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Switching Equipment

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Switching Equipment

With 486 Figures and 44 Tables

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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 switchgear, compiled by Study Committee (SC) A3, represents the latest thinking in switchgear 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 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 switchgear 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, switchgear design engineers, consultants, and users.

I would like to congratulate those involved from SC A3 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 switchgear activities now and in the future.

March 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 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 Council

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.

March 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 valorize 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 720 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.

Like 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 A3 on switching equipment, is the fourth 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.

Secretary General Philippe Adam

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 multiterminal 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 to 2014. He was appointed Secretary General of CIGRE in March 2014.

Preface

The global environment of electric power systems is changing due to various technical requirements. For instance, needs of long-distance, large-capacity EHV and UHV, DC and AC transmission, introduction of renewable energy, active distribution networks, massive exchange of information, integration of HVDC networks with power electronics, massive installations of energy storage, and awareness of environmental sustainability are defined and investigated in various activities. In addition, especially where the power system has a large amount of aging equipment, the development of substation equipment with higher cost efficiency as well as the investigation of equipment lifetime management has become more important corresponding with competitive market situations. These technical issues can stimulate and encourage development of various new technologies assisted with information and communication technology.

The objectives of CIGRE are to disseminate and promote the interchange of technical knowledge and field experience in the field of electricity generation, transmission, and distribution in different countries. Being the largest global association in the field of electric power systems, CIGRE provides a unique platform to combine the expertise of universities, laboratories, manufacturers, and utilities. Numerous international working groups develop solutions for emerging problems in an international context, which are often related to the scope of different CIGRE study committees.

Within CIGRE, Study Committee (SC) A3 has a rather wide scope dealing with DC and AC transmission and distribution equipment. Substantial efforts have been focused on collecting field experience on switching equipment from distribution through transmission voltages and exploring scientific behavior of DC and AC switching equipment in power systems. Especially, a circuit breaker is one of the great inventions of the early twentieth century enabling the AC transmission and distribution networks of today. Many pioneers devoted their energies to develop high voltage circuit breakers with different insulating and interrupting media over a century. Oil circuit breakers were designed up to 420 kV. Air blast circuit breakers were critical in realizing 800 kV transmission systems. Gas circuit breakers realized 1100 kV transmission. The precursors elucidated fundamental interrupting principles and contributed to accelerate the development of large capacity circuit breakers, which now support modern power systems.

In order to maintain human resources to sustain the electric power system and equipment of tomorrow, CIGRE SC A3 has written a Green Book on switching equipment with new manuscripts targeted for students, as well as young engineers, who are just starting their careers and are involved in research, development, design, production, deployment, operation, and end of life of switching equipment used in power systems. The Green Book on switching equipment attempts to define the technical terms essential to switching equipment clearly and comprehensively and covers fundamental subjects on switching equipment used in power systems, which explain interrupting principle of circuit breakers with different technologies, switching phenomena observed in power systems, and history of various circuit breakers including oil circuit breakers, air blast circuit breakers, vacuum interrupters, and gas circuit breakers. The book is also a useful guidebook to understand CIGRE publications such as technical brochures that include state-of-the-art information on emerging subjects, but are targeted for experts. The book also addresses an outlook of future switching technologies.

The authors and the editor hope that this Green Book on switching equipment provides a unique resource for young engineers wishing to develop themselves, and that they obtain valuable inspiration to help the evolution required for future power systems.

March 2018 Hiroki Ito
Chairman of Study Committee A3, High Voltage Equipment

Hiroki Ito was born in Yokkaichi City, Mie Prefecture. He received his B.S. and M.S. degrees from the Tokyo Institute of Technology, Japan, in 1982 and 1984, respectively. In 1984, he joined Mitsubishi Electric Corporation, Transmission and Distribution, Transportation System Center. From 1989 to 1991, he worked as a researcher on the plasma physics and the discharge phenomena in the Coordinated Science Laboratory at the University of Illinois, USA.

After returning to Mitsubishi Electric Corporation, he was engaged in the research and development on high voltage DC and AC gas circuit breakers in the High Power Laboratory. He was engaged in investigations of arc interruption phenomena on high voltage DC and AC gas circuit breakers. In 1994, he received his Ph.D. from Tokyo Institute of Technology. From 1998 to 2005, he was part of the design section of high voltage gas circuit breakers, where he was engaged in the design and development of high voltage gas circuit breakers including controlled switching, especially the development of controlled transformer switching devices and their field demonstration. He was moved to the Research and Development Department in 2005, where he was manager of the department and also an acting director of accredited high voltage and high power laboratories of Mitsubishi Electric Corporation. He is a member of Current Zero Club.

Regarding CIGRE activities, he is a regular member of CIGRE SC A3 and an SC A3 advisory member since 2004. He first joined CIGRE WG 13.07 and A3.07 "Controlled switching" in 1998 and was involved in international surveys on field experience of various controlled switching. He was also a member of IEC PT62271-301, which published testing requirements based on the CIGRE investigations. He was involved in CIGRE TF A3.01 "Electrical endurance tests" in 2004 and also in IEC MT-40 that reconsidered actual field stresses of high voltage circuit breakers and recommended the test programs in IEC TR 62271-310, which is now being discussed for its standardization by IEC SC 17A/WG 61.

Due to increasing demands for electric energy in countries with rapidly growing economy such as China and India, CIGRE decided to investigate the current status of UHV transmission. He was then appointed convener of CIGRE WG A3.22 "Technical requirements for UHV substation equipment" in 2006. WG A3.22 undertook a CIGRE-wide lead in surveying the current state of the art in the field of UHV technology, and then investigated the switching phenomena distinctive in the UHV networks. The resulting findings and recommendations were published in the Technical Brochures 362 and 467. He also led a follow-up CIGRE WG A3.28 "Switching phenomena and testing requirements for UHV and EHV equipment" and published the Technical Brochure 570 "Switching phenomena for EHV and UHV equipment." Since 2012, he has been the Chairman of CIGRE Study Committee A3: High voltage equipment.

Acknowledgments

The CIGRE Green Book has been completed with immense collective efforts and devoted hard work. Since the first circuit breakers were built at the beginning of the twentieth century, the design, manufacturing, testing, and field application of circuit breakers have changed considerably. Through their history of development, circuit breakers applied to power systems were broadly classified by the medium used to extinguish the arc. Fortunately, many experienced experts including H.H. Schramm, Lou van der Sluis, Denis Dufournet, David Peelo, Hubert Mercure, and Russ Yeckley, even though most of them being already retired from their organizations but having valuable experience being involved in the development of circuit breakers with different interrupting media, were able to participate in the Green Book team and make valuable suggestions and even contributed to the writing in cooperation with many active SC A3 members: Anton Janssen, Rene Smeets, Robert Le Roux, Nenad Uzelac, Martin Krigel, Magne Runde, André Mercier, Mark Waldron, etc. By considering the continuity, some younger generations also participated in the team. All the international voluntary efforts produced the CIGRE Green Book on switching equipment with comprehensive new manuscripts. The authors who made significant contributions are listed below as a token of respect for their efforts.

The CIGRE Green Book was originally proposed by Dr. Konstantin Papailiou, former SC B2 Chairman, and approved by Prof. Klaus Fröhlich, former CIGRE President who was also the Technical Council Chairman and SC A3 Chairman. They have continuously provided us much encouragement during the preparation of the book.

The editor would like to express his deepest gratitude and thanks to Harley Wilson for his long-term and daily devoted assistance to review all the drafts and improve the quality of explanations. Also the editor would like to offer his profound appreciation for the utilities in the USA, the Netherlands, Canada, Ireland, Spain, Germany, China, and Japan, and to the manufacturers such as ABB, Siemens, GE (formerly Alstom), Schneider, Meidensha, and G&W, who provided many valuable photos showing classical and modern substation equipment and gave permission to use them in the book. The editor also thanks Tadao Minagawa for assisting in the approval procedure of copyright issues and also Mariko Taniguchi for helping with the re-creation of some old figures that remained as just old hard copies. The editor is also grateful for kind assistance and advice from Dr. Christoph Baumann, Ms. Daniela Graf, and their colleagues at Springer.

Finally, as the CIGRE SC A3 Chair, I appreciate all the organizations in their support of volunteer activities of CIGRE, an international nonprofit association which maintains important values by delivering "unbiased" information based on the kind cooperation and understanding of the supporting families and the supporting companies.

28 March 2018 Hiroki Ito

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About the Editors

Heinz-H. Schramm was active in the development of medium and high voltage switchgear at Siemens AG, during all of his professional life, from 1961 until 2001. From 1985 until 2004, he acted as Chairman of IEC TC 17 "Switchgear and Controlgear" and of IEC SC 17A "High Voltage Switchgear and Controlgear." In 1990, he was appointed Chairman of CIGRE SC 13 "Switching Equipment," a position he held until 1996. Since 1986, he has been lecturing at the Berlin Technical University on switching processes, where he received the title of Honorary Professor. He continues to lecture there, and at several other universities, until today. Also, he is supervising bachelor's, master's, and doctoral theses. In 2001, he was made an Honorary Doctor of the Plzen University at Plzen, Czech Republic. Dr. Schramm is an honorary member of CIGRÉ and was rewarded the CIGRE Medal, the highest recognition of CIGRE. He is a member of IEEE-PES, VDE, and the German Society of Physics (DPG). He is author of many publications, has coauthored some books, and has written a book *Switching in High Voltage Systems*.

Denis Dufournet graduated in 1975 from ENSEM (École nationale supérieure d'électricité et de mécanique) in Nancy, France. He was research engineer and later manager of the research group on Interrupting Principle for Alstom Grid. He continuously joined CIGRE working groups from 1983 to 2014; he was the convener of CIGRE WG A3.28 "Switching phenomena and testing requirements for UHV & EHV equipment." He received several awards from CIGRE: Distinguished Member in 2002 and Technical Committee Award in 2001. From 2004 to 2016, he was Chair of IEC Technical Committee

17 (HV Switchgear) and Chair of IEC Subcommittee 17A (Switching Devices). He has been elected Fellow of the IEEE in 2005. Besides his membership in the IEEE Switchgear Main Committee and in the High Voltage Circuit-Breaker Subcommittee, he is an active member of several IEEE working groups. Since 2002, he is the Chair of IEEE WG C37.011 (Application Guide for TRVs for HV circuit breakers). He received the 2005 I.E. Standard Association International Award.

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.

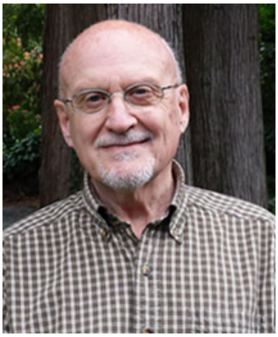
Anton Janssen started his career in the field of transmission, became manager of 400/150/50 kV-Transmission, and later manager of projects for transmission, heat/steam systems, and cogeneration plants for a power company in the southern part of the Netherlands. In 1993, he joined KEMA and became manager of KEMA High-Power Laboratory. In 2002, he joined Liander, a utility covering one third of the Netherlands, as asset manager. As manager, he is mainly involved in strategic (and national) topics in the fields of transmission, sub-transmission, and distribution of both electricity and gas. He is a member of CIGRE (SC 13/A3, acting also as Special Reporter) and IEEE-PES and was a member of several IEC SC 17A WGs. Within CIGRE, he was active as convener of several WGs: Reliability of High-Voltage Circuit-Breakers, Life Management of Circuit-Breakers, Changing Network Conditions and

System Requirements, Line Fault Phenomena, Asset Management, UHV Substation Equipment. Presently, he is active as convener of the joint working group JWG A3/B5/C4.37, dealing with Out-of-Phase Phenomena. He is author of many publications, mainly within CIGRE.

Lou van der Sluis was born in Geervliet, the Netherlands, on July 10, 1950. He obtained his M.Sc. in Electrical Engineering from the Delft University of Technology in 1974. He joined the KEMA High Power Laboratory in 1977 as a test engineer and was involved in the development of a data acquisition system for the High Power Laboratory, computer calculations of test circuits, and the analysis of test data by a digital computer. In 1990, he became a part-time professor, and since 1992, Prof. Lou van der Sluis has been employed as a full-time Professor at the Delft University of Technology in the Power Systems Department. He is a life senior member of IEEE and past convener of WG CC03 of CIGRE and CIRED for the study of transient recovery voltages in medium and high voltage networks. He has been a member of CIGRE WG A3.24 on internal arc testing and a member of CIGRE WG C4.502 to study the interaction between high voltage overhead lines and underground cables. He is a member of the advisory board of SC-A3 of CIGRE. He is the author of the book *Transients in Power Systems* and coauthor of *Electrical Power System Essentials and Switching in Electrical Transmission and Distribution Systems*, all published by Wiley.

Frank Richter holds a degree in electrical engineering. He started his career in the development of medium voltage equipment and vacuum circuit breakers in a French company. In 2008, he joined a manufacturer in the development of high voltage circuit breakers in Germany. Since 2014, he worked as an asset manager for high voltage equipment in a German TSO. He is a member of CIGRE SC A3, and since 2014, he is the secretary of Study Committee A3 and managing the CIGRE KMS websites under the domain of SC A3. He has joined some WG investigations including WG A3.27: Vacuum switchgear at transmission voltages, WG A3.33: Equipment for series compensation, and WG A3.39: MOSA field experience. He is author of several publications, mainly within CIGRE.

René Peter Paul Smeets received a Ph.D. for research work on switchgear in 1987. Until 1995, he was an Assistant Professor at Eindhoven University. In 1991, he worked with Toshiba Corporation in Japan. In 1995, he joined KEMA in the Netherlands. At present, he is with DNV GL's KEMA Laboratories, as a service area leader. In 2001, he was appointed part-time Professor at Eindhoven University, the Netherlands, in the field of high-power switching. He received six international awards. In 2013, he became Adjunct Professor at Xi'an Jiaotong University, China. Dr. Smeets is convener and member of working groups and study/advisory committees of CIGRE in the field of emerging high voltage equipment such as high voltage vacuum and HVDC switchgear. He is convener of two maintenance teams in IEC on high voltage switchgear. He has published and edited three books and authored over 250 international papers on testing and switching in power systems. In 2008, he was elected Fellow of IEEE, and since 2008, he is Chairman of the "Current Zero Club," a scientific study committee on current interruption.



David Peelo is a consultant and former switching specialist at BC Hydro. He is a graduate of University College Dublin (B.E. Electrical Engineering) and Eindhoven University of Technology (Ph.D.). He worked first at the ASEA Power Transmission Products Division in Ludvika, Sweden, and then for BC Hydro for 28 years rising to the position of Specialist Engineer. As a consultant, he has clients worldwide, and in particular he teaches continuing professional development courses on current interruption transients and surge arrester application. He is an active CIGRE member and is a past convener of IEC MT32 (Inductive load switching), convener of IEC PT42 (Current interrupting capability of air-break disconnectors), and a member of IEC MT57 (Application guide for IEC 62271-100 and other circuit breaker-related standards). He is an IEC 1906 Award recipient and a Distinguished

Member of CIGRE. He has authored or coauthored over 70 publications on circuit breakers and surge arrester application, is the author of a textbook on current interruption transients calculation, and a coauthor of a textbook on switching in transmission and distribution networks.

Dirk Makareinis was born in Cuxhaven in Germany, on July 16, 1956. He graduated from the Technical Secondary School, Cuxhaven, and studied at the University of Lübeck. He has over 38 years of experience in the field of high voltage circuit breakers and was working with Siemens AG in Berlin, Germany. He started as a development engineer in the mechanical test field of the Schaltwerk Berlin. After some practice as project engineer for GIS substations, he became Head of the mechanical test field for GIS development and mechanical routine tests. Up to November 2017, he was acting as Head of the sales, offer, and order processing department for high voltage circuit breakers. Currently, he is retired but is still active in the field of high voltage equipment. He started his CIGRE activities in the WG 13.08 "Life management of circuit breakers" and was a member of the WG A3.06 "Reliability of high voltage equipment" and WG A3.29 "Management of ageing high voltage equipment and possible mitigation techniques." In 2014, he was elected to act as country representative for CIGRE SC A3 for Germany and is until today member of the CIGRE Study Committee A3: High voltage equipment.

Martin Kriegel received a Ph.D. in Electrical Engineering from the Institute for High Voltage Technology at RWTH-Aachen, Germany. He has been with ABB Switzerland Ltd. since 1998 and is currently Head of the Interrupter Development Department for high voltage circuit breakers. He has been active in CIGRE working groups that deal with simulation of high voltage equipment, such as WG A3.20 "Simulations and calculations as verification tools," A3.24 "Tools for simulating internal arc and current withstand testing," and A3.36 "Application and benchmark of multi physic simulations and engineering tools for temperature rise calculation."

Robert le Roux is an Electrical Engineer with a range of engineering skills and practical experience obtained internationally. He joined ESB International as a Resident Engineer in 2010 and is presently an Electrical Engineer and consultant with the ESB International High Voltage Power Plant team. He has a track record working on large-scale HVDC, power plant, and civil engineering projects. He has worked on projects for ESB International in Ireland and Bahrain. His role is specification writing for primary plant equipment, technical tender evaluation, and also to assist ESB Networks with problem solving on HVDC and HV equipment-related problems. He is the convener of CIGRE WG A3.39: Application and field experience with metal oxide surge arresters, and a member of JWG C4/B5.41: Challenges with series compensation in power systems when overcompensating lines. He was also member of various other WGs within CIGRE A3 and A2. He is author of many publications, mainly within CIGRE.

Kevin Kleinhans obtained a bachelor's degree in engineering at the University of Cape Town (RSA) in 1996 and a master's degree at the University of Stellenbosch (RSA) in 2003. He is a Registered Professional Engineer with the Engineering Council of South Africa (ECSA) and a Senior Member of the South African Institute of Electrical Engineers (SAIEE). Since he joined Eskom, he has worked for a period of 22 years being engaged in operations, capital projects, and the field of technology. Currently, he is responsible for the Eskom insulation coordination technical specifications and studies relating to steady state, transient, and temporary overvoltages. He is the member of CIGRE WG A3.39 and WG C4.39 and IEC mirror committee Chairman of TC 28 and TC 37 in South Africa.

Ankur Maheshwari has many years of experience in the power engineering sector in various roles in design, engineering, project, and more diversely in asset management of power system equipment from generation and transmission to distribution. He has hands-on experience in the development and application of a structured approach to asset management in line with frameworks in ISO 55001 for major electricity transmission and distribution utilities. This includes defining and implementing leading-edge risk management techniques and assessment and application of reliability-centered maintenance techniques for management of electricity transmission and distribution of electricity utility assets to deliver improved, safe, reliable, and cost-efficient performance outcomes. He is an active member of CIGRE protection and automation and high voltage equipment groups and is the convener of the CIGRE WG A3.29: Management of aging high voltage substation equipment.

Tadao Minagawa was born in Osaka Prefecture, Japan, on July 3, 1963. He joined Mitsubishi Electric Corporation, Transmission and Distribution Systems Center in 1986. He has been working in the field of industrial machines and HV apparatuses, such as gas circuit breakers, gas-insulated switchgears, and power transformers. Especially, he was engaged in the research and development of insulation materials, degradation phenomena, monitoring, and diagnosis techniques of high voltage equipment. In addition, he is currently responsible for the management of Mitsubishi Electric High Voltage and High Power Testing Laboratories. His field of interest is development of advanced T&D equipment, such as HVDC circuit breakers, and asset management strategies of high voltage equipment. He is a member of CIGRE, IEEE-DEI, and IEE Japan. In CIGRE SC A3, he joined WG A3.21: Composite insulators of high voltage apparatus and WG A3.29: Ageing high voltage substation equipment.

Marta Lacorte obtained a master's degree in Electrical Engineering. She worked at Cepel (Electrical Energy Research Centre, Brazil) from 1984 to 1991, dealing with switching equipment. She was transferred to ABB Switzerland in 1992 and worked until 2001 in the Department of SF_6 Gas Insulated Substations (GIS) as technical support, returned to Brazil in 2002 as ABB Switzerland Generated Circuit Breaker representative for Latin America, and was later involved in management of high voltage equipment engineering at ABB Brazil until 2015. She is currently a partner of Ativa Engenharia, a company made up of professionals with experience in conducting electrical studies (fundamental frequency and electromagnetic transients), analysis to define technology and substation arrangements, as well as elaboration of high voltage equipment specification. She is a member of CIGRE SC A3 and SC B3. She is author of several publications, mainly within CIGRÉ.

Antonio C. Carvalho was born in 1956 in Rio de Janeiro, where he graduated as Electrical Engineer and obtained his master's degree in Power Systems Engineering in the Federal University of Rio de Janeiro (UFRJ). He is an active member of CIGRE since 1984 and acted as member of several working groups in Study Committee A3: HV equipment. Presently, he is the Brazilian member of SC A3 and convener of WG A3.30: HV equipment overstresses management. He worked for 13 years in the Brazilian Research Center for Power Industry (CEPEL), 12 years in switchgear development in ABB Switzerland, and in 2004, he joined the Brazilian System Operator (ONS), where he managed the System Engineering Department up to 2017. Presently, he is Senior Manager for Utilities and Regulatory Affairs of ONS.

Magne Runde received his M.Sc. degree in Physics and Ph.D. in Electrical Power Engineering from the Norwegian University of Science and Technology (NTNU), Trondheim, Norway, in 1984 and 1987, respectively. He has been with SINTEF Energy Research, Trondheim, Norway, since 1988. From 1996 to 2013, he also was an Adjunct Professor of high voltage technology at NTNU. His fields of interest include high voltage switchgear, electrical contacts, power cables, diagnostic testing of power apparatus, and power applications of superconductors. He has been the convener and member of several CIGRE working groups and authored and coauthored more than 50 articles in peer-reviewed international journals and more than 60 conference publications.

