages have caused, e.g., in Australia, that certain states have even reverted back to using glass and/or porcelain insulators.

# Electromagnetic Interference (EMI) in Substations

# 41

Jarmo Elovaara

The substation has always been a hostile environment for the telecommunication and control/automation systems. With the development of technology, the situation has become more a more difficult one as the use of modern electronic systems and the amount of computerized equipment with online automation and increased information transfer capability have strongly increased in protection, supervision, and control/automation equipment. At the same time, the level of energy that the components can survive has decreased, and the extent of the HV systems and the use of even higher operation voltages than before have increased such that the inherent susceptibility of modern automation and telecommunication systems to electromagnetic interference has also increased. New technologies such as fiber optics and decentralized electronics (including integrated electronic sensors/systems) have not been able to remove the interference problems.

The first CIGRE Brochure (TB 125) about these matters was published in 1997 by SC 36 (Interference), but since then the power system network control and monitoring have changed significantly making the updating of the Brochure necessary. Moreover, the need was identified to reflect the measurements that have been made and standards which have been published since the first edition of the Brochure. Its new version, TB 535 (EMC Within Power Plants and Substations) was published in the reorganized CIGRE by SC C4 (System Technical Performance) in 2013. The structure of the guide was then changed in response to feedback from users. The new edition is written for those who are responsible for measurement, control, protection, communications, and supervision of circuits. As is said in the introduction of the new Brochure, it provides an overview of problems encountered, characteristics of various environments, solutions adopted to solve the problems,

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

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best practices followed in implementing the solutions, and tests recommended to ensure that such problems will not recur.

Every incident of interference involves a source of disturbance, a coupling mechanism, and a susceptible piece of equipment. Problems arise, if the immunity margin between the disturbance magnitude affecting the piece of equipment and the susceptibility of the piece of equipment is inadequate. Electromagnetic compatibility (EMC) means attaining and maintaining required and adequate margins continuously. Achieving and maintaining adequate immunity margins is difficult, and can be costly, because in reality there are a large number of potential sources and their combinations, coupling mechanisms and paths, as well as susceptible pieces of equipment. The detailed configurations and electromagnetic environment of each installation are unique, and they can even change with time. Therefore, generalizations are difficult to make. SC C4 saw that the best and only practical approach was to use the experience of the designers, builders, and users of different installations to classify the various electromagnetic environments encountered and to manage that. Recommendations and solutions were searched by:

- Characterizing worst-case disturbances and choosing reasonable immunity levels in each environment
- Ensuring that no level of disturbance rises above the threshold provided in each environment
- Specifying the acceptance criteria for each function of each automation and control system
- Specifying the equipment and installation practices that will provide the required immunity levels
- Specifying the tests and acceptance procedures to verify that these levels have been achieved

# Impact of the Substation on the Environment

# 42

Jarmo Elovaara

## Contents


42.1 Site Selection and Impact of the Substation on Environment in Construction Phase .......... 920
42.2 Impact of the Substation during Operation .......... 921
42.2.1 Visual Impact .......... 921
42.2.2 Noise .......... 923
42.2.3 Electromagnetic Fields .......... 925
References .......... 928


So far CIGRE has published very few documents about the impacts of substations on the environment. In the following paragraphs, these aspects and effects are briefly described. The Technical Brochures of CIGRE are referred to when such have been available.

Different methods to protect the environment can be used in transformer stations and switching stations. As an example, a single power transformer contains several tens of tons of insulation and cooling oil and sometimes even more than 100 t. Current transformers will be found from every bay, and their oil weight can vary in the range 50–300 kg. The amount of oil in circuit breakers varies according to the breaker type, but at worst this oil amount can be 50–300 kg per bay. If voltage transformers are used at every line entrance, similar amounts to the current transformers might be found. It is clear that the power transformers require special attention in every substation when the protection of the environment is considered.


J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com



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## 42.1 Site Selection and Impact of the Substation on Environment in Construction Phase

The substation's impact on the environment has to be considered from the very beginning when the site for the substation is selected. The site selection is normally started by studying the environmental conditions, general plans, and terrain and soil properties of the interesting site alternatives. These analyses combined with different technical studies lead to the negotiations with the land owners. Details to be taken into consideration in this phase are, for example:

- Existence of adjacent settlements or vacation/recreational areas
- Distance to the nearest protected area
- Evaluation of the present nature values like groundwater and the vicinity of different kinds of waterways and lakes or sea and wells
- Visibility of the site and possibilities to economically reduce the visual impacts
- Noise-spreading properties of the site and possibilities to reduce the spreading of the noise
- Occurrence of endangered species (animals, insects, and plants) in the areas in question, etc.
- Areas of special scientific or archeological interest.

The role of endangered species is peculiar to Europe because the EU has a list of such species and their existence has to be taken into account in all land use in EU's member countries. The list is based on the rarity of these species in Europe, but the guarding/protection measures are necessary throughout the whole EU independent of how general or rare the animal in question is in a particular country. E.g., in Finland it has happened that it has been impossible to utilize certain otherwise suitable substation places due to the occurrence of the flying squirrel (*Pteromys volans*) in the area in question, although this animal is not rare at all in Finland.

Policies to be followed in case of groundwater areas have changed a lot during the last decades. Earlier transformer stations could be constructed on groundwater areas, but at present this is allowed only exceptionally (at least in industrialized countries). Often already the national legislation forbids all such activities which can contaminate/deteriorate the soil or the ground water, but also smaller administrative areas like communities can have regulations of their own.

Usually the contamination of the groundwater is considered as a more severe damage than the contamination of the soil. The contamination of the groundwater is often an irreversible event, and purification of the groundwater can take a long time and be very expensive. Therefore, the best policy is to avoid groundwater areas and the vicinity of waterways when a substation site is selected. When the construction of a substation on the groundwater area cannot be avoided, the main emphasis has to be given to actions with which one can avoid the pollution of the groundwater. Without going into details these can be summarized, for example, as follows:

- Under the transformer there has to be a watertight oil collection pool which is able to receive the whole oil content of the transformer. The pool should be covered so that the covering prevents burning of the oil which is in the pool.

- The use of HDPE (high-density polyethylene) foil under areas where oil leakages are possible.
- The primary protection construction can be a bunker with an oil collection pool, which is made of watertight concrete. The secondary protection is a tightening construction, which is made of bentonite or clay through which only a minor amount of oil can penetrate. Alternatively, a tightening layer made of HDPE foil can be used, too. Between the primary and secondary protection constructions, there has to be an oil separation well equipped with an oil leakage indication system with the possibility to take samples.
- The surface soil/material has to be inclined so that the rain and meltwaters flow in the oil separation well.
- All waters of the transformer bunker have to end up in the oil separation well connected to an oil separator of type I and thereafter to a sewage system. The maximum allowable content of oil in the water after the separator can be of the order of 5 mg/l. Other waters than the fire-extinguishing waters processed in this way can be infiltrated also in the surrounding soil.
- The oil separation system has to be functional also when the waste oil collection pool is emptied.

During the construction phase, the impacts are mainly negative and most typically caused by the noise and vibrations caused by the earth-moving and excavation works including any blasting operations. Different kinds of power tools and machines are usually needed. The local legislation may require that the authorities and the neighbors have to be informed about the temporary but disturbing noise.

The information of negative effects of vibrations to man or to the fauna is still scattered. Case studies have been made as in the case of lumberjacks using chain saws ("white fingers"/Raynaud's phenomenon), but these results do not usually represent the negative impacts related to the construction works of a substation. Guiding values or limit values for the vibrations have generally not been published although some research institutes might have recommendations of their own. It is worth checking the limit values for the local situation before the works are started. Earth-moving and excavation works can cause remarkable dust problems. The negative effects of dust can be damped down by using water or salt solutions. It is useful to remember that the dust is locally an air pollutant which can transport by breathing the air, e.g., fine particles in the lungs. Impurities in the air like NOx can combine with fine particles and in this way find their way into the lungs possibly later causing health effects.

## 42.2 Impact of the Substation during Operation

### 42.2.1 Visual Impact

The visual impact of a substation is the largest impact, i.e., the greater is the change in the environment, particularly the more "open" the environment is into which the substation is planned. The negative effects of the visual impact can be reduced by applying suitable landscaping actions. These are typically different ways of changing the landscape such as shaping the terrain, the use of plants/vegetation, walls, etc., or simply constructing an indoor substation using, e.g., GIS technology, and paying attention to the appearance of the building.

The present trend is that the visual impact of the substation has to be considered either due to the requirements of the authorities responsible for the general plans or due to the opinion/requirements of the general public living in the neighborhood of the future new substation. Even when an indoor substation is to be constructed, the authorities may put limiting requirements, e.g., for location and visibility of the building to be constructed, green areas in the vicinity of the building, color of the building, surface materials to be used, total height, etc.

This subject has been treated by SC B3 in TB 221 (Improving the Impact of Existing Substations on the Environment) which was prepared by WG B3.03. The brochure was developed for target groups like different technical groups including equipment suppliers, contractors and consultants, grid planners, and engineers as well as maintenance providers, different types of operators, and asset/facility managers as well as science, education, and public groups and even international organizations with similar scope. TB 221 concentrates on important aspects of existing substations that exert a negative impact on the environment and brings up several case studies of innovative efforts used across the globe to reduce the environmental impact. The discussed topics include, e.g., aesthetics, audible noise, release of insulating oil, site contaminants and their remediation, and $SF_6$ gas and electromagnetic fields (Figs. 42.1 and 42.2).

Further, the subject of improving visual impact of existing substations on the environment has been discussed also in session papers 23-201/1998 from A-M. Sahazizian et al. and B3-201/2004 from K. Kawakita et al. Both papers include many photographs of the new solutions illustrating the influence of industrial designers and architects on the outlook of the indoor and outdoor AIS.

**Fig. 42.1** An invisible substation designed for an urban environment adjacent a playground in Japan (Biewendt et al. 2002)

**Fig. 42.2** The use of so-called landscape pylons in a 110 kV substation (Finland)

### 42.2.2 Noise

Earlier even the air-insulated outdoor substations were usually not considered as a source of external noise. The attitudes, however, are changing. The subject of noise is extensively discussed in ► Sect. 11.9, where also noise-level measurements and calculations are described. Here some additional practical aspects related with the environment are presented.

Complaints and claims are given especially due to the transformers and their fans as well as due to reactors. Even the noise of air-cored reactors has been causing complaints in certain cases. HVDC converter stations have turned out to be an object which easily raises complaints due to the filter banks. The noise of a substation is considered especially bad when the substation is located in densely populated areas or in areas which have previously been exceptionally quiet ones.

The protection of silent places has become a topic within the EU. As an example it can be mentioned that Lapland in Finland and Sweden is considered by the EU as an area worthy of noise limitations.

The noise caused by power transformers and reactors is usually concentrated in the low-frequency range and has a very narrow band (mainly 100–120 Hz; the frequency of the noise is caused by the fact that two power frequency currents interact and cause a force). In transformers, the noise is caused by magnetostriction in the transformer core, but the cooling fans bring their own addition to this if they are not running slowly. In air-cored reactors, the noise is caused by the tiny movements of the reactor conductors. The noise of the filter banks of HVDC converter banks has typically a higher frequency content.

All narrow band noise is especially disturbing to the human ear. It also penetrates effectively inside buildings. Noise-level measurements carried out around three-phase transformers, and reactors, as well as SVC and HVDC equipment, have shown that it is best to set the required guarantee level for the noise power level at the specification phase the same value which is given as the requirement in the national legislative construction requirements. Otherwise it may be very difficult to reach the target values of local/national requirements. For example, in Finnish conditions this means 45 dB maximum at the substation fence. The power transformers are usually not a problem because it is possible to fit noise enclosures which can reduce the noise level by in excess of 20 dB. For example, bunkers with concrete walls enclosing each transformer damp the noise levels and help also in case of transformer fires, mischief/vandalism, etc.

If the transformer is suitably specified at the ordering phase, then these noise enclosures can even be fitted at a later date if conditions change. The distribution transformers, however, can be a problem because they are located in city areas frequently in the ground floor of blocks of flats. If relatively light walls, short distances to the transformer and solid contacts between the light walls and concrete ceiling/floor elements are used, conditions can be formed where the normal 100 Hz humming noise of the transformer is effectively transferred to the apartment and a humming wooden floor is created. Fortunately, the problem is easy and cheap to correct, but it causes irritation and bad feelings.

If oil-filled reactors are used, these can be fitted with a noise enclosure either initially or at a later date if the reactor is designed accordingly. These enclosures are similar to those used for power transformers, but they are normally not convenient for air-cored reactors. Air-cored reactors can be fitted with glass-reinforced plastic noise shields which are a close fit around the actual reactor coils. These noise shields can reduce the noise by approximately 8–10 dB. With air-cored reactors used for SVCs or filters, one also has to be aware of the noise from harmonics which a small percentage of the total current can cause a significant increase in noise level. Any DC current present has an even greater impact upon the noise. Frequently reactors may not “automatically” have any reduction constructions.

The noise produced by a laterally arranged triangular 63Mvar three-phase air-cored reactor installation without any damping means creates at the source typically 85–95 dB (A) and at a distance 100 m from the source still about 37–47 dB(A). In case of air-cored reactors, the level of 45 dB (A) has never been achieved in Finland without extra additional actions. When necessary, as a noise-damping solution, a wall has been used. The wall is “directional” in the sense that it is mounted only between the reactor and the dwelling which is disturbed. The wall is made of 21 mm thick plywood board which is weather tolerant. The plywood plates are mounted on an aluminum frame (which should not form any closed loops due to the induced current!), and the whole construction is fixed in the reactor foundations using UV-tolerant rubber cushions designed for vibration damping. The cushions are easy to remove and replace. With this system, the noise level at the dwellings could be damped by 3–5 dB (A), which was in a particular case enough. However, distance is usually considered the main damping factor.

Probably the national noise requirements will become even stricter in the future. (Community opposition to new wind power plants due to the noise is a prewarning about this!)

Even locating the substations in a completely unpopulated area does not necessarily help in the future if general plans later allow construction of houses in the vicinity of the substations. Therefore, permanent contacts with the local community authorities are always extremely important for the grid companies.

### 42.2.3 Electromagnetic Fields

Practically all high-voltage components of the substation are sources of electromagnetic fields. An indoor substation has a housing so that these fields do not influence outside the substation building, when the influence of the feeders is neglected. Very often also the land area reserved for the outdoor substation is so large compared with the actually constructed area that the electromagnetic fields created within the substation need not to be considered outside the outdoor substation area. Vicinity of underground cable channels and right-of-ways of overhead lines are naturally exceptions in this respect.

High voltages and currents can occur in a substation. And because the clearances are always shorter than in areas to which access is not limited, the electric and magnetic fields are at least locally greater than outside of the substation. The standardized clearance requirements are usually based on the dielectric withstand of the air, so that the field effects of the voltage and current always have to be checked separately.

Highest electric fields in an AIS substation are usually found in the vicinity of busbars operating at the highest voltage. Highest exposure arises if in adjacent bays the same phases are running next to each other. This kind of situations should be avoided, if possible, for example, by arranging some extra transpositions on the phase conductors in the in- or outgoing lines.

Very high magnetic fields can be caused by busbars of large generators and by air-cored reactors. Phase-segregated busbars are usually used in case of large generator busbars, and then currents induced in the metallic casing tubes compensate the external magnetic fields.

Air-cored reactors are used in substations in harmonic filters but also in reactive power compensation. In modern systems, the reactors can be semiconductor controlled, and then the created external magnetic field can contain also harmonics, the effect of which should not be forgotten. Compensation reactors can be quite powerful, e.g., three-phase reactor sets of 63Mvar, 21 kV, are in use. Even larger air-cored reactors are found in conventional SVCs (static VAR compensators).

A 63Mvar air-cored reactor creates a strong magnetic field in its vicinity. Also, the fields created by cables/busbars feeding the air-cored reactor can have an important effect and should not be forgotten. As an example, the flux density of the abovementioned three-phase air-cored reactor can reach the level of 1.4 mT at a distance 4 m from the center of the single winding. In a field of this magnitude, mechanical watches may not continue to work, and people can sense also other influences so that it was very clear from the very beginning of the use of air-cored reactors that certain minimum distances to them should be kept to be sure about the safety of the workers. It is particularly important for people who have had a heart pacemaker fitted (particularly the earlier ones) or who for medical reasons have had metal plates inserted into their bodies to stay well clear of any air-cored reactors.

The metallic tank of the oil-filled reactor effectively damps the external magnetic flux density created by the reactor. Then the external field is mainly caused by the feeders of the oil-filled reactor. Oil-filled reactors have typically a greater rated voltage than the air-cored ones, and therefore the magnitude of their external magnetic field density is usually lower than that of air-cored reactors. Also, the volume in which the external magnetic field of an oil-filled reactor is distributed is more limited. Therefore, usually there are less access limitations needed in the vicinity of the oil-filled HV reactors than in case of air-cored reactors.

It is always useful to request from the reactor manufacturer the distribution of the magnetic flux density around the reactor installation. This will make the design of safe working conditions in the vicinity of reactors and their feeders much easier and accurate.

Workers' and the general public's exposure to power frequency electric and magnetic fields has been a topic since 1972 when a session paper from USSR reported undesirable physiological effects of electric fields on human beings performing live line works. These had not been avoided even though the workers had used conducting overalls. Proposals were made to regulate the exposure to electric fields for a stay of indeterminate duration to 5 kV/m, but since 1975 USSR has accepted the limits 10–20 kV/m, the values adopted depended on the frequency with which the exposed areas were visited by workers. In the beginning the main interest was devoted to the power frequency electric fields, but when the number of medical studies on people exposed to power frequency EMF increased, the magnetic field exposure became the most interesting subject, such that the International Agency for Research on Cancer (IARC) classified in 2002 the extremely low-frequency (ELF) magnetic fields as possibly carcinogenic for humans (the Group 2B of IARC; in that group belongs also coffee!). The reason for this classification was mainly the observation that some children exposed to a power frequency ELF field greater than 0.4 μT had contracted leukemia, but it could not be explained how this disease develops due to the magnetic field. In the same IARC publication, static electric and magnetic fields and extremely low-frequency electric fields were considered not classifiable as to their carcinogenicity to humans (Group 3). Lively discussion about the carcinogenicity of ELF field has continued thereafter because it has not been possible to reveal the mechanism how an ELF field could provoke cancer in a man, neither has cancer developed in animals exposed to ELF electric or magnetic fields.

CIGRE became involved in the discussion of carcinogenicity of ELF fields when it formed in the end of 1990s a medical group (WG C3.01) to follow the development of the subject. This group has recently published in Electra 287 (August 2016) a report on the possible link between the 50 and 60 Hz magnetic fields and cancer and drew on the basis on the exceptional data accumulated over the last 35 years the conclusion that the hypothesis on the link between the low residential magnetic fields and cancer has been a false alarm. However, CIGRE does not want to get involved in the legislation about the subject but has left this to the medical, physiological, and radiation protection specialists and in the end to the politicians. It is noteworthy that there is no global consensus about the critical exposure levels to be followed: the requirements within the EU and countries following the IEEE recommendations are slightly different. EU's Council published in 1999 a recommendation which is still valid in case of the general public's exposure to static and ELF electromagnetic fields. The so-called exposure limit values (ELVs) for the general public are at 50 Hz 5 kV/m and 100 μT. In the case of workers exposure, the decision-making has been slower and more difficult. To briefly explain the development, the 2004 version of the Directive had to be withdrawn, and from beginning of July 2016, workers should not be exposed for longer times to 50 Hz unperturbed external fields exceeding the low and high action values 10/20 kV/m and 1000/6000 μT. Temporary exceeding of these values is allowed, but the absolute limit value for the internal electric field value in the workers' body, peak value 0.07 V/m, must never be exceeded. (Fulfilling this limit value requirement can be shown only by performing numerical calculations for the body of a human being in the external field.)

CIGRE has published five Technical Brochures about the subject. The first one, TB 21 (Electric and Magnetic Fields Produced by Transmission Systems), from year 1980 was written by WG 36.01 and described the situation in 1980 on the basis of the know-how valid then. The brochure gave an overview on available calculation methods and means for electric fields and reported about induced voltages and currents in objects located near live conductors, described the calculation and measurement results in case of magnetic fields of a line, and described in some detail the measurement methods available for electric fields as well as also giving an overview about the effects of fields and currents. Five years later the WG 36.01 published TB 74 (Electric Power Transmission and the Environment: Fields, Noise, and Interference). As the name of the brochure describes, this publication was more general but covered also a wider scope, because health aspects, corona, radio and TV interference, and audible noise were included. Mathematical methods were not presented at all. Then it took 12 years before the next brochure, TB 320 (Characterization of ELF Magnetic Fields), was published by WG C4.205. This brochure presents a list and a description of the most important, mainly statistical parameters needed in characterization of the magnetic field. Also, representative statistical ratios between some of the parameters are given. Brochure TB 373 (Mitigation Techniques of Power Frequency Magnetic Fields Originated from Electric Power Systems) was published by WG C4.204 in 2009. It can be mentioned also that the WG B1.23 published in 2013 the brochure TB 559 (Impact of EMF on Current Ratings and Cable Systems) which concentrates strictly on the technical issues and not on the problems related with the human exposure.

It can be concluded that in EMF questions CIGRE's interest has concentrated mainly on the magnetic field exposure and that CIGRE has practically completely omitted the fact that in countries applying mainly guyed portal towers, the electric field values are usually much more decisive than the magnetic fields because the phase conductors locate lower, i.e., nearer the surface of the earth than in free-standing towers. Also some session papers have been written about the magnitude of fields in practice and presented in CIGRE Session 2000. In 2004 CIGRE organized a symposium about EMF questions in Ljubljana, Slovenia, but unfortunately papers published there are no available via, e.g., e-cigre. Some results about the currents induced in the human body in actual electric fields and measured with the conductive, earthed helmet have been presented in SC B3 Colloquium in Berlin in 2007 showing that the internal current densities within the workers body proposed by ICNIRP do not at all match with the proposed external field strengths proposed by the same organization in 2004.

As well as on the effect of magnetic fields from air-cored reactors on humans, these fields can cause serious effects to metallic loops/meshes and fences by inducing very high currents in them with the consequence of excessive heating and even damage unless the relevant precautions are taken.

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# 43 Special Risks Related to Substation Equipment (Transformers, Reactors, and Capacitor Banks)

Jarmo Elovaara

All equipment containing some kind of oil presents a certain risk to the environment. The use of oils in groundwater areas was already considered earlier. Here we concentrate on other aspects of the use of oils.

The oil is used in substation equipment as a coolant and/or insulation medium. Oil leaks taking place from devices containing oil are harmful to the environment. Examples of devices which in substations contain mineral or other oils are power and instrument transformers, capacitors, and sometimes oil-filled cables with/without terminals. Earlier oil was also used as an interruption medium in bulk oil circuit breakers, and some might still be in operation. Usually the oil content of instrument transformers is considered so low that they are not taken into account, when the effects of the substation on the environment are looked at.

Especially large quantities of oil are in large power transformers. To eliminate the risk of oil-leakages, welded tanks are mainly used. Then the most potential leakage places are few including, e.g., turrets, etc. to which, e.g., the bushings are fixed with bolt connections. Most frequently leakages occur in laterally installed high current bushings. To avoid damage caused by oil in nature, the installation sites of transformers are usually constructed so that the whole oil content of the transformer can be collected in an oil pit under the transformer so that no oil can leak over the pit (see details in part B). When an outdoor installation is used, the oil pit has to be constructed so that the rainwaters, etc. can be drained off the pit; otherwise the pit would not be able to collect all the transformer oil in case of a major accident because of the water already collected in it. In smaller indoor transformers used in power plants and office buildings, so-called askarels were earlier used as the coolant and insulation liquid. It was also used as an impregnant of capacitor coils. The reason for

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

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the use of this oil was that the liquid did not burn. However, it turned out that the askarel oils usually contained PCB, which caused in 1968 in Japan the so-called Yusho disease killing about 400000 birds (poultry) and affecting about 14000 people. Moreover, PCB can in certain conditions such as in high temperatures (caused, e.g., by an arc) partly transform via oxidizing to dioxin called TCDD, an extremely toxic carcinogenic item which in 1976 caused the Seveso disaster in Italy (also used in Agent Orange during the Vietnam war). Now there is an agreement about the elimination of the manufacture and reduction of the use of dioxins and PCBs (Stockholm Convention 2004). Nationally many countries have completely forbidden the use of PCBs and dioxins. For a utility the PCB and TCDD are problematic because they can be destroyed only in special plants able to reach temperatures higher than 1200 °C. Furthermore, it is difficult to clean the tubes which had earlier contained PCB oils, and therefore small contents of PCB have even been found from the replacing oils after eliminating the use of askarels.

The capacitor units, in which insulating oils are used, do not contain large amounts of it. Even though the oils are no longer askarels, they are considered harmful to nature. From time to time, breakdowns do happen in the capacitor units, and they can sometimes cause, in spite of the overcurrent protection realized with external or internal fuses, mechanical rupture of the metallic casing of the unit. The insulating oil can then flow out from the unit. To eliminate the possibility that this leaking oil can get in the soil, the capacitor banks using liquid insulants are sometimes equipped with a collecting receiver, above which the capacitor bank itself is mounted.

Transformer fires seldom take place, but when they do happen, they can have catastrophic consequences. TB 537 (Guide for Transformer Fire Safety Practices) has been published by SC A2 about this subject. Usually a short circuit in the winding or an earth fault in oil-filled space does not damage the tank and cause a transformer fire, but an explosion of a HV bushing (especially the ones where resin-impregnated paper is used, because these kinds of bushings originally did not have a PD test as a type test; they were deemed as discharge-free!) or of an on-load tap changer can cause a fire. The transformer and the tap changer can have pressure release valves, but in certain (fortunately very rare) cases, the pressure rise in the tap-changer fault can be so rapid that the mechanically operating pressure release valve is not able to react fast enough with the consequence that a rupture of the tank takes place. Then the oil from the oil conservator can flow down on the transformer tank. Because the tap-changer explosion most probably takes place when very high current flows through it, the oil is ignited and a fire starts. The fire heats up the oil in the transformer tank, oil starts to expand, and a continuous oil flow also from the tank to the outside is provided. If the fire cannot be extinguished at its beginning, the result is a long-lasting fire. A more or less similar process can take place in the case of a bushing explosion.

The fire protection of transformers is described in greater detail in ► Sect. 11.10.2 of this book. It is very important to recognize that a transformer fire (oil fire) might be extinguished by normal fire brigade means, i.e., by squirting water on the transformer, but only in very early stages of the fire. Instead of squirting water, a water spray cloud should be used, which cools down the flames, gases, and oil spray so that flames are extinguished and the oil spray and gases do not catch fire again. The method is the same as that used in fire extinction systems of ships. According to the adopted philosophy, some utilities protect their transformers in this way constructing an automated water spraying system around the transformer; others trust on other techniques (or trust only on insurances neglecting the environmental risks). If there is not any functionally ready fire-extinguishing system installed, it usually takes too much time for the fire brigade to come to the accident place and the transformer (and the environment) cannot be saved, if a catastrophic accident has taken place. If water is squirted on a burning, already hot transformer, the result will only be that the fire and/or oil is finally spread out in a larger area in the environment.

A commercial system is available, which is based on the idea that, immediately after the explosion, the oil level in the tank is automatically lowered and the empty volume is filled with nitrogen fed from pre-mounted vessels. Fire with oil only without any oxygen is not possible, and in this way the fire can be extinguished at a very early stage.

When water is used, one should, of course, pay attention in the design phase of the system to the fact that the fire can take place also in conditions where the ambient temperature is below the freezing point of the water. Consequently, precautions should be taken to prevent the water pipes and nozzles from freezing.

# Use of $SF_6$ and $CF_4$

# 44

Jarmo Elovaara

## Contents

44.1 Properties and Electrotechnical Use of $SF_6$ Gas and $SF_6$-Based Gas Mixtures ........ 933
44.2 Obligations to the User of $SF_6$ and $SF_6$ Gas Mixtures .................................. 935
44.3 Possibilities to Replace $SF_6$ with Some Other Insulating Gas .......................... 936
References ........................................................................................ 937

The design and use of equipment and installations applying $SF_6$ gas or $SF_6/CF_4$ gas mixtures have been considered in ▶ Sect. 12.2 and Part C of this handbook. Here emphasis is given to the environmental effects of $SF_6$ gas and mixtures. Also, a review is given on the possibilities to find an alternative gas for $SF_6$ in electro-technical applications.

## 44.1 Properties and Electrotechnical Use of $SF_6$ Gas and $SF_6$-Based Gas Mixtures

$SF_6$ has very good thermal and dielectric properties and as such it is not toxic. However, power arcing can create toxic residues with $SF_6$. In addition, if these residues get in contact with humidity, they become also corrosive. Therefore, removal of the humidity from the gas compartments is important. A good property of the gas is also that it has a high stability and is non-flammable. These are the reasons why the gas has been used as a breaking and insulating agent in electrical equipment since the 1970s.

The $SF_6$ breakers have replaced almost all other HV breakers, and if the HV equipment is installed in metallic or other enclosures filled with pressurized $SF_6$

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

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instead of air, the necessary clearances between phases and phase and earth can be drastically reduced. It can also be used instead of oil in all kinds of transformers, bushings, cable terminals, etc. In cold temperatures, the strongly pressurized $SF_6$ gas in breakers will liquefy, and therefore mixed-gas solutions like $SF_6$+$N_2$ are used in environments, where this risk exists. The dielectric properties of the $SF_6$+$N_2$ gas mixtures remain practically unchanged when compared to those of pure $SF_6$, but the short-circuit current-breaking capability of $SF_6$+$N_2$ mixture is reduced by one step when compared to that of pure $SF_6$.

Alternatively, some manufacturers use $CF_4$ instead of $N_2$ in mixed-gas solutions, but from the climate change point of view, $CF_4$ is almost as bad a greenhouse gas as $SF_6$.

The negative effects of $SF_6$ (and $CF_4$) became a topic when the climate change started to draw people's attention. It has been established that these gases belong to the group of the most powerful man-made greenhouse gases. For example, $SF_6$ has the global warming potential 23500 as compared to value 1 of $CO_2$. In addition, the release of this gas in the surface of the Earth is finally diffused in the upper layers of the atmosphere where it can stay unaltered for 3000 years and is therefore effective for a very long time. Often it is claimed that $SF_6$ also causes ozone depletion, but this is not true, because the process in question requires the presence of chlorine (Cl). Because of these facts, e.g., the EU has started to restrict the use of $SF_6$ and $CF_4$, but so far within the EU, their use in electrotechnology has not been limited, mainly because their leakages from closed electrical installations to the atmosphere are very small. However, there is the risk that in the future countries will make stricter regulations on the usage of $SF_6$. For example, Australia has already (although temporarily only) imposed taxation on the usage of $SF_6$ (Simka et al 2015).

Gas leakages from GIS installations are traditionally controlled via pressure measurements. EPRI in the USA, however, has developed a tool (camera-utilizing laser beam) which can make a $SF_6$ leakage from an installation visible to the human eye.

In order to achieve the good dielectric properties of $SF_6$ and $SF_6$ mixtures, the gas volume has to be free from dust and small metal particles. Also, the distribution of the electric field must be as smooth as that considered in the design. This means that the installation of the system needs to be made carefully. No dirt, dust, scratches, nor asymmetries are allowed in the installation, because they might form places, where the electric field strength can locally increase over the corona inception voltage and reduce the dielectric strength of the gas. (So-called particle traps can be found from some installations to collect small residues and impurities away from places where they can cause harm.) Forgotten tools in the $SF_6$ tube or scratches made during the installation on the tube wall, etc. can easily cause a breakdown and disrupt the operation. After a fault or a certain number of $SF_6$ breaker operations, the gas needs to be removed from the gas compartment, the gas compartment opened and purified from residue particles found, and the whole installation refilled with pure new gas. The removed gas will then be reprocessed (recycled), which is usually performed by the original gas or equipment manufacturer. When no faults have taken place, this kind of "opening maintenance" and recycling of the gas takes typically place at intervals of 25–30 years. (Gas filling can take place more frequently, at intervals of 10–15 years.) At least within the EU, the persons participating in the recollection of the used gas and the residues have to be specially trained and have to be licensed to do this kind of work. These are examples of actions which were never necessary when air was used as an insulant.

SC B3 and its predecessor SC 23 have been active from the very beginning of the use of $SF_6$ to publish in the form of CIGRE Technical Brochures that guide about correct policies and actions to be followed. SCs 23 and B3 have published altogether 10 Technical Brochures about $SF_6$ and $N_2/SF_6$ gas mixtures. In fact, $SF_6$ is a topic from which SC 23/B3 has published most Technical Brochures. In addition, Study Committees C4 and D1 have both published one brochure about $SF_6$. To describe the broadness of the $SF_6$-related questions for which CIGRE guidance has been prepared, the names of the published brochures are listed below:

- TB 117 ($SF_6$ recycling guide: Reuse of $SF_6$ gas in electric power equipment and final disposal, by TF 23.10.01 in 1997)
- TB 125 (User guide for the application of gas-insulated switchgear (GIS) for rated voltages of 72.5 kV and above, by TF 23.10.03 in 1998)
- TB 163 (Guide for $SF_6$ mixtures, by TF 23.02.01 in 2000), TB 234 ($SF_6$ recycling guide; revised version of TB 117, by TF B3.02.01 in 2003)
- TB 260 ($N_2/SF_6$ mixture for gas-insulated systems, by TF D1.03.10 in 2004)
- TB 360 (Insulation coordination related to internal insulation of gas-insulated systems with $SF_6$ and $N_2/SF_6$ gas mixtures under AC conditions, by WG C4.302 in 2008)
- TB 381 (GIS: State of the art 2008, by WG B3.17 in 2009)
- TB 390 (Evaluation of different switchgear technologies (AIS, MTS, GIS) for rated voltages of 52 kV and above, by WG B3.20 in 2009)
- TB 430 ($SF_6$ tightness guide, by WG B3.18 in 2010), TB 499 (Residual life concepts applied to HV GIS, by WG B3.17 in 2012), TB 567 ($SF_6$ analysis for AIS, GIS, and MTS condition assessment, by WG B3.25 in 2014)
- TB 594 (Guide to minimize the use of $SF_6$ during routine testing of electrical equipment, by WG B3.30 in 2014)

## 44.2 Obligations to the User of $SF_6$ and $SF_6$ Gas Mixtures

Within the EU every member country is required to annually submit a $SF_6$ balance sheet showing how much new $SF_6$ gas has been imported and used gas exported, how much is regenerated, and how much gas has been destroyed. On the basis of these member state figures, the Commission of the EU estimates the amount of gas that has leaked to the atmosphere. CIGRE has not participated in the preparing of this balance sheet, but many manufacturers and grid companies, which were also members of CIGRE, participated in the task force of GIS manufacturers (CAPIEL) which

**Fig. 44.1** A van used to collect the gas from an installation containing $SF_6$ (Dilo)

prepared this kind of balance sheet and recommended that grid companies and manufacturers should keep up annually this kind of balance calculation on a voluntary basis already before the EU started to require it. In this way the electricity industry wanted to inform the authorities that it is acting very responsibly with the gas.

## 44.3 Possibilities to Replace $SF_6$ with Some Other Insulating Gas

$SF_6$ has now been in electrotechnical use for about 40 years. Due to the development of the about last 10 years, the manufacturing industry has very actively searched/developed a replacement gas which would have the same good properties as $SF_6$, both as insulating and arc-quenching gas. First information about these kinds of new gases were presented in CIGRE Session 2014, and some installations are already in test use.

A promising alternative to $SF_6$ is the family of fluoroketones (FK), where the different "family members" differ from each other by the number of carbon atoms in the molecule and by the boiling point. One studied alternative is five-carbon perfluorinated ketone $C_5$ PFK or $C_5F_{10}O$. Because also fluoroketones contain fluorine, there is the risk that the restrictions and limitations set for the use of $SF_6$ are valid also in case of the fluoro-ketone, but at least the manufacturers report that, e.g., the GWP of $C_5$ PFK is less than 1 and its atmospheric lifetime is extremely short (<15 days) so that the gas decomposes in lower atmosphere under UV radiation to negligible quantities of $CO_2$ (Simka et al 2015).

According to one manufacturer, the gas to be used in high-voltage (GIS) applications is a mixture of $C_5F_{10}O$, $CO_2$, and $O_2$, but in medium-voltage GIS applications, the oxygen in the gas mixture is replaced by nitrogen ($N_2$).

Most of the information released so far is related with HV and MV GIS which are not used in very cold ambient conditions. Far less is information available about the replacement gases for outdoor breakers. Apparently this reflects the fact that the breaker question is more complex (due to the lower ambient temperatures) but still solvable. A solution might be the application of a different fluoroketone, where the number of the carbon atoms in the molecule is 4. This substance cannot be used alone because its liquefaction takes place at low ambient temperatures. Consequently the substance has to be diluted into a buffer gas, to which $CO_2$ is selected due to its superior arc-quenching capability. If the dielectric strength of $SF_6$ is taken as the reference value, with the fluoroketone content of 4% in $CO_2$, the minimum operating temperature $-30$ °C can be reached, while the percentage 10% would result to the temperature $-5$ °C only. However, also the GWP value (about 360) is clearly higher than in case of $C_5$ PFK, but the value is anyhow 98.4% lower than that of $SF_6$ (Kieffel et al 2015).

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Simka, P., Ranjan, N.: Dielectric strength of $C_5$ perfluoroketone, Paper presented in the 19th international symposium on high voltage engineering (ISH), Pilsen, Czech Republic, 23–28 Aug 2015, 6 p (2015)

# 45 Handling, Recycling, Disposal, and Reuse of Substations

Jarmo Elovaara

This item has probably not been a subject within any Study Committee or Working Group of CIGRE. Consequently, no Technical Brochures or other publications have been published. However, within corporate members of CIGRE, some new thinking has been gaining ground in this area.

Sometimes older equipment is saved as spare units, but usually the efficiency of the devices of an older design is not competitive. For example, the losses of an old transformer can be much greater than those of a modern one. Therefore scrapping/wrecking has been and is very often the applied solution.

Traditionally the equipment to be scrapped has been sold to a company which takes full responsibility for the future of the equipment. From the grid company/utility point of view, this can be quite an uneconomic way for the grid company to take care of the disposal. In Finland a new model is being followed where the owner of the equipment makes on the basis of competitive bidding a contract with a subcontractor who will take all the practical actions needed for the scrapping. The contract is written so that all waste is finally delivered to parties which have a license to treat the waste in question. The basic idea is that the materials (e.g., the metals, oils, etc.) are separated from each other by the waste-handling subcontractor at the substation, and then the materials are recycled as far as possible. In fact, in 2015 as much as 99.18% of the waste material coming from Fingrid's substations could be recycled.

Even the heaviest and largest equipment in the substation such as 400 MVA power transformers including all its accessories (like tap changer and bushings) can be treated in this way in the substation without polluting the environment and without disturbing the normal operation. All hazardous items like mercury in thermometers and some relays and cobalt in dryers are separated. Oil is collected

J. Elovaara (✉)
Grid Investments, Fingrid Oyj, Helsinki, Finland
e-mail: jelovaar@welho.com

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**Fig. 45.1** Left: ongoing breaking up of a 170 MVA, 220/110 kV transformer in the substation. Right: the site when the work with two phases is complete

in tanks to be recycled. Very powerful hydraulic "scissors" are used to cut the magnetic circuit of the transformer into small pieces. Finally different metals and materials like copper, aluminum, steel, magnetic steel, oil, paper, plastics, etc. form their own entities in leakage-proof containers which are ready to be transported away from the substation to a new customer for reuse. Devices containing $SF_6$ such as breakers can also be treated in this way (Fig. 45.1).

The waste-handling companies are not normally experts of electrotechnics nor HV technology; therefore the grid company, for example, has to take samples and analyze them before the dismantling work to be sure that the material, which the waste-handling subcontractor has to work with, is PCB-free. (The national laws require that material contaminated with PCB has to be sent to a special toxic waste disposal plant.) Similarly, the equipment owner has to ensure that the subcontractors do not have to work with items containing asbestos. Furthermore, special advice/ instructions or material risk information have to be given in case of contaminated $SF_6$ gas and contaminated $SF_6$ vessels as well as even in the case of conductor spools, because they can contain hazardous impregnant like methyl bromide or copper naphthenate.

The equipment owner gets a major part of the income which is obtained when the dismounted raw materials are sold to be recycled. The waste-handling subcontractor gets his fee according to the contract.

Even more steps in this direction could be made. One promising area is earth-works where the use of waste concrete, waste bricks, and ashes could probably be increased. New thinking is breaking also into the design of new substations. The companies are, for example, studying whether it would be more economic to replace old devices in older substations with new and more powerful ones than to construct a completely new substation. Naturally, this type of works needs to be possible without risking the operational security of the grid and occupational safety in the workplace. In this way old foundations and metallic supports could be reused to a much larger extent than now.

# Part H

# Substation Management Issues

This Part will discuss the whole-of-life management of substations, in particular the period following design and construction as the facility comes into full utility ownership and strategic decision making and asset intervention is required.

The concept of Asset Management is outlined, followed by considerations for lifecycle design and costing. The issue of commissioning is discussed in detail as this can have a significant impact on the information necessary for lifetime maintenance and choices around asset interventions which are then subsequently discussed.

Condition monitoring and asset performance is then explored to identify how the utility can extract value from this activity.

Finally, the part touches on risk assessment and managing obsolete equipment.

Johan Smit

# Asset Management in an Electric Infrastructure

# 46

Alan Wilson, Mark Osborne, and Johan Smit

## Contents


46.1 Managing the Asset Base .... 944
46.2 Driving Performance .... 945
46.3 The Asset Manager Role .... 946
46.4 Utility Organization to Achieve Business Goals .... 947
46.5 The Historical Context .... 947
46.6 Legislation and Standards .... 949
46.7 Asset Management Tools .... 950


Whole life management, and in particular the cost analysis of substations, is at the core of asset management. Here effective life cycle costing can influence the middle- and long-term investment strategy of power utilities.

Privatization and the associated high cost of planned and unplanned outages are forcing utilities to look at the life management of substations not only in terms of optimizing maintenance regimes but also in making informed end-of-life decisions for their existing plant. There is no single solution which will fit all utilities or even all situations within the same utility, and each instance needs to be considered in its own right.

Many countries have mature networks where the installed plant has been in service for a considerable number of years, and this may be longer than the lifetime


A. Wilson (✉)
Doble Engineering, Guildford, UK
e-mail: AWilson@doble.com

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl


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originally envisaged. Financial constraints on the asset managers increasingly require maintenance to be cost effective and efficient, not only in terms of the performance of the maintenance itself but also the impact on the network arising from downtime of the equipment. This naturally leads to debate whether the lifetime of the equipment can be economically extended as part of a long-term strategic replacement policy.

Thus, the asset manager needs to concentrate not only in the technical aspects of performance and service quality but also the careful assessment and management of the equipment's effective lifetime and the costs associated with it.

The 1980s and 1990s were periods when significant changes emerged in the organization of many utilities. These were mainly government initiatives and involved increased privatization, competition, and increased regulation. It also witnessed the breaking up of the monopoly provider link between utilities and their home region or country. This provided for a relatively open trading market, price transparency, and growth of long-length links and power flows across continents. Some arrangements facilitated trading with legislation, such as the European directives 90/377/EEC and 90/547/EEC which included breaking the ownership of generation from the networks. These changes in turn provided a greater focus on the need to compete, to control costs, and to maximize the financial return on the assets invested. Asset care, including maintenance, became more visible as activities which were part of the greater business model. The large survey undertaken by CIGRE and published in 2000 as Technical Brochure (TB) 152 identified these changes [1]. Most significant was the development of an asset management model, with a single function empowered by the executive to implement their asset-related strategies. This involved the control of costs to achieve the stated business objectives for network performance, risk exposures, and return on investment.

## 46.1 Managing the Asset Base

Many utilities had undertaken significant construction of their power generation and networks in the 1960s and 1970s. By the end of the century, many were considering the renewal of networks to be imminent.

- The replacement of the aging asset base is an issue for both capital (CAPEX) and operational (OPEX) expenditure. For many government-owned utilities, this means that the ability to raise capital has to be prioritized as a public sector borrowing requirement. This involves competing for funds for capital construction against other unrelated activities such as building hospitals and schools and equipping the military. Privately owned utilities, however, are structured to run as commercial businesses and able to raise capital in an open market, and so to borrow, but only provided they can identify an adequate return on the investment.
- Operating older equipment can have an increased revenue cost (OPEX) in both preventative and corrective maintenance interventions. Both lead to an increase in

operating costs over time. There may be increased safety implications that also lead to new problems. It is essential that utilities gain a clear understanding of where maintenance spending begins to yield a diminishing return and capital replacement of assets becomes more favorable. Regulatory attitude is important. For some such as in Australia, utilities are regulated to replace assets at their book-value economic life to assure a regulated return on asset – there is strong encouragement to replace aged assets as opposed to keeping them serviceable well beyond this time. This is linked to additional pressure to reduce ongoing operating costs. For some others, such as sectors in the USA, the regulatory requirement is to run to failure (see TB 660). To replace or undertake a mid-life refurbishment is an option, and again shifting regulatory attitudes can (and do) prevail. For yet other companies, the ongoing reassessment of actual service life is based on condition assessment, asset health reviews, failure histories, and forensic examination of scrapped units [2, 3]. The timing of replacement is then determined from technical, network, and cost analyses.

## 46.2 Driving Performance

Traditionally, asset care had been a ring-fenced activity undertaken by a utility's own workforce and an appropriate annual budget. The latter had been set at executive level based upon reportable performance levels and overall operating expenditures. A company would identify a budget level often based on its reliability performance. Then, with or without regulator intervention, the utility would manage the budget on an annual basis, possibly through reducing budgets by a factor such as "retail price index minus x%." Maintenance under these conditions is then restricted by what can be achieved within the allocated budget, rather than what might be needed to meet business targets. Activities were often undertaken either within a corrective or a time-based maintenance regime which had been set by the OEM and linked to warranty provisions. These regimes have limited appeal in the new economic and regulatory environment. They are often perceived as creating higher unit costs for maintenance activities and inefficient resource utilization.

Clear signs of change could be seen by 2000. These changes involved adjusting time-based activities according to local experience and are controlled by reliability- and risk-based factors, as reported in TB 152. This was aimed at ensuring that a higher portion of the maintenance resource was allocated to the causes of the highest-impact events. But, with integration of asset capital and operational budgets, it can be expected that regulators may no longer want to see ongoing repairs done on equipment well past useful life. With an aging asset base, regulators want to see a phased rejuvenation. Increasing capital expense in itself will, however, apply even greater pressure to reduce maintenance since new assets will likely have a reduced need.

These changes moved the focus toward developing a performance-driven organization. The executives in these companies need to manage the expectations of new stakeholders. The regulator wants to see the performance improved, while costs and risks are controlled. Risk management is a fundamental role in an asset management company and a legal requirement in some utilities, such as those in the UK. Without government backing, a private utility needs to insure and the insurer will also want to see risks managed. Being privately owned, the shareholders want an acceptable "return on investment" in return for funding the building of the infrastructure "assets." Opening up the market to include intercontinental trading leads to developing competition that is driven by choice and costs.

## 46.3 The Asset Manager Role

In this environment, assets and their utilization are the key for business success for most service provider industries such as telecommunications, rail, gas, water, etc. These assets exist to provide value to the stakeholders. The management of assets has become the critical activity, particularly for the private utility sector. Many companies now have an integrated asset management function to manage all aspects of asset care from planning, purchasing, construction, maintenance, and finally removal from service and scrapping.

To assess and quantify the operation, the company executives also need to identify an agreed service level of performance, costs, and risk exposure. Examples around the strategic risk exposure are discussed in Technical Brochures (TB) from CIGRE. TB 422 and TB 660 cite examples given from Canadian and European TSOs [4, 5]. Company executives will decide which level of exposure is acceptable in each category. It is then the role of the asset manager to identify the most cost-effective work programs to meet performance targets within the context of this risk exposure. The asset manager produces the tactical asset plan. This will assess the actual risk within the network, taking into account time frames. It will also involve identifying measures to reduce or manage the risk to as low as reasonably practicable (ALARP) and to within the levels identified by the executive in their risk statement. It also includes activities to manage the risk, and some such as asset health assessment are described later.

The change to a more commercial approach has led to the need to identify what assets exist, where they are in the network, their relative priority, and what is their role relative to business objectives. This leads to decisions as to what operational and capital expenditure is needed and where it is needed. An asset manager's role is to achieve these objectives, but it follows that there is a role for a "service provider" for the organization who is site based and will perform tasks with a resource level commensurate to the return so identified. The service provider model may involve some measure of outsourcing, and earlier reviews describe this within TB 201 and TB 607 [6, 7]. The maintenance role has thereby changed, to achieve the performance level required for the differing circuits and to maintain safety and environmental standards, while still undertaking sufficient work to allow a cost-effective rate of return on the capital invested.

These wide-ranging changes in organizational structure and goals have driven an evolution in the role of the maintenance engineer (either as an asset owner or a service provider). Their work being determined by business targets and the type of maintenance strategy adopted. It also drives the opportunities to seek more cost-effective ways of working.

## 46.4 Utility Organization to Achieve Business Goals

The centralization of decision-making within an asset management model is a common response as stronger business drivers are introduced into utilities. One outcome of centralized asset management is to identify maintenance priorities and ensure the tasks are delivered in the most cost-effective way. In-house maintenance teams became in effect contractors to implement a plan against set objectives and deliverables. This can be a prelude to an outsourcing process and many have chosen to follow this route. In most instances outsourcing can be successful provided that goals are set to be realistic and achievable, obstacles are minimized, and suitable management controls and contracting models are established. Critical to long-term success is the sustainability of outsourcing contractors, through having appropriate incentives in place to ensure the right behavior.

## 46.5 The Historical Context

However, it was not always this way. The 1980–1990 period witnessed widespread privatization of utilities. This in particular was a major driver to create policies and targets that could be monitored by the people's representative – a regulator. The greater visibility of performance of company directors resulted in significant changes to the way utilities organized and undertook their activities. Previously responsibilities for expenditures were clearly split into functional groups with their own responsibilities and objectives (Fig. 46.1).

In this example, there is no single management function with overall responsibility for OPEX and CAPEX. Significant costs may be wasted by the maintenance department being forced to maintain equipment purchased because it was lowest cost at the time. This practice often resulted in the need for multiple designs, requiring greater knowledge base and spare holdings and often also equipment maintained to beyond economic lifetime. Outage restrictions and budget cuts restrict the ability to prioritize activities to the most system critical assets. Capital budgets in state-owned companies had been achieved after executives battled with government for finance against other national requirements. Maintenance budgets would be allocated based upon requirements to maintain warranties and regions where availability was poorest. As outage restrictions became more widespread, it often became easier to undertake maintenance outages on circuits that could be available rather than on need or network impact.

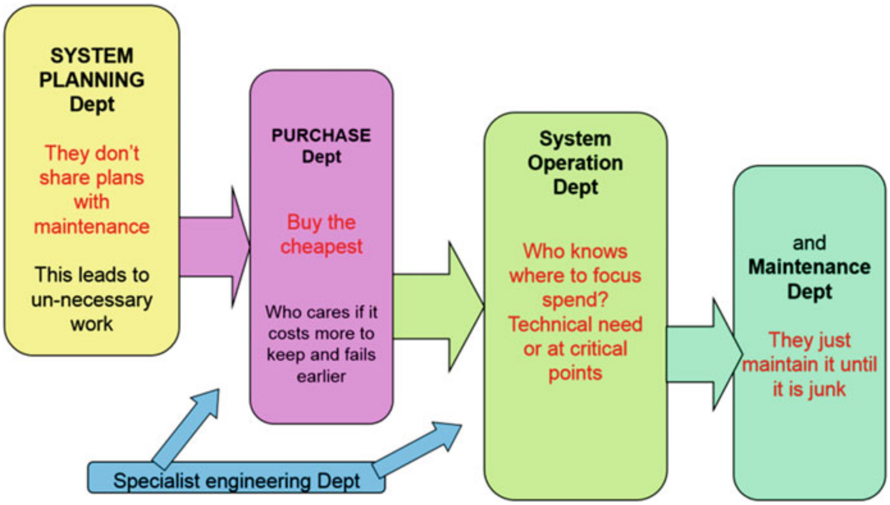


**Fig. 46.1** Example of functional organization

Such a situation was commonplace across various industries. The earliest changes came about within the oil industry. Two major events occurred in the late 1980s that changed their way of thinking. The first was the dramatic drop in oil prices from $35/barrel to below $10/barrel. The second was the 1988 Piper Alpha disaster in the North Sea causing 167 fatalities. These two events led to major improvements in safety organization together with a focus on cost reductions. By 1993 the Piper Alpha Cullen Report had 106 recommendations, and these led to changes in safety management and its high profile [8]. Changes included the development of risk-based methodologies, incorporating the now widely used “ALARP” concept (see ▶ Chap. 52). Both BP and Shell introduced significant initiatives. The 1995 Shell Asset Management business model is the one used internationally in many industries including power networks. Here the model required a defined asset management policy; it created an “Asset Holder’s Mandate” from the CEO. This gave lower management-delegated decision-making authorities and budget freedoms to deliver asset life cycle value in line with business goals. From these led implementations of a range of techniques to reduce asset life cycle costs – such as availability and maintainability modelling, reliability-centered maintenance (RCM), whole life cycle cost (WLCC), risk-based maintenance (RBM), and risk-based inspection (RBI). Technical Brochure 660 “Saving through optimizing maintenance in AIS” addresses these aspects. Regulators in power industries worldwide have been keen to see that utilities have similar processes in place to manage the competing demands of cost reduction, network performance, and the range of risks. From the mid-1980s onward, asset-focused initiatives were introduced in Australia and New Zealand. It was this environment that led a range of utility sectors and their regulators in the UK to create a BSI document, PAS 55, describing agreed "best practice" asset management processes and systems against which utilities could be audited and, if suitable, awarded accreditation [9].

## 46.6 Legislation and Standards

Other drivers to manage are statutory duties, safety and environmental obligations, which need to be balanced with improved return on capital, and internal and external customers' needs. Changes to legislation and regulation have often followed major accidents in a range of industries, from oil rigs, chemical works, and railways all where there was loss of life. Subsequent government inquiries have identified often causes such as lack of maintenance, poor control of activities, and lack of understanding of, and then managing of, the operational risks. Remits for regulators often include supervision of the management of such risks in industries for which they are responsible.

Utilities aim to balance these requirements through establishing comprehensive and fully integrated strategies, together with processes and a culture directed at gaining greatest lifetime effectiveness, value, profitability, and return from the asset. The challenge is to provide systematic prioritization and implementation of processes, practice, and technical improvements to ensure full compliance with safety, availability, performance, and quality requirements at the least sustainable cost for business conditions.

Regulators have been keen to see that utilities have processes in place to manage the competing demands of cost reduction, network performance, and the range of risks. It was this that led a range of utility sectors and their regulators in the UK to create the BSI-PAS 55 document, against which utilities would be audited and if suitable awarded an accreditation. Successful accreditation is not optional in the UK: it is a license condition. The first version of this "publicly available specification," PAS 55, was issued in 2004 after being drafted by a group of engineers representing the Institute of Asset Management and the British Standards. The second edition came out in 2008, and the drafting had expanded to involve 50 organizations in 15 industries representing 15 countries. With wider interest developing in this UK document, PAS 55, an international drafting committee worked to issue in February 2014 the first international asset management standard, ISO 55000 [10]. This clearly created a move toward a universally applicable requirement for certification of company asset management processes.

While the impact of ISO 55000 is too early to judge, the impact of PAS 55 can be seen to have been significant. It had been more than just an audit and a certificate and was used to change organizations which had been founded as service providers into asset-focused ones, achieving business returns on invested capital while understanding and managing risk exposures. Through a structure of reviewing what activities are undertaken and how they are prioritized has led companies to achieve cost savings, "simply" by adopting a PAS 55 processes. Several utilities have claimed 20% reductions in O&M costs.

The essence of PAS 55 is to ensure that a company has set itself up to ensure a clear “line of sight” between the organizational strategy and the asset management activities and implementation. It is from this focus that improvements and savings are achieved. Maintenance activities are no longer an end in their own right undertaken within an allocated budget but activities undertaken to ultimately allow corporate strategies to be achieved and scaled against optimizing the return on investment.

## 46.7 Asset Management Tools

There have been a variety of improvements and developments to aid in the management of assets:

- **New designs of assets** intended to produce a simpler and more reliable operation, typically requiring less intrusive intervention.
- **Resource management** technology that improves efficiency of the site workforce. This involves extensive use of tablets for work programs together with Wi-Fi links to historic data and for uploading new findings and work reports.
- **Data management** that allows field data to be transmitted to a central store (historian server) and used to provide a dynamic utilization of asset data and protection. Introduction and the use of decision support systems that are of a high quality and accuracy are significant to the management of maintenance costs. The entire data-information cycle within modern utilities represents a fundamental aspect of managing maintenance and the cost thereof. Most electricity utilities now maintain a computerized maintenance management system (CMMS) that enables them to forecast, plan, and track execution and follow-up of maintenance of network assets.
- **Modelling of maintenance costs** using activity-based costing tools. The establishment of an activity-based costing model simply combines the resources, network assets, and data within the CMMS with the regulatory chart of accounts by which the utility establishes its financial statements. The utility can then be aware of what elements are predominantly driving maintenance costs and as a consequence allow optimization of tasks.
- **More reliable diagnostics** are now available for condition assessment, together with data transfer and storage.
- **Expert systems** are a growing area that allows predictive analysis of condition data, in effect providing a dynamic risk management tool.
- **Performance indicators** traditionally the Key Performance Indicators (KPI) were used to determine the size of the maintenance budget related to overall network performance. Using these had value in an ongoing asset management-driven organization and the methodology has developed so that many of the parameters are listed in standards such as IEEE Standard 60050-191 [11]. But to these key performance indicators, other maintenance-specific performance indicators need to be added, which remain company specific.

- **Benchmarking** many companies will use these same indicators to measure their performance against cost. Some will seek an annual trend or comparison between different operating units of the same company. Those providing a high performance level at lowest cost are clearly the highest performers, and those companies elsewhere must seek to migrate there in subsequent surveys. Such an analysis is carried out for a range of operational areas – lines, cables, and substations – and there is at least one organized from within North America that takes data internationally.

# Developing Strategic Policies

# 47

Paul Leemans, Mark Osborne, and Johan Smit

## Contents


47.1 Asset Management Roles .......... 955
47.2 Setting Corporate Strategy .......... 957
47.3 Asset Intervention Planning .......... 959
References .......... 960


Many utilities throughout the world have adopted a business model that aligns and links corporate policies and strategies throughout the organization all the way down to activities undertaken at site. Examples of such statements are listed below. These aims are worthy, and most utilities in the last decade would claim to have adopted similar approaches.

- **Safety performance is a company critical value**. Many identify and proclaim that safety concerns are their most important value. This relates to all on-site, staff, contractors, visitors, as well as the public who are neighbors.
- **Finance**. Clearly the company must have a sound financial performance, achieving objectives set by owners and regulators. It also means investing in the infrastructure to an adequate level to achieve the agreed performance level.


P. Leemans (✉)
Asset Management Substations, ELIA, Brussels, Belgium
e-mail: paul.leemans@elia.be

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl



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- **Quality of service and reliability**. This involves not only reliability of the assets and the network but also loss of supply events. The latter are usually reportable events monitored by the regulator who may reward or penalize performance.
- **Environmental impact**. Companies will promote their care for the environment and be careful to manage any oil spills, excessive noise, and release of greenhouse gases or polluting fires after an equipment failure.

These positive statements could be turned into negative outcomes – or risk consequences in the event of an accident or poor performance. Such a list of outcomes is shown in Table 47.1, a list used by a European TSO.

Such activities significantly focus the ways of working within a company. These corporate statements and underlying values are developed and agreed with a range of

**Table 47.1** Risk statement – example

| Severity | Moderate | Serious | Severe | Catastrophic |
|---|---|---|---|---|
| Loss of profits | <1 M€ | 1–10 M€ | 10–100 M€ | >100 M€ |
| Energy not supplied | <100 MWh | 100–1000 MWh | 1000–10000 MWh | >10 000 MWh |
| Health and safety | Mild accidents – dangerous situations – damage to goods | Accidents with injured persons | Accidents with injured persons – permanent disabilities | Fatalities and/or permanent disabilities |
| Laws and legal obligations | Attention drawn by a third party to a liability | Criminal liability | New law created based on a legal precedent<br>Criminal conviction of utility staff | Utility legitimacy in question |
| Environment $SF_6$-oil-fire-endangered species | Local impact or short-term degradable spill | Wide impact or middle-term degradable spill | Long-term degradable<br>Could lead to a loss of ISO 14000 certification | Permanent Impact<br>Loss of ISO 14000 certification |
| Public image | Local and temporary<br>Some external parties or media critics complaining about utility | Regional or national attention<br><3 days<br>Lots of external parties complaining about utility, with critical media exposures | Regional and national criticism<br>1–2 weeks<br>Expression of external official actors (politics, state representative. . .) that target utility's legitimacy | National and regional<br>>2 weeks<br>Long-term external association of public actors/ representatives that greatly affect utility's legitimacy |
| Regulatory context | Regulator asks for information | Regulator asks for a plan of actions | Regulator asks for a change of strategy | Regulator asks for a guardianship for the utility |

company stakeholders. Most importantly company directors may be held to account if there is non-compliance within the organization. This has led to a company organizing itself with an asset management function that is given the responsibility to turn these values into policies and targets through to work programs undertaken throughout the company. This has ensured there is now a higher awareness of corporate responsibility through the company.

## 47.1 Asset Management Roles

The commercial change has led to the need to identify what assets exist and where and what is their role, each relative to business objectives. These business objectives are ones set by the company executive management. In turn this leads to decisions as to **what** operational and capital expenditure is needed and **where** it is needed. An asset manager's role is to achieve these objectives, but it follows that there is a role for a "service provider" in the team who is site based and will perform tasks with a resource level commensurate to the return so identified. The maintenance role has thereby changed to achieve the performance level required for the differing circuits, to maintain safety and environmental standards, and while still undertaking sufficient work to allow a cost-effective rate of return on the capital invested. These wide-ranging changes in organization and goals have driven evolution of the role of the maintenance engineer (into either an asset manager or a service provider). The former is the new function with responsibilities for assets to meet the objectives of company executives. It is here that targets are set and the decisions as to the type of maintenance strategy adopted. The aim is to drive the opportunities to seek more cost-effective ways of working. Besides the technical knowledge and the cost aspect, a third dimension became very important for the asset manager: risk evaluation and risk mitigation.

The majority of site-based staff are there to provide a service to implement the work programs set by the asset management team.

The above changes in roles and responsibilities have led to an organization that provides a clear line of sight between the executive and substation workforce.

**Asset owners** – company directors who are ultimately responsible for the asset set corporate goals, policies, and strategies set by the executive and implemented throughout the company in order:

- To provide corporate direction consistent with regulatory conditions
- To provide a growing and sustainable business ensuring a sound investment return to shareholders
- To provide a safe, secure, sustainable, and cost-effective power supply
- To be well regarded by the client base, citizens, politicians, and the media
- To ensure all legal obligations are met
- To prepare company strategic plans and approve business policies, strategies, and plans and is responsible for them
- To foresee the resources to implement these actions

**Asset managers –** who are responsible for delivery of corporate goals.

- To implement corporate policies through tactical asset plans involving whole lifetime optimization (including OPEX/CAPEX balance) for planning, purchase, operation, and decommissioning of all assets held by the company.
- To implement centralized control over CAPEX and/or OPEX expenditures through single-point accountability within the company, an asset manager, reporting to the executive.
- To provide centralized control over risks – huge financial losses can occur through mismanaged health, safety, and environment-related issues. Regulatory action in such cases has led to regulators removing the company's license.
- To provide lifetime asset decision-making, from investment to disposal, has implications for maintenance schedules.
- To identify maintenance to maximize long-term profits while delivering high service levels and acceptable and manageable risks.
- To implement maintenance strategy evolution from corrective through time based, condition, reliability centered, and risk based, i.e.: focusing work by risk (network impact, environmental impact, etc.).
- To audit and report through targets and key performance indicators.
- Implement a continuous improvement process through reviews and feedback processes.
- To manage service provision, including the role of outsourcing.
- Manage knowledge and expertise for the asset managers.

Often asset fleet strategies are developed for different asset classes (CB, transformers, protection system, etc.) in order to translate the corporate goals, policies, and strategies into asset management plans. An asset fleet strategy describes the "current" situation of the fleet, analyzes the behavior of the existing fleet (costs, failure and failure modes, policies, long-term risk evolution, etc.), and identifies drivers (OPEX cost, reliability increase, outage reduction, outsourcing policy, etc.) for the future fleet.

**Service providers** – resources to deliver AM plans are:

- Construction, maintenance, technical experts, test groups.
- Housekeeping.
- Routine maintenance. Inspect and test.
- Outage restoration, repairs.
- To ensure systems are in place for such a system to operate PAS 55 defines key requirements.
- Establish and maintain widely accessible information systems.
- Have procedures to identify and document risks and mitigation measures.
- Identified risks to be linked to all business processes.
- To have identified all regulatory and legal requirements.
- Each function to have identified AM objectives.
- To have documented system performance targets.

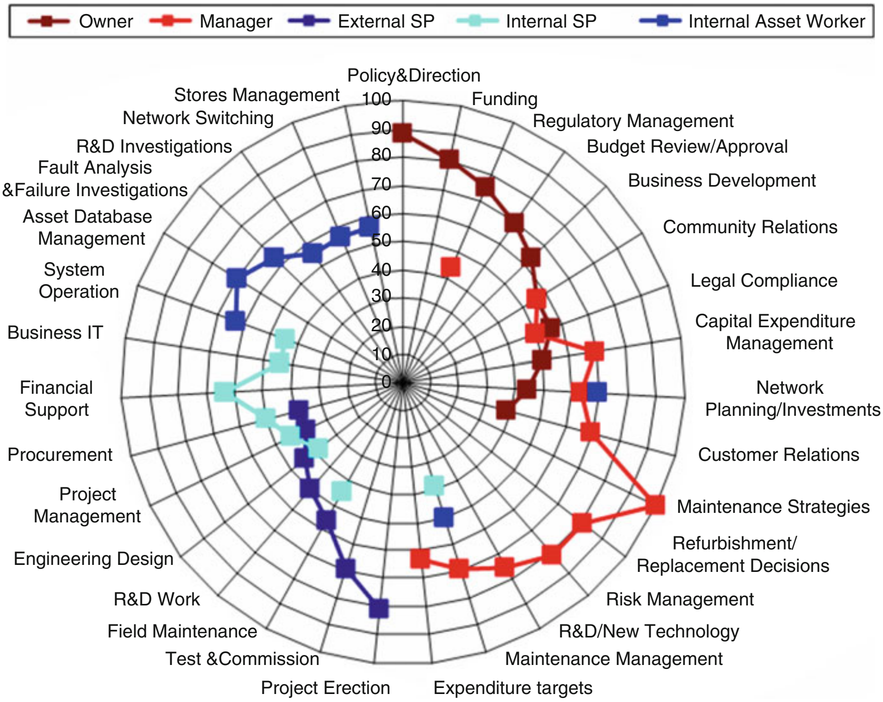


**Fig. 47.1** Utility roles as identified in TB 309

- To have AM plans and strategies identified for all company levels.
- To have clear identified roles, responsibilities, and training.
- To record all asset-related failures/nonconformances, etc.
- All staff must have a defined role; once defined each must have a clear definition of his role and one consistent with company business objectives and performance managed with improvement plans.

In TB 309 the working group undertook an industry survey to determine the extent various roles were undertaken by the various players (CIGRE 2006). The results are shown in Fig. 47.1. Also shown here is the extent of activity undertaken by external providers. Most utilities will use outsourcing, mainly to bring in specialist providers having core skills not within the company. Some new utilities have minimal in-house skills and rely extensively on this route. A fuller discussion on this topic is contained in TB 607 and TB 660.

## 47.2 Setting Corporate Strategy

Typical asset management policies include statements to preserve the core business values, such as:

- **Safety** – no compromise allowed
- **Quality of supply –** monitored to meet requirements
- **Legislative compliance –** any non-compliance dealt with quickly and transparently
- **Cost efficiency –** prudent budgeting and robust financial review
- **Environmental impact –** to be considered for all decisions
- **Reliability of supply –** key focus on units not supplied and particularly for North America SAIDI and SAIFI.
- **Security of supply –** acceptable levels achieved
- **Energy efficiency –** seek opportunities to improve
- **Technology and innovation** – keep abreast, implement trials, and adopt where appropriate

At the highest level, directors must set their appetite for risk and set headline targets. It is from such a statement of values that all business activities ensue including:

- **Safety performance is a company critical value**. Clear process must be put in place to manage safety risks. This will involve method statements to identify exactly what and where activities will take place, where responsibilities lie, and risk assessments and mitigation plans are in place. These will include that worker training, appropriate tools, and personal protective equipment (PPE) are available. Processes must be in place to record all lost time accidents with learning feedback.
- **Environmental impact**. Companies will promote their care for the environment and be careful to manage any oil spills, excessive noise, release of greenhouse gases, or polluting fires after an equipment failure. This will involve site risk assessments ensuring management of any spillage of oil or $SF_6$ release. Plans are needed to audit noise and EMC at the site boundaries.
- **Finance**. Clearly the company must have a sound financial performance, meaning profit growth. Targets can be set and outcomes identified. Beneath the financial targets inevitably will rest infrastructure development. This could be to increase capability for new connections, extending sites, replacing lower rated assets, and replacing aged assets showing risks of failure. For example, a business strategy might be "To improve current pre-tax profit by 10% within 4 years by capacity expansion to meet expected demand. This will be funded through private finance and repaid through future profits." Here the Asset Management Strategy would be something like "To upgrade the core infrastructure by investing up to $xxM over next 5 years." Another strategy might be to increase income from new renewable generation by some amount. The tactical plan must not only increase connection infrastructure but also manage the impact on the existing aged asset base. A further risk from many cable connections from offshore renewable energy resources is to increase the risk of temporary switching overvoltages due to the possibility of exciting parallel resonances in transformers.
- **Quality of service and reliability**. Generally, renewal of the original asset base has not been widespread. Assets are often now older than their intended lifetime.

This could affect not only reliability of the assets and the network but also loss of supply events. The latter are usually reportable events monitored by the regulator who may reward or penalize performance. Activities must be in place to monitor asset performance and risk of failure.

## 47.3 Asset Intervention Planning

Traditionally, OPEX has been budget driven, often to the extent of maintaining assets well beyond their useful life. The newer business focus allows greater flexibility between OPEX and CAPEX expenditure. Often regulators have a

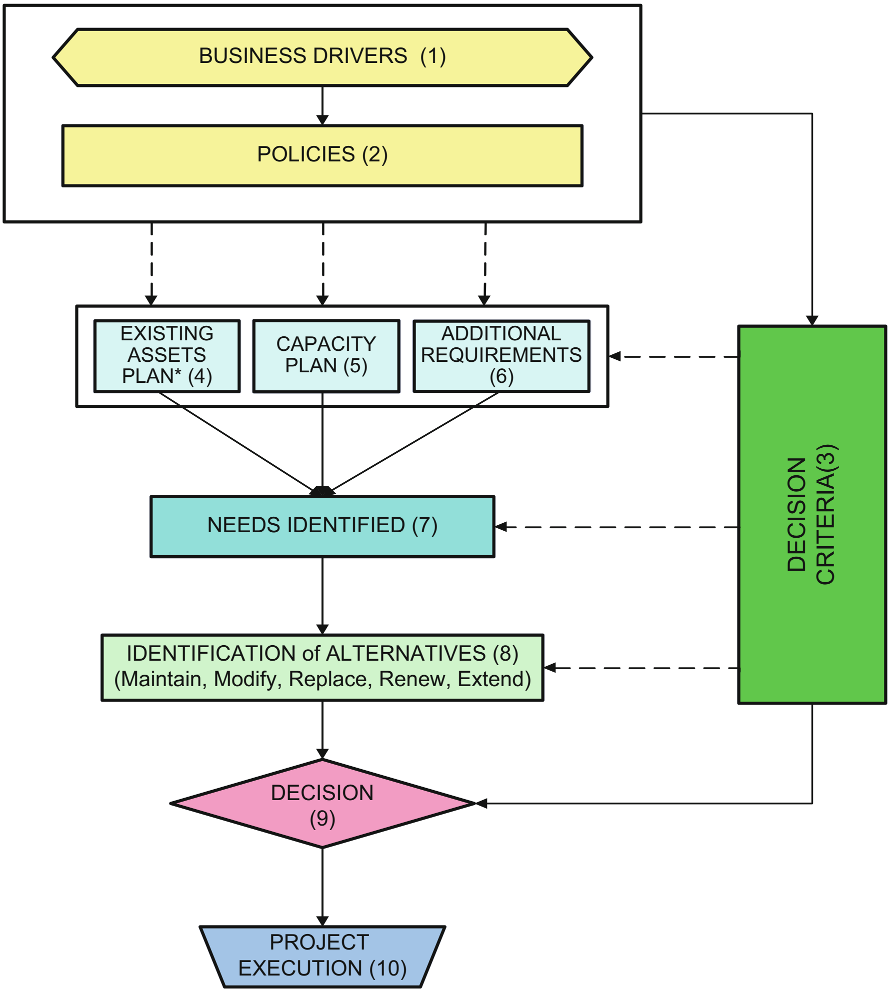


**Fig. 47.2** Integral asset replacement process [13]

significant influence on the balance. But there are other practical issues. Due to the investment peaks in the 1960s and 1970s, the European grid is ageing with an important CAPEX need for asset replacement. Additionally the renewable integration and further interconnection of the European grid leads to an increased need for CAPEX. However, due to resource limitations (production, engineering, contractors, etc), the ability to obtain the outages to execute or to finance the projects (impact on tariffs) the CAPEX plan may not be able to cover all identified needs. If this is the case and replacement investments must be postponed, the asset manager needs to evaluate the risk, for the existing asset fleets, implement risk mitigation actions, or even reevaluate the alternatives (replace or refurbish vs. renew) to shift CAPEX to OPEX or adapt maintenance policies to ensure the reliability for ageing equipments as described in Sect. 7.4.2 of Technical Brochure 660.

Technical Brochure 486 “Integral Decision Process for Substation Equipment Replacement” describes the process that gives the asset manager the possibility to consolidate all the needs (investment plan, existing asset plan needs, etc.) (CIGRE 2012) (Fig. 47.2).

The integral nature of the decision process described in Technical Brochure 486 results from the consideration of both the maintenance needs of existing assets (due to ageing) and the requirements of the capacity plan (due to grid enlargement or structural changes). This integral approach to substation asset replacement is necessary so as to ensure that high-level, general business drivers are systematically applied to all levels of individual replacement projects.