Carsten Protze was Engineer at Siemens Corporation, Germany, from 2001 to 2009. In the first 4 years there, he was in the R&D department of high voltage circuit breakers, while in the last 4 years, he worked in different positions at Ruhrtal Company, a Siemens subsidiary. Starting as sales engineer, he became Head of production and Head of R&D for high voltage disconnectors and earthing switches. In 2003, he received his Ph.D. from the Technical University of Dresden, Germany. Since 2009, he is Head of design and construction of substations and high voltage overhead lines at ENSO NETZ company, a power supplier in Germany. In CIGRE, he was Head of the task force of disconnectors and earthing switches within the WG A3.06: Reliability of high voltage equipment. In IEC, he was a member of IEC 62271-102: High voltage disconnectors and earthing switches. He is an expert member in the German Committee of CIGRE SC A3.

Hubert Mercure was Manager, Technology Business Development and Open Innovation, at IREQ–Hydro-Quebec's Research Institute–in Canada from 2008 to 2014. Prior to this, Dr. Mercure managed a research team in the fields of electrical power equipment and advanced diagnostics of rotating machines, power apparatus, and cables systems. He also enjoyed a career of over 20 years as a research scientist. He is the author and coauthor of many reviewed scientific publications. He has been involved in technical work within IEEE and CIGRE. From 2008 to 2016, he represented Canada as technical expert (regular member) on CIGRE SC A3. He holds a B.Sc. degree in Physics from Université de Montréal as well as an M.A.Sc degree in Aerospace Engineering and a Ph.D. in Engineering Science, both from the University of Toronto, Canada.

André Mercier received his B.Sc. in Electrical Engineering from Laval University (Québec City) in 1977 and, in 1979, completed the credits for an M.Sc. degree in microcomputers. His initial field of expertise was the hardware and software design of control and data acquisition systems for various industries. In 1990, he joined IREQ (Hydro-Québec's Research Institute) as a research scientist for circuit breaker projects, focusing on aspects of monitoring and controlled switching. He is the designer of an innovative controlled switching device for transformer applications and is deeply involved in their commissioning. A long-time individual member of CIGRÉ, he has participated in many working groups. He is now the convener of CIGRE WG A3.35: Controlled switching.

Sébastien Poirier has been a research engineer at IREQ (Hydro-Québec's Research Institute) since January 2009. He is currently involved in R&D projects related to high-voltage circuit breaker condition assessment methods. He is contributing to the development of new diagnostic tools dedicated to improve high voltage equipment maintenance methods and asset management strategies. He is a past member of CIGRE working group A3.28 (Switching phenomena and testing requirements for UHV and EHV equipment) and also a member of CIGRE working group A3.32 (Non-intrusive methods for condition assessment of T&D switchgears). He is the author and coauthor of more than ten journal articles and conference papers.

Nenad Uzelac graduated from the School of Electrical Engineering in Belgrade, Serbia, in 1995, with a major in Electrical Power Engineering and completed Master of Science in Product Development at Northwestern University, Evanston, USA, in 2004. In 1999, he joined G&W Electric Company as an R&D Engineer, and in 2005, he became R&D Manager for developing new MV switchgear including reclosers and fault interrupters. Starting in 2015, he became responsible for G&W Global Research, tasked to develop new technologies. His research interests include AC and DC switching, materials and insulation technologies, condition monitoring and diagnostics, sensors, and arc fault studies. He is an active member of the IEEE Switchgear Committee and also has been participating and convening CIGRE A3 working groups since 2007.

Jay Prigmore received his bachelor's degree in electrical engineering from Lamar University. He received his M.S. and Ph.D. in Electrical Engineering from Arizona State University. His Ph.D. research work was focused on novel concepts of fault current limiters for use in both legacy and future power electronic-based distribution systems. He is presently employed at Exponent Inc. as a Managing Engineer. He is a registered professional engineer in eight states within the USA. He has developed an arc flash mitigation device, which won "product of the year" in the electrical safety category. He is a founding member of NFPA 78 and 1078, which provide guidance on performing electrical inspections and the qualifications of electrical inspectors, respectively. He commonly performed failure analysis on power system equipment and provides expert testimony. He is a senior member of IEEE and a member of the Power and Energy Society, the Power Electronics Society, the Industrial Applications Society, and the Magnetics Society. He is the Chair of the IAS ESW Early Career Development Executive Subcommittee.

Daisuke Yoshida joined Mitsubishi Electric Corporation, Transmission and Distribution, Transportation Systems Center in 1994. He has been working in the design section of gas circuit breakers, where he has been engaged in the gas circuit breaker development and the research on arc quenching phenomena. He is currently the General Manager of Switchgear Department in Mitsubishi Electric Corporation. After he participated in the CIGRE Japanese National Panel of SC A3 in 2002, he was acting as a member of CIGRE WG A3.18, WG A3.20, WG A3.24, and JWG A3/B4.34, and he is currently acting as a member of Advisory Group A3.01 and A3.03 as well as a secretary of the Japanese National Panel of SC A3.

Harley Wilson received a B.S. in Electrical Engineering from Bucknell University (USA) followed by an M.S. and Ph.D. in Nuclear Science and Engineering from Carnegie Mellon University. He initially worked in the Nuclear Fuel Business for 27 years with Babcock and Wilcox and Westinghouse Commercial Nuclear Fuel. His experience was in the nuclear fuel design, performance, and manufacturing areas. Harley then worked for 16 years in the Gas Circuit Breaker Division of Mitsubishi Electric Power Products, Inc. (MEPPI) in Warrendale, Pennsylvania, where he served as Manager of the Power Circuit Breaker Engineering Section. His experience was in gas circuit breaker design, manufacturing, and performance. Some specific areas of involvement in these positions were development and commercialization of several gas circuit breaker designs through 800 kV, implementation of controlled switching technology in the field, development of low temperature designs, resolution of manufacturing and performance issues, and customer interaction. While at MEPPI, he participated in two CIGRE working groups, one as the convener of WG A3.12, as well as on the Study Committee A3 Advisory Group. Harley retired from MEPPI in 2014.

Russ Yeckley received a degree in mechanical engineering from the University of Michigan and later a master's degree from the University of Pittsburgh. He was employed by Westinghouse Electric for 36 years, where his initial work was in the development of oil circuit breakers. His first major program was as a mechanical engineer in the development of the 362 kV oil breaker. He participated in the development and testing of the first commercial SF6 circuit breaker and has been involved in SF6 breaker designs from 46 kV to 800 kV using self-pressure generating, double pressure, and puffer technology. As a consultant, he has worked for Siemens, ABB, and EPRI. He recently retired from Mitsubishi Electric Power Products, Inc., where he worked for 25 years in the design and manufacture of SF_6 circuit breakers.

Hiroki Ito joined Mitsubishi Electric Corporation in 1984, where he had engaged in the research and development of high voltage DC and AC gas circuit breakers. From 1989 to 1991, he worked in the Coordinated Science Laboratory at the University of Illinois. In 1994, he received his Ph.D. from the Tokyo Institute of Technology, Japan. He was the technical director of Mitsubishi Electric High Voltage and High Power Testing Laboratories from 2005 to 2012. He is currently the Senior Chief Engineer of Energy and Industrial System Center, Mitsubishi Electric. In CIGRE, he was the convener of CIGRE WG A3.22 and 28 that investigated the specifications of UHV substation equipment. He is also a member of IEC 62271-310 MT40: Electrical endurance tests of circuit breakers, and IEC 62271-302: Controlled switching. From 2012 to 2018, he has been the Chairman of CIGRE Study Committee A3: High voltage equipment.

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CIGRE Study Committee A3 Activity

1

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Contents

Keywords
CIGRE Study Committee · CIGRE Working Groups · CIGRE Technical Brochures · Switching equipment · Transmission and distribution equipment · Testing technique · Lifetime management · Power system

1.1 Introduction, Major Mission, and Scope

CIGRE Study Committee (SC) A3 is responsible for the collection of information, technical evaluation of power system studies, and technical analyses of both AC and DC substation equipment from distribution through transmission voltages which are not explicitly dealt with by other SCs. SC A3 covers all AC and DC switching

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devices, surge arresters, instrument transformers, insulators, bushings, capacitors, fault current limiters, shunt and series capacitor banks, and diagnostic lifetime management and monitoring techniques. This scope is well suited to the various technical needs of utilities that require technical and sustainable solutions for emerging problems and challenges in changing network conditions.

CIGRE was founded in 1921, and three Study Committees related to insulating material, cable, and switchgear (our original SC was called SC 3) were introduced in 1927. Additional SCs on overhead lines, telephone interface and tower, AC HV, and DC followed. The number of SCs was 9 in 1930 and 19 in 1963 and then was reduced to 15 in 1966 and 14 in 1968. During these transitions, SC 13, our ancestral SC, dealt with "switching equipment" (The History of CIGRE 2011).

SC 13 was transferred to SC A3 during a major CIGRE restructuring which was executed in 2002. Figure 1.1 shows the current SCs in CIGRE. SC A3 carefully selected and focused efforts to pick the most topical and important issues and created a limited number of Working Groups (WG) in a variety of subjects of the extended SC A3 scope for all equipment. Since then, SC A3 brought remarkable progress by conducting a variety of worldwide surveys, providing solutions for emerging problems and promoting support for international standardizations such as circuit breakers, disconnecting switches, metal oxide surge arresters, and UHV equipment.

CIGRE is now dealing with distribution applications besides transmission. Due to the need of more transverse works, CIGRE decided to enforce the distribution activities by adding regular members with medium-voltage backgrounds. In accordance with the scope expansion into "medium-voltage equipment," SC A3 may revise the existing name of "Transmission & Distribution equipment" to a new one covering DC and AC transmission and distribution equipment.

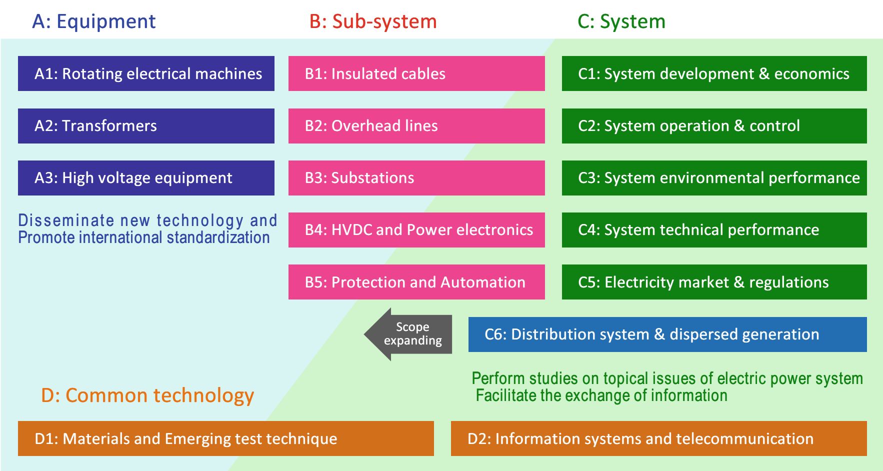

Fig. 1.1 Sixteen CIGRE Study Committees since 2002

In accordance with the CIGRE strategic plan, SC A3 maintains technical values by delivering unbiased information based on scientific exploration in power system as well as field experience of equipment.

SC A3 continuously advances scientific exploration in order to provide technical and economical solutions for emerging problems related to substation equipment as well as to add value to industry information and knowledge by means of synthesizing state-of-the-art technologies and practices. The investigations intensely focus on the detailed behavior caused by the equipment and interaction with the network and other equipment under normal and abnormal conditions. SC A3 also pursues the technical background of developing and existing standards on subjects requested by the IEC.

CIGRE SC A3 continuously executes efforts to collect field experience from distribution through transmission voltages, technical evaluation of power studies, and technical analyses, dealing with both AC and DC substation equipment. These activities focus primarily on the following subjects (Annual Report 2016/2017, SC A3 2017; Annual Report 2015/2016, SC A3 2016; Annual Report 2014/2015, SC A3 2015):

1. Innovative technologies (e.g., DC circuit breakers).
2. Requirements for equipment in changing network conditions, including exploration of the technical background on requirements (support standardization work in IEC).
3. Incorporation of intelligence into HV equipment (e.g., controlled Switching).
4. Monitoring and diagnostics of transmission and distribution equipment.
5. New and improving testing techniques.
6. Reliability assessment, end-of-life management of aging equipment.
7. Mitigation methods for overstressing and overloads.

1.2 Working Groups

Table 1.2 shows the title and the Convener of the WG/JWGs established in SC 13 and SC A3 that investigated various subjects related to transmission and distribution equipment including circuit breakers, current-limiting apparatus, surge arresters, capacitors, insulators, and instrument transformers.

Table 1.3 shows a list of CIGRE Technical Brochures published by SC 13 and SC A3.

1.3 Brief History of Circuit Breaker

A circuit breaker is one of the great inventions of the early twentieth century enabling the AC transmission and distribution networks of today. Circuit breakers with different insulating and interrupting media were developed and put into service.

The first circuit breaker of the bulk oil type was developed by Kelman (1907) in the early 1900s, consisting of a crude arrangement of switches in separate wooden barrels connected in series and simultaneously operated. Bulk oil circuit breakers

Table 1.1 Study Committees 3, 13, and A3 Chairpersons

Period	Name	Country
1921–1934	P. Perrochet	Switzerland
1934–1950	E. Juillhard	Switzerland
1950–1963	H. Schiller	Switzerland
1963–1971	H. Meyer	Switzerland
1971–1978	G. Catenacci	Italy
1978–1984	E. Slamecka	Germany
1984–1990	E. Ruoss	Switzerland
1990–1996	H.H. Schramm	Germany
1996–2002	J. H. Brunke	United States
2002–2006	K. Fröhlich	Austria
2006–2012	M. Waldron	United Kingdom
2012–2018	H. Ito	Japan
2018–202x	N. Uzelac	United States

Table 1.2 List of Working Groups and the Conveners

WG CC 03	TRV stresses in MV systems	L. van der Sluis
TF1	Out-of-phase stresses and testing	H-H. Schramm
TF 13.01	Electrical endurance testing	R. Smeets
TF 13.00.2	Revision of IEC standards relevant to switching devises	J.F. Reid
WG 13.01	Arc physics in circuit breaker	W. Hermann
WG 13.02	Small inductive current switching	S. Berneryd
WG 13.04	Switching test methods	I. Bonfanti
WG 13.06	First international inquiry on HV CB	R. Michaca
WG 13.06	Second international inquiry on HV CB	J. Maaskola/A. Janssen
WG A3.06	Reliability of high-voltage equipment	C. Solver/M. Runde
WG 13.07/WG A3.07	Controlled switching	K. Froehlich/M. Waldron
WG 13.08	Life management of circuit breakers	A. Janssen
WG 13.09	Monitoring and diagnostic techniques	C. Jones
WG A3.10	Specifications for short-circuit current limiters	H. Schmitt
WG A3.11	Application guide for IEC 60056 and 60,694	H.H. Schramm
WG A3.12	Circuit breaker controls	H. Wilson
WG A3.13	Changing network conditions	A. Janssen
WG A3.15	Nonconventional instrument transformers	P. Tantin
WG A3.16	Fault current limiters – Impact on existing and new protection schemes	H. Schmitt
WG A3.17	Surge arrester	B. Richter
WG A3.18	Grading capacitors	M. Runde
WG A3.19	Phase line fault TRVs on CB standards	R. Alexander/A. Janssen

(*continued*)

Table 1.2 (continued)

WG A3.20	Simulations as verification tools	M. Kriegel
WG A3.21	HV apparatus with composite insulators	M. de Nigris
WG A3.22	Requirements for UHV equipment	H. Ito
WG A3.23	Guidelines of fault current limiters	H. Schmitt
WG A3.24	Simulating internal arc testing	N. Uzelac
WG A3.25	MOSA for emerging system conditions	B. Richter
WG A3.26	Influence of shunt capacitor banks on circuit breaker fault interruption duties	A. Bosma
WG A3.27	The impact of the application of vacuum switchgear at transmission voltages	R. Smeets
WG A3.28	Switching phenomena and testing requirements for UHV and EHV equipment	H. Ito/D. Dufournet
WG A3.29	Aging of HV equipment	A. Maheshwari
WG A3.30	Overstressing of HV equipment	A. Carvalho
WG A3.31	Nonconventional instrument transformers	F. Rahmatian
JWG A3.32/ CIRED	Nonintrusive conditioning assessment	N. Uzelac
WG A3.33	Equipment with shunt and series compensation	G. Li
JWG A3/B4.34	DC switchgears	C. Franck
WG A3.35	Controlled switching	A. Mercier
WG A3.36	Simulation for temperature rise test	M. Kriegel
JWG A3/B5/ C4.37	Out-of-phase phenomena	A. Janssen
WG A3.38	Shunt capacitor switching in distribution and transmission systems	E. Dullni
WG A3.39	MOSA field experience	R. le roux
WG A3.40	Technical requirements and field experiences with MV DC switching equipment	C. Heinrich
WG A3.41	Interrupting and switching performance with SF6 free switching equipment	R. Smeets
WG A3.42	Failure analysis of recent AIS instrument transformer incidents	H. Martins

Table 1.3 List of Technical Brochures

Number of TB	Title	WG output
TB 725	Ageing high voltage equipment and possible mitigation techniques	WG A3.29
TB 716	System conditions for and probability of out-of-phase	JWG A3/B5/ C4.37
TB 696	MO varistors and surge arresters for emerging system conditions	WG A3.25
TB 693	Experience with equipment for series/shunt compensation	WG A3.33
TB 683	Technical requirements and specifications of state-of-the-art HVDC switching equipment	JWG A3/B4.34

(*continued*)

Table 1.3 (continued)

Number of TB	Title	WG output
TB 624	Influence of shunt capacitor bank on CB fault interruption duties	WG A3.26
TB 602	Tools for simulation of the internal arc effects in HV and MV switchgear	WG A3.24
TB 589	Vacuum switchgears at transmission voltages	WG A3.27
TB 570	Switching phenomena for EHV and UHV equipment	WG A3.28
TB 544	Metal oxide (MO) surge arresters – Stresses and test procedures	WG A3.17
TB 514	Reliability of high-voltage equipment – Part 6: GIS practices	WG A3.06
TB 513	Reliability of high-voltage equipment – Part 5: Gas-insulated switchgear	WG A3.06
TB 512	Reliability of high-voltage equipment – Part 4: Instrument transformers	WG A3.06
TB 511	Reliability of high-voltage equipment – Part 3: DS and earthing switches	WG A3.06
TB 510	Reliability of high-voltage equipment – Part 2: SF_6 circuit breakers	WG A3.06
TB 509	Reliability of high-voltage equipment – Part 1: General matters	WG A3.06
TB 497	Applications and feasibility of fault current limiters in power systems	WG A3.23
TB 456	Background of technical specifications for UHV substation equipment	WG A3.22
TB 455	Application of composite insulators to high-voltage apparatus	WG A3.21
TB 408	Line fault phenomena and their implications for three-phase SLF clearing	WG A3.19
TB 394	State of the art of instrument transformer	WG 12.16/ SC A3
TB 368	Operating environment of voltage grading capacitors applied to HV CB	WG A3.18
TB 362	Technical requirements for substation equipment exceeding 800 kV	WG A3.22
TB 339	Guideline on the impact of FCL devices on protection system	WG A3.16
TB 336	Changing network conditions and system requirements part 2	WG A3.13
TB 335	Changing network conditions and system requirements part 1	WG A3.13
TB 319	Failure survey on circuit breaker control systems	WG A3.12
TB 305	Guide for application of IEC 62271-100 and IEC 60694 part 2	WG A3.11
TB 304	Guide for application of IEC 62271-100 and IEC 60694 part 1	WG A3.11
TB 264	Controlled switching, planning, specifications, and testing	WG A3.07
TB 263	Controlled switching, unloaded transformer switching	WG A3.07
TB 262	Controlled switching, benefits, and economic aspects	WG A3.07
TB 259	Failure survey on circuit breaker control systems	WG A3.12
TB 239	Fault current limiters in electrical system	WG A3.10
TB 167	Monitoring and diagnostic techniques	WG 13.09
TB 165	Lifetime management of circuit breakers	WG 13.08
TB 135	Circuit breaker modelling	WG 13.01

(*continued*)

Table 1.3 (continued)

Number of TB	Title	WG output
TB 134	MV transient recovery voltage	WG 13. CC.03
TB 083	International inquiry on HV circuit breakers	WG 13.06
TB 050	Small inductive current interruption	WG 13.02
TB 047	Line-charging current switching	WG 13.04

evolved over the next 30 years. Principal developments were carried out in the United States by Slepian of Westinghouse (Slepian 1929) and Prince and Skeats of General Electric (Prince and Skeats 1931).

In Europe, bulk oil circuit breakers reigned until the early 1950s and then were totally supplanted by minimum oil circuit breakers. Bulk oil circuit breakers are in use up to 360 kV with eight breaks in series, while the minimum oil type are used up to 420 kV with up to ten breaks in series. Some utilities still continue to use these types of oil circuit breakers.

Subsequently, the air-blast circuit breaker was developed in Europe, first by Whitney and Wedmore of British Electrical Research Association (Whitney and Wedmore 1930) in 1926 with further developments in Germany and Switzerland in the 1930s and 1940s. The air-blast circuit breakers came into prominent use in the 1960s and enabled the extra high-voltage systems of 500 kV and above. Air-blast circuit breakers were manufactured into the early 1980s when they were supplanted by lower-cost and less complex SF_6 puffer-type circuit breakers. Air magnetic circuit breakers, a variation of air-blast circuit breakers, were used at medium voltages up to 52 kV.