## References

CIGRE SC C1 TB 309: Asset management of transmission systems and associated Cigre activities (2006)

CIGRE SC B3 TB 786: Integral decision process for substation equipment replacement (2012)

# Whole Life Management of Substations 48

Nhora Barrera, Mark Osborne, and Johan Smit

## Contents


48.1 Life-Cycle Factors ........ 962
48.2 Life-Cycle Phases ........ 962
48.3 Life-Cycle Cost Analysis ........ 963
48.4 Application of Whole-Life Costing ........ 965
48.4.1 Design Process ........ 966
48.4.2 Procurement Process ........ 966
48.4.3 Construction Process ........ 967
48.4.4 Testing and Commissioning Process ........ 967
48.4.5 Maintenance Regimes and Condition Assessment Techniques ........ 967
48.4.6 End of Life Options ........ 968
48.5 Evaluation of Substation Life-Cycle Costs ........ 968
48.6 Optimizing Asset Management ........ 969
48.6.1 Reliability Centered Asset Management ........ 969
48.6.2 Stochastic Optimization Algorithm ........ 970
48.6.3 Standard Substation Bays ........ 970
48.7 Managing the Design for the Future ........ 971


This chapter provides some guidance on the factors that need to be considered when deciding the policy to be adopted as the plant matures and the tools and techniques which can be used to assess the condition of the equipment.


N. Barrera (✉)
HV Substations, Axpo Power AG, Baden, Switzerland
e-mail: nhora.barrera@axpo.ch

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl



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The substation's lifetime is typically quoted as 40–50 years, and during this period changes to the substation will be required: new circuits may be connected into the substation, requiring additional bays, new transformers may be installed to increase the substation capacity, or broken equipment may have to be replaced. After some time, the substation becomes a mix of various technologies, and the age of installed equipment will span from brand new to 40 years old.

More utilities are questioning whether replacement is the only viable option. Other intervention strategies which may well be worthy of consideration are retrofit, refurbishment, or repair. It is clear that there is not one solution that suits everyone.

## 48.1 Life-Cycle Factors

In order to assist utilities to make the best choice from the available options, the most common factors to be considered are:

- **Future outlook**: Is the associated power station or substation due for decommissioning in the short term? Or should the decisions considered include even a complete substation replacement?
- **Fault level**: Is the equipment's uprating enough? Or is it economically and technologically better to increase the fault level altogether?
- **Existing equipment**: Has the equipment given good reliable service over a long period? This will give confidence to try to extend the life. In any case, a clear and detailed assessment of the plant condition is always necessary; an assumption on plant condition is not adequate.
- **Operational and project safety**: Always consider the safe operation and maintenance of equipment, as well as the actual plant condition. If a significant life extension is being planned, include an assessment as to whether the existing equipment can be operated in accordance with all of the latest safety requirements.
- **Costs and risk assessment:** Identify and evaluate the viability of the possible options, taking into account the total cost as adjusted by suitable risk factors. This is further explained in the section on evaluation.

## 48.2 Life-Cycle Phases

IEC 60300-3-3 [14] describes six phases for the life cycle of a product: (1) concept and definition, (2) design and development, (3) manufacturing, (4) installation, (5) operation and maintenance, and (6) disposal. Because substations are intrinsic to the grid and unless they are due for decommissioning, disposal is considered only for the equipment. The asset manager then needs to define the cost breakdown structure (CBS) to use and to define the life-cycle cost (LCC) of its substations.

Capital investment costs for transmission projects are the dominant element for procurement decisions. A good understanding of the legacy costs to be inherited with a design can help to select a more appropriate solution, which suits the business plan. This information can in turn assist in managing the operational cost for the ensuing years and beyond.

The effectiveness of the performance criteria on which the life cycle depends can be assessed by monitoring:

- Availability
- Equipment reliability (unplanned unavailability)
- Lifetime costs
- Impact of disturbances to the network (forced outages on the system)

## 48.3 Life-Cycle Cost Analysis

Decisions on maintenance strategies and asset replacement can best be made on the basis of life-cycle costing, which considers the cumulative cost of an asset over its life cycle. Guidance on life-cycle cost analysis is given in IEC 60300-3-3 [14]. The standard states that the total costs incurred over the life cycle can be divided into acquisition cost, ownership cost, and disposal cost.

Life-cycle cost (LCC) = cost of acquisition + cost of ownership + cost of disposal

Acquisition costs can readily be evaluated before the acquisition decision is made, while ownership costs exceed acquisition costs in many cases and are difficult to predict.

The cost of maintenance is a major component of the ownership cost of a substation asset. Labor costs, rental of tools and equipment and spare parts and consumables, as well as costs for outages, including costs associated with unavailability where an asset is out of service for maintenance or following a failure, must be taken into account.

In the calculation of costs, the costs of out-of-merit generation and any penalties imposed by regulators for supply interruption must also be included.

An asset can remain reliable beyond its commercial book life by the use of appropriate maintenance activities. Eventually, however, the level of maintenance required to achieve specified performance may become unacceptable. Life-cycle cost considerations help to analyze dedicated components of the complete system based on the overall network data. Optimizing an existing network is always possible in different ways. Life-cycle cost considerations show the whole impact on all cost portions of these components. It is possible to simulate the different options and finally to select the most economic one.

The basis of all life-cycle cost calculations is a suitable cost breakdown structure. The generic requirements on such a model are summarized in [14].

- **Life-cycle cost calculations** use typically discounted cash flow models. These calculation methods are dynamic models taking into account the effect of time and integrating the net present value in the calculations.

First a suitable discount rate has to be identified, and the optimal duration of the calculation has to be determined. For example, an effective discount rate applied could be in all 6%, consisting of a cost of capital rate of 8% minus an inflation rate of 2%.

Secondly, an appropriate duration of the calculation has to be determined, which should be longer than the expected lifetime of the most long-lasting technology (in example: AIS, HIS, GIS); therefore, the consideration of just one life cycle is not sufficient. The different impact of the earlier or later occurrence of the reinvestment cost has to be respected. An infinite calculation is the optimum, but not realizable, a good estimate is to consider a period of 100 years. Estimations show that a calculation over 100 years is comparable to an infinite calculation with an error of just 0.3%.

- **Cost breakdown structure (CBS)**: The cost breakdown structure has to match the goals of the life-cycle cost considerations. The goal of this approach is to identify potential for optimization of a high-voltage substation from the utility's viewpoint. High-voltage switchgear has very specific properties: initially very high investment costs occur, followed by a relatively long period of operation characterized by high reliability of the components.
  The different concepts require a distinction between system and balance of plant costs, since the respective magnitude of these cost elements itself differs greatly for each of the technologies. Figure 48.1 presents a CBS according to IEC 60300 [14].
- **Data basis**: The basis of any reliable calculation is reliable data. While the acquisition costs can normally be derived easily by the operating utility, it is

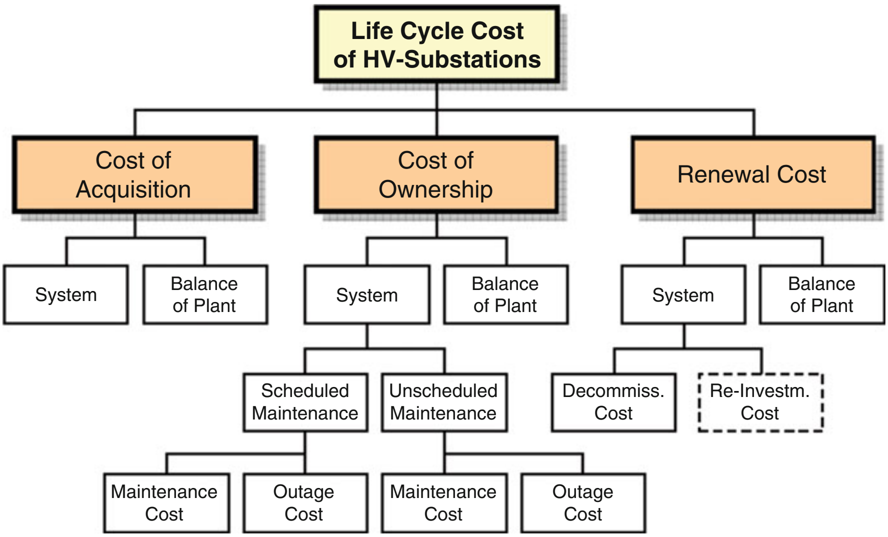


**Fig. 48.1** Selected cost breakdown structure (CBS) according to IEC 60300 [14]

very difficult for the individual utility to determine the maintenance costs, especially the expenditure for unscheduled maintenance.

It is therefore useful to take data which were acquired by independent organizations and which summarize the experience of different utilities and different suppliers.

## 48.4 Application of Whole-Life Costing

Technical Brochure 354 "Guidelines to Cost Reduction of Air Insulated Substations" [15] provides a set of guidelines for effective and efficient design, construction, and commissioning processes in order to minimize redesign, rework, and multiple checks. It provides a practical overview of the issues influencing the cost of substations and how these costs can be controlled and also presents cost reduction opportunities achieved by using pre-engineered, prefabricated, and pretested integrated equipment and installations typical for AIS. However, most of the principles can be applied to GIS substations too.

In the first instance, WG B3-15 issued a questionnaire to assess the opportunities for optimizing the engineering and construction costs of air-insulated switchgear (AIS) substations. The questionnaire received 24 responses from 18 countries which were used in the preparation of the main body of the brochure. This brochure provides a range of important information which contributes to optimizing the construction cost of AIS substations from the conceptual engineering stage to project closeout as follows:

- **Design process**, e.g., standardization and consistency in the use of standards, maintainability, and constructability issues, use of new design/drafting tools, use of new technology equipment (major equipment, integrated equipment), etc.
- **Procurement process**, e.g., development of detailed technical specifications, prequalification of suppliers, establishment of strategic alliances and blanket purchase orders with suppliers, etc.
- **Construction process**, e.g., construction method, use of modern equipment, quality control of workmanship checklists, etc., site logistics, transportation, as well as outage management
- **Test and commissioning process**, e.g., elimination of duplicated testing, well-documented commissioning checklists
- **Project closeout**, e.g., documentation and site cleanup

An engineering checklist that picks up important points from the design process through to project closeout is also discussed in the brochure, as a practical aid for substation construction projects.

A number of case studies are also included in the brochure to show how cost reductions have been achieved in practice by various utilities.

### 48.4.1 Design Process

Issues influencing the design of a substation vary both in their source and in their impact. Some are controllable by the designer, while others are dictated by external factors. In addition, some of these factors can impact the whole project, while others affect only specific areas of the substation. They can include:

- Mandatory requirements such as safety codes, environmental and local regulations, etc.
- Customer needs such as system connections and power supply capacity enhancements from new power suppliers
- Power system constraints such as short circuit levels, system control and operating requirements, and reliability
- Operating and maintenance requirements, including operability, major repairs, spare parts availability, and availability of suitable skills

Minimizing the overall substation cost is achieved by ensuring the initial concept design is carefully and thoroughly executed and that the design incorporates:

- A rigid design process with design reviews at all key stages
- Life-cycle considerations
- Careful consideration of the practicality of construction
- Standardization to the maximum extent practical
- Selection of reliable equipment that is readily interchangeable with alternatives
- Equipment configurations that utilize optimized technology and provide for future extension and replacement
- A high level of quality control

The design should also facilitate accelerated construction including provision for as much early design, off-site manufacture, and pretesting and pre-commissioning as possible. The basic specifications should cover all items having a relevant impact on life-cycle cost and thus being of interest for standardization.

### 48.4.2 Procurement Process

As part of the effort to reduce the total cost of building new or renovating existing AIS, the procurement process is the most obvious target for extraction of cost reductions. However, to obtain maximum benefits, every aspect of this process must be subjected to a thorough review and all associated practices scrutinized, no matter how deeply ingrained they are in the utility policies and procedures.

A main point to consider is the building of strategic alliances or long-term blanket orders, as long-term contracts allow a degree of equipment standardization, thus resulting in reduced requirements for spare parts, standardized maintenance practices, and ultimately lower life-cycle costs for the equipment.

### 48.4.3 Construction Process

All costs incurred during this process are included in the life-cycle cost of the equipment and have been the major focus for optimization and reduction. Typically, the direct cost of procurement, construction, and commissioning accounts for 90% of the total life-cycle cost of HV equipment [16].

### 48.4.4 Testing and Commissioning Process

During this process, the test results provide the fingerprint of the equipment, which will provide important information during the maintenance process. The comparison of future testing during operation will indicate the maintenance activity and the future need for replacement.

Annex 5.1 in the TB 544 [57] provides an excerpt from IEC 60300, which discusses life-cycle costing in HV substations.

### 48.4.5 Maintenance Regimes and Condition Assessment Techniques

Today the asset manager is faced with severe financial constraints, forcing operators to look at their total life strategy including optimizing maintenance regimes and making informed decisions as the plant ages. The paper [55] describes some of the maintenance regimes and condition assessment techniques used, which can vary from strict adherence to the maintenance manual to complete abandonment of maintenance to save cost, giving a wide range of possible scenarios. The asset manager needs to define the best-suited strategy and use the established maintenance regime, which may also be used for gathering the necessary data to establish the end of life options.

To decide the correct approach requires knowledge of the equipment, its operating conditions, and its present condition. A good starting point to achieve this is to apply condition-based assessment combined with targeted maintenance of all of the functionally important components of equipment which has been in service for more than 25 years, providing advantages such as:

- Outage time reduction
- Cost reduction compared to time-based maintenance programs
- Minimizing crisis breakdown situations
- Switchgear life expectancy controlled and even increased
- Less invasive – normal maintenance is known to increase problems

This is discussed further in ► Chaps. 50 and ► 51.

### 48.4.6 End of Life Options

As the time for making the decision on plant life extension or replacement approaches, the options which are generally open to the utility are:

- Replace the equipment on a like-for-like basis, possibly uprating fault levels in the process.
- Replace an AIS substation with a GIS substation and reutilize or sell the land released.
- Refurbish the existing equipment to achieve an extension of the life, including uprating.
- Retrofit part of the equipment, usually the circuit breaker, into the existing back parts to achieve extended life and usually achieve some uprating in the process.
- Some combination of parts of the above options.

## 48.5 Evaluation of Substation Life-Cycle Costs

Life-cycle cost (LCC) calculation is a major topic for substation management but often focuses upon the LCC of individual substation components rather than of the entire substation. However, effective substation management should take into account all potential cost influences including substation layout, substation maintenance, and substation failure. Taking account of all such cost parameters creates a complex, multidimensional problem.

To decide the optimum option for any particular circumstance, it helps to evaluate the available options using the “go/no go” criteria followed by cost/risk optimization. For example:

- Is the condition of the existing equipment suitable for extending the life for the required duration?
- Can the existing equipment achieve the required fault levels with refurbishment and/or retrofit?
- Will the refurbished/retrofitted equipment meet the health, safety, and environment requirements/legislation?
- Is the expertise available to carry out the refurbishment/retrofit and subsequent maintenance for the extended life?
- If replacement is being considered, is there space to start the replacement while systematically decommissioning the old equipment? Is there space to locate and build a GIS switchyard while maintaining the existing substation?
- Can the work be carried out in a safe manner?

Once the above questions have been answered, the remaining options can then be evaluated in terms of cost and risk:

- Capital cost of the equipment required
- Civil work costs

- Labor cost for refurbishment, retrofit, and installation/commissioning of equipment
- Cost of outages required to carry out the work
- Predicted cost for forced outage or other possible losses during the project period, being higher for prolonged duration projects
- Other costs/benefits such as additional land costs or proceeds from sale of land released (AIS-GIS replacements)
- Service life costs in terms of maintenance costs (including costs of scheduled and forced outages based on reliability figures), operational costs (losses, etc.), and decommissioning costs at the end of the life
- Financing costs, if appropriate, and return on investment

From the output of an evaluation similar to that described above, the utility should be able to decide the optimum solution for each individual case.

## 48.6 Optimizing Asset Management

This section discusses excerpts from relevant work presented in CIGRE forums and working groups to illustrate the different approaches to life-cycle costing analysis in HV substations.

### 48.6.1 Reliability Centered Asset Management

The approach [17] involves a modular structuring of the asset management process which defines separate functional modules (Fig. 48.2). Each module requires the availability of certain models and data and in turn delivers defined (partial) results. This structure offers the possibility to adapt the asset management process to the individual situation of different network operators while delivering the most detailed and most meaningful results. In addition to Reliability Centered Asset Management (RCAM®) analysis, a cost evaluation of different scenarios with life-cycle cost analysis of the relevant components provides valuable cost information. All relevant cost dependencies of investment and operating cost can be highlighted.

Thus the prognosis of expected future system performance with regard to supply reliability and to economical indices provides important insight into the relevant correlations, with details of the separate component classes installed in the system. Such information is highly valuable in deciding on the long-term success of network development and asset management.

The RCAM process focuses on the analysis and prognosis of the technical supply reliability performance of electricity networks in dependency of different strategies especially for preventive maintenance and preventive replacement (i.e., definition of technical lifetime) of network components.

The results of the RCAM process provide quantitative information on the correlation between cost and quality in electricity networks, which support the sound

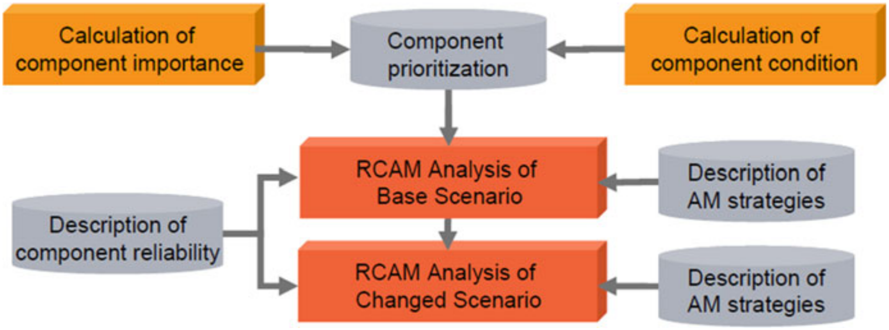


**Fig. 48.2** Typical core modules of the RCAM process [17]

evaluation of, and decision on, different asset management strategies. Besides assessing such different asset management strategies, the available details in the results allow conclusions on the main drivers and issues in the technical and economical network performance (Fig. 48.2).

The paper provides a general description of the RCAM process and some useful examples of practical application of this method.

### 48.6.2 Stochastic Optimization Algorithm

Reference [18] describes the application of an optimization algorithm to identify the lowest LCC substation management solution considering a wide range of possible combinations of all cost parameters. The optimization algorithm can also be used to explore sensitivities to particular variables. The optimization algorithm can identify the substation solution with the lowest LCC and can provide information regarding those cost parameters which have the highest impact on the LCC result. The innovation of this idea is to utilize a single optimization algorithm to assess the LCC of the substation as a whole. The paper also describes the use of the genetic algorithm (GA) to cater for all cost parameters and presents a case study to support the developed methodology.

The main idea of the GA is to find in an iterative way an optimized substation solution. The algorithm changes the components in the substation layout, varying both the technology and the type of redundancy. The algorithm uses an iteration approach, to provide the optimal composition of the substation solution. It can be extended to consider the application of advanced switching technologies.

### 48.6.3 Standard Substation Bays

The reduction in resource and expertise within the industry is driving the need for strategies which minimize the risks and costs associated with the application and installation of new equipment. Establishing a standard process for the installation of a viable population of substation bays will streamline lifetime management activities such as maintenance planning, spares provision, and resource requirements.

The standard bay strategy [16] establishes an approach, which is valid for a large scope of asset replacement work (Fig. 48.3). The benefit of reducing reengineering and repeating good practice will provide a safer, cheaper, and more reliable bay. While not all bays will be uniform in size, the strategy concentrates on the generic elements to improve the project delivery and sensibly design out operational lifetime costs. This will also benefit many other aspects of the business through small enhancements and streamlining of work processes.

This strategy offers significant savings but requires long-term commitment. If the standard bay approach is not installed routinely and redesign creeps in for every scheme, the costs and risks will escalate beyond that of current practice.

A possible strategy could be to streamline the process of replacing assets to achieve a low cost and reliable solution and also deliver the work within the boundaries of a commercial environment. Resource and expertise is a constant target in the drive to reduce operational expenditure; this approach lowers the long-term drain on resources for repetitive work without increasing the risk to the system.

In theory the asset replacement is predictable, and maintenance operations may extend the lifetime of the equipment to a certain extent.

The utility has already implemented a standard approach to the light current bay systems through the integrated Substation Information Control and Protection (SICAP) strategy. Extension of this concept to the whole bay to capitalize on the strategy is a natural progression.

This strategy can only work with an appropriate commercial framework for the key solution providers, encompassing a robust mechanism, which addresses the need for flexible work packages on substations of differing complexity and risk. Reward and penalty criteria must be addressed to reflect performance. All of this will be required for all parties concerned to benefit from adopting this long-term approach. Challenges remain around facilitating:

- Open technology architectures and protocols
- Seamless interface with existing and alternative supplier's equipment (Fig. 48.3)

## 48.7 Managing the Design for the Future

Fully equipped control and common protection schemes, DC distribution boards, etc. for all future bays should ease the potential problems associated with extending existing systems. This is particularly the case with substation-wide schemes, e.g., busbar or circuit breaker fail protection or digital substation control schemes. However, digital protection relays may have a limited lifetime in the de-energized state.

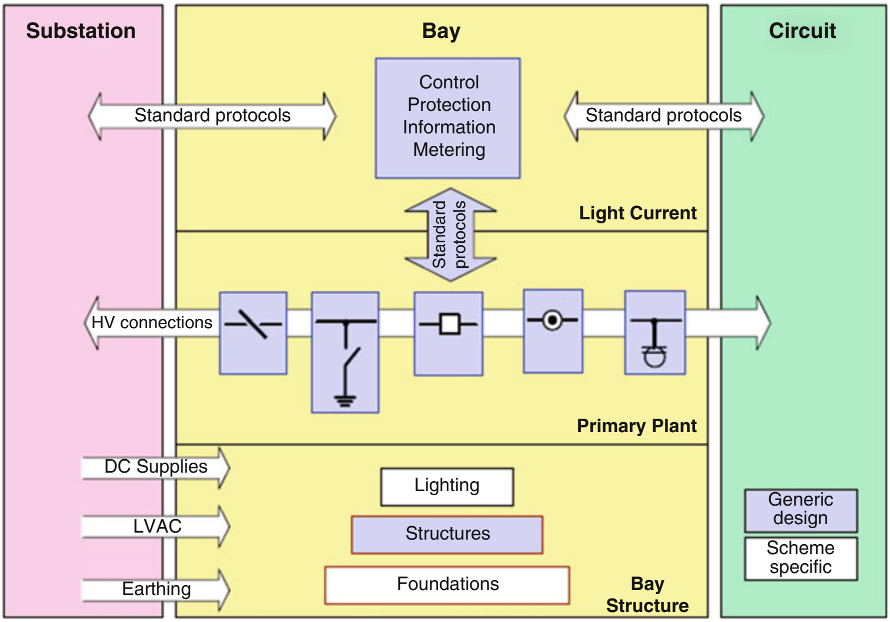


**Fig. 48.3** Boundary and Interface for a Standard Bay Design [16]

Alternatively do not make any advance provision of circuit protection relays to maximize the available future flexibility.

Always consider the balance between design and equipment for future scenarios, and try to reduce the chance of premature equipment replacement.

Take into account that control and protection systems may require more frequent replacement than HV primary equipment and design to facilitate this process.

# Commissioning

# 49

John Finn, Mark Osborne, and Johan Smit

## Contents

49.1 Introduction ..... 974
49.2 Workflow ..... 974
49.3 Stage 1 Pre-commissioning ..... 977
49.3.1 Purpose and General Principles ..... 977
49.3.2 Order for Inspection and Testing ..... 978
49.3.3 LVAC Supplies ..... 979
49.3.4 Building Services ..... 979
49.3.5 Batteries and Chargers ..... 979
49.3.6 Switchgear ..... 980
49.3.7 Transformers ..... 981
49.3.8 Power Cables ..... 983
49.3.9 Earthing System ..... 986
49.3.10 Instrument Transformers ..... 988
49.3.11 Protection Equipment ..... 989
49.3.12 Control, Indications, and Alarms ..... 990
49.3.13 Other Equipment ..... 991
49.3.14 Overall Checks, Interlocking, Synchronizing, etc. ..... 991
49.3.15 Final Pre-energisation Checks ..... 992
49.4 Stage 2 Energization and Final Commissioning ..... 992
49.4.1 Preparation of Switching Program ..... 993
49.4.2 Authorization to Proceed to Stage 2 ..... 993
49.4.3 General Principle ..... 994

J. Finn (✉)
CIGRE UK, Newcastle upon Tyne, UK
e-mail: finnsjohn@gmail.com

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl

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49.4.4 Soak Testing ... 994
49.4.5 Load Testing ... 994
49.4.6 Handover for Operation ... 995
49.5 Documentation ... 995
References ... 996

## 49.1 Introduction

This chapter is not intended to be a manual on how to commission a substation, new bay, or refurbished bay but to explain the basic principles and processes of the commissioning activity. Some people query whether commissioning is the last part of the installation process or is it the first part of the management process of the substation. In reality it is both as you transition from construction or maintenance back to operation.

From the point of view of the installation, the commissioning is the final part of the quality control system to ensure that the customer or asset owner is receiving the required product, fully checked in accordance with the specifications and contract requirements, and fully functional.

From the point of view of the Asset Owner and Asset Manager, this is the first step in taking over responsibility for the asset and ensuring that it meets all of the requirements which were defined in the specification and as may have been modified during the installation process. The records of the Pre-commissioning and commissioning tests provide the basis for the start of all trend monitoring of the substation.

It is therefore usual that the contractor (installer) will perform all of the relevant tests and record all of the results. These tests will be witnessed by a representative of the Asset Owner such that effectively the activity is a joint activity. In the case of asset intervention, this may be a smaller subset of activities; however, the principle is still the same.

The commissioning process is usually divided into two stages. Stage 1 is the performance of all the necessary checks and tests which can be carried out before the substation equipment is actually energized from the network. These checks and tests are often referred to as pre-commissioning tests as they are performed before the actual equipment is put into service or commission. The number of tests carried out during this stage should be maximized as at this stage if anything is found to be incorrect it will not affect the network.

Stage 2 commissioning is the process of actually connecting the new equipment to the network, energizing it and carrying out those tests which can only be carried out when the substation is connected to the network.

## 49.2 Workflow

Figure 49.1 shows the workflow and responsibilities during the planning and commissioning of an air insulated substation.

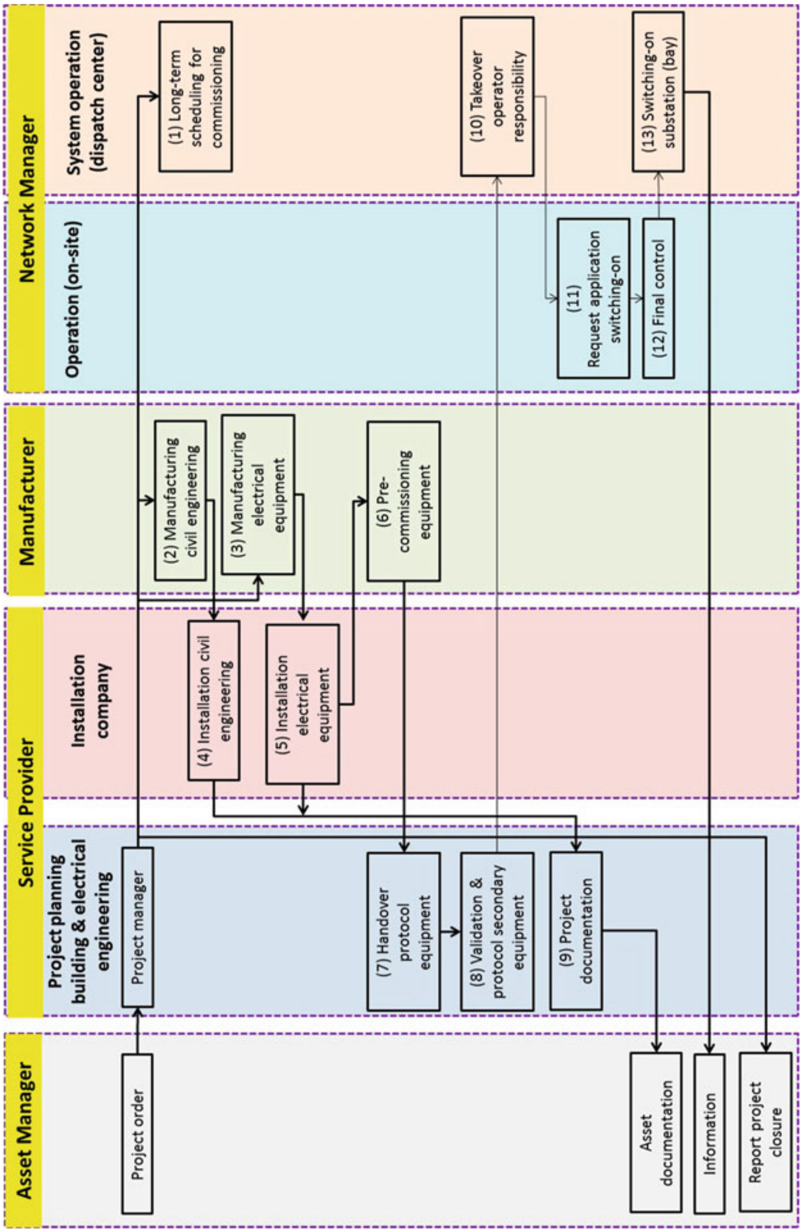



**Fig. 49.1** Summary of HV Testing Practices from survey described in TB514

The numbers of the different steps relate to the designations in the flowchart. The flow chart identifies the roles of the Asset Manager, the Service Providers, and Manufacturer.

Starting from a project order from the asset manager, the project manager as part of the service provider takes over the further workflow and supervises the entire process with several steps which are defined below:

- Setting a fixed date (e.g., 1 year in advance) for the commissioning (switching-on the substation) in the time schedule of the overall project. A time frame of for example 1 week is scheduled and announced to the dispatch center.
- The components of civil engineering (supporters, foundations, etc.) are produced by the manufacturer (building contractor).
- Switchgear/instrument transformers/surge arresters are prequalified, accepted, and tested by the manufacturer. Power transformers are tested by the manufacturer and subsequently transported to the installation.
- The installation of civil engineering for the substation is performed by the service provider.
- The installation of electrical equipment, including the electrical connections, is provided by the service provider.
- The Pre-commissioning of the equipment is carried out by the manufacturer. This includes device settings, filling with oil, mechanical operation of switching devices (functionality) under the supervision of the Service Provider.
- Preparation of a handover protocol regarding the equipment installed, prepared, and signed by the manufacturer. This includes the control of the devices in accordance with the specification and check for possible transport damage. The points of the protocol are based on the description, e.g., with respect to the switchgear, of the IEC standard 62271 (IEC 2011). The general provisions are listed in Part 1 (Chapter 11), and the specific rules for the different devices are carried out in special parts, such as (IEC 2006) for circuit-breakers, Chap. 10: “Rules for Transport, Storage, Installation, Operation and Maintenance.”
- Validation of secondary equipment, this includes, for example, the following tasks:
  - Visual inspection of the high voltage bay marshaling (correct connection of the instrument transformers)
  - DC power supply
  - Functional check of the devices (messages, locking)
  - Control of clamping strips
  - Examination of switchgear, power transformers (without voltage)

The handover protocol has to be prepared (secondary equipment) by the project manager.

- Compilation of project documentation starting from the assembly reports – see (4), (5) in Fig. 49.1 and presentation of the documents to the Asset Manager (asset documentation).

- Handover of operator responsibility by the dispatch center, because the switching authorization is covered by this department.
- All project data are transferred to the asset owner and relevant information to the system operator (dispatch center). The operation (on-site) requests for the switching-on operation.
- Local control by the system operator (on site), of the conditions to check if they are acceptable for a switching-on operation to be given (safety rules, check of the installation, no staff in the substation area).
- The final switching on of the switchgear is carried out by the system operator (dispatch center).

Finally, the system operator informs the asset manager regarding the switching on operation of the substation, as well as the final report (project closure) is written by the project manager to handover to the asset manager.

## 49.3 Stage 1 Pre-commissioning

### 49.3.1 Purpose and General Principles

All of the equipment involved in the substation will have been subjected to the type and routine tests appropriate to the type of equipment and if necessary to any special tests requested by the purchaser. These tests should clearly demonstrate that the equipment is performing as required before it leaves the factory. The purpose of the Stage 1 commissioning tests is therefore not to prove that the equipment actually meets the specifications but rather to ensure that it has not been damaged in transit and has been erected correctly and will perform correctly in situ. Equipment that has selectable settings will not generally have been tested in the factory on the particular settings which are to be used on site and so this can be tested as part of the commissioning.

Furthermore, the tests at commissioning will produce a benchmark for the performance of the equipment when it is first being put into service. For example, insulation resistance value, speed of operation, quality of insulating oil, resistance of joints, etc., can be recorded so that they can be compared with similar measurements taken during the life of the equipment to detect trends. Some equipment such as surge arresters and transformers may have a test which is effectively a "signature" of the state of the equipment and these are very effective for trend analysis.

In today's world, there is a lot of pressure to try to shorten the project times particularly for substation extensions. This would shorten the outage time when installing new or replacement bays. Consequently, there is pressure to shorten or cut down the amount of on-site Pre-commissioning tests. There is a big danger in doing this that the information available for subsequent analysis in the event of faults is not sufficient to assist in the investigation. It is often argued that if the equipment is tested in the factory then it should only be necessary to check that it has not been damaged in the delivery and installation process and is functional. This would seem to be satisfactory; however, the level of detail of the tests and results available from factory tests is often not of sufficient detail to provide the benchmark information which is required. Furthermore, the commissioning tests are usually witnessed by the personnel who will be directly involved in the operation, maintenance, and fault finding during the life of the substation, and so they can ensure that the information recorded is sufficient for their needs. It is notoriously difficult to get factories to perform the level of testing done at commissioning and almost impossible to get the site staff to the factories to witness the tests.

Finally, there are some tests or checks which can only be carried out when the equipment is installed in its final location, for example, checking that the setting of a pantograph disconnector contact is within the catching zone correctly at the relevant ambient temperature.

In the following paragraphs, we will look at the typical types of Pre-commissioning test to be carried out on the main items of equipment in the substation.

### 49.3.2 Order for Inspection and Testing

The following generic list of checks and tests covers most of the substation equipment and provides the recommended order for carrying out the tests. The order is intended to provide as much self-checking as possible. For example, if connections are removed to carry out magnetization curves then performance of the primary injection test at a later stage will check the correct replacement of the connections. Disconnection of wiring associated with an early test should be avoided or if this is not possible then re-testing to prove the disturbed circuit will be required.

The following is a list of the generic checks and tests in the recommended order:

- Inspection of the plant
- High voltage pressure tests of primary plant
- Resistance measurements
- Insulation tests of AC and DC control and protection circuits
- Secondary circuit insulation tests
- CT magnetization tests
- Relay secondary injection tests
- Checking of control circuitry wiring
- Functional tests of control, closing, tripping, and protection including inter-tripping
- Electrical and mechanical interlocking checks
- Functional tests of tele-control, controls, alarms, indications and analogues
- CT and VT ratio and polarity test by primary injection and wiring loop resistance tests
- Testing of back tripping and blocking circuitry
- Final preenergization checks

### 49.3.3 LVAC Supplies

As an AC supply will be required to carry out many of the activities during the commissioning of the substation, it can be advantageous to commission the LVAC system first. The LVAC board will normally have an insulation resistance test to ensure satisfactory insulation resistance followed by a one minute power frequency voltage withstand test. The various protection devices should be proved by primary and/or secondary injection. If the board has interlocking to prevent paralleling of the system supply with a back-up diesel supply, then positive and negative checks should be done on the interlocking. It will not normally be possible to power up the board from its final designed supply so it may be possible to energize the board from an emergency diesel generator if one is being provided for the substation. It is important that the use of such an emergency diesel is agreed between the contractor and the utility before using it. In such a case, the usual checks on the diesel unit should be done before operating it.

If there is no emergency diesel unit available or its use for commissioning purposes is not agreed, then it will be necessary to energize the LVAC board from a temporary diesel generator. Once the LVAC system is functioning, it is possible to then provide power for the battery chargers and other substation auxiliaries as well as for the building services.

### 49.3.4 Building Services

The building services should be commissioned as early as possible to make the essential facilities such as lighting, heating, and air conditioning available during the commissioning process. Lighting levels should be checked in each of the rooms to see that they are as designed and a check made to ensure that there are no dark areas.

### 49.3.5 Batteries and Chargers

Once the LVAC system is working it is then possible to energize the chargers to charge up the batteries. If the batteries are of the vented type then the level of the electrolyte in all of the cells should be checked before putting the batteries on charge. Checks can be made of the voltages at the charger output and at the distribution board to see that they are all within tolerance. The batteries will normally be given a load discharge test before being recharged and made ready for service. The charger fail alarm can be checked by disconnecting the supply to the charger, and the battery voltage can be checked with the charger out of service. With the system in normal condition, the positive and negative earth fault alarms can be checked by connecting each pole to earth independently. With the DC system operational, then commissioning of all other equipment can commence.

### 49.3.6 Switchgear

**Circuit Breakers**

The insulation resistance of the breaker can be checked by using a 5 or 10 kV insulation resistance tester to ensure that the value is in excess of at least 500 MΩ. The resistance of the closed contacts should be checked using a "ductor" test set, and the resistance should be of the order of 10 μΩ per contact. If there are any other clamps within the measurement circuit 10 μΩ for each additional clamp contact should be allowed. A circuit breaker timing test should be carried out and the results recorded for comparison with tests carried out during maintenance in later years. The timing test should include recording the spread in times between different phases of the circuit breaker and also the timing of different interrupters in the same phase of the circuit breaker. The timing of any resistor contacts should also be recorded. The duty cycle O-CO-t-CO should be verified on site to check the energy storage of the mechanism. If the mechanism is of the hydraulic type, then checks should be made of the pressure of the oil and measurements taken during the duty cycle test. The operation of the pump and also the alarm and lockout pressures should be checked.

**Disconnectors and Earth Switches**

There are many different types of disconnector, and the checks recommended by the manufacturer during erection should be performed as the erection progresses. This is particularly important for pantograph disconnectors. It is important to note and record the temperature when setting the position of the fixed contact within the catching zone as its position will vary with temperature as the sag of the conductor increases with increased temperature. The smooth operation of the disconnector should be checked both manually and using the motor operation if provided.

Similar checks should be made on the earth switches. Frequently if there are earth switches mounted on the same structure as the disconnector, then there may be interlocking built in to prevent the earth switch from being closed when the disconnector is closed and conversely to prevent the disconnector being closed when the earth switch is closed. This interlocking should be proven in both directions. If magnetic bolt interlocking is provided, it should be checked that this is strong enough to withstand operation with the motor drive when the interlock conditions are not fulfilled. (Some designs had an interlock disc which was not thick enough to withstand the forces from the motor drive). Insulation resistance and contact resistance measurements should be done as for circuit breakers.

Where induced current earth switches are fitted with separate vacuum bottles, the correct sequence operation of the interrupter and main contacts should be checked.

**Gas Insulated Switchgear (GIS)**

It is usual to carry out a one minute power frequency test on GIS although the alternative of carrying out a longer duration soak test at operational voltage is being accepted in some countries. If a high voltage test is to be done, it is important to ensure that equipment such as voltage transformers and surge arresters are isolated before applying the voltage to earth. This test is very effective in checking that the switchgear has been effectively cleaned and there are no particles or swarf left inside. In order to minimize the risk of a flashover during this test, the use of partial discharge monitoring during the test can be useful. If the test voltage is raised slowly, any problem present will be detected by the partial discharge monitor. The voltage can then be reduced before a flashover occurs. Furthermore, the use of acoustic emission detectors should identify the particular chamber to be investigated to rectify the fault. Checks should also be made of the gas monitoring system for operation of the alarm and lockout pressures. Experience is described in TB 514 and summarized in their Table 6.4 and reproduced here as Table 49.1 (CIGRE 2012).

### 49.3.7 Transformers

When transformers are transported, they will normally be fitted with a "shock" or "Impact" recorder. Ideally this will be an electronic waveform type of recorder with a battery life in excess of 3 months and software able to interrogate the impacts in the frequency domain. As soon as the transformer is delivered to site, the "shock" recorder should be checked for any evidence of impacts during the transportation. When the transformer is located on its foundation then the oil filling/filtering process should be commenced. Samples of the oil should be taken and tested until a satisfactory withstand test voltage is obtained (in excess of 50 kV across a gap of 2.5 mm). When the oil handling process is completed, the following checks should be done.

- Check that all oil levels are correct in conservator, diverter switch tank, bushing, etc.
- Check the operation of low oil level alarms
- Check that all valves are in the correct position – open or closed as required
- Check that thermometer pockets are filled with oil

Insulation resistance values should be checked preferably before the transformer connections are made so that the values can be compared with those taken in the factory. The insulation resistance of the core ground should also be measured as this can also give an indication of any damage in transit.

A vector group test will normally be carried out to verify the phasing is correct for the network.

The following tests should be carried out at every tap.

- Ratio, HV-LV, HV-TV, LV-TV.
- Winding resistance.
- A magnetization current check. This should be done by connecting a 400/230 V supply to the transformer with the LV open circuit. The measurements should be carried out using an analogue ammeter, and it should be checked that there is no break in current as the tap changer moves from one tap to another. If there is a short break, this can be seen when using an analogue meter.

**Table 49.1** Summary of HV Testing Practices from survey described in TB514

| Voltage class | Do you apply power frequency HV test at commissioning? | | Do you apply any kind of impulse HV test in addition to power frequency voltage test at commissioning? | | Do you specify PD measurements during commissioning tests? | | PD conventional method | PD UHF/VHF | PD acoustic | PD other |
|---|---|---|---|---|---|---|---|---|---|---|
| No. of | Yes | No | Yes | No | Yes | No | Yes | Yes | Yes | Yes |
| $60 \leq U < 100$ kV | 14 | 1 | 1 | 14 | 11 | 4 | 10 | 1 | 0 | 0 |
| $100 \leq U < 200$ kV | 18 | 2 | 2 | 18 | 14 | 6 | 13 | 1 | 0 | 0 |
| $200 \leq U < 300$ kV | 16 | 0 | 1 | 15 | 14 | 2 | 14 | 2 | 1 | 0 |
| $300 \leq U < 500$ kV | 17 | 0 | 2 | 15 | 14 | 3 | 12 | 2 | 4 | 0 |
| $500 \leq U < 700$ kV | 11 | 0 | 2 | 9 | 10 | 1 | 8 | 2 | 0 | 0 |
| $\geq 700$ kV | 1 | 0 | 1 | 0 | 1 | 0 | 0 | 1 | 0 | 0 |
| Total | 77 | 3 | 9 | 71 | 64 | 16 | 57 | 9 | 5 | 0 |

Other checks on the tap changer are manual operation, local electrical operation, remote electrical operation, automatic parallel operation, and a check of the limit switches at the ends of the range. Carry out secondary injection of the automatic tap change scheme to verify the settings and dead bands are operating correctly.

The cooling system should be checked by setting and proving the temperature for operation of the fans and pumps and also the winding temperature alarm and trip values. Ensure that the pump filters are fitted correctly and the pump flow is in the correct direction. The winding temperature indicator should be checked by secondary injection and the oil temperature also checked.

The Buchholz alarm and trip should be tested by injection of air and operation of the relevant flag relays verified.

On transmission system transformers, it is now common practice to perform a frequency response analysis (FRA) test, probably a swept frequency analysis (SFRA) test during the commissioning of the transformer. The SFRA test is carried out by applying a voltage to one end of a winding and the output voltage at the other end of the winding is measured, the other windings being open circuit during the test. The voltage is kept the same and the frequency of the applied voltage is swept through a range of frequencies and the output voltages recorded and plotted on a graph. This effectively creates a “fingerprint” for the winding which can be compared against the result obtained in the factory. A change in the “fingerprint” will indicate any movement of the windings, which may have occurred during transport. The commissioning “fingerprint” can also be used for comparison with later tests during the life of the transformer to detect if any damage has occurred to the transformer while it has been in service.

### 49.3.8 Power Cables

Typical checks and tests carried out on power cables are:

- Visual inspection of the cable. Check that the cable is in accordance with the specifications and that there are no signs of damage on the exterior of the cable. All connection points should be checked visibly. The route of the cable should be checked to ensure that the cable bending radius requirements have not been exceeded. If slip-over CTs are being used ensure that the connections are correct to enable correct functioning of the CT. Check that the cable has suitable and correct identification markers.
- Perform resistance measurements on all connections, if possible, to ensure a good connection.
- Carry out an insulation resistance test with a high voltage (15 kV). Each phase should be measured with the other two phases connected together and to earth and all screens, etc., earthed.
- A cable continuity test should be carried out on the conductor and also on the screen or shield.

- A cable pressure (HV voltage) test should be carried out. The purpose of this test is to maximize the reliability of the newly installed cable system by detecting defects before the circuit goes into service. This is normally achieved by converting the latent defects into detectable faults during the test and also by detecting the latent defects as they are being converted.

  The conversion of the defects into faults is usually achieved by putting the cable under electrical stress. This will in many cases start a partial discharge which can be detected, and this will lead ultimately to breakdown of the cable insulation.

  Selecting a suitable voltage and source of voltage can be quite difficult because of the high capacitance of the cable. The voltage must be high enough to cause the defects to breakdown or to create detectable discharge during the test, but not so high as to degrade healthy circuits.

Sources of the test voltage which have been used are DC, AC offline using a suitable resonant test set, AC power frequency online, AC very low frequency (VLF), and damped AC (oscillating wave). Each of these methods has its advantages and drawbacks which are summarized in the following paragraphs.

**DC Test**

This method of testing was very widely used in the past because it solved the problem of reactive power associated with the capacitance of the cable. It also has the advantage that the test equipment required is relatively small and inexpensive and easy to transport. It has the disadvantage that it does not involve polarity reversal and so can never be as effective as AC testing. With the growth in the use of XLPE cables, it has gone out of favor as it has been found to be quite inadequate in testing these types of cable.

**AC Off-line Test**

This method of testing using voltage at or near power frequency is advocated in numerous IEC and other standards. The recommended voltages vary typically between $1.1U_0$ and $2.0U_0$, but a common and sensible suggestion is the use of $1.7U_0$ for a period of 60 min. This method of testing has the advantage that the voltage is high enough to cause accelerated aging of the defects, and because it is at or near power frequency, the aging mechanism is directly related to that which the cable will see in service. This method using a resonant test set is well established and well proven. However, the major disadvantage of this method is that the testing equipment required is very large, expensive, and difficult to transport, typically requiring one or more large articulated low loaders to bring it to site.

**AC Online Test**

This method which is effectively a soak test at normal voltage is accepted by some utilities. The obvious advantage of this method is that it is quick and easy to carry out and does not require any special test equipment. Furthermore, the test is carried out at power frequency. There are, however, some significant disadvantages. If a failure occurs it will almost certainly be destructive and destroy all evidence of the initial cause of the problem. It may also be dangerous for personnel in the vicinity of the fault. In addition, as the test is carried out at normal voltage, there is no accelerated aging of any defects. If this method of testing is carried out, it should be combined with partial discharge investigations to assist in finding any incipient faults.

**Very Low Frequency Test**

This method of testing addresses the problem of bulky test equipment (similar to DC) by applying a test voltage at a frequency of typically 0.1 Hz or even 0.01 Hz. As the reactive power required from the test set is proportional to the frequency, the test sets are small and much cheaper than power frequency sets. However, testing at very low frequency can take a long time to yield results. VLF testing at 0.1 Hz is widely used at 11 and 33 kV, and good results have also been obtained at higher voltages. VLF testing can also be combined with partial discharge monitoring.

**Oscillating Wave Test**

This is done by connecting an inductor in series with the cable under test and then charging the cable from a DC source. When the cable is charged, a high speed solid-state switch is used to connect the inductor in parallel with the capacitance of the cable to form a resonant circuit. By tuning the reactor to the cable capacitance damped oscillations at near-power frequency occur and it is these oscillations which provide the test voltage. This form of testing has the advantages that elevated test voltages can be used and the voltage is approximately power frequency. The equipment required for this type of test is much smaller and cheaper than for resonant AC testing and it can be used in conjunction with partial discharge.

**Partial Discharge Testing**

With the exception of the DC test, all of the above test methods can be combined with partial discharge testing which enables signs of distress from the defects to be detected before failure occurs. During commissioning tests, PD is usually carried out at elevated voltages offline at or close to power frequency. For offline PD testing, it is necessary to disconnect the cables, short out any sheath voltage limiters, and remove the cross links to create a continuous earth sheath. With an offline test using an external test voltage source, it is possible to detect partial discharge inception voltage (PDIV) and also partial discharge extinction voltage (PDEV). Partial discharge testing can also be done online but then only at rated voltage and so it is not possible to detect PDIV and PDEV; however, it does have the advantage that it can provide a continuous monitoring of in service cables.

Because of the complexities of carrying out HV pressure testing on relatively long EHV cable, the method to be adopted should be discussed between the cable supplier and the utility at an early stage to choose the most appropriate method for the particular installation.

### 49.3.9 Earthing System

The earthing system is a very important part of the substation to ensure the safety of personnel and the public when earth faults occur. When the substation is first commissioned, the following tests will typically be carried out.

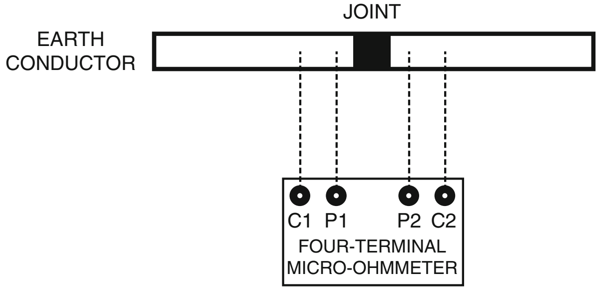
**Earth Conductor Joint Resistance**
This test will be carried out on each joint in the earthing grid to ensure that they are properly connected together. The test is carried out using a four terminal micro-ohmmeter (Ductor) test set with a current injection of at least 10 A (Fig. 49.2).

**Equipment Bonding Tests**
To ensure that each item of plant is properly bonded to the earthing system, a similar test using a four terminal micro-ohm meter (ductor) shall be carried out between the earth grid and a bonding point on the item of plant.

**Resistance of the Earth Grid**
This is a very important parameter as the rise of earth potential at the site under earth fault conditions is equal to the fault current multiplied by the substation earth resistance. This test is usually carried out using a four-terminal composite earth tester with very long leads typically of the order of 1000 m. The method is known as the fall of potential method. The tester injects current between the earth grid and a remote point, and measurements of the voltage are taken at different distances in between. The test set up is shown in Fig. 49.3.

The C1 and P1 probes of the tester are connected to the substation earth grid. The C2 probe is located approximately 1000 m away along a route which ideally is free from any buried electrical cables or pipes. The P2 probe is located at a distance of 80% of the distance to the C2 lead and connected to the tester and the voltage measured. The P2 lead is then disconnected from the meter and relocated at a new distance of 70% and then the resistance again measured. The distance between the current and voltage leads should be at least 300 mm and they should not cross. This process is repeated for distances of 65%, 60%, 55%, 50%, 40%, 30%, and 20% so that a graph of resistance can be plotted against distance. There are different methods of deriving the grid resistance from these measurements. One simple method is to

**Fig. 49.2** Connections for earth conductor joint resistance measurement



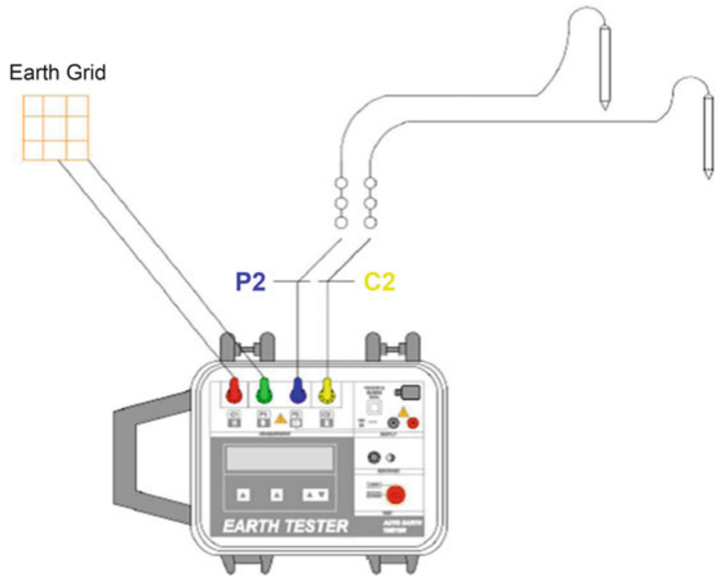



**Fig. 49.3** Typical connection for the fall of potential method of measuring earth resistance

derive from the graph the resistance when the distance is 61.8% and this is the value required. Another method is known as the slope method. This derives the slope coefficient using the 20%, 40%, and 60% measurements in the following formula:

$$\mu = \frac{R_{60\%} - R_{40\%}}{R_{40\%} - R_{20\%}}$$

The value ($\mu$) obtained should lie in the range 0.1–2. If the value falls outside of this range, it may mean that the location of the current probe was not sufficiently distant from the earth grid being measured and so it should be relocated and new measurements taken.

Another way to derive the earthing resistance is to use a specialist earthing simulation software to interpret the results.

**Tower Earth Continuity and Resistance Measurement**

A test may be carried out to check that the terminal tower is connected to the substation earthing grid and if so the resistance of the connection is measured. The continuity check is done by injecting current between the grid and each leg of the tower in turn and checking the current obtained. The leg with the highest current is where the earth continuity conductor is connected. If all legs give the same value, then the tower may not be connected to the earth grid. The resistance measurement can be obtained by injecting current between the tower and the earth grid and measuring the voltage across the connection.

**Electrical Separation Between Separate Earths**

There may be occasions where it is necessary to check that two earths are not actually connected. One example of this is where the substation fence is intentionally earthed separately from the substation earth grid. In order to check that this has been achieved, the earth resistance of the grid and the fence should be measured separately using the fall of potential method mentioned above. Then measure the earth loop resistance using a four terminal micro-ohm meter with one set of current and voltage leads connected to the fence and the other set connected to the earth grid. The earth grids can be considered as separate if the measured resistance from this latter test is greater than 0.8 times the sum of the fence and grid earths added together. If the value is less than this, then there is inadequate separation between the two earths.

**General Safety Precautions**

Working on an earthing system is potentially hazardous and special care is needed. The work should be carried out in accordance with the safety rules pertaining to the site together with any additional guidelines defined for impressed voltages. The staff carrying out the tests should wear insulated gloves and dielectric shoes. The main sources of danger arise from potential differences existing between different earthing systems or even different parts of the same earthing system under earth fault conditions. The work should not be carried out if it is considered that an earth fault is likely to occur, for example, work would not proceed if there is a warning of lightning in the area or when there are planned switching operations. Approved safe methods and tools should be used when making or breaking any connections to or within the earthing system.

With the very long test leads involved, induced voltages may occur if the test leads are run in parallel with a high voltage overhead line or cable for any distance. The tests involving long leads should be carried out by two people with good communication established between them.

### 49.3.10 Instrument Transformers

**Current Transformers (CT)**

The polarity of each CT should be checked by carrying out a DC “flick” test and a loop resistance test should be carried out on the CT circuit. A primary injection test should be done to check the ratio of the CT. If the injection is made between one phase and another, the relative polarity of each phase CT can be checked and a check made that there is no current in the residual connection. It can be advantageous to combine this with an operation check of the protection relays if sufficient current can be injected to cause operation of the relay. Each of the secondary windings should be insulation resistance tested to check the insulation resistance by removing the earth link from the CT circuit under test while leaving all other CT earth leads closed. A measurement of the secondary resistance of each secondary should be made together with a magnetization curve. Where there are several different cores in the CT stack, this enables the different classes of CT to be identified.

**Voltage Transformers (VT)**
A primary injection test to check the ratio can be done by applying a voltage from the LVAC supply and checking the output voltage of each secondary winding. Each secondary winding should be insulation resistance tested to check the insulation resistance. A check should be made to ensure that there is a clear isolation point on the secondary side to prevent back energization when a permit for work is issued.

### 49.3.11 Protection Equipment

**Insulation Resistance**
Before energizing any protection circuits, a full set of insulation resistance measurements should be made, preferably using a 1 kV insulation resistance tester, and the tests carried out with all other circuits earthed. It is important to check that any electronic relays or telecommunications equipment which may be damaged by the test voltage are removed or protected against the voltage. The tests should include the insulation resistance of or between:

- CT circuits
- VT circuits
- DC circuits
- CT and VT circuits
- DC and CT circuits
- DC and VT circuits

When carrying out the tests, the schematic diagrams should be consulted to see how to include all of the circuit in the test.

Individual circuits, e.g., trip, close, and alarm, should be tested to earth and between poles before inserting the fuse and link or switching on the MCB.

**Secondary Injection**
Before commencing the electrical tests on relays, they should be thoroughly examined visually and checked that all packing material has been removed.

The purposes of the secondary injection tests are:

- To check that the relay has not been damaged in transit
- To check the relay performance against specification at the service setting
- To check the relay performance as part of an overall scheme
- With modern numerical relays to check that the correct logic and software files have been selected and to prove the performance in accordance with the required scheme

The DC and tripping should be disabled during the secondary injection testing and the voltage used for injection should be an undistorted sine wave. The injection will normally be made into the circuit so that the CTs will be in parallel with the relay. Care needs to be taken to ensure that the primary of the CTs is not effectively shorted by having earth leads connected on both sides of the CT.

Current operated relays should have the pick-up and drop-off values recorded and if appropriate the pick-up and drop-off times. To avoid overheating of the relay, it may be useful to set up the current value with the relay shorted and then remove the short and apply the current through the relay. Relays which have a timing characteristic should be injected at the plug setting and the timing of operation recorded.

Voltage operated relays in high impedance schemes should be injected with all associated relays, setting resistors, and CTs in circuit.

Complex relays such as distance protection or biased unit protection should be injected using an appropriate test set and in accordance with the manufacturer's instructions. The object should always be to ensure that the relay performs correctly as expected at the service setting.

Secondary injection should also be carried out to prove the correct operation of automatic voltage regulating schemes, synchronizing, under-frequency, etc., and also the correct functioning and readings on local and remote instruments.

**Functional Checking and DC Operations**

This needs to be done by an experienced commissioning engineer working logically and methodically through the schematic diagrams and proving the correct operation or nonoperation of each item in a chain. The checks should be carried out both in the "positive" and "negative" mode. A "positive" check means that the device is in the correct position for operation and that operation occurs. A "negative" check is that the device is not in the correct position for operation and the device does not operate. Any devices which should operate at specific values, e.g., low hydraulic pressure to block a CB operating mechanism, should have the operating levels proven. The minimum operating voltages for closing and tripping of circuit breakers should be checked to ensure that they are in accordance with the specified requirements. Where trip circuit supervision is fitted, in addition to the normal positive and negative checks, the monitoring current flowing through the circuit for CB open and CB closed should be measured.

The correct timing of any time delayed relays whether they be time delayed on pick up or time delayed on drop off should be verified. With automatic sequences such as auto reclosing, the operation of the scheme should be fully checked both positively and negatively. Any timed interactions between schemes such as trip relay reset with auto reclose must be fully proven.

The operation of any transformer mechanical devices such as Buchholz, oil temperature pressure relief should be proven and the flag or other indications checked.

## 49.3.12 Control, Indications, and Alarms

All control, indications, and alarms circuits should have their wiring insulation resistance tested before commencing with the functional checks.

The operation of all circuit breakers, disconnectors, and earth switches should be proved from all possible operating locations preferably in the following order:

- Manual operation
- Local electrical operation
- Remote operation within the substation (standby control)
- Automatic operation (if applicable)
- Remote operation from control center

During these proving tests, the correct functioning of selector switches and any other blocking contacts should be proved both positively and negatively.

Other control functions such as tap changer control, protection in/out switching, etc., all need to be verified.

The indications of the status of all circuit breakers, disconnectors, and earth switches should be proven at all locations. In addition, where a "don't believe it" (DBI) indication is available, the correct functioning of that feature should be proven. Indications are usually taken from the auxiliary contacts on the devices, and for certain functions the timing of the operation of the auxiliary contacts relative to the device main contacts can be important (e.g., disconnector auxiliary switches used for CT switching and tripping contacts in high impedance busbar protections). In such cases the correct timing of the auxiliary contacts should be checked.

The operation of all of the alarms should be performed and the legends checked at all locations. It is quite common for a number of alarms which are enunciated individually locally to be grouped before being sent to a remote location. It is important to check that the correct group alarm is activated.

As there can often be delays in having the communications to the remote control center activated the remote operation, indications, and alarms can all be proved to the marshaling kiosk so that the only unproven part is the communications.

### 49.3.13 Other Equipment

It is not possible in this short section to cover the commissioning of every type of plant so only those items which are common to the majority of substations have been covered. Other items such as surge arresters, capacitors, reactors, and resistors will be found in substations. For these items of plant, the manufacturer's advice should be followed together with any utility procedures, which may have been developed from experience. The recording of all relevant details of the tests/measurements in the results is important so that they can be used later for fault finding and maintenance. As an example of this, when measuring the capacitance of each unit for internally fused capacitors, it is important to record the ambient temperature as the capacitance varies with temperature.

### 49.3.14 Overall Checks, Interlocking, Synchronizing, etc.

The majority of the tests mentioned to date can be carried out on a bay by bay basis. However, there are some things which encompass the whole substation. Some examples of these are:

- Interlocking – whereas some interlocks are bay specific others such as earth switches associated with busbars and on load transfer for busbar selector disconnectors involve bus wiring throughout the whole substation.
- Synchronizing – this will usually involve bus wiring throughout the whole substation to enable the voltage selection to be effective.
- Hard-wired busbar protection will involve bus wiring of CT and trip circuits throughout the whole substation.

These tests should be done towards the end of the program when the circuitry is likely to be complete.

It should be noted that with modern computer control devices, much of the above-mentioned bus wiring may be avoided and the logic required is built in electronically to the computer control device or numerical busbar protection relay. This does not usually present any particular problems for the initial commissioning of green field sites, but when modifications are required at a later date, this can be a difficult process particularly for interlock schemes. The problem is that when software is modified it is only too easy to accidentally modify something which should not have been modified. It is not feasible to repeat all of the positive and negative interlock checks throughout the entire substation so the usual solution is to create a mimic of the entire substation in the manufacturer's works and carry out the tests using the updated software on that. When this is proven satisfactorily, the new software can be uploaded into the control equipment on site. The problem is not so difficult with synchronizing or busbar protection.

### 49.3.15 Final Pre-energisation Checks

When all of the Pre-commissioning testing has been completed, a thorough check should be made to ensure that all test leads, wiring loops, etc., used for testing have been removed. The settings on all relays should be on their service settings and all fuses, links, and MCBs in the correct position for service. It should be noted that some of the settings will be modified for the Stage 2 commissioning, but the changes to these settings should be part of the switching program. Any safety documentation (permits for work, sanctions for test, limitation of access, etc.) should be cleared and all personnel made aware that the site is being prepared for energization.

## 49.4 Stage 2 Energization and Final Commissioning

When all of the Pre-commissioning tests have been completed and in order to finally confirm that everything is fully ready for service, it is necessary to energize the equipment from the system then Stage 2 Commissioning will commence.

### 49.4.1 Preparation of Switching Program

In order to ensure that the first energization of the substation or new bay takes place in a properly organized and controlled manner, it is necessary to prepare a detailed switching program. The program will detail any specific checks which have to be made before the equipment can be switched on. This may well include applying temporary commissioning settings onto protection equipment to ensure that if anything goes wrong the fault will be cleared very quickly. In the past, this typically meant setting down the time multiplier settings on overcurrent and earth fault relays to a setting of 0.1. With modern relays which have multiple sets of settings, then the specific settings for commissioning should be selected on the relays. This selection of the commissioning settings and the return to service settings should be entered in the switching program.

The energization program is usually a step-by-step process. The system voltage will be applied to a short length of busbar or one item of plant at a time. When an item of plant is energized for the first time, some time is allowed to ensure that all is well. The voltage and currents will be checked to see that there is nothing untoward. A visual and audible check of the equipment will be made before moving on to energize the next item in the sequence. As energization is usually achieved by closing a circuit breaker then if the section between the circuit breaker and a disconnector has been energized, then before closing the disconnector the circuit breaker will be opened, the disconnector closed and then the circuit breaker closed again to energize the new equipment beyond the disconnector. In producing the switching program, care has to be taken to ensure that during this step by step process unusual or unacceptable conditions do not occur. One particular condition which can occur during first energization is ferroresonance of voltage transformers particularly with GIS, but it can also occur with AIS substations. If an electromagnetic voltage transformer is connected to a short section of busbar and this is energized through a circuit breaker which has grading capacitors fitted, then ferroresonance can occur between the grading capacitors and the inductance of the VT. When this occurs, very large currents can flow and destroy the VT in a few seconds. This can be a very embarrassing situation during the commissioning process. It is very important during the preparation of the switching program that the potential for such a condition is checked and avoided. The switching program must ensure that this along with checking that at no stage in the program is any item of plant subjected to any condition that it has not been designed to achieve occurs. The switching program must be fully agreed between the contractor, the utility site staff, and the utility control center before any switching takes place.

### 49.4.2 Authorization to Proceed to Stage 2

When the switching program has been agreed and everything is ready to commence the energization of the substation or bay, it is usual for a formal document to be signed to acknowledge this. This document will usually be signed by the contractor and the utility site staff to state that all tests that could reasonably be done with the equipment in the de-energized condition have been completed and that it is now necessary to energize the equipment to finalize the commissioning process. At this stage, a final check should be made that all safety documentation has been cleared.

### 49.4.3 General Principle

When the authorization to proceed has been given, then the energization process can commence. This will normally be controlled from the utility control center who will issue switching instructions to their site staff in accordance with the agreed switching program. The condition of the equipment at each step in the process should be recorded. The purpose of this stage is to ensure that all of the equipment when energized does not suffer any distress and also to check the phasing of voltage transformers and the stability of unit protection schemes to ensure that the polarities are correct such that the protection will remain stable for faults external to the protected zone but trip for faults within the protected zone.

### 49.4.4 Soak Testing

Once certain equipment has been energized, it is quite common for it to be given what is called a soak test. This is typical for power transformers which may be put on soak, i.e., energized at normal voltage for 12 or 24 h with the LV circuit breaker open. At some stage during the soak process the tap-changer should be operated throughout its full range and the voltages checked. A check should be made of the Buchholz to ensure that there has not been any gassing throughout the soak test or an oil sample may be taken to assess the oil for the presence of gas that might indicate an internal fault.

In some cases, a soak test may be applied to power cables and possibly even to GIS. This soak test may be in addition to previous offline pressure tests or in some cases in lieu of an offline pressure test. Checking for partial discharge during these soak tests can be very advantageous.

### 49.4.5 Load Testing

In order to ensure that the system load conditions are accurately represented in the CT and VT secondary circuits, relays, transducers, etc., it is necessary to perform a number of on load tests.

It is normal to carry out phase rotation checks to ensure that this is correct. The phasing will also normally be checked between one set of VTs on one circuit and another set of VTs on another circuit. Checking of the synchronizing should also be carried out.

For unit protection, an operation and stability test should be carried out. If there is sufficient load current then in addition to checking that the relay currents are correct for stable operation, the CTs should be reversed to cause operation of the relay. If there is not sufficient load current, then checking of the currents to show that they have changed from the stable condition may have to suffice. For on load checks on transformers, it should be noted that some current may be flowing in the operate circuits depending upon the tap position of the transformer.

For directional relays, a check on the restraint should be made again reversing the CTs to cause operation if possible.

Checks of the currents in all CT circuits to see that the circuits are complete and that there are no test leads left in place. The measurements can be made by using split plugs in relays or test blocks where available or using clip on ammeters. A check should be made to ensure that there is no residual current under load conditions.

Trip testing of the circuits can be performed and a check made of all relevant inter-tripping. Furthermore, for overhead lines or composite circuits, a check can be made for correct operation of the auto-reclose sequence including any associated auto isolation of equipment.

Many utilities take the opportunity at this stage to check the substation using a thermo-vision camera to identify if there are any hot joints. The thermo-vision camera will also be able to identify any hot spots in the reinforcing bar if induced currents associated with air cored reactors are flowing in the rebar.

On completion of the on load testing a final check should be made to ensure that all settings have been returned to the correct service settings, all test leads removed and isolation links replaced and all control and selector switches in the correct position and locked as appropriate.

### 49.4.6 Handover for Operation

After satisfactory completion of the load tests a formal document should be completed and signed stating that all necessary on load checks have been completed and that the substation is now ready for operational service. This will typically be the time the asset or substation is officially connected to the network and available for any further testing or commercial loading.

## 49.5 Documentation

When commissioning is complete, a full set of documentation should be compiled. This documentation will include:

- A complete and accurate set of marked up as built drawings for the site. These should include not only schematic diagrams but also wiring diagrams/schedules, cabling drawings, etc.
- A record of the service settings applied to all relays.

- A set of all of the test record sheets for all of the Pre-commissioning tests signed by the person who performed the test and signed also by the person who witnessed the test.
- A set of all the records of the on-load tests carried out at Stage 2 of the commissioning.

This documentation forms the backbone of information required for the management of the substation during its operational life.

## References

CIGRE Technical Brochure No 514: Final report of the 2004–2007 international enquiry on reliability of high voltage equipment, Part 6 – Gas Insulated Switchgear (GIS) practices (2012)

IEC 62271-100: High-voltage switchgear and control gear – Part 100: Alternating-current circuit-breakers (2006)

IEC 62271-1: Ed. 1.1: High-voltage switchgear and control gear – Part 1: Common specifications (2011)

# Substation Maintenance Strategies

# 50

Ravish Mehairjan, Mark Osborne, and Johan Smit

## Contents

50.1 Definitions .......... 997
50.2 Maintenance Strategies .......... 998
50.2.1 Failure-Based Maintenance (FBM) .......... 999
50.2.2 Time-Based Maintenance (TBM) .......... 999
50.2.3 Condition-Based Maintenance (CBM) .......... 1000
50.2.4 Reliability Centered Maintenance (RCM) .......... 1001
50.2.5 Risk-Based Maintenance (RBM) .......... 1003
50.3 CIGRE Survey of Maintenance Strategies .......... 1004
50.4 Maintenance Management Strategies .......... 1004
50.5 Developments in Maintenance Management .......... 1006
50.6 Key Elements of Maintenance Management .......... 1008
50.7 Developing Future Strategies .......... 1009

## 50.1 Definitions

A substantial amount of literature is available from various resources and industries in the field of maintenance management. A comprehensive overview can be found in references [22] and [23]. In this chapter, common terminology and definitions are set out which are relevant and applicable in the field of maintenance management.

R. Mehairjan (✉)
Corporate Risk Management, Stedin Group, Rotterdam, The Netherlands
e-mail: Ravish.Mehairjan@stedin.net

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl

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Definitions are given in IEC 60300-3-14 of 2004 [24]. In IEC 60300-3-14 of 2004, application guide, maintenance and maintenance support, maintenance is defined as: "*the combination of all technical, administrative and managerial actions during the lifecycle of an item intended to retain it in, or restore it to a state in which it can perform the required function.*"

Maintenance management is defined as: "all the activities of management that determine the maintenance objectives or priorities, strategies, and responsibilities and implement them by means such as maintenance planning, maintenance control and supervision, and several improving methods including economical aspects."

From these definitions, it can be found that in the current business environment, maintenance and maintenance management are considered as highly complex fields involving many disciplines within a company such as operations, information technology, economics, safety, risk, analytics, accounting, etc. [23]

In IEC 60300-3-14 the following definitions are given: [24]

- Maintenance action or maintenance task is defined, as: "basic maintenance intervention or sequence of elementary maintenance activities carried out by a technician for a given purpose."
- Maintenance policy is defined as: "*rule or set of rules describing the triggering mechanisms for the different maintenance actions.*"
- Maintenance concept is defined as: "set of maintenance policies and actions of various types and the general decision structure in which these are planned and supported."
- Maintenance support is defined, as: "resources required to maintain an item under a given maintenance concept and guided by a maintenance policy."

## 50.2 Maintenance Strategies

In principle, there are two types of maintenance actions. It can either be *corrective* or *preventive*. A brief description of each of these maintenance activities is given according to the European standard EN 13306:2010 [25]:

**Corrective Maintenance**: Corrective maintenance is essentially leaving all assets running until failure and then replacing the part of the assets that have failed. During the time, corrective maintenance is being scheduled and performed (usually referred to "break-in," because they "break-in" to the schedule prepared), the asset is inactive. As a general rule, a breakdown is often ten times more expensive compared to the situation that the failure can be identified and corrected (or prevented) in a planned and scheduled manner. Until now, the majority of components in distribution networks remain correctively maintained. However, with the adoption of Asset Management (AM), utilities are becoming aware of the changing requirements for maintenance. Corrective actions are difficult to predict because failure behavior is stochastic and outages in a network causing interruptions are usually unforeseen. As identified in the survey of maintenance trends reported in Technical Brochure 152 [1], for some utilities corrective maintenance is no longer acceptable as a deliberate strategy. The consequences include not just the loss of an asset, but also damage to adjacent assets, outages, and business interruption costs, safety, and environmental impacts, all with a need for regulatory reporting and damage to public image.

**Preventive Maintenance**: The primary upgrade from corrective maintenance to preventive maintenance is by means of maintenance plans and schedules. Broadly speaking, preventive maintenance plans describe the methods of inspections and maintenance tasks which can efficiently improve the reliability of physical assets. A shift from corrective to preventive maintenance will, inevitably, require some initial investment; however, it will eventually result in moderation of the total volume of planned work and will allow for control of maintenance hours and workload. When preventive maintenance is applied on an asset item, it is called a preventive task. Subsequently, the timeline of the preventive task in an asset population is called the preventive schedule. This is why preventive scheduling will, eventually, result in arranging maintenance resources in advance, which, in turn, will considerably accelerate maintenance delivery and reduce operational costs (note, however, that an initial, increased, investment in the transition period is possible, but will decrease once in a controlled period) [26].

Moreover, each of these maintenance actions or task categories can be triggered by a mechanism, which is usually denoted as a maintenance policy. Examples of maintenance policies are: *failure-based maintenance (FBM), time-based maintenance (TBM), condition-based maintenance (CBM), and risk-based maintenance (RBM).* A maintenance policy, on the basis of a trigger, determines *why* a maintenance task (corrective or preventive) is assigned [27].

### 50.2.1 Failure-Based Maintenance (FBM)

A maintenance action is carried out only after a breakdown. The trigger is therefore purely reactive and with FBM no planning is possible. In this context, FBM requires a sound spare-parts policy.