SF_6 gas was recognized for its unique dielectric properties in the 1920s. There was a patent by F.S. Cooper of General Electric (Cooper 1940) on its use in capacitors and gas-insulated cables. The application of SF_6 gas for current interruption was patented by H.J. Lingal, T.E. Browne, and A.P. Storm of Westinghouse in 1951 (Lingal et al. 1953), but the SF_6 gas circuit breaker did not appear on the market until the mid- to late 1950s. The first SF_6 gas circuit breakers were designed with dual pressure based on axial gas blast principles.

A puffer-type SF_6 circuit breaker, which is often referred to as a single-pressure type, was developed in the 1970s based on a principle invented by Prince who also designed the so-called impulse-type bulk oil circuit breaker, where the oil flow was produced by a piston driven by the operating mechanism. Further evolution of SF_6 circuit breakers led to rotating arc technology up to 72 kV and self-blast technology above 72 kV.

CIGRE SC 13 established the WG 13.01, Practical Application of Arc Physics in Circuit Breakers, in 1984 to explore the switching phenomena of a gas circuit breaker. The WG published many technical reports including a guideline on arc models which are used as a convenient tool to reproduce the arc behaviors and interrupting phenomena of the circuit breaker in different circuits of power systems (CIGRE Working Group 13.01 1988, 1993).

Vacuum interrupters were also developed in the 1920s (Sorensen and Mendenhall 1926), but commercial vacuum circuit breakers first appeared in the 1960s.

The vacuum circuit breaker is commonly used today at medium voltages and is also available at transmission voltages up to 170 kV.

Figure 1.2 shows the interruption capability per break for different circuit breaker technologies. There are a couple of technology transitions. The first technical transition from oil to air was observed around 1960, which realized EHV networks, and another one from air to SF_6 around 1970, which improves large-capacity circuit breakers and the reliability of networks.

The application timelines for the six major circuit breaker types are shown in Fig. 1.3. Oil circuit breakers started manufacture around 1910 and continued until 1990. Air circuit breakers were mainly manufactured from 1950 to 1980. Then SF_6 circuit breakers have dominated since 1970. Vacuum circuit breakers also have a long history of production.

There have been many technical breakthroughs in the development of large-capacity high-voltage circuit breakers with different technologies. Examples of key circuit breaker developments are listed in Table 1.4.

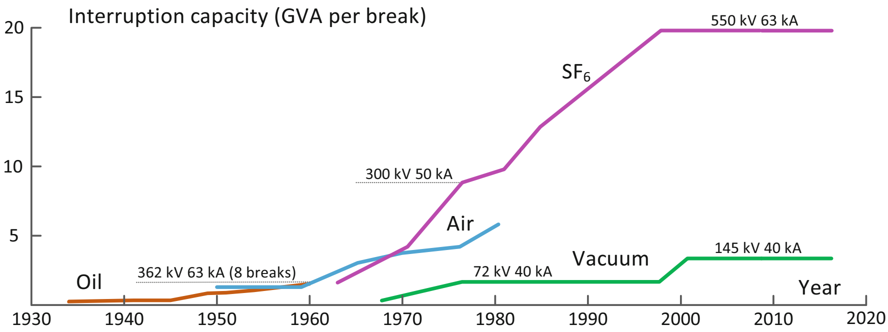

Fig. 1.2 Development of interruption capacity per break for different circuit breakers

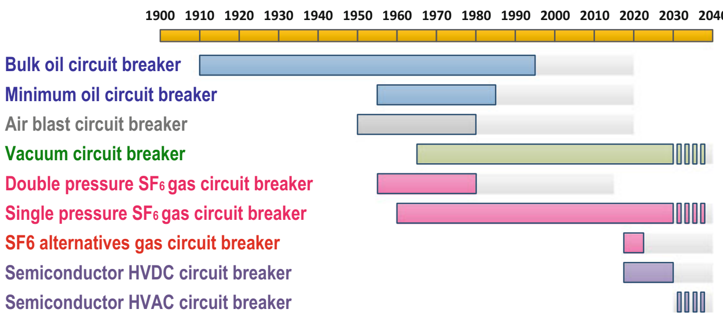

Fig. 1.3 Approximate manufacturing periods of different circuit breakers

Table 1.4 Technological milestones on switching equipment

Year	Technical achievement
Late 1800s	First oil circuit breakers developed and introduced
1920	Investigations on various interrupting media, e.g., vacuum, air, water
1928	Arc theory of AC interruption (Cassie 1939; Cassie and Mason 1956; Mayr 1943; Frost and Liebermann 1971; Stokes et al. 1984)
1930	Air-blast circuit breakers developed
1956	115 kV puffer-type gas circuit breaker introduced (Cromer and Friedrich 1956)
1960	Synthetic tests with SF_6 gas circuit breaker developed
1963	800 kV 50 kA interrupting capability of air-blast circuit breaker introduced
1970	250 kA generator circuit breaker developed
1972	550 kV four-break gas circuit breaker introduced
1994	550 kV one-break gas circuit breaker, 1100 kV gas circuit breaker developed (Yamagata et al. 2007; Jiming et al. 2007)
2009	1100 kV equipment introduced and UHV transmission commissioned

1.4 Summary

The circuit breaker performs an important role in maintaining stable operation of transmission and distribution systems. Technical transition of a circuit breaker using different interrupting media with mineral oil, air, SF_6, and vacuum and their developments toward higher voltage levels and larger interrupting current capacities to meet system requirements have been main concerns of CIGRE (see ▶ Chap. 5). The requirements for circuit breakers have been updated to cover the UHV level in accordance with changing network conditions. SC A3 will continue the investigation of switching behaviors in the emerging HVAC network conditions.

HVDC circuit breakers with different schemes, such as hybrid mechanical and power electronic DC circuit breaker and HVDC mechanical circuit breakers with an active resonant current zero creation scheme (current injection type), are being developed to apply to future HVDC networks. The Green Book deals with some HVDC interruption schemes potentially applicable for HVDC systems in ▶ Chap. 16. SC A3 will continue to collect field experience of DC switching equipment.

CIGRE SC A3 published the first edition of the Green Book focusing on switching equipment, which covers switching equipment used in power systems (▶ Chap. 2), switching phenomena in power systems (▶ Chap. 4), gas circuit breakers (▶ Chap. 6), vacuum circuit breaker (▶ Chap. 7), disconnecting switches and earthing switches (▶ Chap. 9), fault current limiters (▶ Chap. 13), controlled switching (▶ Chap. 14), Lifetime management (▶ Chap. 17).

The Green Book also deals with future technologies related to switching equipment such as semiconductor-type circuit breakers, superconducting current limiters, and switching equipment with SF_6 alternative gas (▶ Chap. 18). SC A3 will periodically update the contents of the Green book and add new subjects based on the field experience investigated by existing and future WGs in order to provide a useful textbook targeted for young engineers and students who will deal with switching equipment for research and engineering purposes.

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Equipment in Power Systems

2

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Contents

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2.1 Introduction

Electricity is supplied to a large number of households, offices, and factories every day. Its availability has increased over the last 100 years since electricity has begun to be supplied in the late 1800s, and nowadays it is considered to be an essential commodity. It is a versatile and clean source of energy; it is rather cheap and "always available." The purpose of a power system is to transport and distribute the electrical energy generated in the power generation plants to the consumers in a safe and reliable way, no matter how far the power generation plants are located from the load. In most cases, alternating current (AC) technology is used for electrical energy transportation, and in a minority of the applications such as a point-to-point international connection and long-distance, large-capacity transportation, direct current (DC) is preferred. The advantage of an AC power system lies in the fact that the voltage can easily be brought to a higher level in order to reduce losses during energy transportation. Figure 2.1 shows a typical AC power system including power generators, power transformers, and substation equipment such as circuit breakers.

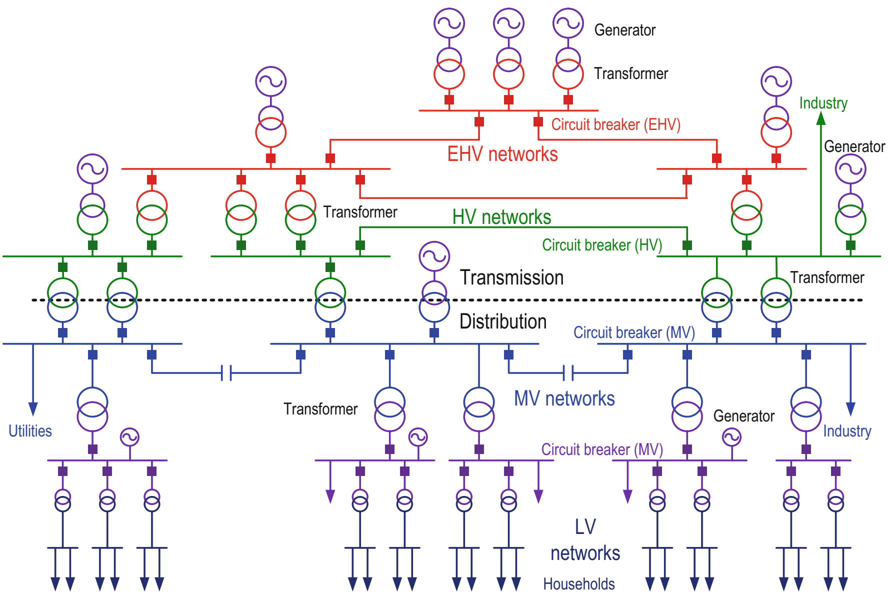


Fig. 2.1 Typical AC power system

Power generators can produce electricity taking care of the conversion of mechanical energy into electrical energy. Overhead lines suspended by a transmission tower comprised of aluminum and copper conductors, and underground cables are used to carry the current with minimum loss. Power transformers can bring the electrical energy to the appropriate voltage level at the load (demand) side. Society's dependence on this commodity has become extremely large, and the social impact of a failing power system is nowadays unacceptable. In fact the electrical power system is the backbone of modern society.

The power system generates, transports, and distributes electrical energy economically and in a reliable way to the consumers, with the constraint that both the voltage and frequency are kept constant, within narrow margins, at the load side. Power quality is a major issue these days, a nearly perfect sine wave of constant frequency and amplitude and always available. Electrical engineering started basically with the evolution of electrical power engineering at the turn of the nineteenth century, when the revolution in electrical engineering took place. In a rather short period of time, power transformers were invented, electric motors and power generators were designed, and the step from DC to AC transmission was made, making it possible to transport large amounts of electrical energy over long distances. Lighting, at first, but rapidly the versatile application of electrical power completely changed society. In this early period, small and independent operating power companies used different voltage levels and operated their system at various frequencies. There were no standards at that time, and electrical engineers were among the first to realize that international standardization would become necessary in the modern world.

Regarding DC versus AC transmission, there was a famous war of currents at the beginning of the power system. Tomas Edison started electricity supply in 1882 and provided DC 110 volts direct current to households in the United States. From the early 1880s on, AC distribution had been expanding with the development of transformers in Europe, and in the United States in 1885–1886, AC can transport electricity to very long distances through cheaper wires and easily step down the voltage at the load side. By the early 1890s, the technical benefits with AC had dominated the market, and the "War of Currents" would come to an end in 1892. Edison General Electric was renamed as General Electric that dominated the US power business and would go on to compete with Westinghouse for the AC supply.

Figure 2.2 shows a one-line diagram of the main substation including main power equipment. The substation has several functions to transform voltage from high to low, or the reverse, and switch off a circuit and on another circuit. For these purposes, the substation has power transformers, circuit breakers, and metal-oxide surge arresters which protect the system and equipment against the excessive overvoltages. Figure 2.3 shows a typical substation configuration.

In daily power system operation, switching is a rather normal action: the system needs to be reconfigured to facilitate the power flow from the generation to the load, a faulted part of the network has to be taken out of service, or a circuit is switched off for maintenance. Circuit breakers, disconnecting switches, and earthing switches are the components that carry out the switching actions. In this CIGRE Green Book, we will give background information on switching phenomena in the network and

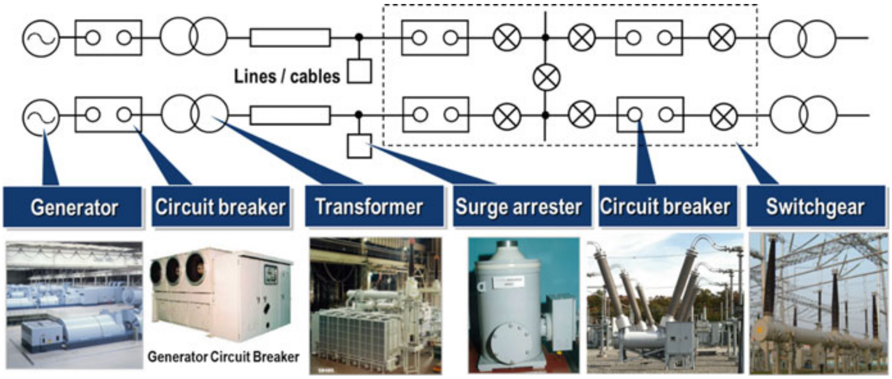


Fig. 2.2 Typical AC substation equipment

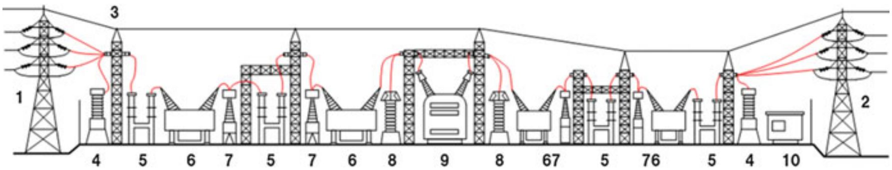


Fig. 2.3 Typical AC substation configuration. 1, incoming overhead line; 2, outgoing overhead line; 3, ground wire; 4, voltage transformer; 5, disconnecting switch; 6, circuit breaker; 7, current transformer; 8, surge arrester; 9, power transformer; 10, control cabinet with protective relay units. (Courtesy of Tokyo Electric Power)

describe the role, design, and constructive details of the various network components, and we will go through the historical development of the switching devices.

Switching operations in power systems are very common and must not jeopardize the system's reliability and safety. Switching in power systems is necessary for the following reasons and duties:

- Taking into or out of service components or sections of the system, certain loads, or consumers. A typical example is the switching of shunt capacitor banks or shunt reactors, de-energization of cables and overhead lines, the reconnection of cables and overhead lines, transformer switching, and so on. In industrial systems, this type of switching is by far the most common of all the switching operations.
- Transferring the flow of energy from one circuit (or section of a substation) to another. Such operations occur when load current needs to be transferred without interruption, for example, in a substation, from one busbar to another.
- Isolating certain network components because of maintenance or replacement.
- Isolating faulted sections of the network in order to avoid damage and/or system instability. The most well-known example of this is the interruption of a short-circuit current. Faults cannot be avoided, but adequate switching devices in combination with a protection system are needed to limit the consequences of faults.

Switching in electrical power systems reconfigures the topology of an electrical network; it involves the making and breaking of currents and causes a disturbance of steady energy flow. Therefore, transients are expected to happen and are observed in the system during the change from the steady-state situation before, when the system was in a certain configuration to the new steady-state situation after switching when a new circuit topology is configured. Switching in the power system involves abnormal patterns of current and voltage that have a limited duration. Attention should be paid to these phenomena because they very often exceed the values met during steady-state operation and can exceed the withstanding capabilities of the equipment. Fundamentally in nature, any change of steady-state conditions generates transients.

The essential parameters in electrical circuits are current and voltage. During switching operations in power systems, transients can be observed in both. Regarding operations related to switching on (making or energization), the components of the system or the equipment are mainly stressed by current-related transients. On the other hand, at switching-off operations (breaking or de-energization), voltage-related transients will especially stress the switching device performing the operation, and sometimes the voltage stress can affect the insulation.

In a generalized concept, switching devices (dis)connect a source circuit to a load circuit. Both circuits are a complicated combination of system components: lines, cables, busbars, transformers, generators, and so on. Through reduction of the complexity to relevant simple electrical elements, either lumped or distributed where necessary, the switching transients can be more easily understood.

When one speaks of electricity, one thinks of current flowing through the conductors from the generator to the load. This approach is valid because the physical dimensions of the power systems are large compared with the wavelength of the sinusoidal currents and voltages at the nominal frequency. For steady-state analysis of the power flow at the power frequency of 50 or 60 Hz, complex calculus with phasors representing voltages and currents in the frequency domain can be used successfully. Switching transients, however, involve much higher frequencies, up to kilohertz and megahertz, such that the complex calculus can no longer be applied. Now the differential equations describing the system phenomena in the time domain have to be solved. In addition, lumped-element modelling of the system components has to be done with care if Kirchhoff's voltage and current laws are used. In the case of a power transformer under normal power-frequency conditions, the transformer ratio is given by the ratio of the number of turns of the primary and the secondary winding. However, for a lightning-induced voltage wave or a fast switching transient, the stray capacitance of the winding turns to each other, and the grounded parts of the tank and the stray capacitance between the primary and secondary coil determine the transformer ratio. In these two situations, the power transformer has to be modelled differently, in a more complex way.

When one cannot get away with a lumped-element representation, wherein the inductance represents the magnetic field, the capacitance represents the electric field, and the resistance represents the losses, travelling wave analysis must be used. The correct "translation" of the physical power system and its components into suitable models for the analysis and calculation of power-system transients requires insight into the basic physical phenomena. Therefore, it requires careful consideration, which is not an easy task.

A transient occurs in the power system when the network changes from one steady-state condition into another. This can be, for instance, the case when lightning hits the earth in the vicinity of a HV overhead transmission line or when lightning hits a substation busbar or line directly. The majority of power-system transients are, however, the result of desired switching actions. Load break switches and disconnectors switch off and on parts of the network under load and no-load conditions, respectively. Fuses and circuit breakers interrupt higher currents and clear short-circuit currents in faulted parts of the system. The time period when transient voltage and current oscillations occur is in the range of microseconds to milliseconds. On this time scale, the presence of a short-circuit current during a system fault can be regarded as a steady-state situation, wherein the energy is mainly in the magnetic fields, and, after the fault current interruption, the system is transferred into another steady-state situation, wherein the energy is predominantly in the electric fields.

2.2 Definitions of Terminology

Power System/Electrical Power Network
Electrical power transmission and distribution networks are a power delivery system consisting of lines and cables that transports electrical power from the generation site to the demand users.

Alternating Current (AC)
AC refers to electrical current flow with positive and negative direction periodically. The waveform of the alternating current is normally a sine wave. In certain applications, different waveforms are used, such as triangular or square waves.

Direct Current (DC)
DC refers to electrical current flow with only one direction: positive or negative polarity. A common source of DC power is a battery cell or charged capacitor.

Medium Voltage (MV)
MV generally refers to the voltage levels up to and including 52 kV corresponding to distribution systems.

High Voltage (HV)
HV generally refers to the voltage levels higher than 52 kV corresponding to transmission systems.

Extra High Voltage (EHV)
EHV generally refers to the voltage levels around 230 kV (the value may differ in country) up to 800 kV. The rated voltages at trunk systems are, for example, 420/380 kV in Europe and in the Middle East, 550/800 kV in the US, Canada and Korea.

Ultrahigh Voltage (UHV)
UHV generally refers to the voltage levels exceeding 800 kV operating in China and testing in India and Japan.

Substation
A substation is a part of the power system consisting of electrical generation, transmission, and distribution system. Substations transform the voltage from high to low level or low to high level. There are various switching equipment to close a circuit or interrupt a nominal or a fault current along with measuring equipment and overvoltage protection units such as surge arresters.

Busbar
A conductor to which several circuits are commonly connected in the substation.

Generator
A rotating electric machine which is intended to convert mechanical energy into electrical energy.

Power Transformer
A static piece of apparatus with two or more windings which, by electromagnetic induction, transforms a system of alternating voltage and current into another system of voltage and current usually of different values and at the same frequency for the purpose of transmitting electrical power.

Overhead Line
An electric line whose conductors are supported above ground, generally by means of insulators and appropriate supports (transmission tower or electric pole).

Underground/Submarine Cable
An electric line with insulated conductors buried directly in the ground or laid in cable ducts, pipes, troughs, directly on the sea bottom, etc.

Gas-Insulated Line
An electric line whose conductors are contained in a metal enclosure and insulated with a compressed gas.

Surge Arrester
A surge protective device designed to limit the duration and frequently the amplitude of the voltage.

Switching Equipment
Equipment designed to make or break the current in one or more electric circuits.

Circuit Breaker
A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in power systems

from damage caused by excessive currents, typically resulting from an overload or short-circuit conditions. When a fault occurs, circuit breakers quickly clear the fault to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand a system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Dead Tank Circuit Breaker
A circuit breaker with interrupters inside an earthed metal enclosure. The conductor applied with the system voltage is fed outside from the interrupters through the bushings.

Live Tank Circuit Breaker
A circuit breaker with interrupters inside a tank (composed of porcelain or composite insulators) insulated from earth. The conductor can be connected directly with a live part of the breaker terminals.

Oil Circuit Breaker
A circuit breaker in which the contacts open and close in mineral oil. The “bulk” or dead tank oil breaker has the contacts in the center of a large metal tank filled with oil. The oil serves as an extinguishing medium and provides the insulation to the tank. The live tank “minimum” oil breaker design has the contacts and arcing chamber inside a porcelain insulator filled with a small volume of oil compared to bulk-oil circuit breakers. The arc evaporates the surrounding oil and produces hydrogen and carbon compound. The process removes the heat from the arc and eventually interrupts the current at power-frequency current zero.

Air-Blast Circuit Breaker
A circuit breaker in which the contacts open and close in the air. Since the air interrupts and dielectric withstand capability at atmospheric pressure is limited, a compressed air to several MPa is required to high-voltage applications. The air relatively creates high arc voltage, which can decrease the fault current and assist thermal interruption capability.

Vacuum Circuit Breaker
A circuit breaker in which the contacts open and close within a highly evacuated vacuum enclosure. When the vacuum circuit breaker separates the contacts, an arc is generated by the metal vapor plasma released from the contact surface. The arc is quickly extinguished because the metallic vapor, electrons, and ions produced during arcing are diffused in a short time and condensed on the surfaces of the contacts, resulting in quick recovery of dielectric strength.