### 50.2.2 Time-Based Maintenance (TBM)

A policy in which precautionary maintenance actions are carried out is triggered by a predetermined scheduled interval. This is a periodic policy. At time intervals recommended mainly by the original equipment manufacturer (OEM). The time intervals are decided according to asset type and fixed for the whole lifecycle (usually with reference to manufacturer instructions and updated with historic operational and failure behavior). In literature, this policy is commonly denoted as a preventive policy [27]. The periodic policy can also be triggered by the use of the component, such as number of switching actions or operating hours. In general, the preventive action coming from this policy may constitute of component replacements or may also be cleaning, lubricating, or adjusting, etc. This is the traditional preventive strategy and derives from requirements in the OEM warranty. Since the manufacturer designs the same product for a large panel of users having a range of operating environments, the OEM must select worst case/most challenging situations. This means that for most users the maintenance timing is conservatively based. But this approach is justified on several counts:

- The future climatic conditions and service applications are not specified and these could be severe in some cases.
- Operational conditions, such as load factor or short circuit level, could approach nominal rated conditions. The equipment may be subjected to frequent short circuits.
- The equipment may be installed in a critical position for the network.
- A warranty must be provided for typically 3–5 years and some defined maintenance regime must be specified to protect the OEM.

Thus, for the manufacturer and user, the TBM schedule typically proposed offers the lowest risk exposure. It has the significant advantage of being easily planned which is a consideration if the maintenance requires an outage. However, these risk-averse policies do imply higher costs and users generally define their own time intervals for use once the warranty periods have passed. In some countries, user committees have been formed and have created national maintenance policies. Usually these would have been indicated by shared service experience and common operating environment.

### 50.2.3 Condition-Based Maintenance (CBM)

Basically, condition-based maintenance differs from time-based maintenance in the sense that a shift is made in scheduling methods, namely, from a periodic method to a "fully" predictive method. Therefore, CBM is a predictive policy. Being predictive refers to estimating the probability of failures on assets. With condition-based maintenance, an early indication of an impending failure (by applying condition monitoring, diagnostics or inspection methods) can be detected and the consequences of an unexpected failure can be avoided. CBM can use fairly low-level methods such as human senses for inspections (denoted as detective-based maintenance) or deploy sophisticated monitoring and diagnostic tools (denoted as predictive-based maintenance). More advanced is the use of various monitoring parameters and network condition to predict remaining lifetimes of component (denoted as prognostics or health-based maintenance) [28]. CBM has its key role where the diagnostics are able to identify problems very early in the deterioration stage. This will allow a judgment on the state of each element in the circuit end to be made and so justify a planned outage for bundled work. But there are some failure modes that the transition time between a good to failed condition is too rapid to allow intervention. In this case, other strategies need to be applied. There will be a cost saving due to unnecessary "routine" TBM maintenance work being avoided. But there will be increased cost too:

- From capital and operating costs of the surveillance methodology selected.
- By needing to determine the appropriate response strategy and interpret and handle data.
- A higher skill level is required to apply Failure modes, effects, and criticality analysis (FMECA) and then assess the data rather than with time based work determined by rote.
- From a poorer outage and work planning capability, leading to poorer resource utilization.

There is often a need to align maintenance planning to maximize system availability and fit in with outage and constraint management. Thus, there are practical difficulties trying to do all maintenance by CBM and why other methods were developed, such as RCM and RBM.

### 50.2.4 Reliability Centered Maintenance (RCM)

This technique is most attractive where reliability is the important driver, e.g., in safety critical industries. Originally developed for new assets RCM looked to identify risk, and if possible to design it out, either at the asset or network stage. The latter is an important differentiator from TBM and CBM strategies in that it includes not only an asset and its deterioration, but as part of a system. It then identifies the link to the consequences of failure within the "system" to the network outside. It is the assessment of system failure modes on the network that leads to prioritization of tasks, such as maintenance and asset replacement, together with the choice and timing of condition assessment tasks that indicate the need for a decision. A second stage in the application of RCM proved necessary to modify the methodology derived for new assets and build in service experience, sometimes called a "back fit." Undertaking this RCM process relies upon having knowledgeable site staff able to work in quality circles at each substation. It leads to a very site-specific maintenance profile, albeit achieved using significant resource.

The greatest impact of RCM has been in industries where tailored time-based routines can be applied – where failure rates are well defined and consistent within the equipment category. The birth of RCM can be traced back to the late 1950s and concerns about aircraft reliability. The evolution of this work was eventually published as a United Airlines report in 1979 by Nowlan and Heap [29]. Success brought down costs dramatically for most airlines while improving reliability.

Originally it was intended that RCM would be based around the use of reliability statistics such as failure rates and life expectancy. Nowlan and Heap proposed six failure life patterns as shown in Fig. 50.1 in their report, and they derived data indicating the incidence of each and their data are listed under column “UAL.” This table is taken from a more comprehensive US Navy report [30]. Other studies in this table include the Broberg report also relating to aircraft and two others from US Navy: MSDP for surface ships and SSMD for submarines.

Even in the classic report from Nowlan and Heap, only a small proportion of failure rates with age have shown evidence of wear out. Characteristics A and B are attractive, indicating an onset of unreliability when failure rates increase significantly. This would allow a concept of a defined lifetime for an asset group. However, apart from one of the Navy reports, this widely held view is not substantiated by evaluation. Only Navy values listed under “MSDP” showed an age-related failure, and this was where one cause, saline corrosion, dominated. The rest followed a mainly random failure rate, D, E, and F.

Many have tried to force limited population failure data for substation assets to demonstrate applicability of a bathtub-like curve. But where a random failure rate is more appropriate throughout life, the best that such curves can tell us is how a family of assets perform on average but not how a specific asset is going to perform. The main reason is that for complex equipment such as transformers and circuit breakers, there are many causes and modes of failure and each will change in importance over lifetime as may be seen in publications in CIGRE brochures from A2 and A3 groups. This will lead to an aggregation of failure

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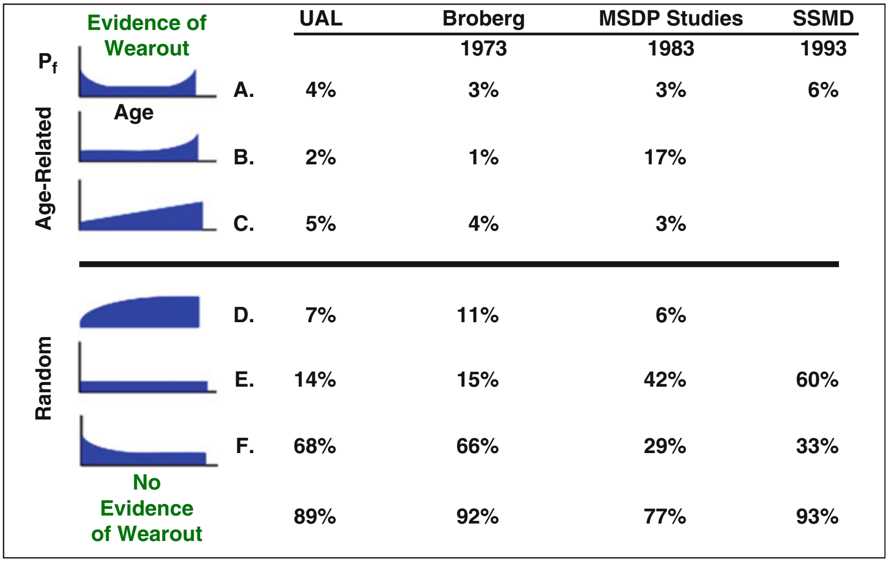


**Fig. 50.1** Failure data from reference [30] – a publically available US navy report

characteristics and appearing as a more random failure rate with time when viewed at a population level. This has led RCM practices to be linked with TBM and CBM methods, devised after failure mode and effects analysis to indicate the timescales for deterioration of a specific mode or diagnostics to detect onset of deterioration of each critical mode. This is not to imply that age-related modes do not occur, but that they need to be managed at an asset level.

But there are always going to be exceptions. For some utility assets such as medium voltage cables, the design is fairly homogeneous and here pronounced wear out patterns are typical and failure data confirms this. Utilities are then able to place a life-limit on age of cables and retire them based on this.

### 50.2.5 Risk-Based Maintenance (RBM)

The state-of-the-art maintenance policy is the risk-based version, which is guided by the principles of risk management. RBM develops the system reliability and network impact within RCM to a further stage. In doing so, it draws upon RCM, CBM, TBM, and CM and uses aspects from each, where appropriate. Its goal is to minimize costs of maintenance to achieve an acceptable performance, to increase the mid- and long-term profitability under acceptable risk conditions. Thereby a balance is sought between performance, cost, and risk. In practice, it means assessing the condition of high-risk components with greater frequency and thoroughness and then to maintain in a superior manner. This allows costs for both actions and consequences to be introduced into the analysis, so leading to optimization in terms of return on investment. Perhaps in some situations it really is more cost effective to do nothing and wait for repair on failure. With RBM the focus is on circuits, sites, and equipment, basing the program of care on their overall impact. Regulation is an important driver.

A risk is composed of a stimulus (i.e., the root cause) and its consequences. The risk-based approach refers to the quantitative assessments of (1) the probability of stimulus (event), and (2) on business values (Key Performance Indicators (KPI)) evaluated consequences. In the planning of maintenance, the stimuli are the failure modes for risk-based maintenance, which brings the term failure mode and effect analysis (FMEA). In scheduling risk-based maintenance, the potential failures on asset items are the stimuli. The probabilities of these stimuli are highly recommended to be derived from condition diagnosis (hence, the importance of the upcoming role of condition monitoring in a risk-based management regime). However, in practice, FMEA is mainly based on failure statistics if not expert judgments. The consequences of failure modes and potential failures are, if at all possible, measured with a number of KPIs, such as customer minute loss, financial loss, safety. These KPIs connect the operational-level maintenance tasks with high-level corporate business values. In practice, this link of consequences and failure modes through a certain KPI framework is not yet applied and most of the time not straightforwardly implementable for distribution companies. Decisions on preventive maintenance plans or schedules are based on the risk register of failure modes or potential failures. Risk register is a process to rank the expected value of risks, while the expected value is the multiplying product of probability and consequence.

In the literature, more variations of maintenance policies can be found such as *Design Out Maintenance* (a proactive policy). More literature on this can be found in references [23] and [27].

## 50.3 CIGRE Survey of Maintenance Strategies

Most utilities apply a range of maintenance strategies. This was captured in the survey undertaken by CIGRE and published in 2000 as Brochure 152 [1]. Figure 50.2 below is extracted from this brochure:

In totality, the most common strategy in this 2000 survey was TBM at 35 (47%), with off-line CBM second at 26 (31%), and this can be seen clearly in columns for substations, transformers, lines, towers. For cables and control equipment, the second most used was corrective maintenance. Responses varied between regions. In Asia 100% of utility respondents used TBM, while in South America the dominant strategy was off-line diagnostics and CBM.

Some 48% (CIGRE 2000) responded that they did more maintenance than recommended by the manufacturers. This was particularly true in lower labor cost countries: Asia, South America, and Eastern Europe. In North America in particular, less maintenance was being undertaken.

## 50.4 Maintenance Management Strategies

In practice, a set of maintenance policies and actions of various types exist and require a general decision-making structure for selecting among them. This is known in the literature as maintenance concepts [27]. The literature provides a wide range of maintenance concepts that have been developed through a

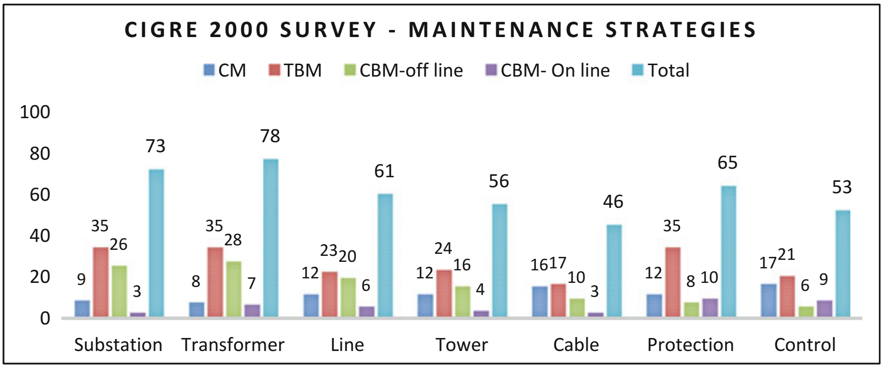


**Fig. 50.2** Maintenance strategies in use, 2000 survey

combination of theoretical knowledge and practical experience. In [27], a summary of the most popular maintenance concepts and their characteristics are given and illustrated here.

| Maintenance concept | Description |
|---|---|
| Quick & Dirty (Q&D) | A decision chart with a number of questions on failure behavior of assets is made taking into account the business context, maintenance capabilities, and cost structure. By following the chart and answering the questions, a number of recommendations for an appropriate policy are found. Usually, companies develop tailor-made Q&D decision charts. No in-depth analysis is used in this method. It is seen as a method to quickly set some priorities |
| Life cycle cost (LCC) | This is a methodology to calculate and to follow up on the whole cost of a system from inception to disposal. All expenses for purchase, operation, and disposal of an investment, including project costs are taken into account. This method originates from the 1960s and is gaining interest again, perhaps due to the focus on lifecycles in PAS-55 and ISO 55000 [9, 10]. The method follows a number of steps according to a detailed breakdown structure of the cost of the system under investigation over the lifetime. This method is based on a sound philosophy; however, it is both resource and data intensive. Another approach commonly used is the Total Cost of Ownership (TCO) method, which can be seen as an expansion of the LCC. In TCO calculations, expenses or indirect costs elements are added such as unproductive use of equipment, entire supply chain costs for the business |
| Total productive maintenance (TPM) | TPM aims at getting the most efficient and effective use of equipment (Overall Equipment Effectiveness (OEE)). In this method, total participation (organization-wide) is needed. TPM mainly promotes the implementation of preventive maintenance tasks based on small group tasks. This method has been successful in the manufacturing industry. It considered human and technical aspects; however, it is time consuming to implement |
| Reliability centered maintenance (RCM) | RCM is a structured approach focused on the reliability and was initially developed for systems with a high-risk component in the failure of systems (environments). It is a powerful approach based on a step by step procedure; however, it is resource intensive and time consuming |
| RCM-based | In literature, various concepts inspired by RCM principles can be found. For instance, C.W. Gits [31] developed an RCM-like concept where the focus is on technical and organizational aspects rather than on economic aspects. However, a new RCM is proposed in this concept where quality improvement tasks focus on most important failure modes in the company and the elaboration of task packaging are new features. Also, the incorporation of sound management principles is introduced in the implementation of RCM. Risk-based maintenance (RBM) [32] is basically RCM, however, with a strong statistical background. In doing this, the drawbacks from ad hoc FMEA in traditional RCM and too much of experience knowledge based on gut-feelings are reduced. In literature, RBM is sometimes seen as a maintenance policy or maintenance concept, as mentioned earlier in this |

(*continued*)

| Maintenance concept | Description |
|---|---|
| | section. Streamlined RCM is seen as a simplified or abbreviated version of the traditional demanding RCM method, usually promoted by industrial leaders. Nevertheless, streamlined RCM should be carefully applied in order not to lose the RCM benefits |
| Customized | These concepts are usually in-house developed using the benefits of existing concepts. Examples are Value Driven Maintenance (VDM) in which the management of shareholder values is linked to traditional maintenance philosophies. Companies usually have their own, unique, prioritized method and would like to use the benefits of multiple existing maintenance concepts |
| Lean maintenance | Lean maintenance comes from the idea of lean manufacturing. Lean means reassigning resources to more value-added work, eliminating all waste of work, effort, and material. Lean maintenance uses tools from the quality management field. Lean maintenance is a proven concept in, for example, Toyota |

In Fig. 50.3, maintenance actions, policies, and concept as related to each other are shown [27]. It is not always clear from literature whether, for example, a RCM-related maintenance concept is a concept or a policy. There are literature sources available that state that RCM can be seen as a priority-oriented policy, for instance [33].

Two fundamental maintenance actions exist, e.g., corrective and preventive. Maintenance policies are the mechanism that triggers a maintenance task, such as a calendar plan, a condition state, or a certain risk level. Maintenance concepts are the previously conducted decision-making procedures or analyses that are necessary for selecting between maintenance policies.

## 50.5 Developments in Maintenance Management

Maintenance management has changed drastically over the past decades. In the electricity network sector, similar developments have taken place as a result of the changing maintenance environment. Nowadays, there are different degrees of mixed maintenance tasks, policies, and concepts implemented in transmission and distribution electricity networks.

Although maintenance management is evolving from reactive (corrective) to more and more preventive and proactive maintenance regimes, a complete migration to a single one task, policy, or concept is unlikely. In Fig. 50.4, the development in maintenance management as it has evolved over the past is shown [32, 34]. This is, however, a general representation of maintenance management regimes and does not necessarily reflect the situation for electricity networks. The developments have followed a slower pace in this sector, mainly, as a result of the long lifetimes of power system assets in relationship to the redundantly designed networks and stations. Maintenance could in this sense be postponed for longer periods compared to other sectors. Due to the fact that these assets are gradually coming to the end of

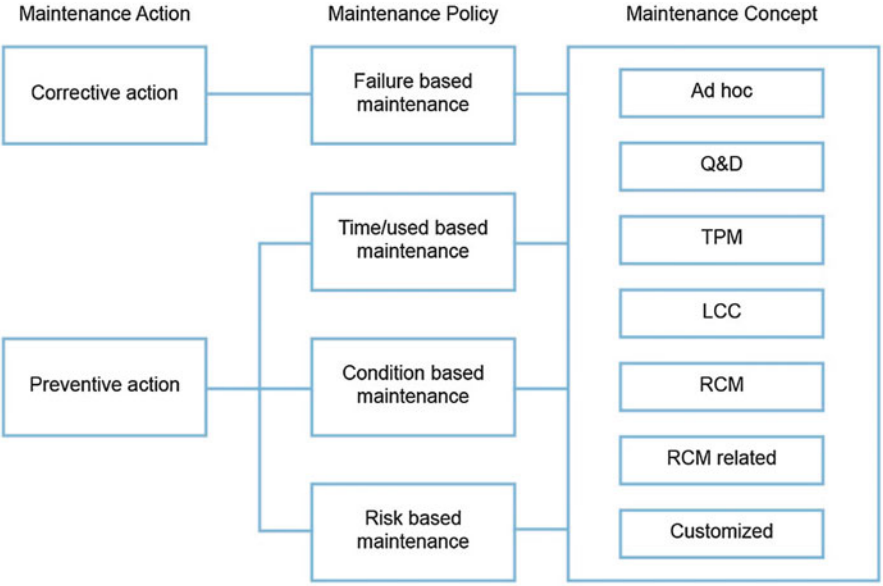


**Fig. 50.3** Interrelationship of the different definitions of maintenance action, policy, and concept with each other

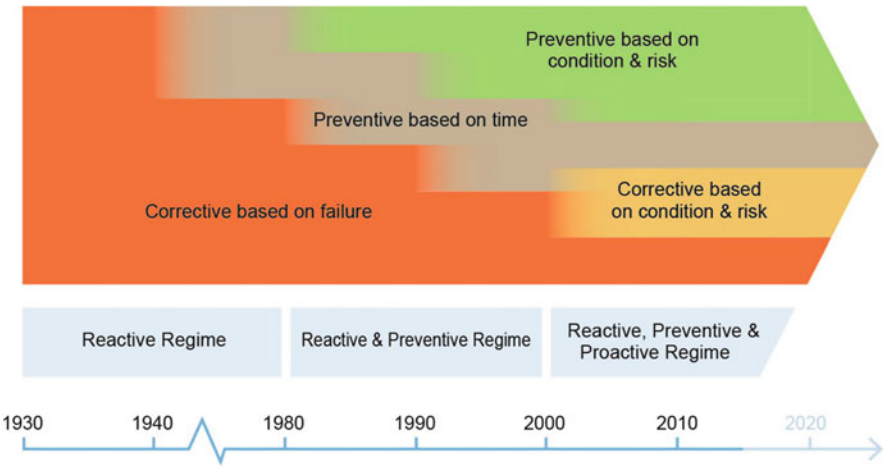


**Fig. 50.4** Maintenance evolution in policy implementation [26]

their technical lifetimes, maintenance management and replacement strategies are crucial aspects in managing the populations of assets. Nevertheless, these trends are happening as well for transmission (started earlier) networks and more recently at a faster pace in distribution networks.

## 50.6 Key Elements of Maintenance Management

Maintenance management has evolved, based not on solely technical grounds, but rather on techno-socio-economic considerations. Therefore, it becomes clear that maintenance cannot be managed as a purely technical and technological function only [27]. Maintenance management has to take into account and deal with aspects such as financial insights, the management of maintenance budgets, the management of resources and skills, adopting maintenance processes for effective measurement of the contribution of maintenance to the overall business, data and data quality, computerized maintenance management systems (CMMS) [23]. Thus, maintenance management has to take into account a myriad of considerations. Having said this, literature, however, reports [23] that many utility network companies have difficulties in practice with enabling an integrated view for maintenance management. According to [23] this is mainly due the lack of essential supporting pillars for maintenance management from an organization-wide (business) point of view. *Process management:* maintenance management based on process management is according to a strategy. It is required to have methodologies which allow clear definition of the processes, their execution, and data requirements. The aim of having maintenance management processes is to improve the efficiency through the management of business processes that are modelled, automated, integrated, controlled, and continuously optimized.

- *Quality management:* the management of quality is concerned with the quality of the service provided through the network. In general, it can be said that the performance or the quality of the service that is delivered is determined by the design, operational status or condition, operation, and maintenance of the network. The level of performance to ensure the appropriate level of service is achieved by having processes of continuous improvement, incorporation of diagnostic and monitoring tools, analytical methodologies, and new technologies.
- Information and Communication Technology (*ICT) management:* as maintenance management is increasingly needing more information from the business environment, ICT is beneficial for the optimization of maintenance management due to the proper exchange of updated information and coordination of automated procedures. The proper exchange of information and the coordination is important for maintenance management; however, interoperability among different systems (and vendors) is required to ensure this.
- *Knowledge management:* knowledge management is the key to effective maintenance. Maintenance requires up-to-date data, information, and knowledge about assets. Basically, this is needed for the planning, scheduling, and execution of maintenance and the continual improvement of this process. Most of the time in electricity networks, there is a large amount of dispersed knowledge available amongst technical workers, specialists, and managers. However, due to the dispersion or lack of methodologies that extract this knowledge, it remains unprofitable and inaccessible.

## 50.7 Developing Future Strategies

There exists a mix of maintenance strategies in use and this will continue into the future, albeit with differing levels of success. The general belief that these will converge to a single strategy is unlikely.

The most advanced utilities use a mix of strategies – driven by “criticality and risk” – but tempered with the practicalities and economics of planning maintenance and maximizing equipment availability. With the greater understanding of assets, their condition, performance, and cost of use, there will be opportunities to focus resources where they are needed. Often this will lead to cost savings in the totality, but in some specific areas may increase cost of ownership.

It will always be more economic to repair low impact/criticality equipment after it has failed – so giving some limited application of CM. There is always likely to be a place for TBM which enables a **predictable** resource and access pattern. There will be increasing opportunity to use condition-based maintenance, with both off-line and on-line diagnostics. In the latter case, asset condition can be transmitted to a control room as with relay outputs for protection. As the reliability of on-line diagnostic devices improves, they will develop to integrate data from a variety of diagnostic systems, perhaps pulling together condition relative to load, temperature, weather, etc. This would then lead to dynamic asset health displays. The ability to integrate data sources on a substation level remains a problem to be overcome. This is a semantics issue due to varying protocols in use such as common information model (CIM) and asset-specific protocols, for example, IEC 61850 (IEC 2003), and its diverse predecessors. For circuit breakers and tap changers, their wear out failure modes may be subject to a better use of failure statistics and so amenable to reliability-based assessment.

The best performers will recognize that whatever mix of preventive maintenance strategies they need to have an “asset mitigation plan” with the appropriate actions to maintain, repair, and replace or simply to protect against the more catastrophic consequences of an in service failure. This will take into account the opportunities within a wider business environment, ensuring that the strategies make best use of downtime – for example, by forecasting the work requirement to be undertaken at the next intervention opportunity. Understanding the mix and using the appropriate tool for the job is likely to be a differentiator, and increasingly being able to demonstrate and support the rationale is going to be expected in a world increasingly conscious of the need to manage risk.

# Substation Condition Monitoring

# 51

Nicolaie Fantana, Mark Osborne, and Johan Smit

## Contents

51.1 Definitions and Terminology ..... 1012
51.2 Incentives for Condition Monitoring ..... 1014
51.3 Condition Monitoring Principles ..... 1016
51.4 Condition Monitoring Strategies ..... 1018
51.4.1 CIGRE Survey of Common Preventive Maintenance Methods ..... 1019
51.4.2 In-Service Monitoring ..... 1019
51.5 Permanent Monitoring ..... 1025
51.6 Analysis and Diagnostics ..... 1026
51.6.1 Traditional Condition Monitoring ..... 1027
51.6.2 On-line Condition Monitoring (OLCM) ..... 1027
51.7 Evolving Condition Monitoring Strategies ..... 1029
51.7.1 Hybrid Condition Monitoring ..... 1029
51.7.2 Holistic Condition Monitoring ..... 1029
51.8 Data Collection and Management for Condition Monitoring ..... 1031
51.8.1 Data Collection ..... 1031
51.8.2 Data Management Over Equipment Lifetime ..... 1033
51.9 Condition Data Analytics ..... 1036
51.10 Value from Condition Monitoring ..... 1037
51.11 Outlook for Condition Monitoring ..... 1042
References ..... 1042

N. Fantana (✉)
Consultant, ex. ABB Research, Agileblue consulting, Heidelberg, Germany
e-mail: nicolaie.fantana@outlook.com; fantana@ieee.org

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl

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**Fig. 51.1** Examples of catastrophic failures of substation equipment (CIGRE 2011)

Managing substation assets and understanding their performance and condition is a basic fundamental requirement for utilities to deliver a reliable and secure power system. Due to increasing economic constraints, an increasing effort is being made to improve and refine the methods, approaches, or tools for substation asset performance management and condition monitoring.

The goal of these methods and tools is to assess equipment condition and equipment performance/capabilities, in a timely manner, with justifiable effort. The analysis needs to recognize in time potential failures and developing degradation in equipment, so that remedial actions can be taken such that the substation and the power system are kept operational, and risks and outages are reduced. Condition monitoring is a valuable tool to help avoid unplanned outages, to avoid catastrophic failures, such as the ones shown in Fig. 51.1.

The supervision of the condition and performance of substation equipment is generically termed as condition monitoring.

This chapter gives an overview of approaches, definitions, and concepts for managing substation power equipment asset performance, for systematically and effectively monitoring power equipment condition over life.

## 51.1 Definitions and Terminology

The definitions presented below are often used in the context of substation equipment condition monitoring and performance assessment. These are based on the way they are defined in dictionaries, in other CIGRE publications, and especially based on definitions from CIGRE Technical Brochure 462 (2011)

(i) “**Condition**”

According to Merriam-Webster dictionary (CIGRE 2011) a simple definition of “Condition” is: “the state in which something exists: the physical state of something.”

(ii) **Condition of an asset**
The condition of an asset is an expression of the state of equipment in terms of functionality, its capability to perform its tasks in the substation, in the power system.

The terms/categories used to describe condition are presented in Table 51.1 similarly to the way it is presented in (CIGRE 2003). This is a document on the life management of transformers, but it applies well to substation equipment in general.

Other terms associated with monitoring include

(a) Monitoring. – Wikipedia (2014): To monitor or monitoring generally means to be aware of the state of a system, to observe a situation for any changes which may occur over time, using a **monitor** or **measuring device** of some sort.
(b) IEC 60050 definition 351-22-03; to monitor, verb, to check at regular intervals selected values regarding their compliance to specified values, ranges of values or switching conditions. IEC 60050 definition 351-30-12; process monitoring system – equipment for continuous observation and logging and also for operation of technical processes.
(c) "Condition monitoring (CM)" – Monitoring the condition of equipment continuously or at predefined intervals during its operational life.
(d) "On-line condition monitoring" – CIGRE TB 462 (2011), defines on-line condition monitoring as: "Continuous on-line (equipment energized and connected to the network with the device(s) permanently installed) monitoring primary equipment to measure and evaluate one or more characteristic parameters with the intention of automatically determining and reporting the state of the equipment."

*"Diagnostics" or "diagnostic testing"* may be defined as:

Investigative tests performed on primary or secondary equipment to verify its function by measuring one or more characteristic parameters. A diagnostic test can be performed on-line (equipment energized and connected to the network) or off-line (equipment de-energized and disconnected from the network). Diagnostics can also

**Table 51.1** Condition classification, naming, and definitions

| Condition | Definition |
|---|---|
| Normal | No obvious problems. No remedial action justified. No evidence of degradation |
| Aged Normal in service | Acceptable, but does not imply defect-free |
| Defective | No significant impact on short-term reliability, but asset life may be adversely affected in the long term unless remedial action is carried out |
| Faulty | Can remain in service, but short-term reliability likely to be reduced. May or may not be possible to improve condition by remedial action |
| Failed | Cannot remain in service. Remedial action required before equipment can be returned to service (may not be cost effective, necessitating replacement) |

be the method used to analyze the data coming from CM systems; it can be carried out by an expert person or by an Expert System as part of the CM.

A diagnostic test is typically initiated to gain more detailed information about the condition and/or performance of the equipment under investigation. It is typically considered a more detailed investigation. Diagnostic tests can be started following prior concerns stemming from alarms, such as from monitoring systems or protection devices, results from lab measurements, or other indications on degrading or abnormal condition or performance.

Other definitions referring to "substation equipment" and "condition monitoring devices" and used in CIGRE technical documents are:

- *"Equipment"* – refers to the individual piece of equipment being monitored in the substation. It can be:
  - Primary equipment, e.g., circuit breaker or transformer
  - Secondary equipment, e.g., CT or VT
  - Auxiliary equipment, e.g., battery or charger
- *"Devices"* – refers to the applications used to monitor the equipment in the substation and network, e.g., for on-line condition monitoring. The on-line condition monitoring approach in substations can be basically subdivided into two main groups as done in ▶ Sect. 50.1, distinguishing:
- *"Equipment monitoring devices"* – represent specialized hardware and/or software designed for and installed on each individual piece of equipment in the substation.

  Each equipment monitoring device is specifically designed for on-line condition monitoring, for the specific primary equipment, and on-line monitoring is its primary purpose.
- *"Network monitoring devices"* – in the sense of TB 462 (2011), are devices or installations already installed in the substation and network, which can be used for on-line or off-line condition assessment and monitoring for substation equipment because they contain relevant data for this equipment. Such systems or devices may include SCADA systems, transient recorders, protection devices, etc. They gather general information and data about all equipment in the substation and network. These data alone or combined with some other data from the utility enterprise, dedicated monitoring devices allow to assess the condition of an equipment by means of a complex analysis and processing using specialized software.

  Each network monitoring device gathers substation-wide and network-wide data. These data can also be used successfully for on-line condition monitoring; however, it is not its primary purpose.

## 51.2 Incentives for Condition Monitoring

The main reason for considering condition monitoring is the value it brings to the substation owner. Typically, the value associated with investing in forms of systematic condition monitoring and procedures to assess condition is to develop the potential to:

- Avoid failures and consequential costs
- Avoid hazards to humans
- Reduce operation and maintenance costs
- Life extension and deferral of capital expenditure for assets near their end of life
- Improve asset capability and push assets harder
- Deferral of capital expenditure for assets close to their ratings
- Controlled loading and overload ability

The conventional off-line diagnostic procedures, such as testing on site (either on demand or planned) and periodic inspections, are used practically by all substation owners and are effective in detecting the condition of equipment. On-line condition monitoring and sensing is increasingly used to enhance the quality or validity of the asset data. A survey performed by CIGRE WG B3.12 (CIGRE 2011) identified some incentives and drivers behind utilities reasoning to install on-line condition monitoring (OLCM) systems. This applies equally well to all condition monitoring activities.

The main drivers to install condition monitoring, especially on-line condition monitoring which have been found, are shown in Fig. 51.2.

The respondents of the survey have considered that the most important drivers to install OLCM are: cost savings, for example, maintenance savings, an unwanted (negative) company image in case of outages and failures, life prolongation of aged equipment in a precarious situation, better basis for asset decisions.

WG B3.12 investigated the challenge “obtaining value from on-line monitoring of substation equipment” through adding intelligence to condition monitoring of equipment. Also the role of monitoring is mentioned in other technical brochures, such as in the special situations of the off-shore substations (CIGRE 2011) or the IEEE guide for transformer condition monitoring C57.143 (2012). Obtaining value from condition monitoring and its evolution has been the subject of numerous sessions and presentations in recent years in CIGRE and IEEE, such as in (CIGRE 2015) and (Fantana 2015).

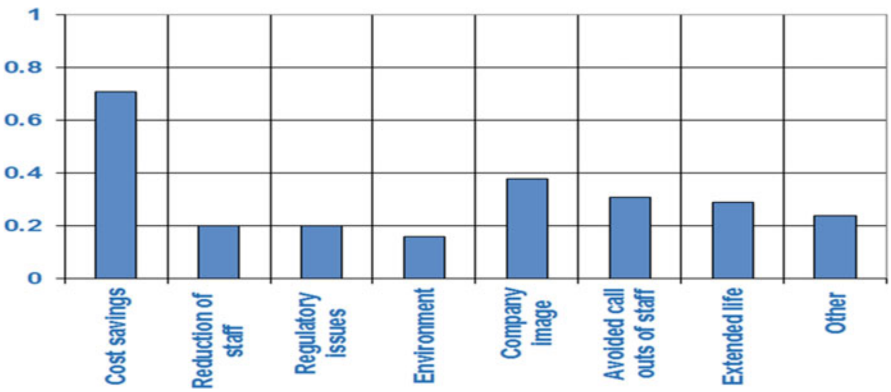


**Fig. 51.2** Main drivers in utilities to install condition monitoring, especially on-line condition monitoring (CIGRE 2011)

The condition assessment and continuous condition monitoring of substation power assets is a key element in substation asset management and in effectively managing substation assets over operational life time.

## 51.3 Condition Monitoring Principles

The condition of substation equipment over time is shown in a simplified way in Fig. 51.3. The condition, blue curve, is decreasing over time, under the influence of various stress factors, which can be known, partly known, or unknown to the equipment owner from the available data. In the same picture, the red curve represents the cost to bring the equipment back to the operational "normal" condition. These restore-to-normal costs can increase with heavier failures or important degradation and bad condition. Consequently, at a certain moment in the equipment's life, the restoration or repair of the equipment is too expensive and the equipment has to be replaced, even if the failure point F has not yet been reached.

To assess the evolution of the condition over time requires monitoring and diagnosis actions to know the changes which occur in the equipment in order to detect in time the degradation occurrence and to avoid the unexpected failure, point F in Fig. 51.3.

The initial part of the simplified condition curve shows at some moment in time a point "S," where the degradation starts. It follows a continuing degradation, which is (typically and hopefully) detected by some of the on-line or off-line diagnostic methods used, point "D" in the figure.

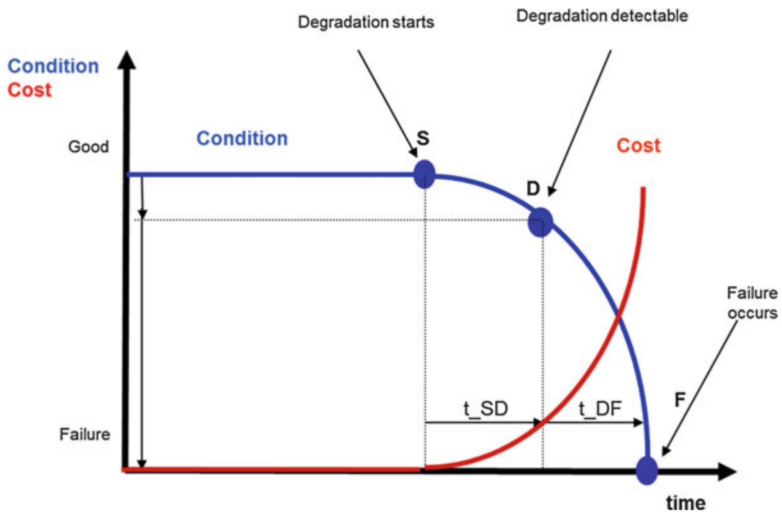


**Fig. 51.3** Typical condition and cost evolution shapes for substation equipment, over its lifetime (Fantana 2015)

The detection at point D depends on numerous factors such as detection method used off- or on-line, type of degradation, available algorithms, and knowledge to detect the degradation changes or understand the signal patterns, sensor and diagnostic method used, sensor or method sensitivity, experience in interpretation of the detected signs of degradation, and more.

Depending on the pace of the degradation phenomena, the time from start to detection and from detection to failure is very important in deciding which type of condition monitoring approach to use.

Performance assessment and condition monitoring requires two key elements:

- Data about the equipment
  From construction details and materials to equipment life aspects, such as stresses, operation modes, incidents, failures, etc.
- Knowledge related to equipment and its subsystems
  Degradation mechanisms, materials, functional aspects, time evolution, generated by-products, etc.

The condition assessment process has many uncertainties and often some degree of incomplete data and imperfect knowledge, typically this can include:

- Not all relevant information over time or not exact information can be obtained, or it is too expensive to collect.
- There are microdefects or defects in the materials or construction, defects appearing during transport, commissioning, etc., and which may exist or occur and often remain unknown.
- Unexpected external influences may affect the equipment without being noticed or recorded, which in a simplified model cannot be considered as influencing factors, for example, some over-voltages, fast transients, internal circulating currents.
- The knowledge available for condition assessment is growing; however, it is not complete often because of either new engineering solutions are used or historical performance data are not available. This is especially true regarding the long-term behavior of materials and new designs used or new equipment types.
- Unknowns related to the estimation of the long-term behavior and expected condition of the equipment stem from the network and environmental stresses acting on the equipment. Environment and networks are changing, for example, consider the impact of smart grid, distributed generation, power electronics, and the climate changes.

Condition monitoring systems span a very wide range of functionality and complexity. The complexity can be due to sensors used, data needed to be collected, and data processing, but also the information technology involved and communication means which are used.

Condition monitoring and sensors need to be adapted to each different type of equipment and their subsystems and need to consider deterioration mechanisms, failure types, and different time evolution of defects.

Condition monitoring installations vary dramatically and vary significantly in their range of costs and value generation (CIGRE 2011). In addition to the initial purchase and installation costs for these devices, there are some recurring operational costs associated with maintaining the devices, acquiring the data, and investing the time to analyze and interpret the data in order to make well informed decisions.

## 51.4 Condition Monitoring Strategies

The condition and performance assessment of substation equipment is part of the utility maintenance and asset management procedures, policies, or strategies.

The condition of equipment is of interest for different utility departments: for the maintenance department, to take immediate or short-term actions and for the asset management and planning departments in a utility for mid to long-term planning of upgrades, replacements, or other substation or network-related activities.

The condition monitoring for substation equipment is relevant over the entire operational lifetime.

When setting up a condition monitoring approach, besides data to collect and knowledge to use aspects such as the following also need to be considered:

- How fast should be the response, what is the desired/required timeframe to get condition information about an equipment?
- What is the ambition level of the condition monitoring approach, in terms of how accurate the assessment result has to be?
- What is the affordable or desired effort or cost level, immediately for installation and over long time in operation?
- How will data obtained be integrated in a utility overall concept, in a maintenance and asset management strategy?

Nowadays a lot of approaches are used for condition monitoring, and practically each utility or substation owner has their own blend of procedures and policies. These particular approaches consider aspects such as the cost constraints, the regulatory constraints, technical expertise, substation equipment's present condition, human hazards, social impact of loss of energy supply, equipment major failures, environmental aspects in the area where the substation is operating, used technologies so far, and gained experience.

The approaches or policies used are most often a balance between the effort and cost to assess the condition of substation equipment and the substation as a whole and the accuracy and reliability/trustworthiness of the assessment effort.

The condition assessment and condition monitoring give information on the technical performance capabilities and the expected behavior of the electrical equipment under normal or abnormal conditions, at a certain moment in time or for a specific system status or operation.

The basic approaches for condition monitoring are:

- Conventional condition monitoring
- On-line condition monitoring
- Hybrid or mixed condition monitoring
- Holistic condition monitoring approach

### 51.4.1 CIGRE Survey of Common Preventive Maintenance Methods

Where RCM and RBM have been used, the common outcome has been to decide upon maintenance triggered by condition and risk exposure. A starting point is to identify a set of diagnostics to match failure modes and applied in a periodicity to match the risk exposure.

A representation of a process is shown in Fig. 51.4. (CIGRE 2016). The first stage is to avoid an outage by gathering information without necessitating an outage. This may involve survey methods applied to a complete substation, or having preinstalled condition monitoring systems. Where an anomaly is identified, this will trigger rectification if the problem and its solution is clear. If not, prior investigation and testing are undertaken, usually during an opportune outage. Following these tests, negotiations must begin to arrange a suitable outage to maintain or correct the equipment.

### 51.4.2 In-Service Monitoring

Site inspections have long been a key site activity. One approach is, therefore, to build upon the routine patrol and add more noninvasive diagnostic activities. These

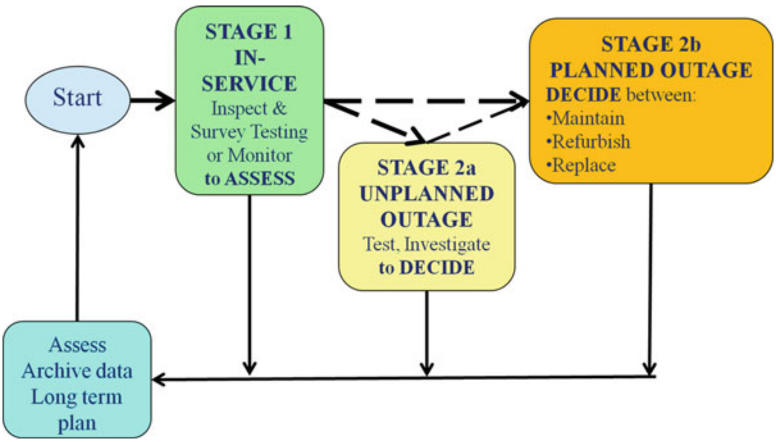


**Fig. 51.4** Implementing a CBM maintenance strategy

are all of a survey nature, i.e., carried out in an energized substation without supply disruption and can be undertaken by skilled technicians. The timing for these activities will depend on local policy and assessments undertaken as part of an RCM or RBM program. If any abnormality is identified, a report is issued and a work order triggered. An advantage of this approach is that all assets in the substation are reviewed, with a focus placed on high value ones like power transformers together with associated disconnectors and switches.

These activities include several described below. Most are noninvasive. Others may involve taking a sample for analysis, or coupling a measuring instrument to a preinstalled sensor.

- **Visual inspection**: This is usually a monthly activity, very traditional but with outcomes now recorded on a tablet and uploaded daily to server, to store and initiate a planned intervention. It should identify:
  - Security breaches
  - Malfunctions – unusual noise/smell/weather or animal damage/debris. Porcelain damage
  - Noting temperature gauges, feeder load readings, pressure readings, oil levels, batteries, breaker operations, surge counts, control cubicles sound, and heaters/coolers working (if appropriate)
  - Noting evidence of rusting, oil leaks, water leaks, malfunction of oil containment, and separators
- **Thermal imaging**: Usually this is part of an annual inspection but could be more often if RCM analysis indicates such a requirement. It is mainly poor connection issues that are detected, but also fan operation and faulty insulators in a string. The method is surprisingly effective at identifying internal problems developing within assets, such as low bushing oil levels, blocked radiator tubes, faulty internal transformer flux shunts. Ideally, it needs a reasonable load to be present to initiate overheating. It has some complications. In the past the cost of thermal imaging equipment and its complicated nature required specially trained and certified operators. The evolution of these devices and the dramatic cost reductions now means that it can be undertaken by most field electricians that perform the patrol/substation inspections (Fig. 51.5).
- **Oil testing**: Oil tests have been performed to identify problems in oil filled equipment for many years. Initially the test was for oil quality and combustible

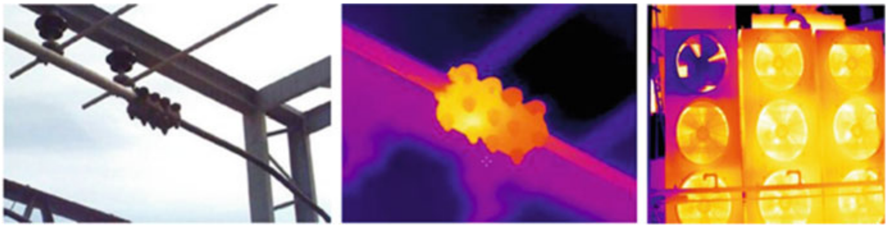

**Fig. 51.5** Examples of thermal imaging results

gases. The earlier gas test was often achieved by trying to ignite gases bled from a Buchholz relay. The development of chromatography allowed more sophistication and detection of gases other than hydrogen from the relay. The common practice now is to sample oil from power transformers, shunt reactors, bulk oil breakers, CTs, and in some cases HV bushings. Sampling is normally performed without any supply interruption. Laboratory analysis of an oil sample allows a wide range of diagnostics. These samples are analyzed for dissolved gases (DGA), for oil quality, moisture content, and paper aging compounds. Sampling and testing is made with a periodicity varying between 6 and 24 months, depending upon a risk and reliability analysis. More recent applications include portable instruments developed for both a periodic on-site dissolved gas analysis and permanently installed analyzers allowing continuous assessment.

- **Partial discharge (PD) monitoring:** There are a range of techniques that can be used for on-line diagnoses. These are shown in Fig. 51.6. More detailed information can be found in CIGRE Technical Brochure 660 (2016). As with IR and UV scans, a degree of expertise is required in application; a degree of complexity in instrumentation must remain to ensure extraneous signals are correctly identified and eliminated.
- **UV cameras**: A day-light ultra-violet camera is used in a very similar manner to the infra-red camera but in this application scanning metal work and insulators for light emitted during corona activity. Clearly there needs to be a line of sight to the PD source.

  As shown in Fig. 51.7, these PD sources produce optical energy predominantly in the UV spectral range, but as with all light detection methods the use is restricted to external activity. One European utility has a particular problem with synthetic insulators, namely, erosion where there is concentrated discharge, and it is this which is shown in Fig. 51.7. Here the UV camera allowed a simple means for evaluation of the problem.

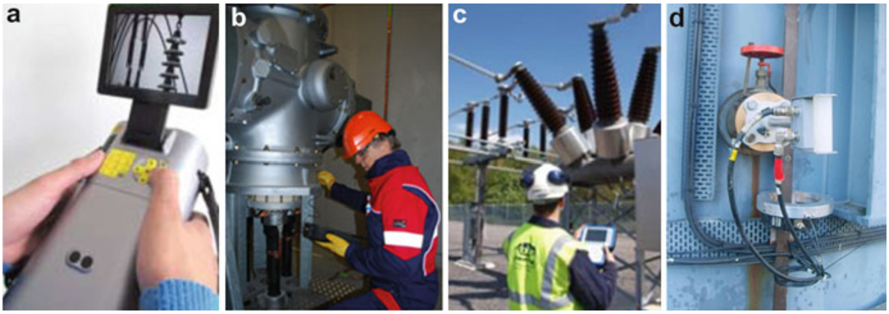


**Fig. 51.6** PD survey techniques in use. (**a**) Daylight UV camera. (**b**) Acoustic emission scanning for PD in metal clad equipment. (**c**) UHF emission scanning around a circuit breaker using an antenna sensor and a UHF frequency analyzer. (**d**) Detecting PD levels in a power transformer showing here two different possible sensors: a UHF probe inserted into an oil valve and a split HFCT on a neutral strap. These would be used with a UHF PD detector or frequency scanner shown in photo **c**

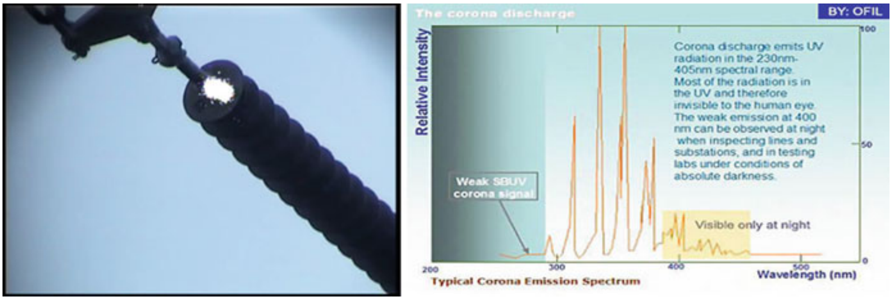


**Fig. 51.7** UV spectral response and corona around a defective insulator

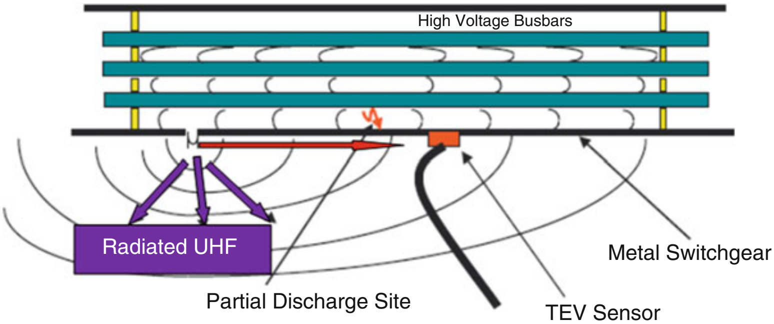


**Fig. 51.8** External TEV current and Uhf radiation from flange position in metal clad switchgear

- **Acoustic emission:** For PD sources inside metal clad equipment, particularly GIS chambers, acoustic emission (AE) sensors are used to detect minute vibrations in the chamber walls, as shown in B in Fig. 51.6b. Energy from an internal PD radiates from the source as longitudinal waves in the gas or liquid. The energy is transmitted through the metal containment walls on impact and then travels in the metal as slower transverse or shear waves. Following Snell's law, it is mainly the energy striking fairly normally to the chamber wall that is transmitted through to create the shear waves in the outer surface. The AE probe is positioned onto the chamber surface and moved along every 2 m or so to identify a source. If a source is detected then the sensor is moved around to maximize the signal level and so the point of impact. For location in transformers, several sensors are used and time of flight methods applied to locate the source. For GIS applications, the probe will also detect movement of free particle contamination as well as PD. As a variant to the contact probe, some have used an AE sensor located in an optimized microphone held against vent holes in air filled cable boxes and metal clad switchgear up to 33 kV. This would then detect and locate PD directly from the longitudinal wave. A version of this method has been

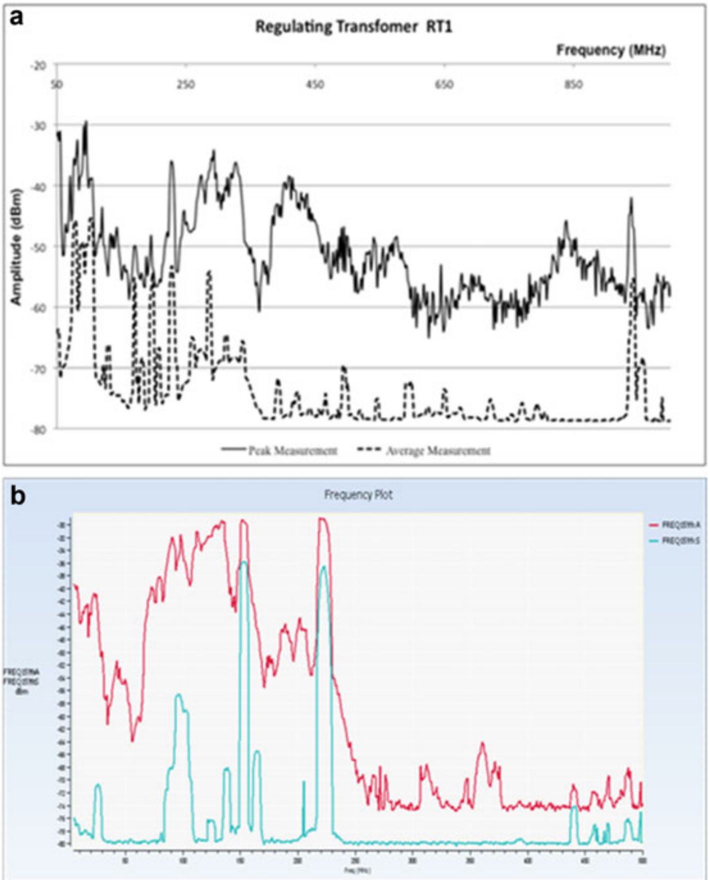


**Fig. 51.9** Identifying PD with a frequency UHF scanner, (**a**) with an antenna input, (**b**) with a 300 MHz HFCT on a transformer neutral strap

with an ultrasonic microphone mounted in a parabolic reflector and used with a telescope or laser pointer to identify point sources of PD in AIS.

- **UHF scanning**
  - A high frequency transient earth voltage (TEV) probe is commonly used to scan metal-clad equipment in a similar manner to the use of an AE sensor. Here it is detecting transient skin effect currents flowing in the casing. The PD itself is contained within the chamber, but it creates a current flow at the defect and this must be part of a circuit involving the supply and the earth connection. As such a transient earth current is induced and flows as skin effect current along the inner surface of the chamber, through any nonconducting breaks, such as gaskets at flanges and along the outer surface on route to earth. These pulses of current in the outer surface are detected with a UHF “TEV” sensor as shown in

Fig. 51.8. By moving the probe along the chamber, the flange and so the chamber section containing the PD may be identified.

- A faster survey method for both AIS and metal clad equipment is the use of a high frequency scanner with a matching antenna to detect air-borne radiated UHF signals. This may be the radiation from the same TEV current in Fig. 51.8 or in a routine patrol of a yard as shown in C in Figs. 51.6 and 51.9. Clearly for metal clad applications, it is quicker to detect in a walk-by than having to make a contact near each flange position. Where PD is located near to a transformer, this may then be investigated or confirmed using either a split core HFCT around a neutral strap or with a UHF oil valve probe. Both are shown in D in Fig. 51.6.

  For the air insulated substation, the operator walks through the site making scans between 50 and 1000 MHz adjacent to primary equipment. What the scanner and antenna are identifying is any radiated UHF from compensating current flowing in the circuit created with bus runs which are connected to any equipment with PD. Defects in equipment can produce radiated emissions up to 1000 MHz. What is detected is a frequency response that depends both on the discharge type and the radiating circuit.

  Also detected within AIS, albeit at lower frequencies, perhaps up to 300 MHz, are UHF emissions produced by external corona and surface discharges. Any telephone and TV reception will be seen from narrow frequency spikes. Examples are shown in Fig. 51.9. Both examples are illustrated with a double trace. In a typical AIS, there will be corona and surface discharge which produce similar signal levels throughout the site. A general site spectrum of this background is taken as the reference for the survey and shown as the lower traces in both examples. The upper trace in each case is that from near to the equipment having a PD source. In the first spectrum shown in Fig. 51.9, the problem was localized using the antenna and scanner to a connection issue within a regulating transformer. It was then pinpointed with acoustic emission probes. In the second unrelated example, the problem was traced to a transformer and investigated/confirmed with the HFCT on the neutral strap, as per image D in Fig. 51.6. (Here it was the frequency response of the HFCT that restricted detected signals to below 500 MHz). The cause was a developing inter-turn fault in the transformer winding.
- Internal sensors can sometimes be fitted in GIS and transformers. These may be used for permanent monitoring or for periodic measurements. In some cases, sensors can be retro-fitted as with the transformer oil valve probe shown in Fig. 51.6 or for GIS strapped to surfaces of inspection windows or onto insulating spacers.

- **Other survey methods**: Several useful techniques are in use. This includes gas analysis for $SF_6$ systems, gas leakage detectors and locators, surge arrester performance using compensated third harmonic current measurement, timing measurements for circuit breakers and tap changers, and secondary voltage measurements for CVTs.

## 51.5 Permanent Monitoring

So far, we have discussed activities which relate to periodic measurements using noninvasive systems of a survey nature. A further development is to include permanent diagnostic installations where the output, or an alarm, is transmitted to an operator for initiating maintenance or de-energization. This includes systems such as those measuring changes in bushing power factor/capacitance, on-line dissolved gas analyzers on transformers, and PD measurements using probes in rotating machines, GIS ,and more recently transformers. In general, these have been standalone systems, working independently of other data gathering on site, often with vendor specific analysis systems and data protocols. Some on-line monitoring systems merely report data and others use expert systems to interpret the data at site, thereby reducing the need to transmit large amounts of raw data.

This CBM data can be displayed in its raw form with alert levels, or after processing and application of expert systems either at the asset or on the substation or a remote server.

- **At an asset level** – On-line continuous monitoring levels at individual assets such as
  - Partial discharge in GIS is the most widely used of these systems, with many vendors and many systems installed around the world over the last 30 years.
  - Bushing power factor, with the lead vendor having 10,000 bushings under surveillance over a 10-year period.
  - Partial discharge on a transformer or cable system is a more recent trend.
  - $SF_6$ gas and dissolved gas-in-oil analyses.
  - $SF_6$/CB timing trend analysis.
- **On a substation server** – On-line continuous monitoring outcomes specific to one type of diagnostics such as:
  - Permanent display of monitoring status/alerts from a variety of diagnostics identified by asset and bay
  - Database of events
  - $SF_6$ density thresholds of all compartments
  - Temperature of all compartments
  - Internal arc detection
  - Partial discharge acquisition
- **Combined diagnosis** – an asset condition based upon an expert system using integration of all data, from on-line and periodic sensing, from protection system alerts. These would be used:
  - For network control: Assets which are normal and can be operated routinely
  - For network control: Assets identified which are showing an alert and some operational restriction may apply
  - For asset management: Assets identified which are showing an alert and require investigation, repair, or replacement

The technology challenges in applying such continuous on-line diagnostics are more significant and tend to result in a higher cost option. However, over recent

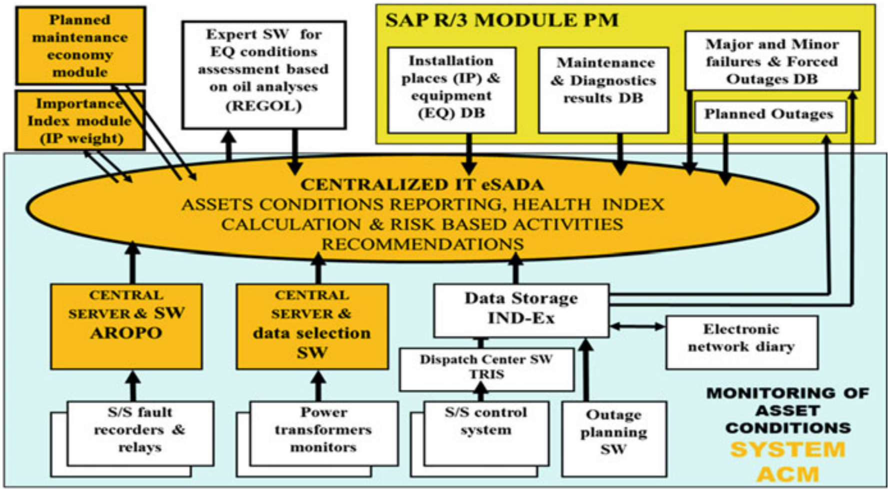


**Fig. 51.10** Integrated asset condition and CBM platform example

years, some of these technology issues have advanced, particularly with respect to sensors, data capture, handling, and storage. The trend is away from stand-alone and vendor-specific systems and towards outcomes routed to the substation server, there to be integrated with other operational data. This is becoming easier with a common platform of (IEC 2003), and there is ongoing work within IEC TC57 to develop new asset classes in the common information model (CIM) to allow common access to all data that can be used for condition assessment. This feature will allow condition data to be integrated with operational conditions for correlating condition data to load or switching. This having been achieved, condition monitoring can be used not only by the asset manager for maintenance and replacement planning, but also by the network operators for active system management. The long-term reliability of these systems has been an issue in the past, and some remain so. Many are emerging technologies and the expert systems continue to be improved.

TB 462, (CIGRE 2011) has case studies describing implementations by TSOs in the UK and Czech Republic. In most cases, utilities were fitting on-line monitors in the expectation of achieving lower costs by deferring maintenance to when it was needed. Figure 51.10 taken from TB 462 demonstrates the level of data integration that some are implementing.

## 51.6 Analysis and Diagnostics

Whatever inspection, survey, or continuous analysis method is used, the assessment is to identify a change in behavior. Outcomes may indicate timings for maintenance throughout most of life and eventually trigger refurbishment or replacement. Once equipment is removed from service for some maintenance work, it would be normal to undertake investigative testing. Recent close-up faults might have damaged a transformer winding. This would be a time to undertake sweep frequency response analysis.

### 51.6.1 Traditional Condition Monitoring

The conventional condition monitoring is based on the use of a set of data collected by persons on site for example in routine inspections, from results and tests done on material samples taken on site and analyzed in the lab, from off-line diagnosis tests in the lab, on-site diagnostic measurements, or even observations of abnormal behavior done by persons.

Where suspect behavior is detected through one of the above procedures, further condition monitoring can be done on-demand. This applies typically to incidents, protection alarms, or special situations in the network or substation identified at the design stage and implies diagnostic measurements and testing on site.

Taking samples from equipment on-site, inspections by rounds in substations or diagnosis measurements can be part of the maintenance or response strategies in utilities, in case of failure. Collection of inspection and diagnostic data can be at an event or are often collected in predefined fixed time intervals. Examples are such as dissolved gas analysis for transformers, verification of circuit breakers, and determining movement curves for circuit breakers, diagnosis measurements for determining electrical properties, or specific signals – e.g., partial discharge, dielectric losses, visual periodic inspections, and more.

Condition monitoring or a check of the present condition can be an on-demand activity in case of incidents or warnings or special situations, where diagnostic and testing methods are used.

The analysis of such periodically or on demand collected information is done by equipment experts. Nowadays more and more software systems and tools are used to process and evaluate the condition based on this type of data by using rule-based systems or systems using experience-based knowledge for the interpretation of data.

A lot of effort in research and application has been put into the conventional condition monitoring and assessment. It has reached a reasonable level of acceptance and is used in many utilities. The ambition level in terms of precision is moderate, the time response is slow to very slow, for example, the detection of an occurring defect is detected only after 0.5–1 year, in case of samples taken only every half year or year, but still this condition monitoring mode is one of the basic choices in utilities.

### 51.6.2 On-line Condition Monitoring (OLCM)

OLCM refers to an arrangement where the primary equipment is supervised with monitoring device(s) and sensors permanently installed. Monitoring of the primary equipment aims to measure and evaluate one or more characteristic parameters, indicating degradation, with the intention of automatically determining and reporting the state of the equipment typically if

- Failures are developing very fast and need a fast response time.
- The equipment is critical for the network and requires high availability.
- Life prolongation is needed for a limited time, to keep the equipment operational despite not perfect condition, sort of "running-at-the-edge."
- Lifetime information is needed, i.e., rich data can be recorded and can be a valuable information for assessment or other activities later.
- The substation is in a remote difficult to access area, or the cost of accessing the substation is very high. An example for the latter is off-shore substations, as described in TB 483 (CIGRE 2011).
- OLCM can be easily integrated in an intelligent information system in a utility and supply raw or processed data to substation systems or to utility systems and utility stakeholders.
- No human intervention on site is needed during normal operation, to get the collected data, etc.

The following aspects should be considered when installing OLCM:

- There is a lifetime mismatch between primary equipment and monitoring and sensing devices, typical life expectancy is 40+ years for power equipment versus 10–15 years for OLCM devices, especially due to sensing and electronics components.
- The cost of OLCM initially, including purchasing and commissioning and over time, has to be considered. This also needs to include annual service charges for software and maintenance contracts.
- When is the best time to install OLCM systems? With new equipment, the easier and less costly way is to have a monitoring system from the beginning. Adding OLCM to old equipment is more costly and with limitations or even impossibility to install all desired sensors at the right place.
- Skills are needed for handling OLCM devices and their sensors, IT, communication, and data.
- The OLCM data have to be handled in terms of amount, quality, processing and integration in the utility.
- The OLCM system should bring value, e.g., by improving utility processes, reducing costs, or avoiding failures. The technical brochure TB 462 (2011) has considered in detail the "obtaining value from on-line condition monitoring" aspects.

Aspects related to OLCM in substations and for substation equipment have been the topic discussed in a row of recent panel sessions in CIGRE and IEEE as well as in some joint activities of the two organizations.

Panel sessions on OLCM, applications, on evolution and obtaining value from on-line condition monitoring, took place more recently at IEEE PES General meetings, during IEEE T&D or IEEE substation committee conferences, during round tables and workshops at CIGRE or often as joint CIGRE-IEEE activities, (Fantana et al. 2014).

## 51.7 Evolving Condition Monitoring Strategies

On-line condition monitoring should not be seen as a stand-alone and independent system for condition monitoring and assessment but ideally combined with conventional condition monitoring approaches, and this leads obviously to the hybrid condition monitoring approaches.

### 51.7.1 Hybrid Condition Monitoring

Tailored approaches for condition monitoring in utilities combine the advantages of the conventional condition monitoring with those of on-line condition monitoring. Many utilities use hybrid approaches and combined condition monitoring strategies; however, the approaches used in practice can be very different. These differences may originate in aspects such as existing installed utility equipment and their networks; in existing experience with conventional diagnosis, condition assessment, or on-line monitoring; in the amount of devices where on-line monitoring exists and is used, the criticality of the equipment supervised and regulatory constraints.

An often-encountered hybrid solution for condition monitoring consists of using on-line monitoring on critical power equipment in substations, while for less important, less critical, or less costly equipment, the condition is assessed in the conventional way, with periodic inspections and sample taking and lab analysis or other diagnostic methods and inspections on-site. OLCM provides more detailed and more real- or near-time information, which can be used for more accurate and near-time condition assessment.

While conventional monitoring devices use local sensors, the hybrid approaches may additionally use data from substation or utility enterprise systems. This would imply that besides using sensor and local equipment data, the monitoring system itself can use some historic information from substation or from events or maintenance history. The CIGRE technical brochure TB 630 considers such systems and aspects in case of a transformer intelligent condition monitoring device for power transformers (CIGRE 2015). The generic approach and the methods and algorithms described can be adapted to other types of equipment too, and the monitoring system can fit into hybrid condition monitoring and holistic condition monitoring approaches in utilities.

### 51.7.2 Holistic Condition Monitoring

These approaches are a more recent trend to use *all* available and relevant life data about substation equipment, from operation, environment, maintenance, and events;

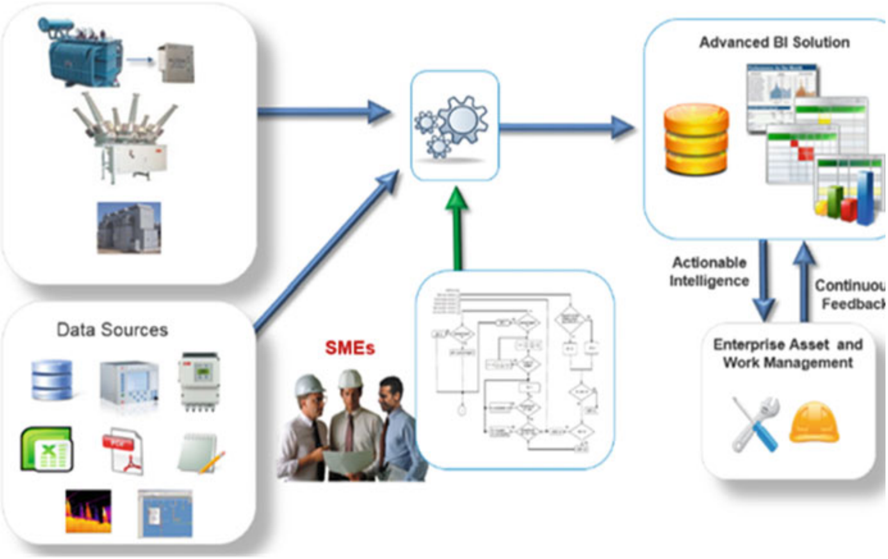


**Fig. 51.11** Example of an integrated center for enterprise asset health. The SME are subject matter expertise for each type of equipment (Fantana 2015)

they are holistic and integrate data and information for condition monitoring and assessment purposes. Such approaches are enabled by evolution of technologies, which collect easily and with reasonable cost substation equipment data, network, and other data.

Such holistic approaches are encountered also in the case of so-called “asset health centers,” of a utility enterprise, for example, as mentioned in (Fantana 2015), (Fig. 51.11).

These approaches typically try to consider, integrate, and use all available data and knowledge about the substation or network equipment:

- To consider and handle all major equipment and equipment types in the utility, in the substations, typically is starting with most important such as transformers, GIS, and breakers but can be further extended to all equipment of interest, and it can consider any utility asset.
- Bring together all relevant and available data from equipment, operation, environment, events, diagnosis, maintenance, etc. It is desired to integrate all available and relevant data, ranging from site inspections, diagnosis tests, on-line monitoring, SCADA systems, etc.
- Consider equipment’s life, its history and evolution, previous events, which may affect the equipment.
- Implement a consistent approach, based on a set of algorithms using state-of-the art of the knowledge condition evaluation knowledge, using systematic condition evaluation procedures/methods for condition assessment for each equipment type.

- Flexible and can be extended with new types of equipment to consider and update or upgrade in terms of knowledge and algorithms of condition assessment of a certain equipment type.
- Develop models and condition evaluation algorithms which can be based on models, heuristics, or statistical approaches may use complex reasoning or inference strategies or use any combination of these.
- These systems (if fully implemented) can estimate not only the condition but also predict the time of failure of an individual equipment item, considering all consequences in case equipment fails.

Presently, such systems and tools exist and have started to cover the most important substation equipment, e.g., transformers and circuit breakers; however, other assets from the network can also be considered across the utility enterprise.

## 51.8 Data Collection and Management for Condition Monitoring

The advances in sensors, information technology, and communication make it increasingly easier to collect data from the substation equipment and from the power system, with justifiable costs. By knowing relevant historical details about the equipment, its condition can be more accurately assessed.

The amount of data related to substation equipment, which can be easily collected, over its life, is continuously increasing. There are multiple data sources, where the data can originate such as:

- SCADA systems
- Monitoring systems and sensors for equipment in substations
- Protection devices and their own data store/buffer
- Transient data recorders or other recorders installed in the network
- Sensors in substations for ambient and environmental conditions
- Human collected data/information
- Enterprise systems data on operation or equipment activities, e.g., maintenance
- Other enterprise systems or supervision installation

The efficient use of data in condition monitoring, asset management, and decision making has to consider the following two main aspects:

- Data collection
- Data management

### 51.8.1 Data Collection

The collection of substation equipment life data for condition monitoring and asset management is perceived as an important element, by the engineering community.

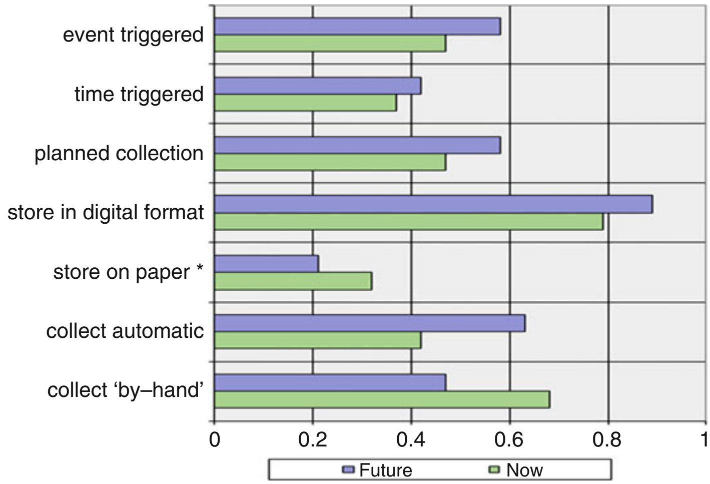


**Fig. 51.12** Current and expected future practices regarding data collection for condition monitoring

The current practices in utilities, such as how is the data collection practically done, what data are recorded, how is it stored and used, have been revealed by a set of surveys performed by CIGRE WG B3.06 for substations data in general and WG A2.44 related to data for transformer monitoring (CIGRE 2014, 2015). Beside current practices the expected trends in data activities have been asked in the surveys. How data for condition monitoring are collected presently and how this is expected to change in the future are shown in Fig. 51.12. The main expected future evolution of data collection practices is towards strong increase of automatic data collection, collection of data to be triggered by an event, the use of digital formats, and in practice to move away from use of paper on site and at inspections.

Failure and failure data have an important role in the lifetime of equipment and are important among the event triggered data.

Failures are an event in the equipment's life but at the same time a valuable source of information for increasing knowledge about aspects such as:

- The individual equipment
- Families of similar equipment
- The design weaknesses and failure modes
- Possible influence on failure from system or from other equipment
- Possible influence from the environment
- Impact of the maintenance policies
- The impact of maintenance and operation practices, etc.

In Fig. 51.13 results are shown on the typical procedures presently used in utilities on how data from failure cases are collected.

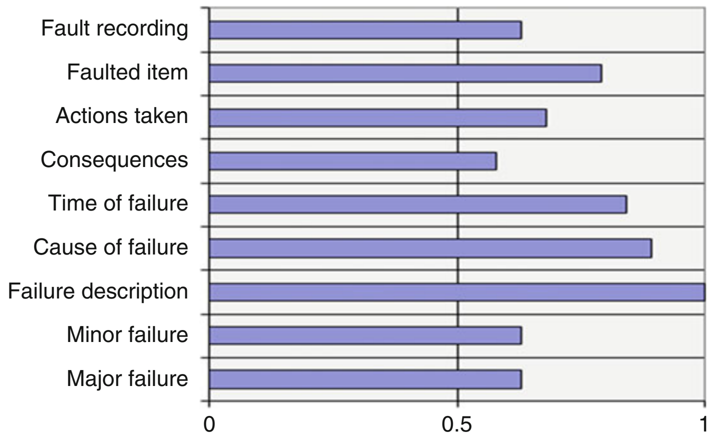


**Fig. 51.13** Practices and data collection for failure cases

Typically for failures, the collected data are quite detailed, and most often the failure description as well as time and cause of failure is recorded. The failure is also sometimes classified in minor and major failure, as recommended by CIGRE. Notable in the responses is that consequences of a failure, which are important to be known and tracked, are recorded and stored in only about 60% of the cases.

### 51.8.2 Data Management Over Equipment Lifetime

The condition of substation power equipment may need to be monitored and assessed for decades. Equipment lifetimes of 40+ years are not uncommon. As a consequence *lifetime* data management for substation equipment is a must. Details on data and life aspects, of lifetime data management for power transformers, have been analyzed and presented in the (CIGRE Technical Brochure TB 298 2006).