Sulfur Hexafluoride (SF_6) Circuit Breaker
A circuit breaker in which the contacts open and close in sulfur hexafluoride. Current interruption in a SF_6 circuit breaker is obtained by separating two contacts in sulfur hexafluoride having a pressure of several tenths of MPa. After contact separation, the

current is carried through an arc and is interrupted when this arc is cooled by a gas blast of sufficient intensity.

Disconnecting Switch
Switching equipment capable of opening and closing a circuit with either negligible/leakage current is opened or made or without significant change in the voltage across the terminals of each of the poles of the disconnecting switch. It is also capable of carrying currents under normal circuit conditions and carrying for a specified time currents under abnormal conditions such as those of short circuit.

Earthing Switch
An earthing switch for the purpose of earthing/grounding and insulating a circuit.

Instrument Transformer
A transformer intended to generate an information signal to measuring instruments, meters, and protective or control devices. The term "instrument transformer" encompasses both current transformers and voltage transformers.

Current Transformer
An instrument transformer in which the secondary current, in normal conditions of use, is substantially proportional to the primary current and differs in phase from it by an angle which is approximately zero for an appropriate connection.

Voltage Transformer
An instrument transformer in which the secondary voltage, in normal conditions of use, is substantially proportional to the primary voltage and differs in phase from it by an angle which is approximately zero for an appropriate connection.

2.3 Abbreviations

AC	Alternating current
DC	Direct current
CB	Circuit breaker
MV	Medium voltage
HV	High voltage
EHV	Extra high voltage
UHV	Ultrahigh voltage
SIL	Surge impedance loading
GIL	Gas-insulated transmission line
EMF	Electromagnetic Field
atm	Standard atmosphere (a unit of pressure defined as 101,325 Pa)
rpm	Revolution per minute
MVA	Megavolt ampere (corresponds to MW)
Hz	Hertz (defined as one cycle per second)

2.4 Generation

The work horse for the generation of electricity is the synchronous machine. The bulk of electrical energy is produced by three-phase synchronous generators. Synchronous generators with power ratings of several hundred MVA are nowadays common; the biggest machines have a rating up to 1500 MVA. Under steady-state conditions, they operate at a speed fixed by the power system frequency, which is why they are called synchronous machines. As generators, synchronous machines operate in parallel in the larger power stations. A rating of 600 MVA for one generating unit is also quite common.

In a power generation plant, the shaft of the steam-, hydro- or wind-turbine is mounted in line with the shaft of the synchronous generator (Fig. 2.4). It is in the generator that the conversion from mechanical energy into electrical energy takes place. The two basic parts of the synchronous machine are the rotor and the armature (stator). The iron rotor is equipped with a DC-excited winding which acts as an electromagnet. When the rotor rotates and the rotor winding is excited by a DC source, a rotating magnetic field is present in the air gap between the rotor and the armature. The rotor excitation field is supplied from an auxiliary DC generator that can be placed on the shaft (on-shaft exciter) or outside the turbine-generator set. The armature has a three-phase winding in which a time-varying electromagnetic field (EMF) is generated by the rotating magnetic field.

Synchronous machines are built with two types of rotors: cylindrical rotors (in a horizontal position) which are driven by steam turbines at 3000 or 3600 rpm and salient-pole rotors that are usually driven by low-speed turbines, like hydroturbines as shown in Fig. 2.5. Salient-pole rotors are mostly mounted in a vertical position. In cylindrical rotors the field winding is placed in slots, cut axially along the rotor length. The diameter of the rotor is usually between 1 and 1.5 m which makes the machine suitable for operation at high angular velocities because of the rotational speed: 3000 or 3600 rpm. These generators are named turbogenerators. A

Fig. 2.4 1050 MW turbine generator, 2100 MW/2 units (Courtesy of J Power)

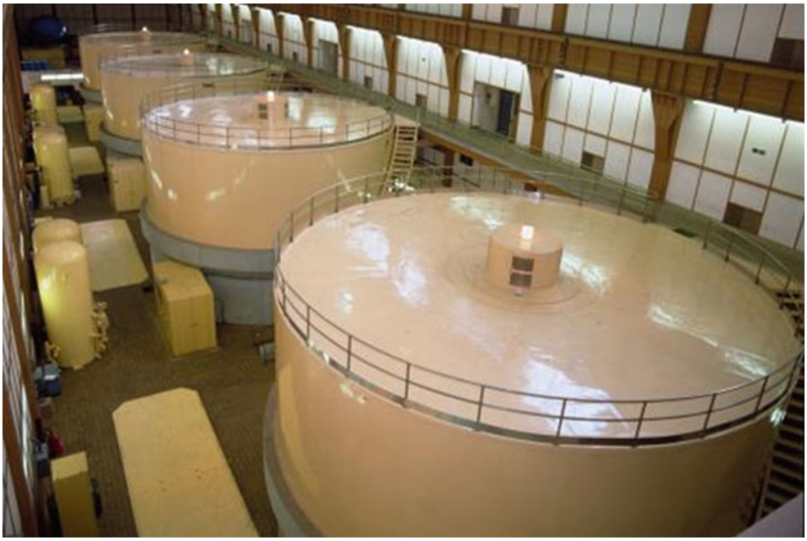


Fig. 2.5 87.5 MW salient-pole generator, 350 MW/4 units, 50/60 Hz dual frequencies. (Courtesy of J Power)

turbogenerator rotor has just one pair of poles. Salient-pole machines usually have more pairs of poles, so they can produce a 50 Hz or 60 Hz frequency, operating at a much lower rotational speed (like 50 to 100 rpm).

The energy efficiency of the generators is very important. Synchronous generators in power plants have an efficiency of 99% or even higher. This means that for a 600 MW generator, 6 MW heat is still produced, and therefore the machine has to be cooled in order to keep the temperature of the windings and the insulation material within speciation limits. Large turbogenerators are cooled with hydrogen or water. Hydrogen has 7 times the heat capacity of air and water 12 times. The hydrogen and/or water flows through the hollow stator windings. Cooling equalizes the temperature distribution in the generator, because temperature hot spots, when they occur, can greatly affect the life cycle of the electrical insulation and reduce the expected lifetime of generators.

2.5 Network Structures

The network structure is formed by the overhead lines, the underground cables, the transformers, and the buses between the points of power injection and power consumption. The number of voltage transformations from the highest voltage level to the lowest voltage level determines the principal network structure of a power system. Network structures can be distinguished in system parts with single-point feeding and with multiple-point feeding.

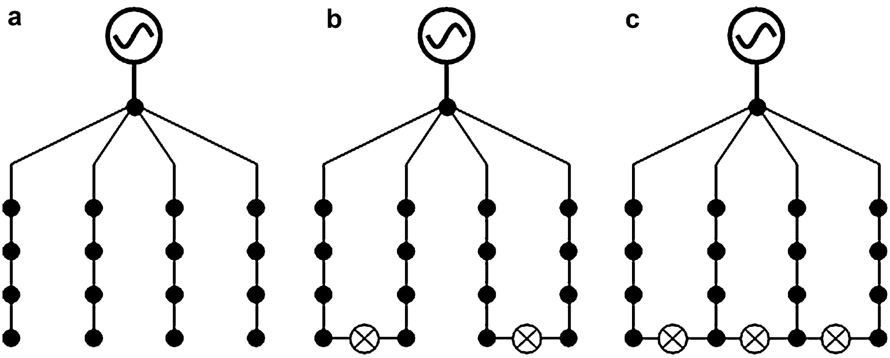


Fig. 2.6 Network structures with single-point feeding. (**a**) Radial structure; (**b**) loop structure; (**c**) multi-loop structure

A single-point feeding network can have three layouts, as depicted in Fig. 2.6:

- A radial structure, in which all substations (or consumers) are fed by lines or cables connected directly to one central supply; a network with a radial structure is less expensive to build.
- A loop structure, in which each and every substation (or consumer) within the system is fed from two directions; networks with a loop structure are more reliable but more expensive to build.
- A multi-loop structure, in which the substations (or consumers) are fed from the supply by more than two connections; networks with a multi-loop structure are very reliable in their operation but more costly.

In Fig. 2.6b and c, a bus-segregation switch is placed on positions where it is possible to open a loop in the grid. During operation, the system operator can decide to create “openings” in the grid, by means of switching devices, so that both the loop and multi-loop structures can be operated as radial networks. This is a common practice in the Dutch distribution networks (or in many countries); most of these networks have a (multi-) loop structure but are operated as radial networks as this keeps the protection of the network simple. After a fault situation, e.g., a short circuit that has been cleared, a grid opening can be “relocated” in order to change the network configuration and restore the energy supply as shown in Fig. 2.7.

A multiple-point feeding network nearly always has a multi-loop structure as shown in Fig. 2.8. Transmission networks are in general operated in a multi-loop structure, as the multi-loop network gives a rather high reliability of the power supply. In the case that a fault occurs in a multi-loop system, the power supply can (usually) be continued. Let’s imagine that the left feeder in Fig. 2.8 is short-circuited. The feeder will be isolated from the network (by the protective devices and the circuit breakers), which implies that the power supply from the left side is interrupted. However, we still have power supply from the right side, which feeds all the substations in the multi-loop structure.

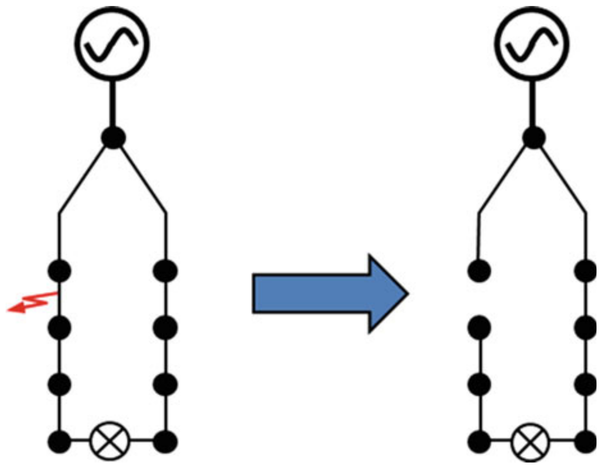


Fig. 2.7 Restoration of energy supply in a faulted, radially operated, system

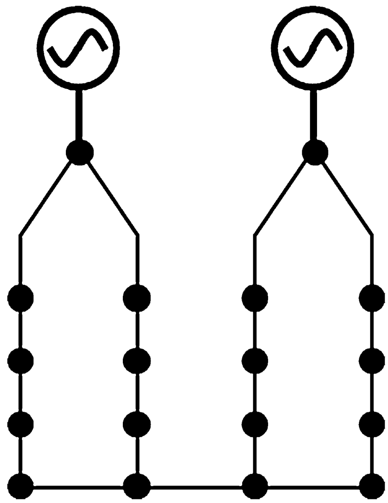


Fig. 2.8 Network structure with multiple-point feeding

2.6 Substation

The simplest way to look at the power system is to consider it as a collection of nodes, which we call substations, and connecting power carriers, such as overhead lines and underground cables. By means of substations as shown in Fig. 2.9, the power of a generating plant can be supplied to the system, the power can be divided over the connected lines, and the power can be distributed to the consumers. Furthermore, power transformers can be installed in the substations in order to interconnect different voltage levels. Substations play an important role in the protection of the power system, where

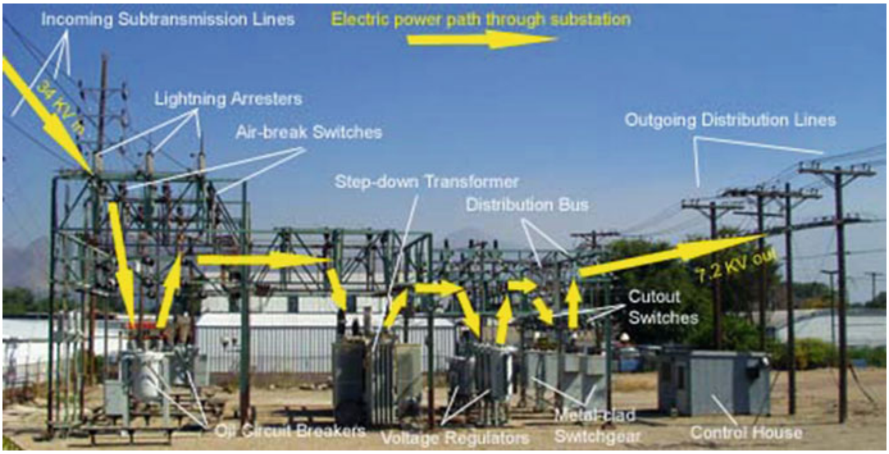


Fig. 2.9 Typical substation equipment. (Information downloaded from the website of Occupational Safety and Health Administration, United States Department of Labor: https://www.osha.gov)

the protection equipment (voltage transformers, current transformers, and protective relays) is installed together with the circuit breakers and disconnectors that perform the switching operations.

The system grounding is also established in the substations, and from the individual stations, measurement signals are guided to the control center. More detailed information is available in another CIGRE Green Book and documents published by Study Committee B3 dealing with substations.

2.7 Protection

With the increasing dependency of our society on electricity supply, the need to achieve an acceptable level of reliability, quality, and safety at an economic price becomes important to customers. The power system as such is well designed and also adequately maintained to minimize the number of faults that can occur.

Power system protection is a field in electrical power engineering dealing with protecting the equipment and the power infrastructure from faults by isolating the faulted components or circuits from the rest of the network. The objective of a protection scheme is to keep the network in a stable operating mode. More detailed information is available in another CIGRE documents published by Study Committee B5 dealing with protection and automation.

In normal operating conditions, a three-phase power system can be treated as a single-phase system when the loads, voltages, and currents are balanced. A fault brings the system to an abnormal and unbalanced condition. Short-circuit faults are especially of concern because they result in a switching action, which often results in transient overvoltages as a consequence of the operation of a circuit breaker.

Line-to-ground faults are faults in which an overhead transmission line touches the ground because of wind, ice loading, or a falling tree limb. A majority of transmission-line faults are single line-to-ground faults. Line-to-line faults are usually the result of galloping lines because of high winds or because of a line breaking and falling on a line below. Double line-to-ground faults result from causes similar to that of the single line-to-ground faults but are very rare. Three-phase faults, when all three lines touch each other or fall to the ground, occur in only a small percentage of the cases but are very severe faults for the system and its components. In the case of a symmetrical three-phase fault in a symmetrical system, one can still use a single-phase representation for short-circuit and transient analysis. However, for the majority of the fault situations, the power system has become unsymmetrical. Symmetrical components and, especially, sequence networks are an elegant way to analyze faults in unsymmetrical three-phase power systems because in many cases the unbalanced portion of the physical system can be isolated for study, the rest of the system being considered to be in balance. This is, for instance, the case for an unbalanced load or fault. In such cases, we attempt to find the symmetrical components of the voltages and the currents at the point of unbalance and connect the sequence networks, which are, in fact, copies of the balanced system at the point of unbalance (the fault point).

Protection systems are installed to clear faults, like short circuits, because short-circuit currents can damage the cables, lines, busbars, and transformers. The voltage and current transformers provide measured values of the actual voltage and current to the protective relay. The relay processes the data and determines, based on its settings, whether or not it needs to operate a circuit breaker in order to isolate faulted sections or components. The classic protective relay is an electromagnetic relay which is constructed with electrical, magnetic, and mechanical components. Nowadays computerized relays are taking over as they have many advantages: computerized relays can perform a self-diagnosis, they can record events and disturbances in a database, and they can be integrated in the communication, measurement, and control environment of modern substations.

A reliable protection is indispensable for a power system. When a fault or an abnormal system condition occurs (such as over−/undervoltage, over−/under-frequency, overcurrent, and so on), the related protective relay has to react in order to isolate the affected section while leaving the rest of the power system in service. The protection must be sensitive enough to operate when a fault occurs, but the protection should be stable enough not to operate when the system is operating at its maximum rated current. There are also faults of a transient nature, a lightning stroke on or in the vicinity of a transmission line, for instance, where it is undesirable that these faults would lead to a loss of supply. Therefore, the protective relays are usually equipped with auto-reclosure (auto-reclosing) functionality. Auto-reclosure implies that the protective relay, directly after having detected an abnormal situation leading to the opening of the contacts of the circuit breaker, commands the contacts of the circuit breaker to close again in order to check whether the abnormal situation is still there. In case of a fault of a transient nature, the normal situation is still there, the protective relay commands the circuit breaker to open its contacts again so that either the fault is cleared or consecutive

Fig. 2.10 Three single-phase independent operated gas circuit breakers. (Courtesy of TenneT TSO B.V)

auto-reclosure (C-O-C operation) sequences can follow. In most cases, the so-called backup protection is installed in order to improve the reliability of the protection system.

When protective relays and circuit breakers are not economically justifiable in certain parts of the grid, fuses can be applied. A fuse combines the "basic functionality" of the current transformer, relay, and circuit breaker in one very simple overcurrent protection device. The fuse element is directly heated by the current passing through and is destroyed when the current exceeds a certain value, thus leading to an isolation of the faulted sections or components. After the fault is repaired/removed, the fuse needs to be replaced so that the isolated grid section can be energized again.

A substation basically consists of a number of ingoing and outgoing power carriers that are connected to one or more common substation bus sections (busbars) by circuit breakers, disconnecting switches, and instrument transformers: the feeders. Figure 2.10 shows an example of a live tank gas circuit breaker installed in an open-air-insulated substation. A circuit breaker is a mechanical switching device, capable of making, conducting, and breaking currents under normal circuit conditions but also interrupting currents under abnormal conditions as in the case of a short circuit.

Disconnecting switches are primarily used to visualize whether a connection is open or closed. Figure 2.11 shows an example of a pantograph disconnecting switch. Different from circuit breakers, disconnectors do not have current-interrupting capability. Therefore, a disconnecting switch cannot be opened when it is conducting a current and when a recovery voltage builds up across the contacts after opening. A disconnecting switch can interrupt a small current when, after opening, a negligible voltage appears over the contacts. The instrument transformers in the substation, like voltage and current transformers, provide measured values of the actual voltage and current to the protective relay and the metering equipment. The protective relays have the task to detect and locate

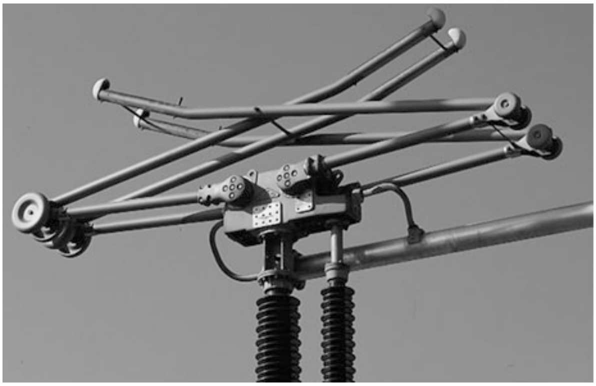


Fig. 2.11 Pantograph disconnecting switch in open position. (Courtesy of TenneT TSO B.V)

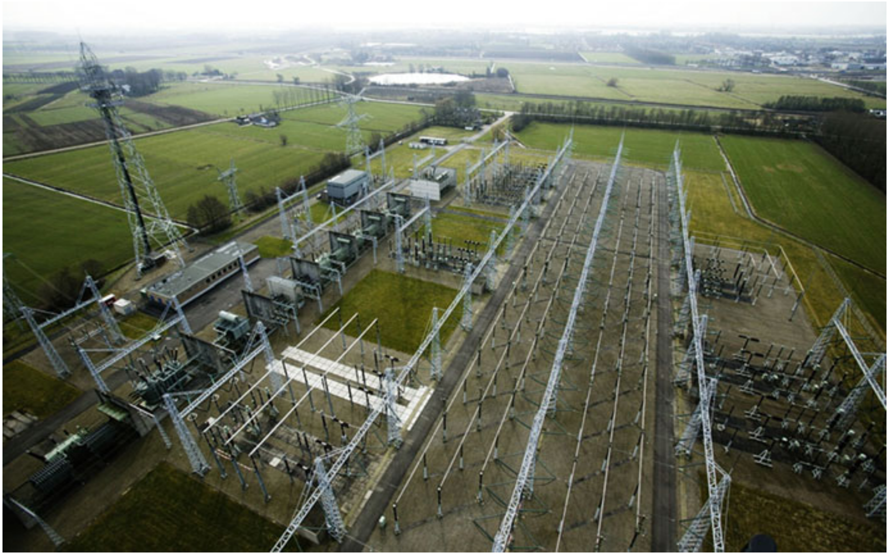


Fig. 2.12 Air-insulated substation. (Courtesy of TenneT TSO B.V)

disturbances in the system, such as short circuits, and to switch off only the faulted part of the network by opening the appropriate circuit breaker(s).

When space is available, substations are commonly erected in the open (an air-insulated substation, see Fig. 2.12). The ambient air serves as the insulating medium and insulators support the live parts. These open-air substations do require quite some space but offer advantages: quick assembly and easy repair and expansion and the possibility to install components of different manufacturers. When pollution is an issue, e.g., the substation is planned close to an industrial area or in a coastal region, the substation can be placed indoors. If the available space is limited, the choice is made for an SF_6 gas-insulated station (see Fig. 2.13). In such a gas-insulated station, the live parts are located inside an earthed metal enclosure.