There are challenges to lifetime data management, which have been identified and are valid for all power equipment in substations in general and important for condition assessment and condition monitoring:

- Handling of the ever-increasing amount of data
- The selection/extraction/use of relevant data for post event analysis and performance assessment
- Data quality
- Data storage and data access during equipment's life
- Data availability on demand to different utility users/departments
- Allow timely access to data, handle data with short and long term relevance
- Ensure consistent rights of access to data
- Data security

Some aspects from current practices on how condition monitoring data are collected and stored are shown in Fig. 51.14, based on survey from CIGRE WG

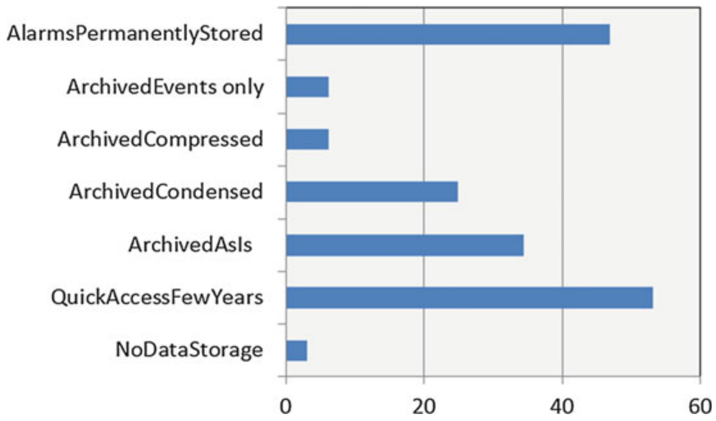


**Fig. 51.14** Storage over time of data usable for condition monitoring

A2.44. Good practice is that alarms and events are stored permanently, for later analysis and use. Current practices are that recent data are kept in systems allowing quick and on demand access for the first 1–2 years after the event. Data older than the typically 1–2 years are moved and stored in long time archive data stores, with big capacity but longer access times. Not all data are transferred to long time archives, some is compressed or processed and some is deleted, depending on the utility policies, data capacity, tools which can later on use such data and if the specific data will be used later at all. Also, for storing data over time, a couple of options are available: the simplest but most costly is to store data as collected, "as-is," without any processing, for preserving the original data for any later analysis. Sometimes the original data are just compressed by using some algorithms. Often data are "condensed," i.e., preprocessed to keep only some reduced essential engineering-relevant information and hence saving storage space.

The proper **management of data** in a utility has to face more than technical challenges. One such challenge is to overcome the data division or the data islands/silos and the historically grown utility structures.

Also challenging is the integration of existing utility data in a usable and meaningful way, to fit the algorithms and procedures for condition monitoring or other activities. As identified in TB 576 "IT strategies for utilities" (CIGRE 2014), there are often organizational data silos in utilities depending on internal organization such as maintenance data, geographical information system (GIS) data, operation data, data from energy management system, data from enterprise resource planning systems (ERP), documents typically placed in a document management system or file server, etc. The typical case is a combination of structured and not structured often text data. Technologies such as data warehousing are used which is periodically integrating and preparing for use data from enterprise systems. Such a case of integrated data management is generically described in Fig. 51.15. To link the available data to a specific asset is done in this example, by cross-linking the identification keys from the individual enterprise system over a central key register.

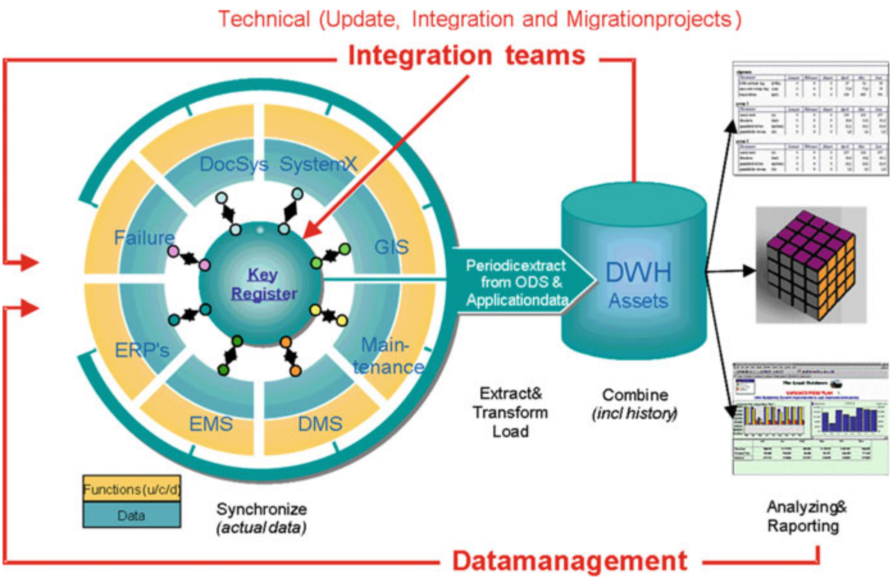


**Fig. 51.15** Example of integrated data management considering multiple enterprise systems (CIGRE 2014)

The combined data from all systems are placed in a data warehouse system for visualization and analysis on demand, by various stakeholders, including, for example, maintenance or planning.

An integrated data management system is a sound data foundation for enterprise activities and for a systematic substation equipment condition monitoring, too. Useful data for condition monitoring, stored in such a system, range from on-line monitoring data, periodic inspection, diagnosis and tests on the equipment, maintenance information, operation and network events, environmental stresses, failure records, and other documents, but also linked to the enterprise resource planning, work and updates done, materials used, and also geographic information on the location and equipment details on nameplate, etc.

The type of data about technical equipment which can be found in such systems and can be used for condition monitoring can be:

- **Fixed asset data**
  It describes the installed equipment characteristics and its location in the substation. Most often this equipment data does not change over equipment's life and contains unique identifier such as a serial number. It can change sometimes with relocation or uprating of the equipment.
- **Data blocks over life**
  These can be documents, files, images, etc., stemming from performed activities over the equipment's life. The discrete technical data blocks are related to an event or action, involving an equipment, which can be performed on demand or is

repeated periodically. Data blocks for an equipment can stem from activities such as installation, inspection, repair, relocation, upgrades, and diagnosis. Also alarms or other events affecting the substation can be considered here.

- **Continuous data recordings over life**
  The continuous technical data records are basically time series, or time records. This type of data stems most often from monitoring systems but can also originate from protection relays, transient recorders, or other sensing devices, etc. Often these data are preprocessed either by models or statistically analyzed to extract key information and reduce storage space at the same time.

Data collection and management is a key element in the decision-making process for asset management.

## 51.9 Condition Data Analytics

Condition monitoring for substation equipment will typically support a systematic decision making process for asset management, as discussed in CIGRE TB 576 (2014). The positioning, collection, data management, and condition monitoring in an integrated decision making process for substation equipment and asset management are shown in Fig. 51.16. The technical data from equipment are the basis for condition monitoring of substation equipment. For condition monitoring the technical data, operational and environmental data over life are needed, basically all information which, based on the knowledge we have about the equipment, may impact on the equipment's condition. After data collection, a natural step in data

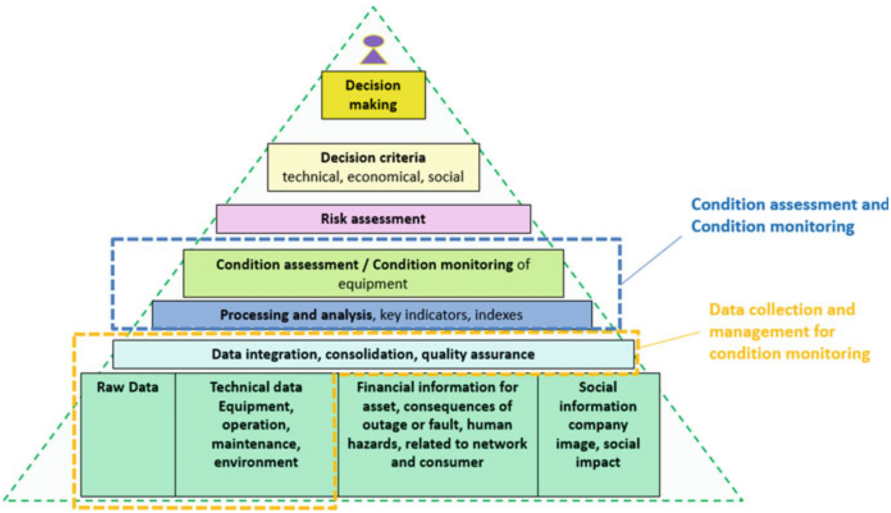


**Fig. 51.16** Positioning condition monitoring and data management in an integrated decision making process for substation equipment asset management

management is data integration, consolidation, and quality assurance. All relevant data sets, usable later in the process, have to be considered.

Knowledge plays an important role in all these activities. Deriving the technical condition of equipment relies strongly on knowledge of materials, phenomena, and equipment construction. For the data, the algorithms or processing, and especially interpretation, needs knowledge and experience.

Processing of the basic raw data, based on knowledge, for deriving some intermediary values usable for condition monitoring may also be involved. These are more informative and more compact in terms of data space needed than the raw data. It is a condensing of the information.

The above steps of data collection and management have to be done for the entire life of the substation power equipment.

Knowledge plays a key role in condition monitoring in which the data collection and condition assessment should be guided by the end user requirements.

The processing and analysis of the data can build only on the knowledge available for the specific equipment, the physics and chemistry behind it, long-term performance considering the design, materials used and operational situation.

There are numerous mathematical methods to process data collected such as presented in the CIGRE TB 630 (2015). The interpretation of results is meaningful and usable only using the proper equipment knowledge.

Although condition assessment and monitoring is a key element and influencing factor in asset management decisions, there are also other aspects such as economic, social and legal or environmental, which are also considered for asset decision making, for risk or performance-based maintenance, for example, and for long-term planning.

## 51.10 Value from Condition Monitoring

All the effort in terms of time and money spent for condition monitoring is expected to pay back, i.e., to allow cost reductions, better operation, and avoid hazardous situations, to bring value to the utilities. This expectation is valid for all types of condition monitoring whether conventional, on-line, hybrid, or holistic.

CIGRE WG B3.12 produced TB462 to analyze ways to obtain value from substation on-line condition monitoring (OLCM) called “Obtaining value from monitoring topic” (▶ Sect. 50.1). Many of the findings apply however to condition monitoring in general and go beyond on-line aspects and will be addressed in the following.

The working group investigated on-line condition monitoring systems that are complementary to, and in some cases substituting, traditional diagnostic testing procedures. It also considered the technology currently available and usable for on-line condition monitoring. It provides guidelines around the factors that need to be considered in practice such that value from on-line condition monitoring is obtained and optimum solutions using OLCM for modern HV substations and various groups and departments in utilities.

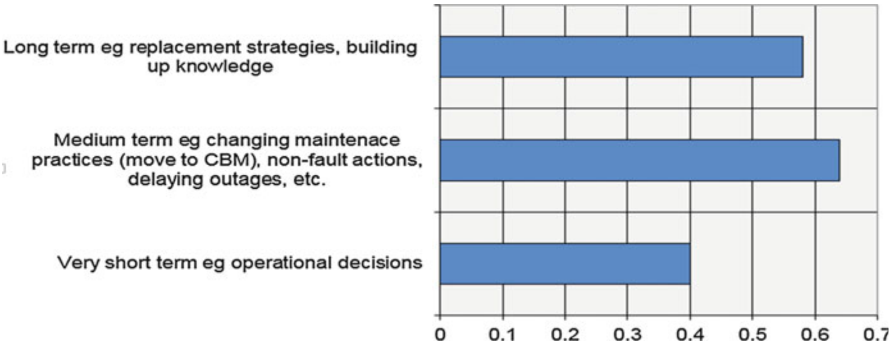


**Fig. 51.17** Where does the value come from in using condition monitoring systems

A survey carried out by the working group (CIGRE 2011) identified the present status and utility practices and accordingly key questions have been:

- Where does the value come from in using condition monitoring systems?
- Which policies and strategies for condition monitoring does your company have?
- What does your company see as a way of obtaining the best overall value from CM devices?
- "Where does the value come from in using CM systems?"

The responses to this survey question are shown in Fig. 51.17. The value from condition monitoring can positively impact short-term activities such as operational decisions; however, more substantial benefit stems from medium term activities, e.g., applying new types of maintenance, such as condition based, risk based, and long-term activities, e.g., support for replacement strategies.

The medium-term achievements obtained from condition monitoring and on-line condition monitoring were commented on by survey respondents which have mentioned benefits from OLCM such as obtaining typical behavioral trends for a variety of equipment under different operation conditions, obtaining more information for prediction of possible faults.

An important aspect is to get a wider base of data about equipment for failure analysis after a fault. Condition monitoring allows a company to take better, condition and risk aware decisions and appropriate actions and also gather experience.

Recommendations are provided around how to proceed regarding adopting condition monitoring, how to apply it, under which conditions, etc. Effort is required to develop a strategy or vision for the future, i.e., on how to move into the future and steps to apply condition monitoring and to use it over long periods of time. The aspect related to the life expectancy, mismatch between condition monitoring devices and primary equipment, and how to replace condition monitoring devices over the equipment's life have also been mentioned by a few of the respondents.

"What does your company see as a way of obtaining the best overall value from Condition Monitoring devices?"

The two main paths to obtain more value from condition monitoring are expected to be:

- The integration of condition monitoring systems for the substation
- The integration of on-site monitoring systems with enterprise systems, enterprise service centers for assets

moving towards what was called hybrid and holistic condition monitoring approaches.

In the substation, an integrated condition monitoring system is a widely expressed wish or preference. The inclusion of condition monitoring functions into protection and control devices was also expressed, since data in these devices contain valuable details; however, it is not presently used.

To obtain value from condition monitoring, on-line and off-line, using integrated and holistic approaches, will need investments. Also, it will require a systematic strategy in the utility regarding data from operation, events or supervising, and on used monitoring devices and systems.

The use of information technology (IT) and communication (C) is expected to grow towards more complex and sophisticated IT&C systems. More data analysis and processing tools at the equipment and substation level and on enterprise level too, more sensor and monitoring devices in substations with local processing and storage, new data processing, and assessment methods will be needed or existing ones improved.

Also, personnel with appropriate skills will be required, to handle the sensors and IT&C installations and electronics, but also skill for understanding the electrical and equipment problems and the network operation under, for example, new conditions as expected from the smart grids.

A difficulty of installing especially modern on-line monitoring systems and sensors is to prove the value of a monitoring system or device. Since its value comes from *avoiding* the failures, the outages, or the hazards, then these should not happen in practice when such systems are installed or their consequences should be far less than without such installations.

The technical brochure TB 462 (CIGRE 2011) deals also with techniques used to justify condition monitoring. Numerous methodologies are available for determining if investment in condition monitoring is worthwhile. Some methodologies are less rigorous than others, but this does not mean they are less effective or of reduced value. The best methodology for a utility is one that accurately considers all plausible options, addresses the concerns of key stakeholders, and provides detailed documented information to the decision makers. In general, the final methodology includes a combination of risk analysis, economic analysis, implementation considerations, and structured process review. The technical brochure TB 462 has investigated methods such as:

- Cost Benefit Analysis (CBA) Techniques.
- The CBA is considering aspects such as net present value (NPV), internal rate of return (IRR), payback period, etc., with focus on condition monitoring solutions.
- Lost Opportunity Value (LOV) Technique.
- Qualitative Risk Analysis Technique – Is an approximate method aiming to identify major areas of risk.
- Quantitative Risk Analysis Technique – This is an exact evaluation of costs and is very detailed and needs a lot of effort. Often however not all details to perform it are available.

Qualitative Risk Analysis is a relative measure of risk or asset value. Risks or asset value are separately ranked descriptive categories such as low, medium, high; not important, important, very important; or on a scale from 1 to 10. Qualitative risk analysis does not involve numerical probabilities or predictions of failure. Instead, the qualitative method involves defining the various plausible events, determining the likely impacts and the consideration of the effectiveness of counter-measures such as condition monitoring in case the event occurs. The aim of such methods is to identify the areas of risk for which investment may be applied to achieve the greatest gain in terms of risk reduction vs. expenditure (or greatest "bang for buck"). This method can be used where capital is constrained and a limited amount is available to be expended – a common scenario. Potential condition monitoring projects can be ranked in a list and the funds applied to the highest risk projects to the limit of available funding.

Basic condition monitoring risk methods may be described based on a format as illustrated below in Table 51.2, reproduced from a reference by a major North American utility (50.1). In this approach, the risk of not implementing a monitoring system would be estimated and compared with the risks if a monitoring system is installed. The user would be required to estimate the likelihood of adverse events in both cases and to anticipate the consequential costs or other impacts of adverse effects. For the case that a monitoring system is installed, the adverse event would include a failure of the monitoring system resulting in a failure of the assets being monitored. The selection of the topics for which impacts are to be estimated is typically directly related to the Key Performance Indicators (KPI) used by the utility. The magnitudes of these adverse impacts depend on the criticality of the device within the system and of the assets being monitored, its replacement cost, location, and other factors.

These factors will differ between utilities and also between differing voltage levels within the same utility. However, once these factors are determined, the risk is estimated by simply multiplying the net impacts times the likelihood of the adverse events happening. The results are then ranked by comparing with the utility's risk acceptability and risk response standards. Relative risk is assigned (low, medium, or high) and response/preventing actions determined. From the perspective of valuing the benefit of monitoring, the risk reduction through the investment in monitoring is the difference between the two risk results (with and without monitoring).

**Table 51.2** Example of a matrix used by a major utility to define the business risk in terms of ranges of impact and likelihood (CIGRE 2011)

| Likelihood of occurence | | | | | | |
|---|---|---|---|---|---|---|
| **90%** or greater that event will occur **within next year** | **5** | Moderate | Moderate | High | Extreme | Extreme |
| **50%** or greater that event will occur **within next year** | **4** | Guarded | Moderate | High | Extreme | Extreme |
| **10%** or greater that event will occur **within next year** | **3** | Guarded | Moderate | Moderate | High | Extreme |
| **1%** or greater that event will occur **within next year** | **2** | Low | Guarded | Moderate | Moderate | High |
| **<1%** or greater that event will occur **within next year** | **1** | Low | Low | Guarded | Guarded | High |
| **Impact criteria** | | **1** | **2** | **3** | **4** | **5** |
| **Safety** | | First aid injury/illness | Medical aid injury / illness | Lost time injury / temporary disability | Permanent disability | Fatality(ies) |
| **Financial** | | Impact totalling <$500,000 | Impact totalling $500,000 - $1,000,000 | Impact totalling $1M - $5M | Impact totalling $5M - $10M | Impact >$10M |
| **Reliability** | | **One of:** <250,000 customers hours lost **or** <2GWh of energy not delivered | **One of:** 250,000 to <1M customers hours lost **or** 2 to <7GWh of energy not delivered | **One of:** 1M to <3M customers hours lost **or** 7 to <20GWh of energy not delivered | **One of:** 3M to <7M customers hours lost **or** 20 to <50GWh of energy not delivered | **One of:** 7M or more customers hours lost **or** >50GWh of energy not delivered |
| **Market efficiency** | | Customers and rate-payers lodge complaints to utility | Utility customers and rate-payers lodge complaints to Government or the CEB | Government or CEB enquiry conducted into utility practices and policies | Government or CEB impose strategic and operational changes upon utility | Failure to delivere required level of service resulting in loss of license to operate |
| **Relationships** | | External opposition resulting in short-term delays or modifications to work-plans | External opposition affecting utility's ability to implement its work-plans is constrained and/or substantive modifications of its work-plans are required | External opposition resulting in increased regulatory oversight, shareholders scruting and/or restricted access to work-sites | External opposition resulting in increased regulatory legistratibe court actions or government intervention resulting in a loss of responsibilities impacting utility's corporate mandate | External opposition resulying in loss of license and/or corporate restructuring |
| **Organization and people** | | Negligible impact on service delivery and staff | Impacts on efficiency or effectiveness of some services, but would be dealt with internally | Portions of organisation experience unexpected attrition or reduced attraction factors | Ability to achieve corporate goals is threatened or there is a significant increase in the cost of service | Unexpected loss of multiple critical staff including senior leadership and the ability to deliver critical services |
| **Environment** | | Non-reportable environmental incident | Reportable environmental incident with short-term mitigation (<6 months) | Reportable environmental incident with long-term mitigation (6 months or more) | Reportable environmental incident with regulatory fines and mitigation possible to achieve | Reportable environmental incident with regulatory prosecution and/or uncertain mitigation |

## 51.11 Outlook for Condition Monitoring

There is a continuous evolution in terms of monitoring devices, favored by microelectronics, sensors, IT, and communication progress, but also a continuously increasing knowledge base for substation equipment, materials, designs, and systems, both of which are essential for condition assessment and monitoring.

The general trend in condition monitoring is for data collection and visualization only to an integrated decision support and asset management, which can do systematic, repeatable, and reliable monitoring of the condition and of the performance of the equipment.

Condition is an important factor for decision making for substation equipment activities, planning or operation, but it has to be considered together with economic aspects and social implications and environmental factors too.

Condition monitoring and performance assessment of substation devices is a permanent task in an utility, which can be optimized to meet the allowed cost and expected benefits, and it is a key element in all modern activities for asset management and for well-informed decision making.

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# Managing Asset Risk and Reliability of Substations

# 52

Gerd Balzer, Mark Osborne, and Johan Smit

## Contents


52.1 Risk Basics ..... 1044
52.2 Risk Assessment Process ..... 1045
52.3 Applying Risk Analysis ..... 1047
  52.3.1 Failure Mode and Effect Analysis ..... 1048
  52.3.2 Examples ..... 1051
52.4 Residual Life Concepts Applied to HV GIS ..... 1053
  52.4.1 Asset Life ..... 1054
  52.4.2 Obsolescence Management ..... 1055
  52.4.3 Life Extension Functional Requirements ..... 1055
References ..... 1056


Recently risk assessment is becoming a much more important tool when evaluating the appropriate level of asset intervention. The following paragraphs show the basic procedure for performing a risk analysis and the Failure Mode Effect Analysis (FMEA) which is a basis for the risk investigation (Balzer and Schorn 2015) in relation to substation assets.


G. Balzer (✉)
Institute of Electrical Power Systems, Darmstadt University of Technology, Darmstadt, Germany
e-mail: gerd.balzer@eev.tu-darmstadt.de

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl


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## 52.1 Risk Basics

Reliability in the context of a maintenance strategy introduces concepts like criticality in terms of an interruption of supply. A subsequent risk assessment should consider not only the Energy Not Supplied (ENS) but also other costs of an outage to be compared with the financial expenses for maintenance.

Risk analysis and risk management are some of the essential tasks of the asset manager regarding the functionality and reliability of their infrastructure. In general, three different risk areas can be distinguished:

- Risk to the investor: return on investment, including an appropriate rate of return.
- Risk to the project: is it able to provide the desired performance in a designated time, considering the costs.
- Risk to the system: understanding the “performance” and impact on the entire system, specifically network availability and reliability.

The goal of a risk evaluation is to find the optimum solution from several aspects, but because of the complexity of the relations, usually it is not possible to find a single total optimum and compromise is necessary. The following items are some of the aspects:

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

If a risk assessment has been applied previously, it is presupposed that further consideration is only necessary with regard to system questions concerned with system development. These system questions summarize the requirements of the system, which is the basis for the future network planning. For example:

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

The above-mentioned questions can be extended due to the requirements of individual companies. If one question is answered with “yes,” it means that a refurbishment activity should not be undertaken and a more complex analysis should be performed.

## 52.2 Risk Assessment Process

A risk assessment attempts to answer the following questions (ISO/IEC 2009):

- What can be done and why?
- What are the consequences?
- How likely is the occurrence of the event?

Figure 52.1 shows the workflow when performing a risk assessment and the subsequent consideration and mitigation to reduce risks, if this is necessary.

The different steps of the workflow according to Fig. 52.2 are as follows:

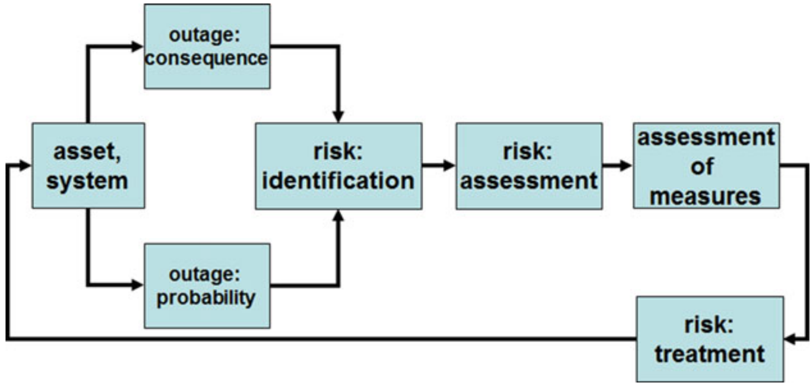
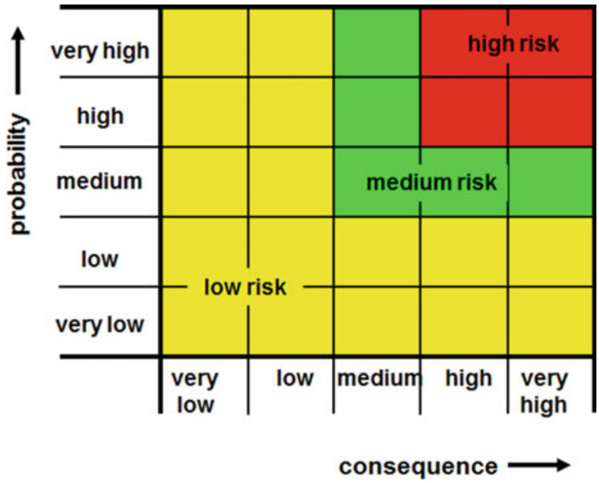



**Fig. 52.1** Workflow of a risk assessment

**Fig. 52.2** Risk map with tolerance lines or areas



- ***Asset, system:*** Based on the assets of the entire network, the significant variables are analyzed with regard to an outage of components or a supply interruption at a network node.
- ***Outage: consequence:*** Identify the consequences for each possible outage.
- ***Outage: probability:*** Assign failure rates, using historical performance where available.
- ***Risk: identification:*** Calculation of the different risks in case of different outages (based on cost/per year), alignment of a list of priorities, representation in a risk diagram Fig. 52.2.
- ***Risk: assessment:*** Assessment of the risks in respect of the objectives of the company.
- ***Assessment of measures:*** Assessment of maintenance measures to reduce the risks to acceptable values.
- ***Risk: treatment:*** Implementation of the appropriate maintenance measures.

In general, risk can be defined as: Risk = probability × consequence.

The probability arises from the failed equipment, which is in service, whereas the consequence is caused by this outage, for example: replacement cost, non-delivered energy, or personal injuries and so on. Risk maps are used for the visualization of the result of the risk assessment according to Fig. 52.2 based on the probability and consequence with different classes, which start from "very low" to "very high."

The probability of a failure depends on the failure rate of the equipment, which is in operation, while the consequence is a question of the outage impact, for example, the costs of renovation, the energy not supplied, personal injury, etc. Here, each fault is evaluated based on the probability of occurrence ($y$-axis) and on the possible consequences of a failure ($x$-axis). While the dimension of the probability is uniformly determined: failure per equipment and year (1/a), but under certain circumstances, the classification in terms of consistency is difficult because a financial assessment is not always possible, such as for personal injury and image of the company.

This figure helps to identify the risks in the system, for example, an outage with a high probability of occurrence and high consequences should be indicated in the right top corner. If any risk is calculated above this line, special measures have to be taken to reduce the risk.

The following maintenance tasks can be assigned to the risk classes according Fig. 52.2:

- High risk: The risk is to be reduced by appropriate measures within a specified time, such as 6 months, to a medium risk.
- Medium risk: The risk is to be reduced by appropriate measures within a certain time, such as 12 months, so that no further actions are necessary.
- Low risk: No action is necessary.

Next, the probable intervention costs are determined and compared with the costs for the possible countermeasure scenarios (Balzer et al. 2006):

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

The basis of a risk analysis includes both, the detailed knowledge about the condition of various assets, the influence and impact of a maintenance measure on the failure behavior, and the feedback to the nonavailability of electrical energy of the entire system.

Other influences also need to be evaluated, which include, for example, the environmental and social components, and can be described as societal (public opinion, corporate image). These are more difficult to quantify.

## 52.3 Applying Risk Analysis

Traditionally maintenance periodicity has been time based, and similarly it has been perceived wisdom that end of life replacement would follow the onset of unreliability of the asset group. This presumes that the needs for both would follow a "bath-tub" reliability behavior, as shown in 50.2 (A). This was one of the six models developed in 1979 by Nowlan and Heap in their classic research into aircraft engine reliability (Nowlan and Heap 1978). But as with these American studies on engines, the general experience obtained by studying the failures of power industry assets is also that such wear-out modes are not common. Where there is a significant population of equipment with similar design, same manufacturer and operational environment such a statistical approach may be useful. Elsewhere the experience is that condition monitoring is the effective tool for assessing the need for intervention – maintain, repair, refurbish, or replace. The respondents to the questionnaire in TB 660 showed that utilities followed this approach in conjunction with time-based, reliability-centered, and risk-based methodologies. Refer to ▶ Chap. 53 for more information.

In terms of managing the risk, the general tool is based upon an asset health review. This links the business values for performance and risk to performance. As shown in Fig. 52.3, a wide range of inputs are used to identify the exposure, with a mitigation plan identified from this.

The risk exposure is assessed at step 4 in this figure. The data are used in an asset health index shown in Fig. 52.4 (Heywood et al. 2014); this factors in the service experience of the design group with current condition indicators. From this a series of scores are developed indicating the timing and severity of any need for intervention. Not shown here but elaborated in the reference is that this score is modified if some mitigation action is

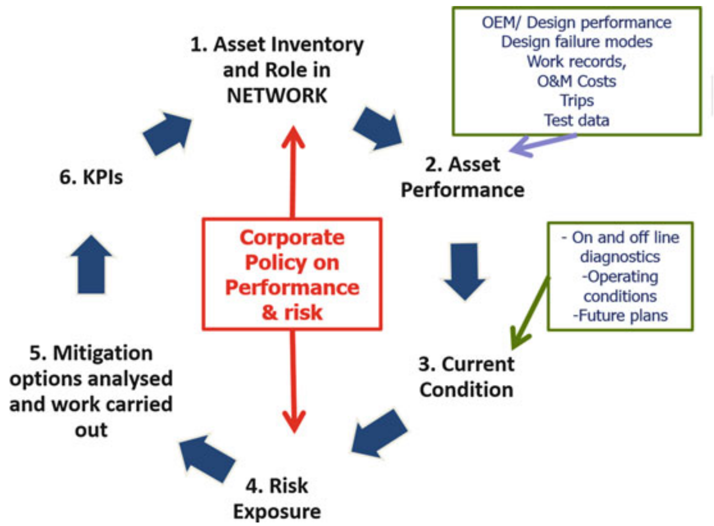



**Fig. 52.3** Asset investment planning


**Fig. 52.4** Example of a historical UK asset health review process

performed. This type of asset health method is used in several countries for transformer fleet assessment, and there is an ongoing working group A2.49 looking to get a common scoring method. The approach is less well developed for other substation assets.

### 52.3.1 Failure Mode and Effect Analysis

The failure modes and effect analysis (FMEA) method is an important part of reliability-centered maintenance (RCM) strategy and the risk analysis. It was applied for the first time in the aircraft industry in the 1960s with the development of the Boeing 747, which was more complicated than the existing aircrafts at that time. The concepts and the basics are written in papers (Nowlan et al. 1978; Smith 1993). The principle of a FMEA study is to investigate what requirements, e.g., a circuit-breaker or substation, have to meet, by which damages the required functions cannot be fulfilled, and furthermore, which damages can be expected not only at the faulty equipment but also in the overall system and the environment (safety relevance/strict liability). Finally, an essential part of the procedure is to determine the consequence of a failure, which, for example, can lead to operational limitations, damages to persons and environment:

- What functions and performance standards can be defined for the system component or equipment taking into account the operating conditions (functions)?
- How does a system component fail, so that the function cannot be maintained (malfunction)?
- What causes the malfunction (failure modes)?
- What impact has the disturbance of the system component (fault effect)?
- How can the faults be detected early, if necessary in advance (detection of faults)?
- What is the failure probability (failure probability)?
- What risk arises due to the outage and is it possible to set up a sequence of different risks (evaluation of risk)?
- Assessment of the current maintenance activities in respect of different outages (measures against faults).

The evaluation process to perform the FMEA method can be illustrated by the workflow of Fig. 52.5.

The above-mentioned steps are described in case of a circuit-breaker in detail below.

**Functions of Equipment**

The general function of a switching device or substation is to carry the expected power flow corresponding to the maximum rated power based on the design (primary function). In addition, some secondary functions can be defined, which the component has to fulfil, for example, indication of a disturbance. Based on the above definitions, it is obvious that primary and secondary functions can be disturbed by certain occurrences.

**Malfunction of Equipment**

A malfunction will occur if the above-defined primary and secondary functions cannot be fulfilled, which may result in a partial or complete failure. In this context, the following questions must be answered in each case:

- Which malfunctions are possible?
- How are these malfunctions triggered?

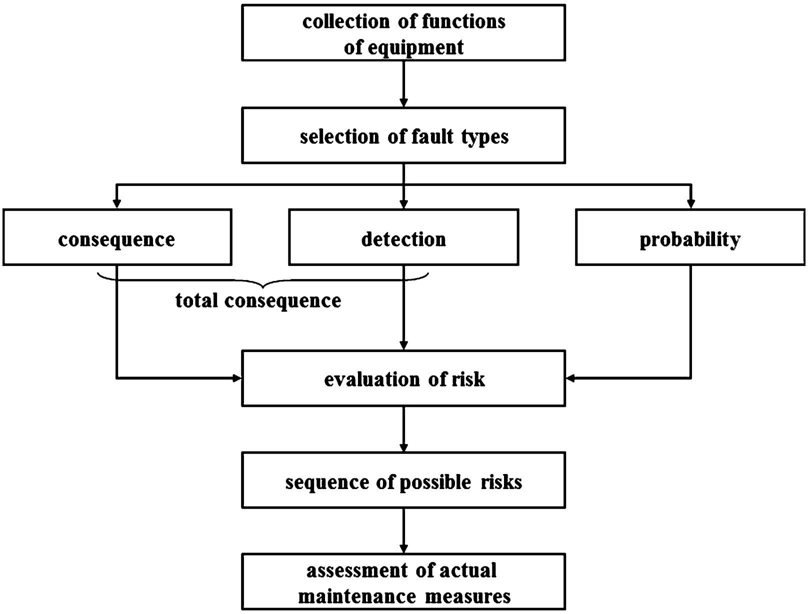



**Fig. 52.5** Workflow of the FMEA assessment process (Balzer and Schorn 2015; Choonhapran 2007)

**Failure Modes**
The next step consists of defining the failure modes (failure reasons) that lead to various malfunctions that are described above. The result is to determine the faulty component of the entire equipment or substation.

**Fault Effect**
Fault effects are of major importance for a subsequent assessment of a fault in terms of a maintenance task, which occur as consequence of a failure. For example, four main groups can be defined (people, environment, downtime, and repair costs), with corresponding subgroups due to different consequences. In addition, other criteria can be specified dependent on the operational use. These may include sales shortfall, energy not supplied, penalty, image damage of the company, etc.

**Detection of Faults**
In assessing the fault effects, it is important whether a failure of a component or the malfunction of equipment can be recognized by a diagnostic or monitoring system in advance. In this case, a supply interruption may be avoided.

**Failure Probability**
The assessment of the possible failure probability can be evaluated and classified with the help of a detailed data file from individual equipment components. In the following first example (clause Sect. 52.3.2), the values for circuit-breakers are used, which is described in detail in (Drescher 2004).

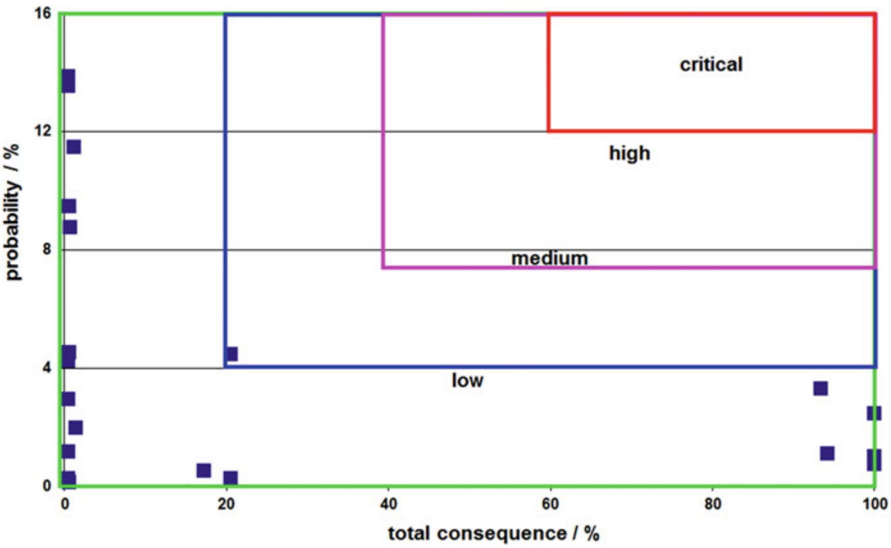



**Fig. 52.6** Risk diagram of assessing a circuit-breaker (Balzer and Schorn 2015; Choonhapran 2007)

**Evaluation of Risk**
The evaluation of individual faults using the scoring system leads to a classification of risks, which should be used when planning maintenance activities. By multiplying the individual reviews according to (Balzer and Schorn 2015), a one-dimensional view of the result is possible. Here, it is useful to apply a two-axis representation with the risk defined as the product of severity of the disturbance and the failure associated probability (risk diagram) (Fig. 52.6). The overall consequence (horizontal axis) results from the product of the outage consequence in case of a fault and the possibility of detection.