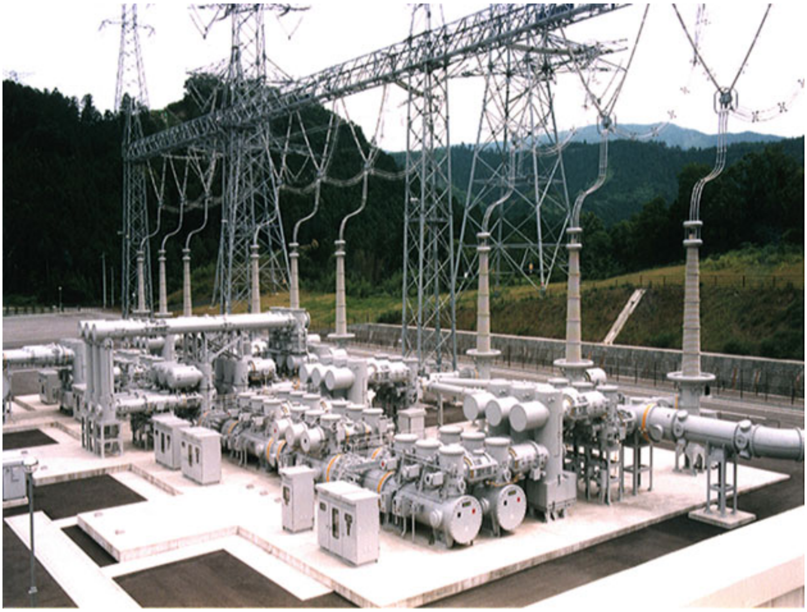


Fig. 2.13 Gas-insulated substation

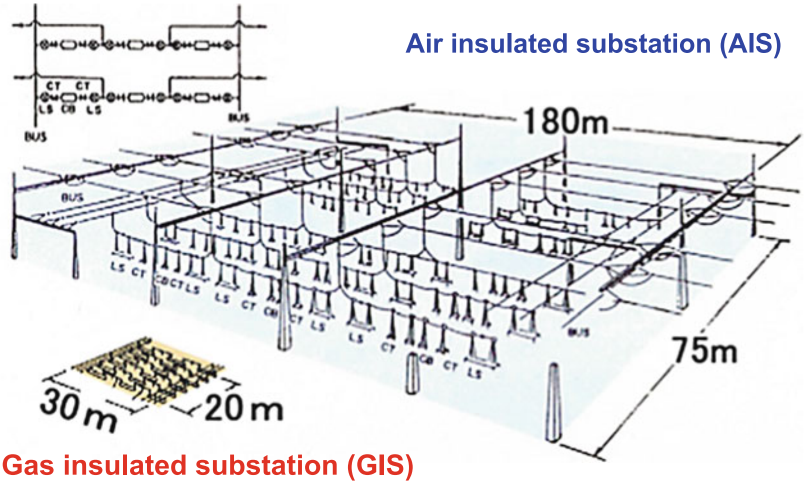


Fig. 2.14 Typical comparison of the installation areas between AIS and GIS

Pressurized SF_6 gas serves as an insulating medium in the enclosure. Pressurized SF_6 is a very good insulator that can be used with electric field strengths that (at a pressure of 5 atm) are about 12 times higher than in atmospheric air. A gas-insulated substation that is filled with SF_6 gas requires only 10–20% of the space of a comparable open-air substation as shown in Fig. 2.14.

2.8 Overhead Lines, Underground Cables, and Gas-Insulated Lines/Busbars

It is in principle an economical and an environmental issue whether to choose an overhead line or an underground cable for transmitting and distributing electrical power to densely populated areas. Underground systems are in general more reliable than overhead systems, because they are not exposed to wind, lightning, and vehicle damage. Underground systems do not disturb the environment, and they require less preventive maintenance. The main disadvantage, however, is its higher costs: for the same power rating, underground systems are in general six to ten times more expensive than overhead systems. In many populated countries, underground cables are commonly used in the MV and HV networks below 72 kV.

Transmission lines produce reactive power (capacitive behavior of the line), because of the electric field component, and consume reactive power (inductive behavior of the line) because of the magnetic field component. When the load of the transmission line is such that the capacitive reactive power and the inductive reactive power of the line are in balance, the operating condition of the line has a power factor equal to 1. We call this surge impedance loading (SIL) of the line. For a loading condition below the SIL point, the produced capacitive reactive power is larger than the consumed inductive reactive power, and the line delivers net capacitive reactive power to the system, and the voltage at the line end will increase. This can be compensated by shunt reactors. If the transmission line carries an amount of active power exceeding the SIL point, the capacitive reactive power is less than the consumed reactive power, so the line will absorb capacitive reactive power from the system resulting in a voltage drop at the end. More detailed information is available in another CIGRE Green Book and documents published by Study Committees B1 and B2, respectively, dealing with overhead lines and cables.

Figure 2.15 shows typical examples of transmission towers with a single circuit (a couple of three-phase lines) and double circuits (two couples of three-phase lines, six lines in total besides grounding wires located on the top of the tower). More detailed information is available in the CIGRE Green Book published by Study Committee B2 dealing with overhead lines.

Besides the existing technologies of overhead transmission lines and solid insulated underground cables, gas-insulated transmission lines (GIL) offer an additional solution for high-power transmission. GIL can be applied for voltages from 100 kV up to 800 kV. Most applications of the GIL are at 420 kV and 550 kV. The upper ranges of 800 kV find only a few applications in China. The gas-insulated transmission lines (GIL) used in the substation are mentioned as the gas-insulated busbars (GIB, see Fig. 2.16).

The GIL consist of a central aluminum conductor that rests on cast resin insulators, which center it within the outer enclosure. This enclosure is formed by a 400 to 600 mm diameter aluminum tube, which provides a solid mechanical and electrotechnical containment for the system. Figure 2.17 shows an example of 275 kV 6300 A GIL (pure SF_6 insulation) with length of 3 km installed in the underground tunnel. To meet up-to-date environmental and technical issues, in some applications, GIL are filled with an insulating gas mixture of mainly nitrogen and a smaller percentage of SF_6 of the line, and capacitor banks might be necessary to compensate for this.

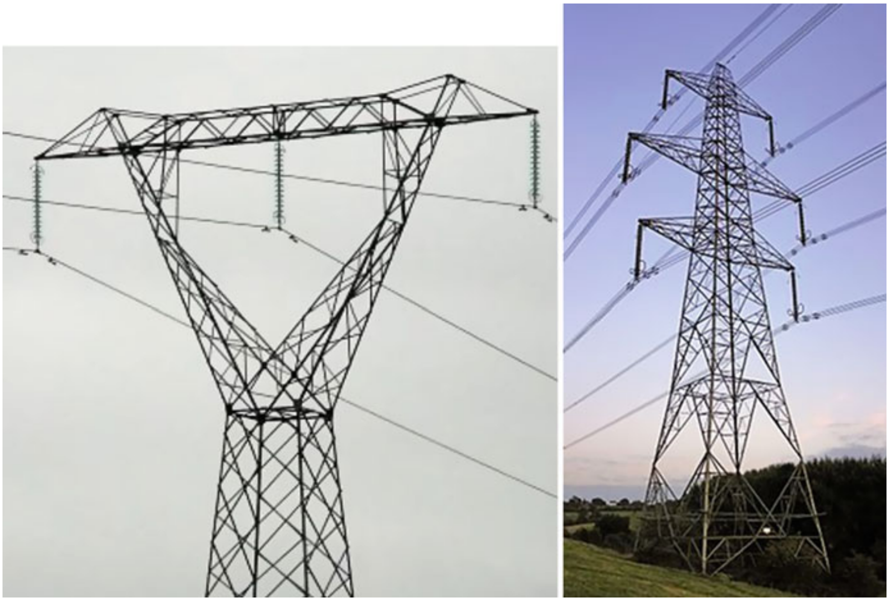


Fig. 2.15 Examples of overhead line with a single circuit and double circuits

Fig. 2.16 Gas-insulated busbar in 550 kV substation (GIB). (Courtesy of Kansai Electric Power)

2.9 Power Transformers

Power transformers are essential components in the AC power system as they make it possible to convert electrical energy to different voltage levels with an efficiency of more than 99%. That enables us to generate power at a relatively low voltage level (10–25 kV, limited by the insulation of the generator) and to transport it at high voltage levels (72/110 kV–420/550 kV and higher) to reduce the losses during transportation,

Fig. 2.17 275 kV 6300 A gas-insulated lines with length of 3 km. (Courtesy of Chubu Electric Power)

whereas domestic consumption can take place at a low and (more or less) safe voltage level (400 V and below). Transformers consist essentially of two coils on a common iron core. The iron core serves as the magnetic coupling between the two coils such that nearly all the magnetic flux from one coil links with the other coil.

The transformer ratio, under normal operating conditions, is given by the ratio of the number of turns of the primary winding and the secondary winding. Power transformers often have in addition to the primary and secondary winding another winding, the tertiary winding. This tertiary winding is either used for the electricity supply of the substation or for voltage regulation in the network. The tertiary winding is also called "regulating winding."

From the viewpoint of designs, power transformers are mainly classified into two different structures: core type and shell type. Figure 2.18 shows schematic drawings of coil arrangements for the core-type and the shell-type transformers. The core-type transformers used for power system commonly have a plurality of concentric coils, which are insulated with each other: low-voltage coils are arranged inside close to the core, and high-voltage coils are located outside. In contrary, the shell-type transformers typically have a multilayer rectangular shaped coils. The high-voltage rectangular hollow-shaped coils are clamped by the low-voltage rectangular hollow-shaped coils at both sides. Then both coils are clamped by the rectangular hollow-shaped core as shown in Fig. 2.19.

Figures 2.20 and 2.21 show examples of the core-type and the shell-type transformers.

2.10 Shunt Reactor

Transmission lines or underground cables, in particular for voltages of 72.5 kV and above, can produce a large amount of capacitive reactive power (for instance, when dispatch of variable renewable energy sources is low) which could cause the voltage profile of the network to exceed the maximum level.

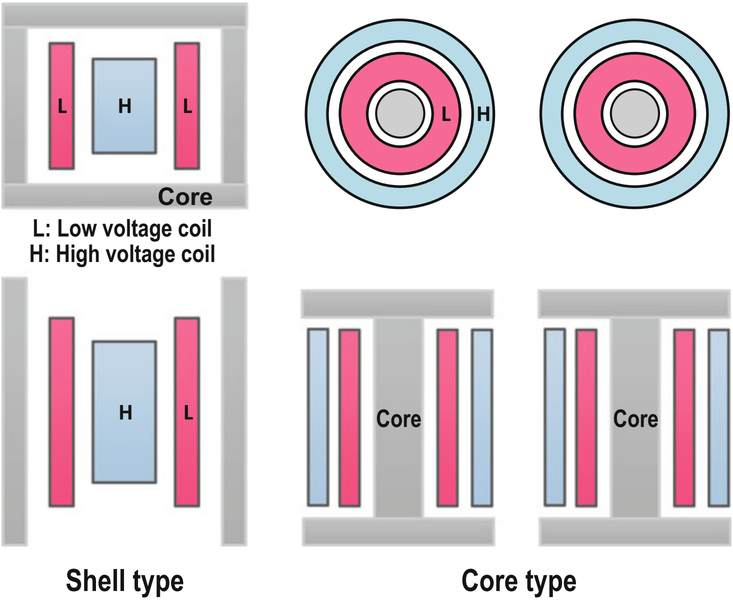
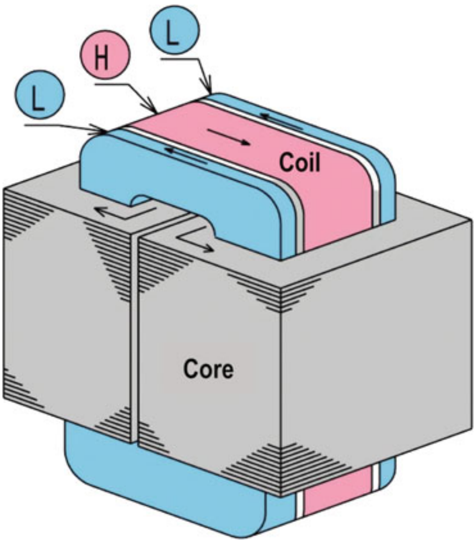


Fig. 2.18 Coil arrangements of shell-type and core-type transformers

Fig. 2.19 Coil and core arrangement of the shell-type transformer



Shunt reactors absorb reactive power and influence the voltage regulation by reduction of the voltage profile. The need of increasing and expanding the transmission system, in order to cope with the power transfer from large variable renewable energy sources, can lead to the necessity to install more shunt reactors at the

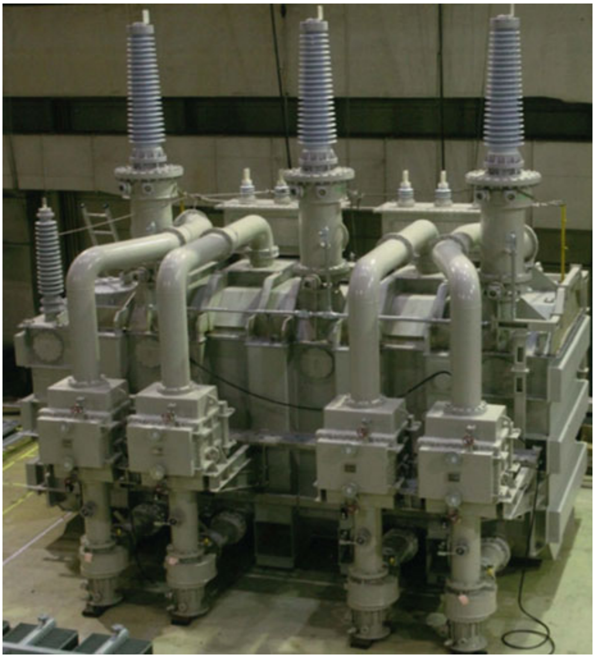


Fig. 2.20 132 kV 50 MVA SF_6 gas-insulated power transformer (core type)

Fig. 2.21 345 kV 750 MVA power transformer (shell type)

transmission level to control the increase of capacitive reactive power when the infeed of variable renewable energy sources is low (no wind for the wind farms, for instance). The transmission lines, when they do not carry a high amount of active power, have to deal with strong line-charging phenomena, as a result of the Ferranti effect. Shunt reactors keep the voltages within the desired margins.

Fig. 2.22 20 kV, 22.5 MVA shunt reactor bank. (Courtesy of J Power)

Shunt reactors can be installed as a three-phase unit or as three single-phase units. This depends on the rated reactive power, system voltage, or planning and design criteria. The shunt reactor can be permanently connected (fixed shunt reactor) or switched through a circuit breaker and can be installed at the transmission line terminals or connected to the substation busbar. Figure 2.22 shows an example of 20 kV shunt reactor which is a similar structure of power transformer with some cooling units.

Variable shunt reactors with a tap changer are applied when a precise and slow voltage regulation is required. For more coarse but flexible voltage regulation, switched shunt reactors are applied. For large reactive power ratings and high voltage levels, shunt reactors are of the gapped iron core oil-immersed type to minimize the losses and to reduce audible noise and vibrations. For the lower voltage levels and smaller reactive power ratings, the shunt reactors are dry-type reactors sometimes without an iron core to lower the cost.

2.11 Capacitor Banks

Capacitor banks produce reactive power to compensate for the inductive reactive power coming from transformers, from transmission lines that are loaded above their SIL level, or from inductive loads. The use of capacitor banks results in an increased transmission capacity and in a reduction of the losses because of the improved power factor and leads to a better voltage profile.

Fig. 2.23 23 kV, 22.5 MVA shunt capacitor bank. (Courtesy of J Power)

A capacitor bank consists of several capacitors of the same rating that are connected in a parallel/series arrangement (Fig. 2.23). Capacitor banks can be permanently connected (fixed capacitor bank) or switched through a circuit breaker and can be installed at the transmission-line terminals or at the substation busbar. For voltage ratings of 72.5 kV and higher, each bank has its own circuit breaker. The inrush or outrush currents can be kept under control in an active way (by controlled switching or with a pre-insertion impedance) or passive with series reactors.

Series reactors (also called damping reactors) can contribute to resonance in the network. The need of increasing and expanding the transmission system, in order to cope with the power transfer from large variable renewable energy sources, can lead to the necessity to install more capacitor banks at the transmission level to control the increase of inductive reactive power when the infeed of variable renewable energy sources is high (excessive wind for the wind farms, for instance).

2.12 Circuit Breaker

A high-voltage circuit breaker is an indispensable piece of equipment in the power system. The main task of a circuit breaker is to interrupt fault currents and to isolate faulted parts of the system. Besides short-circuit currents, a circuit breaker must also be able to interrupt a wide variety of other currents at system voltage such as capacitive currents, small inductive currents, and load currents. The following requirements are also imposed on a circuit breaker:

- Excellent conductor to carry the nominal current in the closed position
- Excellent insulation to withstand overvoltages in the open position
- Rapid and reliable operation from closed to open position (and vice versa)
- No prominent overvoltages during switching operation

The need to perform all these tasks in a reliable way places circuit breakers among the most complex pieces of equipment installed in the power system. Circuit breakers are present at all voltage levels, in our household miniature circuit breakers (MCBs) protect our domestic apparatus and electronic equipment, at medium voltage they safeguard city quarters, and at the highest voltage levels, they protect the transmission corridors for bulk power.

High-voltage circuit breakers have to operate under very different climatic conditions, at high and extremely low temperatures; under high humidity, with ice load; in windy environments; and at high altitudes. They must be able to withstand seismic activity and function reliably in areas with high pollution as well.

Most circuit breakers are mechanical switching devices, driven by an operating mechanism, that in closed position continuously carry the rated current. However, when a protective relay sends a trip command, it has to operate in a very short period of time.

The first circuit breakers were built at the beginning of the twentieth century, and since then, the design, manufacturing, testing, and field application of circuit breakers have changed considerably. The worldwide experience with circuit breakers over the years, in a diversity of applications, and the exchange of this knowledge in Study Committee 13 and later in Study Committee A3 brought new insights that resulted in new medium- and high-voltage switching equipment.

Circuit breakers have to be capable of interrupting a wide range of currents, from rated nominal current to the maximum short-circuit current that they can handle. In addition, they have the task to energize and de-energize under normal service conditions shunt reactors, capacitor banks, transformers, generators, motors, cables, and transmission lines.

A circuit breaker consists of:

- The main contacts that carry the current under normal service condition
- The arcing contacts that facilitates the switching arc during current interruption
- The arcing chamber where hot gas is generated by the arc
- The operating mechanism that stores the energy to move the contacts apart
- Support insulators

For higher voltage levels, circuit breakers are sometimes equipped with pre-insertion resistors. The purpose of these resistors is to mitigate the transient recovery voltage after an opening operation or to reduce the inrush current after a closing operation. For transmission-line switching, the value of the pre-insertion resistor is typically between 200 and 600 Ω.

Nowadays controlled switching is widely used to reduce switching transients. Besides that modern SF_6 circuit breakers have better switching performance than their oil and air-blast predecessors which makes the use of pre-insertion resistors less necessary.

The electric arc is, except for power semiconductors, the only known element that is able to change from a conducting to a nonconducting state in a short period of time. In high-voltage circuit breakers, the electric arc is a high-pressure arc burning in oil, air, or sulfur hexafluoride (SF_6). In medium-voltage breakers, the low-pressure arc burning in the vacuum is more often applied to interrupt the current. The current interruption is performed by cooling the arc plasma so that the electric arc, which is formed between the breaker contacts after contact separation, disappears. This cooling process or arc-extinguishing can be done in different ways. Power circuit breakers are categorized according to the extinguishing medium in the interrupting chamber in which the arc is formed. That is the reason why we speak of oil, air-blast, SF_6, and vacuum circuit breakers.

In 1907, the first oil circuit breaker was patented by J. N. Kelman in the United States (Kleman 1907). The equipment was hardly more than a pair of contacts submersed in a tank filled with oil. It was the time of discovery by experiments, and most of the breaker design was done by trial and error in the power system itself. In 1956, the basic patent on circuit breakers employing SF_6 was issued to T. E. Browne, F. J. Lingal, and H. J. Hills (Lingal et al. 1956).

Presently the majority of the high-voltage circuit breakers use SF_6 as the extinguishing medium. J. Slepian (1929) has done much to clarify the nature of the circuit breaker problem, because the electric arc proved to be a highly intractable and complex phenomenon. Each new refinement in experimental technique threw up more theoretical problems. The practical development of circuit breakers was, especially in the beginning, somewhat pragmatic, and design was rarely possible as deduction from scientific principles. A lot of development testing was necessary in the high-power laboratory.

A great step forward in understanding arc-circuit interaction was made in 1939 when A. M. Cassie (1939; Cassie and Mason 1956) published the paper with his well-known equation for the dynamics of the arc and, then in 1943, O. Mayr (1943) followed with the supplement that takes care of the time interval around current zero. Much work was done afterward to refine the mathematics of those equations and to confirm their physical validity through practical measurements (CIGRE Working Group 13.01 1993, 1988). It becomes clear that current interruption by an electrical arc is a complex physical process when we realize that the interruption process takes place in microseconds, the plasma temperature in the high-current region is more than 10,000 K, and the temperature decay around current zero is about 2000 K per microsecond, while the gas movements are supersonic. The understanding of the current interruption process has led to SF_6 circuit breakers capable of interrupting 63 kA at 550 kV with a single interrupting element.

2.12.1 Oil Circuit Breaker

Circuit breakers built in the beginning of the twentieth century were mainly oil circuit breakers. Also water breakers have been developed, but maintaining proper dielectric insulation after a breaking operation was a too big challenge. In those days the breaking capacity of oil circuit breakers was sufficient to meet the required short-circuit level in the substations. Presently, oil and minimum-oil circuit breakers still do their job in various parts of the world, but they have left the scene of circuit breaker development. The first oil circuit breakers were of simple design, an air switch that was put in a tank filled with mineral oil. These oil circuit breakers were of the plain-break type, which means that they were not equipped with any sort of arc-quenching device. In 1901, J. N. Kelman of the United States (Kleman 1907) built an oil-water circuit breaker in this way, which was capable of interrupting 200–300 A at 40 kV. Kelman's breaker consisted of two open wooden barrels, each containing a plain-break switch. The two switches were connected in series and operated by one common handle. The wooden barrels contained a mixture of water and oil as the extinguishing medium (Fig. 2.24).