**Measures Against Faults**
At the end of the entire evaluation process, the studied faults must be classified with respect to a maintenance measure in order to minimize operational risks in case of an outage. It is important to know which behavior patterns can be assigned to a fault in the selection of maintenance measures.

## 52.3.2 Examples

**Circuit Breaker**
The first example deals with HV circuit-breakers, and the evaluation of FMEA shows that almost all faults of the investigated $SF_6$-circuit-breakers can be classified as "low" (Fig. 52.6). This leads to the conclusion that a change of the maintenance strategy for such a circuit-breaker is not necessary due to the used FMEA investigation. Risks with larger effects have a low probability of failure (danger to persons,

no detection of faults, faults in the switching chamber which can cause a malfunction of the switching off operation). On the contrary, the outages with a high probability (e.g., sensors or relay failure in the control area) have little effect on the entire operation and can be classified as noncritical risks. The faults which are close to the border line of the risk classes "low/medium" belong to, e.g., tripping latch spring drives according to the evaluation.

**MV Substation**

In principle, it is also possible to determine an optimum maintenance strategy for an entire substation using a FMEA study. In the following, this method is applied to a medium voltage system and different operating components are taken into consideration (Balzer and Schorn 2015):

- Switching bay (including busbar, cable joints)
- Circuit-breaker
- Switch-disconnector
- MV/LV power transformer
- Voltage and current instrument transformer
- Protection and control
- Civil works

The risk for each event can be determined by particular scores related to the assessment criteria by multiplying fault effects with their frequency. Based on these faults, maintenance measures can then be defined, which could avoid these fault events. Finally, it has to be checked whether these target measures are already covered by today's maintenance activity (actual measure).

As a result of this investigation, both the urgency as well as the necessity of additional maintenance can be determined, resulting from the difference between the target measures and the current measures. For example, Tables 52.1 and 52.2 show

**Table 52.1** Assessment of components of a substation (fault causes, damages), in extracts (Choonhapran 2007)

| No. | Priority | Equipment | Cause | Damage |
|---|---|---|---|---|
| 1 | 131 | Bay | Lightning overvoltages | Busbar: external flashover, electric arc |
| 2 | 131 | Bay | Pollution, moisture | External flashover, electric arc |
| 3 | 98 | Bay | Aged insulation | Internal fault |
| 4 | 33 | Bay | Incorrect distances | External flashover, electric arc |
| 5 | 30 | MV/LV power transformer | Overvoltages | Defect insulation |
| 6 | 28 | Bay | Lightning overvoltages | Cable junction: internal fault |
| 7 | 23 | Circuit-breaker | Faulty drive | Energy transmission (electric arc) |

**Table 52.2** Assessment of components of a substation (target measures, current measures); the numbering is in line with the fault causes and damages according to Table 52.1 in extracts (Choonhapran 2007)

| No. | Priority | Equipment | Target measures | Actual measure |
|---|---|---|---|---|
| 1 | 131 | Bay | Surge arresters at appropriate points | Examination by network planning |
| 2 | 131 | Bay | Moisture: control of heating and windows, loose downpipe; Pollution: cleaning, especially air-insulated substations | Inspection/service (bay) |
| 3 | 98 | Bay | Visual inspection: color change of surface; noise, subsequent PD test | Inspection/service (bay) |
| 4 | 33 | Bay | Wrong dimensioning, it must be dimensioned for spacing | Requirements by project planning/ approval |
| 5 | 30 | MV/LV power transformer | Surge arresters | Examination by network planning/ project planning |
| 6 | 28 | Bay | Surge arresters at appropriate points | Examination by network planning |
| 7 | 23 | Circuit-breaker | Overhaul | Inspection/service (bay) |

the results of a complete analysis of a substation in terms of fault causes, the following damages, and the set points and current measures. Table 52.1 illustrates the order of various faults and the subsequent damages to the equipment, while Table 52.2 describes the necessary maintenance activities and the activities carried out at the time to which these target measures can be assigned.

## 52.4 Residual Life Concepts Applied to HV GIS

The life-cycle cost (LCC) of a HV substation is generally given by the cost to acquire, own, and renew and has been presented throughout this section and described in detail in (IEC 2017), independent of the technology applied: air or gas insulated, including the hybrid alternative. However, since LCC is applied to the equipment as products and a GIS is a product in itself, the considerations given apply to the complete substation, when GIS is present.

Thus, the consideration of the residual life of GIS is paramount to the LCC of the substation, including the disposal of the GIS at the end of its life cycle. This section includes only the main considerations regarding LCC.

A few GIS installations are now more than 40 years old and many have exceeded 30 years of their service life. The intended service lifetime of early GIS was anticipated to be around 25–30 years. Today expectations are 40 years or more.

Despite exceeding the intended service lifetime, the GIS was originally designed for, service experience with early GIS has been and remains generally good. No generic life limiting mechanisms have been reported so far. However, issues of ageing and deterioration have occurred in the following areas:

- Gas leakages (mainly for outdoor installations)
- Operating mechanisms
- Secondary systems

Life extension of these GIS installations can be achieved in many cases by enhanced maintenance and refurbishment. Experience shows that where end of life has been reached, the most important factors limiting lifetime have been of an external nature such as:

- System changes (ratings or extensions)
- User operational requirements
- Obsolescence
- Support and knowledge of old GIS

Life extension can in some cases be achieved by retrofit, but replacement is often required.

Condition assessment is discussed in detail for all major parts of the GIS including the related diagnostic and monitoring techniques focusing on the wear of switching devices and contacts, insulation, and enclosures.

As the number of GIS installations approaching end of life increases, it will become increasingly important to ensure that experience with aging and deterioration mechanisms and their diagnosis is captured in order to better estimate residual life.

A general evaluation process for residual life options is discussed CIGRE brochure 499 (CIGRE 2012) considering the three main inputs: equipment factors, external factors, and changing system requirements. Some examples are provided to use asset health indices and evaluation of options. However, a detailed procedure to determine the residual life of a GIS cannot be given. Varying factors of influence on the decision-making process of users in terms of a residual life decision may have a very different importance or may not be valid for other users. This fact is also expressed by the comparatively high number of practical examples showing the distinct approaches.

If the decision is made to replace the GIS, then appropriate procedures should be followed for recycling and disposal of materials used in the GIS.

### 52.4.1 Asset Life

Working Group 37.27 estimated asset lives for GIS in the range 30–50 years, with maintenance costs being given as one of the reasons for the variance (CIGRE 2000).

The choice of an appropriate maintenance strategy has a significant impact on the life cycle cost of assets and on end of life decisions. Utilities have used a number of different strategies in order to optimize maintenance.

### 52.4.2 Obsolescence Management

Utilities expect the support of current products and products recently discontinued. However, manufacturers are often able to provide support over the service lifetime of the equipment. Some examples of services that may be available are given in the following paragraphs. The challenge to the manufacturer in providing this support is the trade-off between the long lifetime of the GIS and the industrial development with decreasing product life cycles.

Since manufacturers' product responsibilities may have changed during the lifetime of the installed equipment, it is suggested that it should be part of the users' asset management policy to maintain knowledge of the current contacts for service and spare parts.

### 52.4.3 Life Extension Functional Requirements

In order to support the assessment process and make available additional options for life extensions, the following recommendations are suggested.

To original equipment manufacturers:

- Assure availability of documentation for installed equipment
- Provide failure history/Statistics for installed equipment types (major/minor failures)
- Inform the user of changes in maintenance recommendations or other activities if any
- Assure lifetime support of installed equipment (assessment, maintenance, modifications, repair, spare parts)
- Provide solutions for extendibility of installed GIS

To users:

- Consideration in the original planning phase for possible extensions, replacements and refurbishments in future
- Keep the documentation available about the installed equipment (technical, schematics, reports, and test sheets)
- Collect and file documentation of equipment history including maintenance actions, operations, modifications, diagnostic results, measurements, tests carried out, and minor and major failures.

- Dialogue process with the OEM about minor and major failures
- Formalize the process of updating maintenance policies and practices based on latest industry experience.

  Participate in future CIGRE reliability surveys

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# Managing Obsolete and New Technologies in Substations Together 53

Jan Bednarik, Mark Osborne, and Johan Smit

## Contents

53.1 Introduction .... 1058
53.2 HV Equipment Replacement .... 1058
53.3 Protection Upgrades .... 1058
53.4 Control System Upgrade .... 1059
53.4.1 Existing Hardwired Control Systems May Need to be Modified/Expanded to Contain New Bays .... 1060
53.4.2 A New Numerical Control System May Replace an Existing Hardwired or Numerical Scheme .... 1060
53.4.3 Hybrid: A New Numerical Control System May be Used for New Bays While Keeping the Existing System for Existing Bays .... 1060
53.5 New Bay Installation .... 1061
53.5.1 New Capacity .... 1061
53.5.2 Increase the Load Capacity .... 1061
53.5.3 Change in Busbar Configuration .... 1061
53.6 Managing the Design for the Future .... 1061
53.7 Concluding Remarks .... 1061
References .... 1062

J. Bednarik (✉)
Networks Engineering, ESBI, Dublin, Ireland
e-mail: Jan.Bednarik@ESBI.IE

M. Osborne
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

J. Smit
High Voltage Technology and Management, Delft University of Technology, Delft, The Netherlands
e-mail: J.J.Smit@ewi.tudelft.nl

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## 53.1 Introduction

The substation lifetime can easily exceed 40–50 years; it is the assets within the substation which have lifetime limiting factors. Changes to the substation will be required during this period and into the future. New circuits may be connected into the substation, which will require additional bays. New transformers may be installed to increase the substation capacity. Aging and broken equipment may need to be replaced.

After a short time, the substation becomes a mix of various technologies. The age of installed equipment will span from brand new to 40 years or older.

Depending on the extent of any substation upgrade, phases of the development may require the coexistence of both new and old technology. This must be handled as a part of the project to ensure that the required schemes like interlocking or busbar protection remain operational during the lifetime of the project.

This chapter highlights some common problems and possible approaches that can be used to manage them. ▶ Chapter 9 contains additional guidance for managing innovation.

The CIGRE brochure 486 (2012) covers the design process of the substation upgrade, while CIGRE brochure 532 (2013) covers aspects associated with substation uprating and upgrades.

## 53.2 HV Equipment Replacement

AIS equipment replacement may be considered as “like for like.” In this case replacement of instrument transformers, disconnectors, and circuit breakers should be purchased having similar electrical characteristics to minimize changes to the rest of the substation. In some cases, like replacing the current transformers, it may be difficult to change ratios from the existing ones when connected to old busbar protection or similar schemes where the actual ratios are set in the hardware and are difficult to modify.

While keeping the new equipment similar, the replacement may be done to enhance the existing functionality. For example, nominal and short circuit ratings may be increased to facilitate new substation requirements.

More complex devices like circuit breakers or transformers may require substantial changes to the existing substation to facilitate for new signals, control schemes, etc.

Alternatively, if most or all of the equipment in a bay is to be replaced at one time, e.g., for increased thermal rating, then adoption of a different technology, e.g., hybrid or GIS, may be a more economical or efficient solution.

## 53.3 Protection Upgrades

The replacement program needs to be carefully coordinated and planned to align with allowable system security requirements, especially since the remote end on circuits will require work at both ends. This may also affect the performance of the substation during depleted modes (Fig. 53.1).

**Fig. 53.1** Existing protection panels

Upgrading existing protection to modern numerical relays is challenging and introduces the following implications within the substation:

- DC load – Load may increase and more MCBs may be required. Upgrade of the existing DC system (battery, charger, DC boards) may be required as well.
- Current Transformer (CT) performance – New installed protection relays may have higher requirements for the CT performance. This may require replacing the CTs, cables to the CTs (to reduce the impedance), or other measures.
- Integration or interfacing into existing schemes – Existing bus zone protection, circuit breaker fail protection, or other schemes must remain functional after the protection upgrade. Modifications of standard designs are almost always required to accommodate the existing schemes. Alternatively, it may be more economical or efficient to replace the old protection scheme (i.e., busbar protection) as well.
- New alarms may need to be accommodated. This may require expansion of existing hardwired or digital alarm systems or an upgrade to some modern digital one.
- The compatibility of new hardware and platforms within the existing substation environment.

## 53.4 Control System Upgrade

Different scenarios may occur regarding the substation numerical control system. The process for the interim and transfer of control will need to be carefully planned to ensure the system operator, and remote operations are fully aware of their capability and responsibility. This is particularly challenging during the testing and commissioning phase when switching actions may be required.

This can be complicated by whether the systems are duplicated or possess any built-in redundancy and how this is managed during outages and transfer.

### 53.4.1 Existing Hardwired Control Systems May Need to be Modified/Expanded to Contain New Bays

The existing scheme may remain as is and new extensions or modification will be used for the changes. Some old material may no longer be available, so suitable replacements are needed.

This scenario may be used as an opportunity to replace old technology with the new equivalents (e.g., replace old MCBs or contactors, replace individual electromechanical panel meters with digital multimeters, replace filament bulbs in indicators with LEDs, or replace mechanical position indicators with LED semaphores).

The existing control system may be enhanced by adding a connection to the control center in the substation that has manual or local control only.

### 53.4.2 A New Numerical Control System May Replace an Existing Hardwired or Numerical Scheme

New control system is built and the substation is transferred bay by bay from the old one to the new. Careful handling of this transition is essential to ensure that the station remains in service during the upgrade as much as possible.

### 53.4.3 Hybrid: A New Numerical Control System May be Used for New Bays While Keeping the Existing System for Existing Bays

It may be practical to keep the existing system in service for the existing bays and install the new system for the new bays only. This approach may reduce the time and cost necessary to install the new bays.

This approach may be useful where an existing substation is extended with a new busbar (e.g., a new MV busbar is added to an existing transmission substation, where the transmission substation control system is adequate).

The interfacing challenges need to be thought through, especially where protocol conversion is employed to ensure the “correct” message is sent.

## 53.5 New Bay Installation

### 53.5.1 New Capacity

New feeders will usually be installed using the current designs and material. Connections to the station wide schemes like interlocking or busbar protection will need to be adapted to match the existing scheme.

### 53.5.2 Increase the Load Capacity

When the substation is upgraded, existing schemes may be incorporated in the new installation. Where most of the bays are upgraded, it may be practical to upgrade the remaining control and protection schemes of the rest of the substation too.

Settings will need to be verified to ensure that any energization of the new capacity does not inadvertently trip protection based on previous network conditions.

### 53.5.3 Change in Busbar Configuration

The addition of a new sectionalizer or coupler bay or a change in busbar configuration may be installed to cater for new system demands. Single busbar substation may be upgraded to double or triple busbar. Existing bypass busbar may be removed with all relevant switchgear and control or protection schemes.

## 53.6 Managing the Design for the Future

Fully equipped control and common protection schemes, DC distribution boards, etc., for all future bays should ease the potential problems associated with extending existing systems. This is particularly the case with substation-wide schemes, e.g., busbar or circuit breaker fail protection or digital substation control schemes. However, numerical protection relays may have a limited lifetime in the de-energized state.

Alternatively, consideration should be given to not making any advance provision of circuit protection relays to maximize the available future flexibility. Always consider the balance between design and equipment for future scenarios and try to reduce the chance of premature equipment replacement. Take into account that control and protection systems may require more frequent replacement than HV primary equipment and design to facilitate this process.

## 53.7 Concluding Remarks

This Part H addresses the topic of substation lifetime. During the ensuing decades of asset ownership many things will change and happen, some foreseen and some not. The utility will need to be capable of making informed decisions. This part hopefully has provided some useful guidance on where to start and what issues to consider with regards to substation asset management and the life-cycles factors to be considered during establishing and implementing policies. CIGRE Technical Brochure 532 (2003).

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# Part I

# Future Developments

*Mark Osborne*

# Future Developments in Substation Design 54

Mark Osborne

## Contents

54.1 Evolution of Substations to Date ........ 1068
54.1.1 Background ........ 1068
54.1.2 Looking Ahead ........ 1068
54.2 Digital Substations ........ 1070
54.2.1 Automated System Operation ........ 1071
54.2.2 Asset Awareness ........ 1071
54.2.3 Commissioning and Testing ........ 1071
54.3 Novel Materials and Technologies ........ 1073
54.3.1 Drivers for New Materials ........ 1073
54.3.2 Generic Issues to Consider ........ 1073
54.3.3 Commissioning and Testing ........ 1074
54.3.4 Roles for New Technology ........ 1074
54.4 Designing for Modularity and Flexibility ........ 1075
54.4.1 New Installation Techniques ........ 1076
54.4.2 Changing Attitudes to Maintenance ........ 1077
54.5 DC Substations ........ 1077
54.5.1 Design Issues ........ 1078
54.5.2 Standards ........ 1078
54.6 Chapter Summary ........ 1078
References ........ 1079

The previous chapters have established the principles which underpin substation design and management. This chapter will highlight some of the medium- and long-term factors that could influence the direction of future substation design. It will focus on changes in the energy landscape and new developments in technology that may challenge the designer in their traditional way of thinking and consequently affect the design process and asset management strategy.

M. Osborne (✉)
Asset Policy, Engineering and Asset Management, National Grid, Warwick, UK
e-mail: mark.osborne@nationalgrid.com

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The role of the substation is likely to be affected in the coming decades as the nature of generation and demand changes require society to adapt to sustainable and renewable energy sources.

## 54.1 Evolution of Substations to Date

### 54.1.1 Background

The background for change has been discussed in many papers (Technical Brochure 380 2009; Technical Brochure 483 2011) and around the need to decarbonize the electricity industry. Alternative sources of generation and uptake in demand side energy management will impose new challenges and characteristics on the substation, whether it is a generator, transmission, or grid supply point.

In the 1996 CIGRE Paris session, a paper was published (The Future Substation 1996) entitled “The Future Substation: a Reflective Approach” (23-207) on behalf of the Substation study committee. The position paper provided an excellent assessment of the substation community’s thinking at the time on issues which would challenge substation design and operation in the future. It refined the decision-making criteria down to four elements:

- Functionality – what is necessary
- Technology – what is feasible
- Economics – what is affordable
- Environment – what is acceptable

The chapter highlighted that the role of the substation is an enduring one, but it will need to adapt in response to many changes. These include the external impact of new generation patterns coming about from renewables and demand side management making the network more complex. Changing aspects of society and stakeholder expectations will also be influential in the need case for new substations. The economics associated with new build especially where space is limited will influence the choice of technology. The uptake of optimized configurations is anticipated based on improved availability and faster replacement rather than duplication.

The capability and performance of modern equipment will influence the configuration and operational philosophy employed in new substations. Better reliability and increasing automation along with new methods of monitoring and asset management may prioritize design away from routine maintainability to risk and reliability focused intervention.

### 54.1.2 Looking Ahead

The issues back in 1996 are still very relevant; however, there have been some additional changes since then which may reprioritize the thinking. As we look towards 2050 from a substation design and operation perspective, utilities need to adopt philosophies which, to a greater extent, consider the following scenarios:

- Rising temperatures, rising sea level, and increasing occurrence of extreme weather conditions will affect the substation physical environment.
- The impact of substation and energy infrastructure on the environment.
- Increasing role of external "stakeholders" in decision making that will affect the substation lifetime.
- Existing substation assets will be driven harder and under different network conditions from those perceived decades ago when they were specified, manufactured, and tested.
- The role of energy storage in the balancing of society's energy needs.
- New operating environments will emerge offshore, possibly submarine and in time outer-space.

Energy will become more dispersed across different technologies and applications requiring greater coordination of many sources to provide safe, reliable, and efficient energy services. Success will be measured in the effectiveness and resilience of a substation to address elements of the scenarios described above. The following four design aspects are likely to be key factors which will influence future substation construction, operation, and management.

1. There will need to be higher energy density solutions driven by
   (a) Smaller and compact installations
   (b) Increasing urban energy demand
   (c) Constrained space limitations
2. Progressive move towards low carbon footprint solutions in order to
   (a) Improve efficiency
   (b) Decrease substation emissions (or possibly replace $SF_6$) and
   (c) Minimize the use of natural resources and carbon intensive materials such as concrete
3. Substations need to become more "modular" such that they will be
   (a) Quicker and simpler to install
   (b) Flexible configurable designs to meet different applications
   (c) Secure and robust as energy becomes more integrated into communities
4. Substations will require telematics to
   (a) Better utilize these information rich sources to improve network operation
   (b) Monitor system performance and asset health
   (c) Develop prognostic tools to optimize system accessibility and downtime

These additional influences introduce the need to consider different strategies and technologies to manage the impact relative to the utility. However, these will introduce different risks, maintenance, and certification requirements which will significantly impact upon the design and operation of the substation itself.

The adoption of new technologies will require utilities and solution providers to establish new skills and disciplines. This may become burdensome for utilities to retain a larger range of skills to cater for the broad scope of asset types across their network from electro-mechanical systems, solid state microprocessor, numerical algorithms, Ethernet services, communication protocols to new cyber security functions.

Utilities need to derive value from their business. Therefore, the asset management strategy (Institute of Asset Management) needs to be foremost at the design concept stage, rather than an afterthought. This may drive the concept of service provision and the need for performance metrics much as other public sector services have experienced. This in turn may support the case for faster installation and modular solutions requiring an alternative approach to fault management and performance monitoring.

## 54.2 Digital Substations

There is no doubt that digital solutions are available and will proliferate in future substation build. The challenge is how to harness this economically and effectively while retaining the dependability and reliability required for a substation.

There is a vast potential to be realized from the latent capability within digital substation automation. This can be loosely apportioned into two areas:

- Automated system operation. Using functions such as wide area monitoring to inform regional and network level control and protection
- Asset diagnostics and prognosis. Utilizing data within the relays to provide better knowledge of plant status, ability to employ remote servicing, etc.

IEC 61850 will drive the deployment of microprocessor technology into the substation environment. This is possibly the most significant shift that will be seen in substation technology since the replacement of air blast and oil-based insulation with $SF_6$.

In addition to the deployment of IEC 61850, the development of a common information model (CIM) along with object orientated messaging will enable new systems to communicate between different manufacturer solutions. These applications rely on the integrity of communication systems and data management to ensure reliable and secure operation. These issues are being addressed through various smartgrid initiatives and trials. This is demonstrating an issue that utilities have traditionally avoided which is heavy reliance on external services and systems to assure substation operability.

“SmartGrid” has been a very over-used word. However, at its heart is the ethos of making the network more effective, whether through better awareness or better decision making tools.

This does not necessarily require high tech solutions, but access to and the utilization of information on which decisions can be made. The key role of the substation in the delivery of smartgrids will center on the enabling information technology infrastructure and implementing the security necessary for the appropriate level of data access and management.

### 54.2.1 Automated System Operation

Substation automation is well established and discussed in the previous chapters. The future will be about expanding this capability beyond the substation perimeter and coordinating multiple substations and regions of the power system.

Careful thought will be required to establish and implement the appropriate control hierarchy and resilience to manage risks around asset unreliability, such as failure to function or inadvertent operation. As these systems grow in size and criticality, the impact of mal operation becomes much more significant, so safeguards must be established to limit the effect of any un-intended operation at a regional level.

This complexity is a key risk factor which needs to be evaluated and understood at the design stage where simpler or socially undesirable options are not chosen on economic merit alone. This is likely to drive the development of better modelling and testing solutions.

### 54.2.2 Asset Awareness

The capacity for monitoring and sensing within the substation has come on leaps and bounds. This will grow exponentially as utilities try to improve reliability and availability of the system through better informed decision making based on the increased extent of data available from the substation.

This enhanced capability needs to be tempered with the fact that in order to take more risk, the engineer needs to be more knowledgeable and confident in the validity and integrity of their data and decisions. Poorly informed decision making could result in more unreliability or, even worse, danger to personnel or possibly the public.

The tools need to be robust and reliable as they increasingly are used to underpin business decisions.

### 54.2.3 Commissioning and Testing

Most legacy control and protection systems have some form of proprietary-based communication and data structure. These systems will continue to operate for many years and may not necessarily be replaced to make way for new IEC 61850 platform technology. As such, solution integrators will need to develop interface protocol converters to enable new and old to work together.

Modern telemetry will need to be interfaced with old legacy solid-state control systems developed decades ago. Utilities need reliable, tried, and tested systems. Moving to a new platform is inherently fraught with risk. Generally, this requires new skills, equipment settings, spares, and methodologies. These systems need to have good change management processes, and the energy industry should look to the financial and telecoms sectors for examples of good practice.

Consequently, gradual migration tends to be favored which inherently prevents achieving the most from the new technology. Timescale is very much a driver, where a utility is constrained by the two paradigms:

- Establishing confidence in a new technology or platform takes time.
- Networks cannot be “just” replaced without impacting on security, safety, and reliability.

The increasing use of power electronic and digital systems introduces a further challenge in that the protection is integrated into the control of the power electronic devices. This raises the question that utilities will need to think through their commissioning program, i.e., the proving tests before the equipment is made live onto the system. This will be particularly relevant for wide area automation where an inadvertent operation may have a large network impact, since it will be impossible to isolate a substation bar or similar onto which the application can be commissioned with minimal impact.

The use of Hardware in the Loop testing (HIL) will go a long way to prove the performance and integrity of these applications; however, further work is necessary to ensure that the final installation and integration to the utility has been performed correctly.

It will also be necessary to make these solutions easily extendable or modified as system conditions change and more so, how to replace them when the hardware either malfunctions or requires replacement due to obsolescence. This is a particularly strong driver for interoperability and common communication protocols.

The maintenance, performance testing, and monitoring of smartgrid systems will become a more automated process, utilizing the on-line connectivity of these systems, to carry out regular polling and reports, which only highlight by exception. These solutions will need to incorporate intelligent applications and decision support tools capable of informing the utility when issues arise and any specific actions which are necessary. This would seem to be a natural progression if we look at how other industries have changed the nature of maintenance and services provision, e.g., car, photocopiers, and mobile phones.

This will further support asset management practices, which value the ability to predict and establish the least regret option with respect to either the business climate (regulatory) or societal climate and provide a robust mechanism to deliver the services required of a substation. A successful implementation will center on the ability to provide the following:

- Self-supervisory systems
- Self-initiating with fall back safety modes
- Structured testing regimes with appropriate levels of automation to fully evaluate the capability of applications

## 54.3 Novel Materials and Technologies

While there have been significant step changes in the substation automation and communication sectors, the pace of change on the primary equipment side is much more conservative.

This section highlights the opportunities and blockers for new materials and technologies which could provide new applications or benefits to the energy systems and their impact on the substation.

Study committee D1 “Materials” is responsible for many of these topics; however, their application and impact on the substation environment is the role for B3.

### 54.3.1 Drivers for New Materials

One of the reasons that some technologies seem to take a long time to gain acceptance in the energy industry is that of being asked to try and find applications for new materials as opposed to new technology providing solutions to industry problems.

The challenge that all new technologies face is why would the utility install it? It needs to be either cheaper than the current option, remove a major safety hazard or risk and primarily not introduce any new risks. It will be necessary to have an attitude to innovation and entrepreneurial spirit to bridge the proof of concept and acceptability criteria.

While there will be gradual improvements and optimization in traditional substation equipment, the key areas where development is anticipated that will affect the substation are that of power electronic applications and energy storage solutions. These two will introduce new and different technologies into the substation sector.

### 54.3.2 Generic Issues to Consider

The energy industry is conservative by nature, and as such for a technology or application to be successful, there needs to be an evidence trail to demonstrate confidence in the performance, longevity, and reliability. Utilities historically have liked to be the second to adopt a technology; however, as the energy sector becomes more competitive this may be a differentiating factor rather than a luxury.

One of the demonstrations of confidence is testing, and if a reliable and robust regime of testing methodologies can be quickly established to allay the engineers concerns, this will go a good way towards bringing it onto the system.

Design standards, especially internationally agreed ones, help to bring new technology along as it enables the substation designer and their commercial counterparts to be able to compare and tender competitively to get a reasonable price and avoid having bespoke solutions which can only be procured from one supplier.

The balance between innovation and standardization is addressed in ▶ Chap. 9 and TB 389 (Technical brochure 389 2009) which considers a number of different aspects. One of the key points to note is that once a new concept is developed, proven, and rolled out, this then should become a standard or business as usual option such that commercial, operational, and population understanding can be established. In the meantime, the organization can be developing the next innovative application.

### 54.3.3 Commissioning and Testing

The testing of new technology to older standards and processes can be restrictive and limit the implementation, so thought needs to be applied here to be considerate of modern technology. One of the key issues towards reducing outage times is to minimize the amount of testing that is carried out on site. Cooperation with the equipment suppliers is required to ensure that they carry out the relevant tests to provide the utility with the baseline information they require when the substation is first put into service.

Detecting condition and failure of new materials will possibly require new monitoring systems depending on the nature of the technology; however, these will need to be suitably robust and functional for use in a substation environment.

The use of pilots and trials is an effective method to understand the type of tests necessary to measure performance and commission the application safely. Once established, this would speed up the roll out process without significantly increasing the risk.

### 54.3.4 Roles for New Technology

At this time, the new emerging requirements in the electricity delivery arena center on methodologies which support or deliver remote sensing and reliability indication. This introduces a relatively low risk in terms of new concepts for the utility while quickly and at a relatively low cost providing benefits and improving availability and safety.

#### 54.3.4.1 Composites

Composites provide opportunities for light weight, stronger, and more efficient fabrication techniques to produce solutions which can be safer and lower cost to produce, yet offer similar performance to the "traditional" materials associated with HV equipment.

Substation safety is a key argument behind the use of composite materials, typically where the failure mode is less destructive or catastrophic than associated with traditional materials such as porcelain, concrete, and steel.

A further benefit is likely to be the opportunity to speed up the replacement of switchgear modules or structures constructed with composite material such as support insulators, bushings, and prefabricated buildings, without the need for cranes or long duration construction programs.

Furthermore, it is likely that the use of composite materials will be incorporated into the designs of future high voltage equipment, but these are out of the scope of this book.

The impact on the substation will be around integrating these new materials and their impact on substation wide electrical phenomena such as earthing, impressed voltage, EMF, and EMC performance. The longer-term issues which need to be evaluate will be around whole lifetime performance, such as losses, maintenance burden, failure modes, and effect and compatibility with other substation materials.

#### 54.3.4.2 Nano-materials

The opportunity to improve the performance of a material through the application or augmentation using nano-materials may help designers to either eliminate un-necessary equipment or reduce the risk or stress assets see in service. This could also encourage more compact designs optimizing the asset footprint.

These technologies can enhance the material performance to distribute current more effectively reducing the heating or profiling of the voltage grading to reduce the electrical stress seen during operation enabling design modifications to reduce the size, weight, or functionality of the equipment.

#### 54.3.4.3 Superconductivity

For many decades, superconductivity has been on the verge of adoption into mainstream electricity delivery; however, economics continues to hinder the progress due to more competitive alternatives and concerns around the reliance on specialist auxiliary systems such as cryogenic cooling.

Developments of superconductivity in HV cables are the most advanced with a number of demonstrations around the world. Its use in the substation would largely be associated with transformers, energy storage, and fault current limiting applications. From the substation perspective, the interface between the superconducting material and the HV system needs to be carefully considered, particularly around the dielectric integrity and the current limiting features for the economic viability especially at EHV.

There would be new risks to manage associated with personnel handling and maintaining cryogenic material in terms of training, safety, and work processes around handling.

Whereas various Technical Brochures and papers highlight the benefits of this technology, it does seem to have fallen into the category of a solution looking for a problem rather than providing a solution to an urgent problem.

## 54.4 Designing for Modularity and Flexibility

The introduction to this chapter highlighted the increasingly dynamic nature of the power system becoming a key driving feature in the utility's decision making and equipment selection. This is the driving force behind utilities wanting to be able to flex their networks in response to these changing circumstances.

There is no one solution which suits every utility on every continent; however, there are some basic requirements which need to be addressed:

- System Access
- Service Availability
- Security of Supply.

The following are desirable techniques or technologies which can lessen the impact on the above during construction, operation, maintenance, or intervention which most utilities will increasingly covert, appreciate, and value:

- The pursuit of flexibility
- Faster and quicker installation methods
- Low impact substations
- Compact solutions which can fit into existing footprints without affecting existing substation practice
- Reduced outage times
- Ease of maintenance and minimal intrusive intervention
- Functional lifetimes.

### 54.4.1 New Installation Techniques

As the technology becomes more versatile, utilities will focus on minimizing the time and resource on construction and maintenance and improving safety.

Where possible, utilities and solution providers will seek to work off-line in a nonlive environment, such that work can be carried out more quickly without the constraints of working under utility operational safety rules. Off-site substation assembly and prefabrication and use of modular bays are increasingly being investigated to deliver substation replacement and refurbishment in a shorter time. The benefits include minimal outage durations, less site assembly, and testing which typically costs much more than factory assembly and testing. The solutions produced must optimize the use of common services and auxiliary systems, and the requirements of the site staff need to be fully integrated into the designs such that they are readily accepted when delivered to site.

There is an increasing role that information systems can play in the delivery and construction phase of substations such as Building Information Management (BIM). The concept of BIM allows the use of modelling tools to examine and optimize the construction design program and cost. Features can be employed such as three-dimensional visualization and augmented reality to assess the effectiveness of access and safety features. This can also be coupled with the program to visualize the construction progress, particularly in proximity to energized bays. This can be further utilized with applications like laser surveys and ground penetrating radar of existing facilities to accurately locate underground and hidden services. This enables the installers and utility to walk through the design and identify potential risks and hazards before they are constructed, resulting in an optimized lower risk and efficient design.

This is not only limited to the construction phase, but can also be incorporated into the operate and maintain phase to train staff, identify hazards, manage faults, and defects plus develop new management approaches to mitigating risks. This methodology can also be applied to developing new approaches to:

- Disaster recovery
- Fast deployment to reduce costs of emergency return to service
- Managing capability and resources more effectively

### 54.4.2 Changing Attitudes to Maintenance

The last few years has seen the emergence of the role of Asset Management becoming increasingly important in the utility decision making process.

Resource and system access is driving many utilities to constantly review their maintenance and asset intervention strategies; however, most substations will probably incorporate a number of different generation technologies, which may not enable common maintenance strategies to be adopted.

The role of nonintrusive monitoring is likely to be expanded in order to minimize the need for intrusive maintenance, thus ensuring outages are only required for essential work. This will tend to move the focus on reliability and availability from the primary assets to the monitoring systems.

Business intelligence system such as asset health indicators and substation performance metrics will become more central to utility operating strategies, particularly as socio-economic factors such as regulation, competition, and environmental ambitions will have to drive value for consumers and shareholders.

## 54.5 DC Substations

Within the last decade, substations have been constructed for offshore applications. Although marine power is not new, the movement of bulk power and operation at EHV in this environment is new. The need to use insulated cables throughout introduces a network dominated by capacitance. The traditional limitations of AC networks begin to limit the power transfer capabilities, presenting the opportunity for HVDC transmission which is currently being developed for offshore and the first DC grids are likely to be offshore.

There are many switchyards incorporating DC around the world, typically this is for a linear application between two different transmission or distribution systems. The future challenge is the development of a DC bussing substation or multicircuit DC solution. Initial thoughts consider the AC switchgear equivalents, however, should we really be thinking in terms of a power electronic-based substation, where the control, bussing, and protection is carried out in the converters or other power electronic devices? Again this will be primarily assessed within Study Committee B4, although the integration of these new solutions into the substation will need to be addressed such as the requirements to be able to safely isolate and work on parts of the substation while power still flows.

### 54.5.1 Design Issues

Many of the basic substation design fundamentals will be valid irrespective of whether the technology is AC or DC. The safe operation of the substation will still require methods to switch, isolate, and make equipment safe for maintenance. However, effort will need to be focused around:

- Procedures and methodologies to manage DC currents and fields in the earthing system, particularly associated with trapped charge.
- Protection and automation is another significant departure, as it is typically combined into the power electronic control system. New methods and strategies are required to detect and clear faults, since in DC the systems will need to operate significantly faster than AC solutions to prevent large system collapse events.

### 54.5.2 Standards

Work is underway on establishing standard voltages and electrical and safety distances for DC systems. This is necessary so there is some consistency between different designs and in the longer term multivendor solutions can be safely operated together. This will also encourage competition and reduce costs, making DC more accessible and viable as a network choice.

This should also enable type rests to be agreed, which will reduce the necessity for repeating type tests, thus enabling the costs to be reduced in the longer term.

## 54.6 Chapter Summary

The adoption of new technology into the substation is a balance of risk and economics. The pace of change is growing, and the substation community needs to become faster at successfully implementing change and being responsive to external factors. While the industry needs to be aware of and consider the implementation challenges, it should avoid un-necessarily impeding the introduction of viable new technologies through lack of awareness or fear.

The use of pilots and trials to field test these devices is an effective method to advance the equipment, what is a more challenging request is sharing the learning so equipment is not un-necessarily impeded through perceived negative experience. In this regard, the active involvement of the site staff in the new developments is absolutely essential, and this is an area where the industry has been particularly weak in the past. If these issues can be resolved then it is not unreasonable that new technologies and materials could be accepted in a shorter timescale than has been experienced in the past.

This is a role that CIGRE will actively play by encouraging utilities and engineers to share and develop best practice with the wider community to enhance the performance of substations.

Hopefully, the reader has found some useful advice from this book, helping to ensure the role of the substation will continue to be an essential part of power systems into the future.

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