In the 1930s, the arcing chamber appeared on stage. The breaker, a metal explosion pot of some form, was fitted with an insulating arcing chamber through which the breaker contacts moved. The arcing chamber, filled with oil, fixes the arc, and the increase in pressure inside the arcing chamber improved the cooling effects on the arc considerably. Later, the design of the arcing chamber was further improved by pumping mechanisms, creating a cross flow of oil, giving extra cooling to the arc (Fig. 2.25).

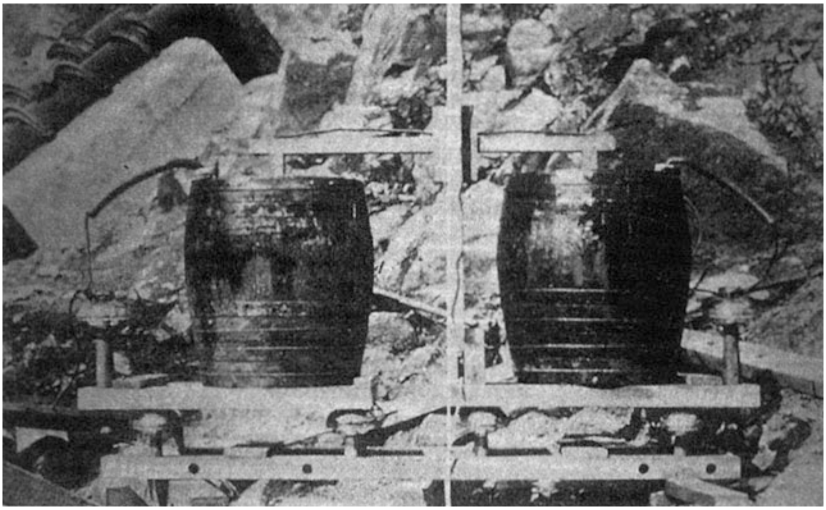


Fig. 2.24 Kelman's oil circuit breaker built in 1901 (40 kV, 300 A) (Wilkins and Crellin 1930)

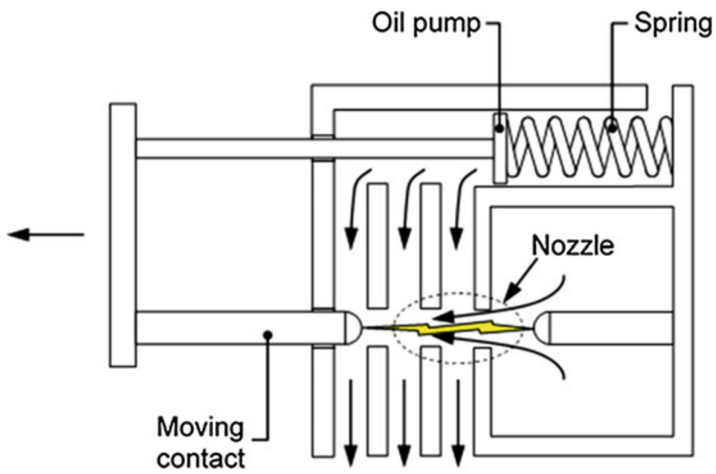


Fig. 2.25 Cross section of an oil circuit breaker assisted with pressurized oil

In the bulk-oil circuit breakers, the contacts were located in the center of a large metal tank filled with mineral oil. The oil serves as the extinguishing medium and provides the insulation to the tank. For current measurements current transformers were fit around the bushings of the breaker. Figure 2.26 shows an example of 168 kV bulk-oil dead tank circuit breaker.

A next step in the development of oil circuit breakers was the minimum-oil circuit breaker. The contacts and arcing chamber were placed into a porcelain insulator instead of in a bulky metal tank. Bulk-oil circuit breakers with their huge metal tank containing hundreds of liters of mineral oil have been popular in the United States. Minimum-oil circuit breakers conquered the market in Europe. Figure 2.27 shows an example of 245 kV 50 kA minimum-oil live tank circuit breaker produced in 1985.

The principle of arc extinction in oil breakers is based on the decomposition of oil in hydrogen and methane gas by the arc. Eighty percent of the gas is hydrogen which has excellent dielectric properties and a high specific heat constant. Minimum-oil breakers work best at higher currents that provoke a sharp rise in pressure and strong convection. The interruption of low currents, when the gas quantity released by the arc is lower, has always been a challenge for the design engineers. Minimum-oil breakers are sensitive for a dielectric reignition after the interruption of a capacitive current. Oil is a good electrical insulator, and when the breaker contacts are open, it isolates the grid voltage across the contacts.

2.12.2 Air-Blast Circuit Breaker

Air is used as an insulator in outdoor-type substations and for high-voltage transmission lines. Air can also be used as the extinguishing medium for current interruption. At atmospheric pressure, the interrupting capability, however, is limited to low-voltage

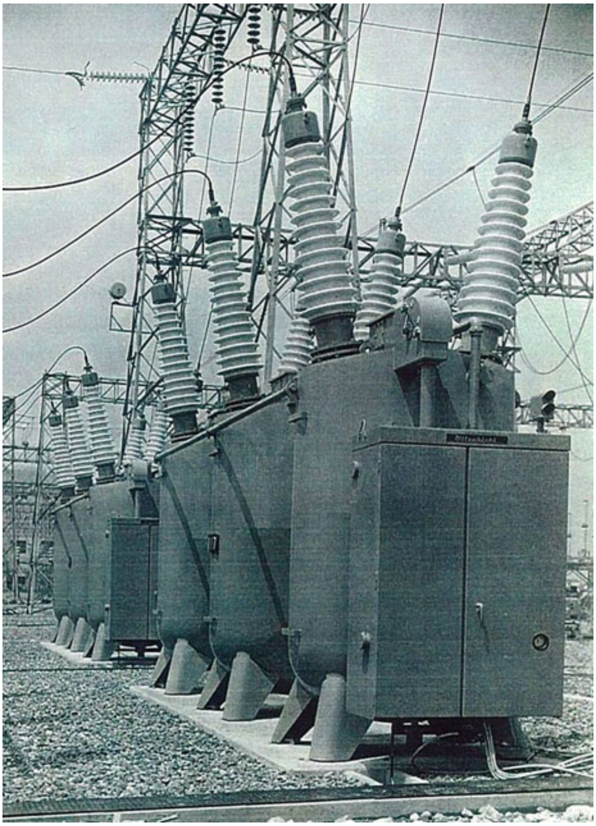


Fig. 2.26 168 kV bulk-oil, dead tank oil circuit breaker developed in 1959. (Courtesy of Mitsubishi Electric)

and medium-voltage only. For medium-voltage applications up to 50 kV, the breakers are mainly of the magnetic air-blast type in which the arc is blown into a segmented compartment by the magnetic field generated by the fault current. In this way, the arc length, the arc voltage, and the surface of the arc column are increased. The arc voltage decreases the fault current, and the larger arc column surface improves the cooling of the arc channel. Figure 2.28 shows 36 kV vintage air-blast circuit breaker.

At higher pressure, air has much more cooling power because the arc is cooled by convection as a result of the large pressure difference between the inside of the breaker and the ambient air outside. Air-blast breakers operating with compressed air can interrupt higher currents at considerably higher voltage levels. Air-blast breakers using compressed air can be of the axial-blast or the cross-blast type. The cross-blast type air-blast breaker operates similar to the magnetic-type breaker: compressed air blows the arc into a segmented arc-chute compartment. Because the arc voltage increases with the arc length, this is also called high-resistance interruption; it has the disadvantage that the energy dissipated during the interruption process is rather high. In the axial-blast design, which can be classified into the insulator nozzle type like the AEG design and the metal nozzle type employed in most other designs, the arc is

Fig. 2.27 245 kV 50 kA live tank oil circuit breaker. (Courtesy of ABB, product of ASEA in 1985)

cooled in the axial direction by the airflow. The current is interrupted when the ionization level is reduced around current zero. Because the arc voltage hardly increases, this is called low-resistance interruption. During operation, air-blast breakers make a lot of noise, especially when the arc is cooled in free air.

Air-blast circuit breakers were the preferred technology for extra high voltage (EHV) until the evolution and dissemination of SF_6 gas circuit breakers. Figure 2.29 shows an example of 800 kV air-blast circuit breaker. Due to the inherent high arc voltage of air, air-blast circuit breakers can provide technical advantages for rapid decaying of the DC component of an asymmetric fault current and a reduced period of the delayed current zero phenomenon (interval of missing current zero). However, higher cost and longer periods of maintenance work will limit its applications to specialized network conditions.

2.12.3 SF_6 Gas Circuit Breaker

The superior dielectric properties of SF_6 were discovered as early as 1920. SF_6 has molecular weight of 146, five times heavier than air. The dielectric strength is at

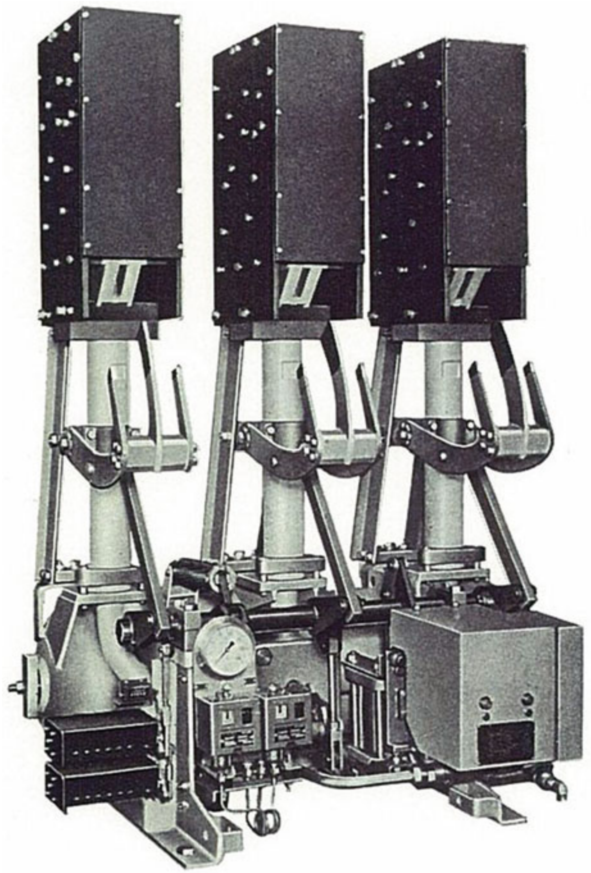


Fig. 2.28 36 kV air-blast circuit breaker developed in 1953. (Courtesy of Mitsubishi Electric)

atmospheric pressure three times better than that of air, and the dielectric strength increases rapidly with increased pressure. At a pressure of 2 atm (0.2 MPa), it has the same insulating properties as mineral oil. Contamination by air does not alter the insulating properties substantially. SF_6 is well suited for application in circuit breakers because it is an electronegative gas, therefore having an affinity for capturing free electrons, which gives rise to the formation of negative ions with reduced mobility. This property leads to rapid removal of electrons present in the plasma of an arc in SF_6, thus increasing the arc's conductance decrement rate when the current approaches current zero. SF_6 is an exceptionally stable and inert gas, but in the presence of an arc, it produces very toxic by-products such as SF_2 and SF_4 that recombine to form nontoxic products immediately after arc extinction. This reversible chemical reaction during arc generation and arc extinction processes is a unique feature of SF_6 to maintain its excellent interruption performance for a long period. The resulting main stable toxic products are metal fluorides that are deposited as white powder and are absorbed in an activated aluminum filter containing aluminum trioxide.

Fig. 2.29 Latest-generation 800 kV air-blast circuit breaker. (Courtesy of GE, produced by Alstom)

It took until the 1940s before the first development of SF_6 circuit breakers began, but it took till 1959 before the first SF_6 circuit breaker came to the market (Friedrich and Yechley 1959). These early designs were descendants of the axial-blast and air-blast circuit breakers, the contacts were mounted inside a tank filled with SF_6 gas, and during the current interruption process, the arc was cooled by compressed SF_6 gas from a separate reservoir. The liquefying temperature of SF_6 gas depends on the pressure but lies in the range of the ambient temperature of the breaker. This means that the SF_6 reservoir needed to be equipped with a heating element that introduced an extra failure possibility for the circuit breaker; when the heating element does not work, the breaker cannot operate. Therefore the puffer circuit breaker was developed, and the so-called double-pressure breaker disappeared from the market. Figure 2.30 shows an example of 240 kV double-pressure-type gas circuit breaker. In the single-pressure puffer circuit breakers of two generations with 245 kV 50 kA double breaks and with single break as shown in Fig. 2.31, the opening stroke made by the moving contacts moves a piston, compressing the gas in the puffer chamber and thus causing an axial gas flow along the arc channel. The nozzle must be able to withstand the high temperatures without deterioration and is made from Teflon. Presently, the SF_6 puffer circuit breaker is the breaker type used for the interruption of the highest short-circuit powers, up to 550 kV 63 kA per interrupters with live tank design and dead tank design as shown in Figs. 2.32 and 2.33.

Puffer circuit breakers require a rather strong operating mechanism because the SF_6 gas has to be compressed. When interrupting large currents, for instance, in the case of

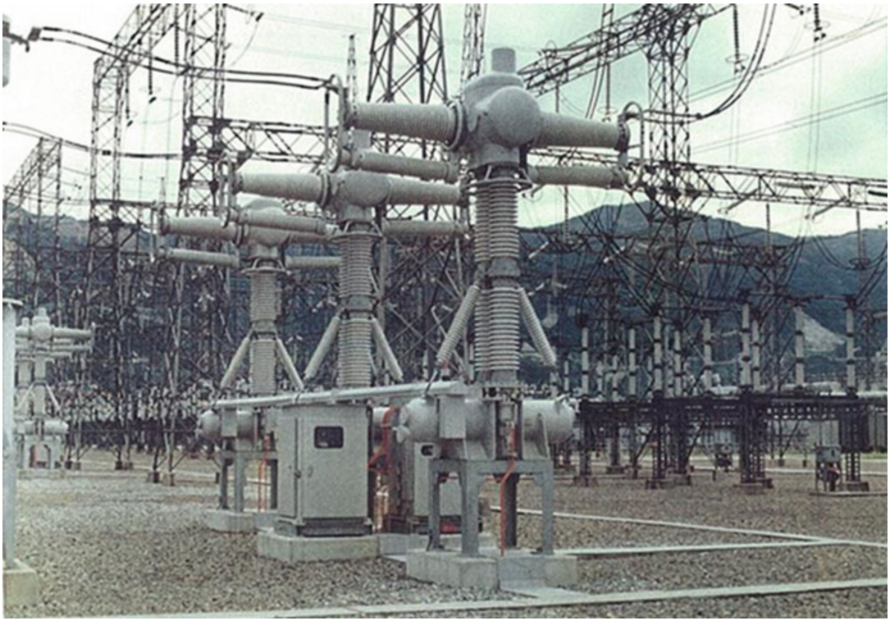


Fig. 2.30 240 kV double-pressure-type SF_6 puffer circuit breaker

a three-phase fault, the opening speed of the circuit breaker has a tendency to slow down by the thermally generated pressure, and the mechanism (often hydraulic or spring mechanisms) needs to have enough energy to keep the contacts moving apart. Strong and reliable operating mechanisms are costly and form a substantial part of the price of a breaker. For the lower-voltage range, self-blast circuit breakers are now on the market. Self-blast breakers use the thermal energy released by the arc to heat the gas and to increase its pressure. After the moving contacts are out of the arcing chamber, the heated gas is released along the arc to cool it down. The interruption of small currents can be critical because the developed arcing energy is in that case modest, and sometimes a small puffer is added to assist in the interrupting process.

In other designs, a coil, carrying the current to be interrupted, creates a magnetic field, which provides a driving force that rotates the arc around the contacts and thus provides additional cooling. This design is called the rotating-arc circuit breaker. Both self-blast breakers and rotating-arc breakers can be designed with less powerful (and therefore less expensive) mechanisms and are of a more compact design than puffer breakers.

2.12.4 Vacuum Circuit Breaker

Between the contacts of a vacuum circuit breaker, a vacuum arc takes care of the interruption process. As already discussed in the paragraph about the switching arc,

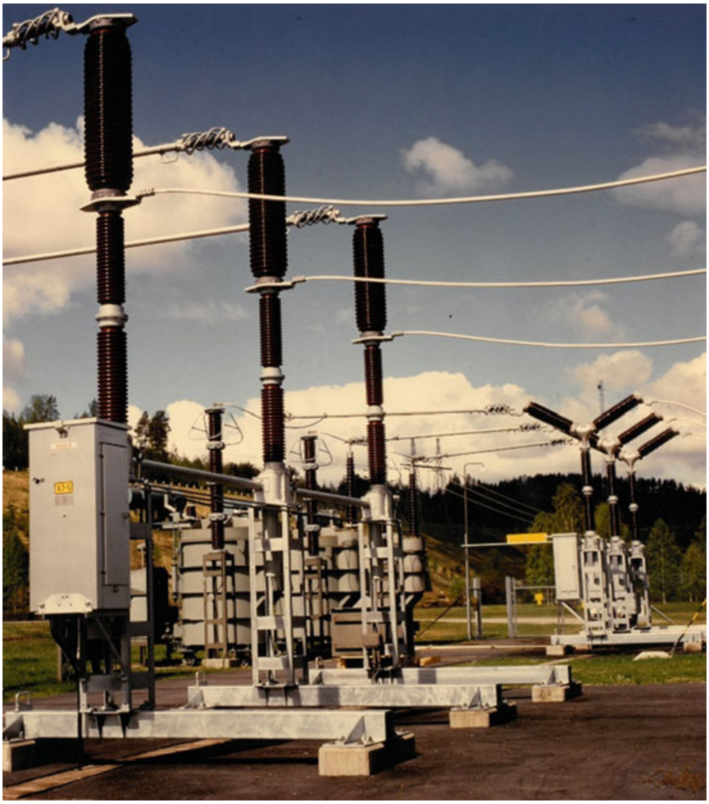


Fig. 2.31 245 kV 50 kA double-break and single-break SF_6 puffer circuit breakers. (Courtesy of ABB, ASEA products with double breaks in 1983 and with single break in 1985)

the vacuum arc differs from the high-pressure arc because the arc burns in the vacuum in the absence of an extinguishing medium. The behavior of the physical processes in the arc column of a vacuum arc is to be understood as a metal surface phenomenon rather than a phenomenon in an insulating medium. The arc is maintained by ions of metal material vaporized from the cathode. The density of this metal vapor is proportional with the current, and the plasma reduces when the current approaches current zero. At zero current the contact gap is rapidly deionized by condensation of the metal vapor on the electrodes. When the arc current goes to zero, it does so in discrete steps of a few amperes to 10 A, depending on the contact material. For the last current step to zero, this can cause a noticeable chopping of the current. This current chopping in turn can cause high overvoltages, in particular when the vacuum breaker interrupts a small inductive current, for example, when switching unloaded transformers or stalled motors. The absence of ions after current interruption gives the vacuum breaker a high dielectric withstand capability.

Fig. 2.32 550 kV live-tank SF_6 gas circuit breaker (Courtesy of Dominion Energy)

Fig. 2.33 550 kV 63 kA single-break SF_6 gas circuit breaker. (Courtesy of Chugoku Electric Power)

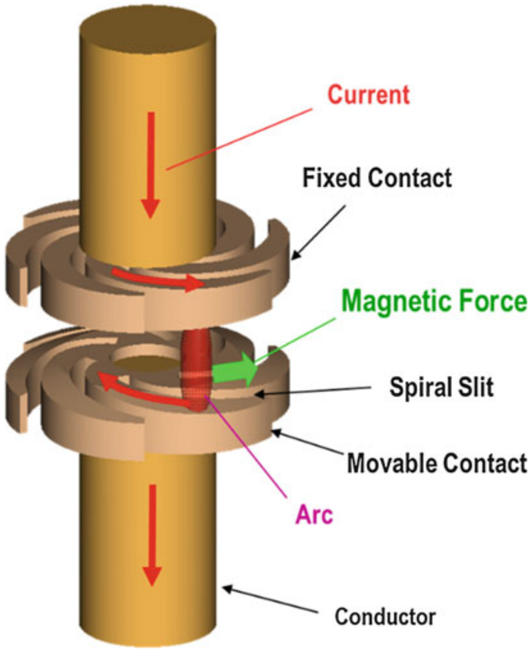
Fig. 2.34 24 kV 25 kA 1250 A vacuum circuit breaker. (Courtesy of Mitsubishi Electric)

The first experiments with vacuum interrupters had already taken place in 1926 (Sorensen and Mendenhall 1926), but it was not until the 1960s when metallurgical developments made it possible to manufacture gas-free electrodes that the first practical interrupters were built. In the 1970s, 36 kV vacuum interrupter was generally accepted as the unit voltage. The vacuum circuit breakers have been established as a reliable option for current interruption especially in MV networks. Figure 2.34 shows an example of 24 kV vacuum circuit breaker. Vacuum circuit breakers that continued to evolve and are gradually applied on a large scale in power networks up to 145 kV vacuum circuit breakers are available.

There are no mechanical ways to cool the vacuum arc, and the only possibility to influence the arc channel is by means of interaction with a magnetic field. The vacuum arc is the result of a metal-vapor/ion/electron emission phenomenon. To avoid uneven erosion of the surface of the arcing contacts (especially the surface of the cathode), the arc should be kept diffused or in a spiraling motion. The latter can be achieved by the electrodes with several spiral slits in the arcing contacts (see Fig. 2.35) or by applying horseshoe magnets as used in the vacuum interrupters (see Fig. 2.36). There is generally less energy required to separate the contacts of a vacuum circuit breaker, and the design of the operating mechanism usually results in reliable and maintenance-free breakers.

Vacuum breakers are produced for rated voltages up to 72.5 kV (some manufacturers also produce vacuum circuit breakers for 145 kV; see Fig. 2.37), and for the

Fig. 2.35 Vacuum interrupter with spiral slits in the contacts to bring the arc in a spiraling motion



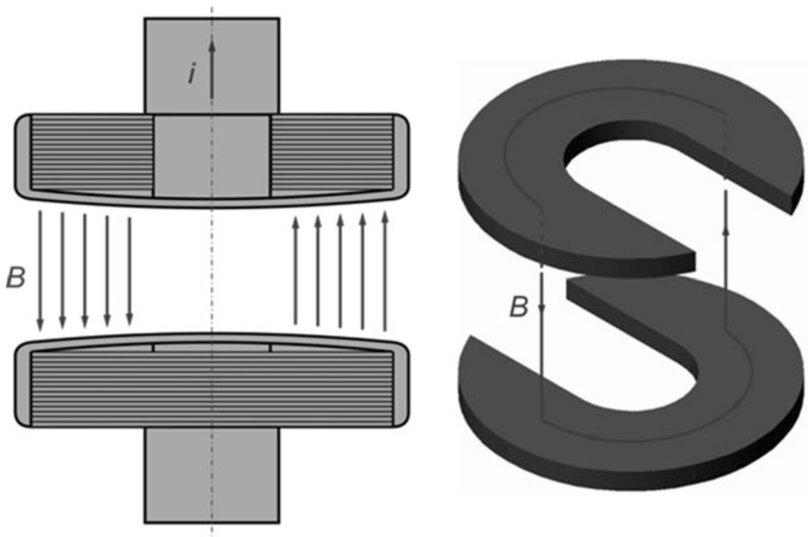


Fig. 2.36 Vacuum interrupter with horseshoe magnets. (Courtesy of Eaton Electric)

breaking current, the rating goes up to 31.5 kA. CIGRE WG A3.27 investigated several vacuum interrupters at transmission levels from 72 kV to 145/168 kV (CIGRE TB 589 2014). More detailed information is described in ▶ Chap. 7.

Fig. 2.37 Vacuum interrupters used at transmission levels (CIGRE TB 589 2014)

2.12.5 Generator Circuit Breaker

Generator circuit breakers are breakers applied at a rated voltage matching the rated voltage of a generator. They are located between the generator and the step-up transformer. When no generator circuit breaker is applied, an alternative solution is a circuit breaker at the high-voltage side of the step-up transformer. The advantage of this solution is the less complicated, simple high-current connection (generator bus duct) between the generator and transformer. The advantage of having a generator circuit breaker is the possibility to connect the auxiliary plant to the medium-voltage side of the (permanently energized) step-up transformer.

In the 1960s generator circuit breakers were developed for the higher power ratings. Air-blast technology was used, and the generator circuit breakers were equipped with an auxiliary switch and an opening resistor in parallel with the main interrupting chamber. The opening resistors were necessary to reduce the zero-crossing phenomenon and to decrease the rate of rise of the transient recovery voltage. In the late 1970s, generator circuit breakers with SF_6 technology came on the market. Figure 2.38 shows an example of 13.8 kV 100 kA SF_6 puffer-type generator circuit breaker. These breakers have no opening resistors and can be built more compactly.

The electrical and mechanical performances of a generator circuit breaker are very different from standard MV distribution switchgear. The common standard available worldwide that covers specifically the requirements for generator circuit breakers is IEC/IEEE 62271–37-013 (2015). Apart from the ratings and other relevant characteristics, this standard contains guidelines for the type testing of generator circuit breakers. Load currents for large generation units can be as high as 50 kA, which often makes forced cooling necessary.

2.13 Surge Arrester

Overvoltages, which stress a power system, can generally be classified into two categories regarding their origin:

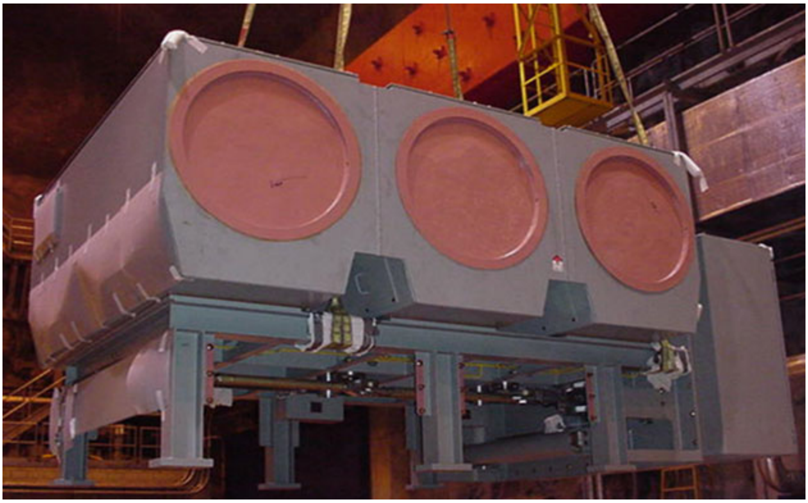


Fig. 2.38 13.8 kV 100 kA 12,000 A generator circuit breaker. (Courtesy of City of Tacoma, United States)

- External overvoltages, generated by lightning strokes, which are the most common and severe atmospheric disturbances
- Internal overvoltages, generated by changes in the operating conditions of the network, like switching

Surge arresters are placed in substations with the purpose to limit lightning-induced overvoltages and switching-induced overvoltages to a specified protection level, which is, in principle, below the withstand voltage of the equipment. The ideal surge arrester would be one that starts to conduct at a specified voltage level, at a certain margin above its rated voltage, holds that voltage level without variation for the duration of the overvoltage, and ceases to conduct as soon as the voltage across the surge arrester returns to a value below the specified voltage level. Therefore, such an arrester would only have to absorb the energy that is associated with the overvoltage.

The design and operation of surge arresters have radically changed over the last 30 years from valve or spark gap-type silicon carbide (SiC) surge arresters to the gapless metal-oxide (MO) or zinc-oxide (ZnO) surge arresters. Major steps in the development of surge arresters have been made, and modern surge arresters fulfil the present-day requirements (Fig. 2.39).

A metal-oxide surge arrester is essentially a collection of billions of microscopic junctions of metal-oxide grains that turn on and off in microseconds to create a current path from the top terminal to the earth terminal of the arrester. It can be regarded as a very fast-acting electronic switch, which is opened to operating voltages and closed to switching and lightning overvoltages. An important parameter of an arrester is the switching impulse protection level (SIPL) defined as the maximum permissible peak voltage on the terminals of a surge arrester subjected to switching impulses under specific conditions.

Fig. 2.39 Metal-oxide surge arresters (MOSA) in 550 kV substations. (Courtesy of Kansai Electric Power)

In order to keep the power supplied to a metal-oxide arrester at the system operating voltage small, the continuous operating voltage of the arrester has to be chosen such that the peak value of the resistive current component is well below 1 mA, and the capacitive current component is dominant. This means that the voltage distribution at operating voltage is capacitive and is thus influenced by stray capacitance. The voltage-current characteristic of the metal-oxide material offers the nonlinearity necessary to fulfil the mutually contradicting requirements of an adequate protection level at overvoltages and low current, i.e., low energy dissipation at the system operating voltage. Metal-oxide surge arresters are suitable for the protection against switching overvoltages at all operating voltages.

Traditionally, porcelain-housed metal-oxide surge arresters are used. For satisfactory performance, it is important that the units are hermetically sealed for the lifetime of the arrester discs. The sealing arrangement at each end of the arrester consists of a stainless steel plate with a rubber gasket. This plate exerts continuous pressure on the gasket, against the surface of the insulator. It also serves to fix the column of the metal-oxide discs in place by springs. The sealing plate is designed to act as an overpressure relief system. Should the arrester be stressed in excess of its design capability, an internal arc is established. The ionized gases cause a rapid increase of the internal pressure, which, in turn, causes the sealing plate to open and the gases to flow out through the venting ducts. Since the ducts are directed toward each other, it results in an external arc, thus relieving the internal pressure and preventing a violent shattering of the insulator.

However, porcelain-housed distribution arresters have tended to fail due to problems with sealing. The benefits of a leak-tight design, using polymers, have been generally accepted, leading to the changeover from porcelain to polymers. Polymer-housed arresters have a very reliable bond of the silicone rubber with the active parts. Hence, gaskets or sealing rings are not required. Should the arrester be electrically stressed in excess of its design capability, an internal arc is established, leading to rupture of the enclosure, instead of explosion. The arc will easily burn through the soft silicone material, permitting the resultant gases to escape quickly and directly. Hence, special pressure relief vents, with the aim of avoiding explosion of porcelain housing, are not required for this design. Moreover, polymer-housed distribution arresters are cheaper than porcelain-enclosed ones.

2.14 Switchgear at Distribution Levels

The roles of distribution networks are recently changing due to rapid increases of dispersed and intermittent wind and solar power generations. The dispersed power generations directly connected to distribution networks may cause a reversed load flow from the distribution to the transmission networks. Switchgears used at distribution levels are required to operate the distribution systems more reliably and efficiently.

CIGRE did not intensively investigate the switching phenomena and the requirements at distribution levels due to the lack of information on equipment performance in the field. SC A3 will increase the activities to investigate the equipment at distribution systems in the future (Fig. 2.40).

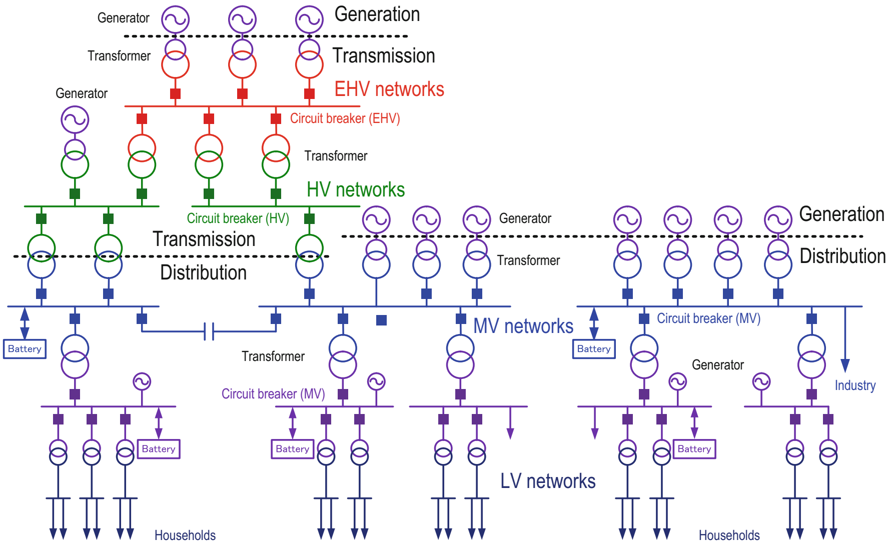


Fig. 2.40 Change of the roles of distribution system and equipment

MV switchgears are an essential part of the electrical power distribution system, contributing to its reliability and safety. It is typically installed on the power lines ranging from 1 kV up to 52 kV (IEC standards) or 38 kV (IEEE standards). The term switchgear is used to describe different types of equipment including electrical disconnecting switches, load break switches, reclosers, and circuit breakers. Their purpose is to control, protect, and isolate the equipment in distribution networks. They can be used to de-energize equipment to allow work to be done, to switch on/off the load, or to clear faults downstream.

As compared with HV switchgear, MV switchgear consists of two main components:

- Power-conducting components that conduct or interrupt the flow of electrical power
- Control systems such as control panels, current transformers, potential transformers, protective relays, and associated circuitry that monitor, control, and protect the power-conducting components

Ratings and specifications of MV switchgears must meet several different standards and requirements, including IEEE (Institute of Electrical and Electronics Engineers) and ANSI (American National Standards Institute) for North America and the IEC (International Electrotechnical Commission) standards around the world besides each national standard.

MV switchgears can be classified either by insulation type, by interrupter type, or by its construction below:

1. Classification by insulation: Most of MV switchgears available today use either gas or solid dielectric material for the insulation. While there was a strong penetration of solid dielectric insulation in the last two decades, the gas-insulated switchgears are still being produced utilizing air, SF_6, nitrogen, CO_2, and some gas mixtures. In recent years, there is a lot of research in the field of "alternative gases" to find a potential replacement for SF_6, and some new gases and gas mixtures are currently being evaluated.
2. Classification by interrupter technology
   (a) Air-insulated switchgears (AIS)
   (b) Gas-insulated switchgears (GIS)
   (c) Vacuum interrupter
3. Construction
   (a) Outdoor (must withstand the elements and large temp. range)
      (i) Pole top mount
      (ii) Pad mount (installed in a cabinet or a housing)
      (iii) Vault mount (installed in a wall)
   (b) Indoor
   (c) Live tank/dead tank
   (d) Metal clad/metal enclosed
   (e) Arc resistance

Fig. 2.41 Pole top recloser with solid dielectric insulation in accordance with IEEE C37.60/IEC 62271–111. (Courtesy of G&W Electric Company)

Reclosers are applied for overcurrent protection, mainly on overhead distribution systems in case of a temporary fault (not the case of a permanent failure). Reclosers help the network to self-recover itself and significantly improve reliability by isolating the smaller faulted sections and limiting customers' impacts due to outages. Typically, three-phase simultaneous operations are performed. However single-phase reclosing can be implemented on single-phase fault clearing to improve system reliability and availability. Fig. 2.41 shows an example of an independent pole-operated recloser with vacuum interrupters.

Reclosers are also used in substations as a circuit breaker. Dead tank designs allow reclosers to be used as a switch, a fault interrupter, or an intertie switch in pad-mount configurations. Site-ready designs with integrated lightning arresters and PTs allow customers to save installation time with a plug-and-play solution. Embedded voltage sensors on both sides of the vacuum interrupter permit the use of reclosers in distribution automation projects such as auto-transfer and loop-switching duties. Reclosers are tested in accordance to dual logo IEEE C37.60/ IEC 62271–111 standard. The rating of the recloser shown in Fig. 2.42 is 27 kV, 12.5 kA, 800 A. The reclosers are typically used up to 40 kV, with the fault interrupting ratings up to 16 kA.

Load break, fused, and vacuum fault interrupting switches are commonly utilized in underground distribution systems for system reconfiguration and protection. Each switch may include one or more load break mechanisms which operate as an electric disconnect. These are often applied for system segmentation to separate a tie radial or a loop feeder. In addition, switches may be equipped with either fuses or vacuum interrupters for a load and/or system protection.

Medium-voltage distribution switches are available in both sealed and non-sealed designs. The sealed design shown in Fig. 2.42 utilizes SF_6 as the insulating medium

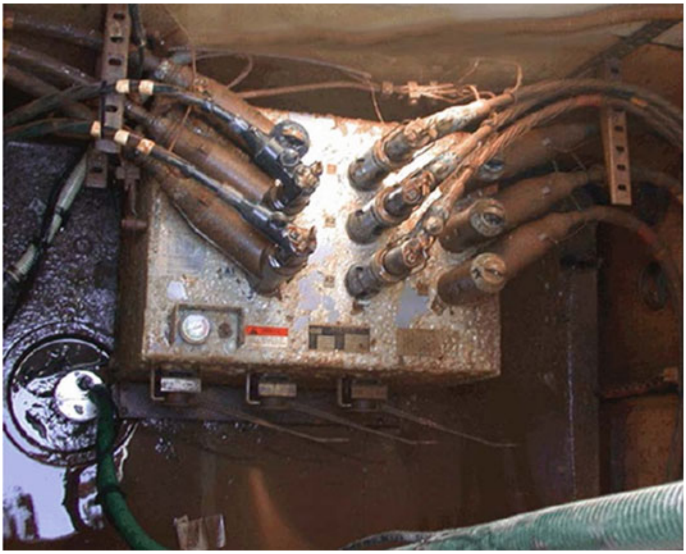


Fig. 2.42 27 kV 630 A SF_6 insulated dead tank switch. (Courtesy of G&W Electric Company)

Fig. 2.43 27 kV, 630 A solid dielectric insulated switchgears: dry vault (left) and pad-mounted (right) applications. (Courtesy of G&W Electric Company)

around the internal components and is designed and tested in accordance with the IEEE C37.74 standard for MV distribution applications up to 38 kV. Due to its dead tank design, it can be submerged and operated underwater, which is required for wet vaults that can operate in flooding.

Medium-voltage distribution switchgears with a variety of insulating mediums are available for a number of different applications. Figure 2.43 shows two different vacuum interrupter switches which use solid dielectric encapsulation for the insulation. These dry vaults are often applied for the inside of a building or above ground, inside of a pad-mount enclosure. Some types of switchgear are designed only for load break operations, while others are designed to cope with fault clearing as well.

They are tested in accordance to IEEE C37.74 standards and include ratings up to 38 kV, 630 A, and fault interrupting up to 25 kA.

Due to the permanent nature for this type of switchgear, each application has to consider a number of factors prior to the purchase and installation of the gear. These include:

- Load growth – How many loads will the switch need to protect and can the typical load value be increased over time?
- System changes – How will the switch be operated in the future and will that include remote or automated reconfiguration options?
- Total cost of ownership – As vault-style switchgear is typically difficult to remove or access for repair, the cost of replacement components and amount of expected maintenance must be included in the initial evaluation.

Figure 2.44 shows an example of air-insulated metal clad switchgear. It is constructed with grounded metal barriers to enclose all live parts. Typically, it has a removable (drawout type) circuit breaker, insulated bus, mechanical interlocks, voltage and current sensors, as well as a low-voltage control compartment isolated from the primary voltage areas in case of failures. It is used in a wide variety of applications including generation and distribution systems, industrial plants,

Fig. 2.44 36 kV, 2000 A, air-insulated metal clad switchgear. (Courtesy of Schneider)

Fig. 2.45 17.5 kV, 2000 A, 31.5 kA drawout circuit breaker with vacuum interrupters. (Courtesy of ABB)

commercial buildings, etc. This class of switchgear protects transformers, motors, generators, capacitors, distribution lines, and feeder circuits. It is tested in accordance to IEEE C37.20.2 standard.

Figure 2.45 shows an example of a 27 kV removable (drawout type) vacuum circuit breaker. The drawout circuit breaker is removable and can be separated from the power source in order to facilitate maintenance. It can be connected back to the power source using either a manual or motor-assisted racking capability.

Figure 2.46 shows an example of a ring main unit (RMU), which is a totally sealed, gas-insulated compact switchgear device, typically comprising of a circuit breaker, a disconnecting switch, and an earthing (grounding) switch. It is used on MV distribution lines in compact substations, small buildings, residential housing complexes, airports, wind power, etc. Since the gas tank is hermetically sealed, the environmental factors like moisture, dirt, and small insects are not affecting it. It enables connection, supply, and protection of transformers on an open ring or radial network. RMU is tested in accordance with IEC 62271–200 standard "AC Metal-Enclosed Switchgear and Controlgear for Rated Voltages Above 1 kV and up to 52 kV."

Figure 2.47 shows an example of arc resistance switchgear, which is a special type of switchgear designed to withstand the effects of an internal arcing fault as indicated by successfully meeting the test requirements. These requirements are specified in a number of national and international standards, including IEEE C37.20.7 "Guide for Testing Metal-Enclosed Switchgear Rated up to 38 kV for Internal Arcing Faults" and IEC 62271–200 "AC Metal-Enclosed Switchgear and

Fig. 2.46 24 kV, 630 A, gas-insulated ring main unit for secondary distribution. (Courtesy of Schneider)

Fig. 2.47 6.9 kV, 4000 A, 50 kA arc resistance switchgear tested per ANSI/IEEE C37.20.7. (Courtesy of Siemens)

Controlgear for Rated Voltages Above 1 kV and up to and Including 52 kV." Although the probability of the occurrence of an internal arc in MV switchgear during its life is very low, it can't be totally ignored. The causes of internal arcs

Fig. 2.48 29 kV, 900 A, 25 kA one-second short time and 42 kA peak fault closing. (Courtesy of S&C Electric Company)

include operational faults, system overvoltages, dielectric breakdown of material, and overstress of switches and circuit breakers, to name a few. The internal arc heats the surrounding gas resulting in an overpressure in the switchgear compartment. The hot gases may cause serious damage to the equipment and personnel in close proximity to the switchgear. In order to secure the safety of the operators, overpressure relief systems are integrated inside the switchgear to redirect the hazardous exhaust gases away from the areas where the operator might be working.

A circuit switcher is an economical equipment alternative to a circuit breaker. Figure 2.48 shows a circuit switcher unit utilizing interrupters that provide circuit interruption without external arc or flame. Arc extinction takes place within the SF_6 interrupters, which utilize a specially designed trailer and liner to create the necessary deionizing gases for efficient circuit interruption.

A circuit switcher is a mechanical switching device with an integral interrupter, suitable for making, carrying, and switching currents under normal circuit conditions. It is also suitable for interrupting specified primary-bus fault current and transformer-limited fault current that may be less than its rated short-circuit making current and rated short-time withstand current. A circuit switcher can also have an integral isolating disconnect. They are designed and built per IEEE C37.016 “Standard for AC High-Voltage Circuit Switcher Rated 15.5 kV Through 245 kV.” The fault interrupting rating of a circuit switcher is somewhat lower from the corresponding circuit breaker, and the operating times are longer. Also, it is not rated for auto-reclosing; the operating sequence is only close-open operation. The primary applications for the circuit switcher are switching and protection of power transformers, shunt reactors, bus, and transmission lines.

2.15 Fuses

A fuse is the oldest and simplest protective device to perform overcurrent operation in an electrical circuit. The early pioneers, such as Michal Faraday, had observed that a wire could be fused by an electric current, and so the fuse was born. Primitive fuses consisted of an open wire between two terminals (Thomas Alva Edison, e.g., used a lead wire), but soon improvement was sought, and the wire was replaced by a strip, made of different materials, usually of lower melting point than copper, like zinc. But as the available power increased, the behavior of the fuse became increasingly violent until attempts were made to screen the fuse element by a tube, and fuse designers concentrated on how to limit the emission of flame from the ends of the tube. A useful degree of breaking capacity was achieved, but the introduction of the filled cartridge fuse marked the greatest advantage.

A fuse is a weak link in a circuit and as such has one important advantage over circuit breakers. Because the element in the fuse has a much smaller cross section than the cable it protects, the fuse element will reach its melting point before the cable. The larger the current, the quicker the fuse element melts. The fuse interrupts a very large current in a much shorter time than a circuit breaker does, so short in fact that the current will be cut off before it reaches its peak value, which in a 50 Hz system implies operation in less than 5 milliseconds, and serious overheating and electromechanical forces in the system are avoided. This current-limiting action is an important characteristic that has application in many industrial low-voltage installations. The single-shot feature of a fuse requires that a blown fuse has to be replaced before service can be restored. This means a delay, the need to have a spare fuse and qualified maintenance personnel who must go and replace the fuse in the field. In a three-phase circuit, a single-phase-to-ground fault will cause one phase to blow and the other two phases stay connected.

Fuses for high-voltage applications require a high breaking capacity. The cartridge is made of tough material, usually ceramic, and the cartridge contains, apart from the fuse element, a filler, such as powdered quartz, as is shown in Fig. 2.49. The purpose of the quartz filler is to condense as quickly as possible the metal vapor that is produced when a large overcurrent blows the fuse element. The filler prevents a dangerous pressure rise in the hermetically sealed enclosure. The filler should be neither too fine nor too coarse: an intermediate grain size provides the optimum cooling. The main classification of fuses is into current-limiting and non-current-limiting types.

Current-limiting fuses describe a class of fuses defined by the behavior that occurs when the current is so high that the fuse element melts before the peak of the fault current. The element is heated so rapidly that there is no time for heat loss to the surroundings; there is then a uniform temperature along the element, and all parts reach their melting temperature simultaneously. The wire thus becomes a liquid cylinder that becomes unstable and breaks up into a series of droplets. The fuse element has been replaced by a line of globules. The current is constrained to pass through them, because the surrounding filler has a nearly infinite resistance. In consequence the voltage drop at the beginning of arcing is considerable and causes rapid suppression of the current. The number of globules per centimeter is about

Fig. 2.49 7.2 kV fuse for industrial use rated current, 70 A; rated breaking current, 40 kA. (Courtesy of Mitsubishi Electric)

10–12, and as the voltage drop in a short arc is about 20 V, the voltage drop across the element is approximately 200–250 V per centimeter. The maximum voltage rise across a fuse depends on the length and the design of the fuse element. Upon melting, this type of fuse introduces resistance in the circuit so rapidly that the current stops rising and instead is forced quickly to zero, before a natural current zero would occur. The fuse limits the current in magnitude as well as in duration hence the name current-limiting. The current-limiting fuse introduces an overvoltage, called the fuse-switching voltage, into the system during the current-limiting action.

Non-current-limiting fuses or expulsion fuses melt under the same circumstances but add only a small resistance into the circuit, so that the current continues to about the same peak as would occur if the fuse had not melted. An expulsion action (that is where gas is generated by the arc and expelled along with ionized material) produces a physical gap such that, at natural current zero, the arc does not reignite and the current is interrupted. The expulsion fuse limits the duration of the fault current, but not its magnitude.

2.16 Summary

Chapter 2 introduced various equipment used in generation, transmission, and distribution networks. They include power generators, power transformers, circuit breakers, disconnecting switches, earthing switches, instrument transformers, and surge arresters.

Circuit breakers perform an important role to operate transmission and distribution systems efficiently and reliably. SF_6 gas circuit breakers have been applied to all system voltages up to UHV levels, and vacuum interrupters have penetrated into distribution systems and transmission systems up to 145 kV due to its excellent frequent operation capability with less maintenance work. Switchgear at the distribution voltages may change the requirements in changing network conditions due to rapid increases of dispersed and intermittent wind and solar power generations.

CIGRE SC A3 will continue to investigate the field experience with switching equipment in the changing network conditions and provide useful information for the experts in electrical industries.

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Interrupting Phenomena of High-Voltage Circuit Breaker

3

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Contents

Keywords

Circuit breaker · Arc · Thermal interruption · Dielectric interruption · Air · Oil · Vacuum · Gas

3.1 Introduction

Opening and closing operations of mechanical circuit breakers normally generate arc discharge phenomena between contacts. In the 1940s, Mayr, Cassie, and Browne (CIGRE WG 13.01; CIGRE Working Group 13.01; Cassie 1939; Mayr 1943) expressed arc behavior using dynamic arc equations with a couple of arc parameters

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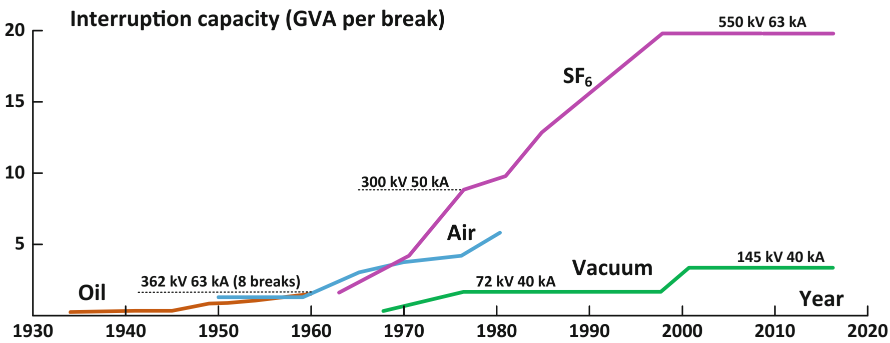


Fig. 3.1 Unit interrupting capability of circuit breakers with different technologies

and showed that they reproduce interrupting phenomena analytically in conjunction with circuit equations of power systems. Intensive investigations to explore superior interrupting media were conducted by EPRI in the United States (EPRI Report, EL-284 1977; EPRI Report, EL-1455 1980; EPRI Report, EL-2620 1982) and revealed physical properties of many potential interrupting media. Furthermore, a practical computer thermo-fluid dynamics simulation has made it possible to analyze the arc interrupting behavior in detail by using more precise arc models (Herman and Ragaller 1977; Kuwahara et al. 1983; Smeets and Kertesz 2000).

The development of circuit breakers has been closely linked with a remarkable growth of demand for higher voltage and larger short-circuit capacity of transmission systems. Since the late 1800s, a diversity of interrupting technologies using oil, air, vacuum, and SF_6 gas as interrupting media had been realized and contributed to large capacity power transmission constructions.

Oil circuit breakers developed transmission networks in 1900. Air blast circuit breakers with multi-break designs realized 765 kV transmission networks in 1965. Then SF_6 gas circuit breakers facilitated large capacity transmission and eventually realized UHV transmission in 2009. Simultaneously, vacuum circuit breakers have been widely applied in medium voltage distribution networks, which are now available up to 145 kV ratings. Figure 3.1 shows the technical evolution of unit interrupting capability of circuit breakers with different technologies.

This chapter deals with fundamental interrupting phenomena of circuit breakers focusing mainly on vacuum and SF_6 technologies.

3.2 Definitions of Terminology

Circuit Breaker

A switching equipment, capable of making, carrying, and breaking currents under normal circuit conditions and also making and carrying for a specified duration and breaking currents under specified abnormal circuit conditions such as those of short circuit. When a fault occurs, circuit breakers are required to clear a fault quickly to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand a system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Gas Blast Circuit Breaker
A circuit breaker in which the arc develops in a blast of gas. When the gas is moved by a difference in pressure established by mechanical means during the opening operation of the circuit breaker, it is termed a single pressure gas blast circuit breaker; when the gas is moved by a difference in pressure established before the opening operation of the circuit breaker, it is termed a double pressure gas blast circuit breaker.

Sulfur Hexafluoride (SF_6) Circuit Breaker
A circuit breaker in which the contacts open and close in sulfur hexafluoride. Current interruption in a SF_6 circuit breaker is obtained by separating two contacts in sulfur hexafluoride, which has excellent dielectric and arc-quenching properties. After contact separation, current is carried through an arc and is interrupted when this arc is cooled by a gas blast of sufficient intensity.

Air Blast Circuit Breaker
A circuit breaker in which the contacts open and close in air. Since the air interrupting and dielectric withstand capability at atmospheric pressure is limited, compressed air of several MPa is required for high-voltage applications. The air creates a relatively high arc voltage, which can decrease the fault current and assist thermal interruption capability.

Oil Circuit Breaker
A circuit breaker in which the contacts open and close in mineral oil. The “bulk” or dead tank oil breaker has the contacts in the center of a large metal tank filled with oil. The oil serves as an extinguishing medium and provides the insulation to the tank. The live tank “minimum” oil breaker design has the contacts and arcing chamber inside a porcelain insulator. The arc evaporates the surrounding oil and produces hydrogen and carbon compounds. The process removes heat from the arc and eventually interrupts the current at a current zero with power frequency.

Vacuum Circuit Breaker
A circuit breaker in which the contacts open and close within a highly evacuated bottle in a vacuum enclosure. When the vacuum circuit breaker separates the contacts, an arc is generated by the metal ions vaporized from the contact surface. The arc is quickly extinguished because the metallic vapor, electrons, and ions produced during the arc are diffused in a short time and condensed on the surfaces of the contacts, resulting in quick recovery of dielectric strength. The advantages of vacuum as a current interrupting medium were known as early as the 1920s. Practical vacuum interrupters were available in the late 1960s, when some metallurgical developments made it possible to manufacture gas-free electrodes and ultra-tight sealing.

Reignition

Resumption of current flow between the contacts of a mechanical switching device within an interval of less than a quarter cycle of power frequency after interruption at current zero. A reignition that occurs during the thermal interrupting region does not generate voltage transients harmful to the power system.

Restrike

Resumption of current flow between the contacts of a mechanical switching device with an interval of a quarter cycle of power frequency or longer after interruption at current zero. A restrike that occurs during the dielectric interrupting region may generate transients that could be harmful to the system and equipment.

Residual Current

When the arc current reaches zero, the conductivity (g) in a vanishing arc across the contacts still has a certain value and maintains a very small current due to the existence of charged particles. The current after interruption at current zero is called the residual or post-arc current (I). The residual current contributes to energy input due to ohmic heating (I^2/g) by the electrical field across the contacts, which may raise the temperature and increase the conductivity, while the cooling by a gas flow of a circuit breaker contributes to lose energy and to reduce conductivity.

Thermal Interruption/Thermal Interrupting Region

Thermal interrupting period of a circuit breaker occurring within an interval of less than a quarter cycle of power frequency after interruption at current zero, where the residual current inputs energy into the vanishing arc by ohmic heating. When a circuit breaker cannot provide sufficient coolability, thermal reignition may happen.

Dielectric Interruption/Dielectric Interrupting Region

Dielectric interrupting period of a circuit breaker within an interval of a quarter cycle of power frequency or longer after interruption at current zero, where the transient recovery voltage (TRV) is applied between the contacts. The dielectric strength across the contacts generally increases with the contact gap. When the TRV exceeds the dielectric strength across the contacts at any moment during the dielectric interrupting region, dielectric breakdown named restrike will occur.

Recovery Voltage

The voltage which appears across the terminals of a pole of a switching equipment after current interruption.

Transient Recovery Voltage (TRV)

A transient recovery voltage for circuit breakers is the voltage that appears across the terminals after current interruption. It is a critical parameter for fault interruption by a circuit breaker; its amplitude and the rate of rise of TRV are dependent on the characteristics of the system connected on both terminals of the circuit breaker and on the type of fault that this circuit breaker has to interrupt.

Disruptive Discharge
Phenomenon associated with the failure of insulation, in which the discharge completely bridges the insulation, reducing the voltage between the electrodes to zero or nearly zero. The term *sparkover* is used when a disruptive discharge occurs in a gaseous or liquid dielectric. The term *flashover* is used when a disruptive discharge occurs over the surface of a solid dielectric in a gaseous or liquid medium. The term *puncture* is used when a disruptive discharge occurs through a solid dielectric.

Diffuse Arc
Vacuum arc mode is characterized by a number of fast-moving plasma strings, which exist apart from each other carrying current of 30–100 A each dispersed over the electrodes.

Constricted Arc
Vacuum arc is characterized by a single bulk plasma column similar to an arc observed in gases, potentially carrying a large current.

3.3 Abbreviations

AMF	Axial magnetic field
CB	Circuit breaker
RRRV	Rate of rise of recovery voltage
SF_6	Sulfur hexafluoride
TMF	Transverse magnetic field
TRV	Transient recovery voltage

3.4 Fundamental Interrupting Phenomena with Oil and Air

The interrupting process with a mechanical circuit breaker is normally accompanied by an arc generated between the contacts after contact separation. The arc is a main switching element of the mechanical circuit breaker to transform the conductor state to the insulator state economically covering all ratings in power systems.

The arc interrupting process in alternating current normally happens at one of the periodical current zeroes due to power frequency. An arc characterized by the existence of plasma can carry a large current through a normally non-conductive interrupting media such as oil, air, SF_6 gas, as well as vacuum with and without metal vapor. The plasma refers to charged particles composed of electrons and positive and negative ions.

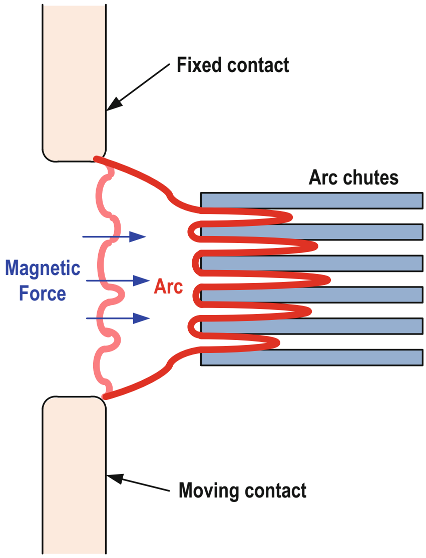


Fig. 3.2 Interrupting principle of air circuit breaker with magnetic-driven arc scheme

In the arc plasma, the collision between moving charged particles and neutral particles creates new charged particles enhanced by higher temperature. Simultaneously, a deionization process decreases the charged particles when electrons and positive ions recombine to neutral particles.

Low-voltage circuit breakers normally use air to extinguish the arc. Figure 3.2 shows a magnetic-driven-type air circuit breaker equipped with some arc chutes composing of mutually insulated parallel plates. The arc chutes divide the arc into smaller and extended arc length in order to cool down effectively resulting in an increase of the arc voltage which limits the current through the air circuit breaker. The current-carrying parts near the contacts provide easy deflection of the arc into the arc chutes by a magnetic force of the current path, in addition to magnetic blowout coils or permanent magnets that could also deflect the arc into the arc chutes.

Oil circuit breakers rely upon vaporized mineral oil to extinguish the arc. Mineral oil has better insulating and interrupting properties than those of air. In an oil circuit breaker, the fixed contact and moving contact are immerged inside an enclosure filled with oil. When the contacts are separated under load carrying or short-circuit current conditions, an arc is generated, and the oil is vaporized by arc heating and decomposed into mostly hydrogen gas (along with a small amount of methane, ethylene, and acetylene) and ultimately creates a hydrogen bubble (showing a relatively higher thermal conductivity) surrounding the arc, which can displace the oil near the arc and effectively remove the heat from the arc (see Fig. 3.3). Accordingly, this highly compressed gas bubble surrounding the arc prevents reignition after current extinction at current zero with power frequency. Figure 3.4 shows a typical configuration of a minimum oil circuit breaker.

3.5 Interrupting Phenomena with Gas Circuit Breaker

Gas circuit breakers normally use gas such as air, sulfur hexafluoride (SF_6), and mixtures containing SF_6 as insulating and interrupting media to extinguish the arc generated between the contacts. In particular, a gas circuit breaker with SF_6 mostly loses its electrical conductivity, when the temperature of the vanishing arc falls below 2000 K.

Figure 3.5 shows a schematic of arc currents generated across the contacts of a gas circuit breaker. The temperature of large arc currents of several ten kA is 15,000–20,000 K, comprising of a high-density conductive plasma with low arc

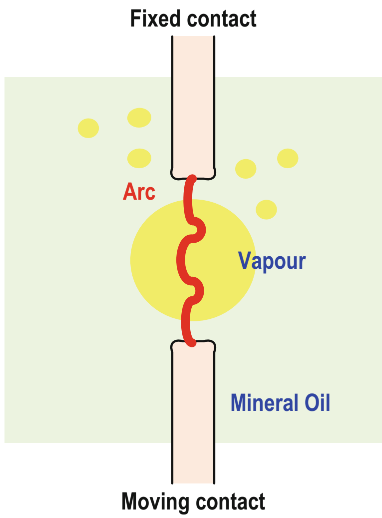


Fig. 3.3 Arc interruption in an oil circuit breaker

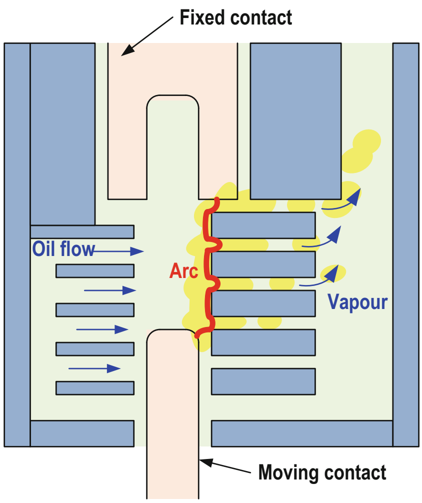


Fig. 3.4 Configuration of minimum oil circuit breaker

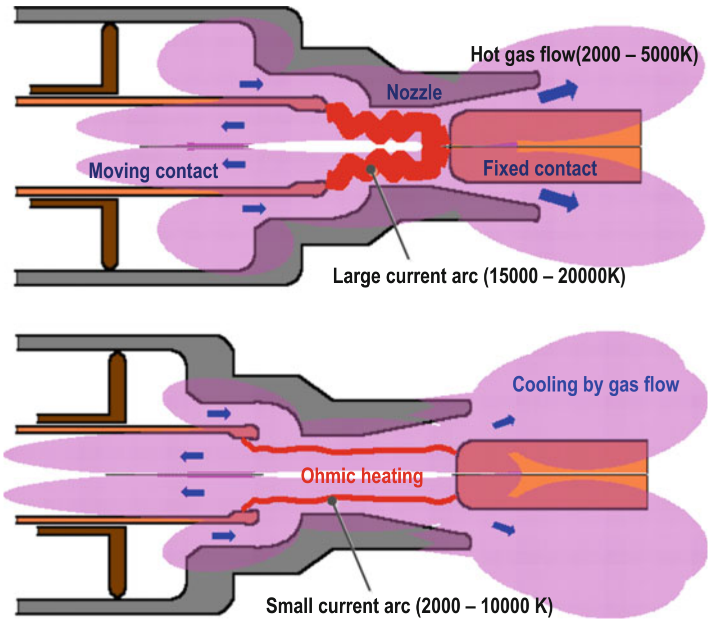


Fig. 3.5 Arc-quenching process with a gas circuit breaker

voltage. The temperature of an arc carrying a small current near the passage of current through zero is 2000–5000 K. Arc voltage shows a suppression peak before current zero.

Every time the current passes through zero after contact separation, the circuit breaker has an opportunity for arc extinction. When the arc current reaches zero, the conductivity (g) in a vanishing arc across the contacts still has a certain value and maintains a very small current due to the existence of charged particles where there used to be an arc column. This current is called the residual or post-arc current (I). The residual current contributes to energy input due to ohmic heating (I^2/g) by the electrical field across the contacts, which may raise the temperature and increase the conductivity, while the cooling by a gas flow contributes to energy loss and tends to reduce the conductivity.

Figure 3.6 shows a typical physical model related to the arc interrupting process near current zero in the case of a gas circuit breaker, where the arc is heated by ohmic heating and cooled by heat transfer due to gas flow (black arrows show gas flow) and heat conduction by the ambient temperature and heat radiation (white arrows means heat conduction and radiation). The balance between energy input and cooling will determine interruption success or failure.

Figure 3.7 shows an example of calculations of the temperature profiles with SF_6 and N_2 gas at conditions of stable currents of 20 A and 200 A. As compared with the temperature profile with N_2 gas, that of SF_6 shows a smaller arc diameter which provides a higher temperature gradient resulting in higher heat conduction. The SF_6

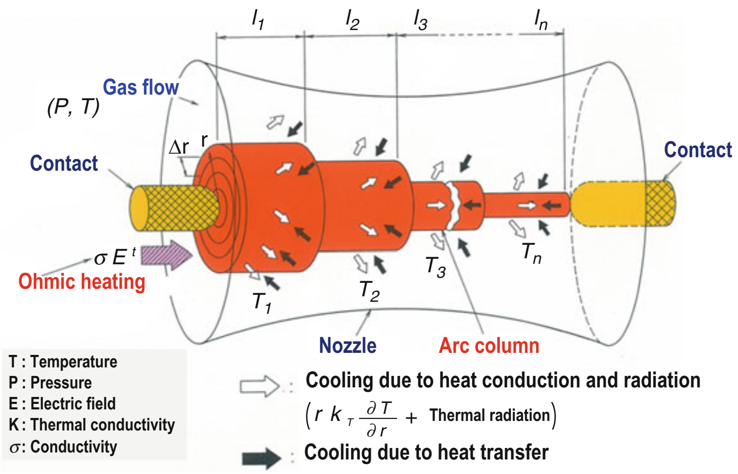
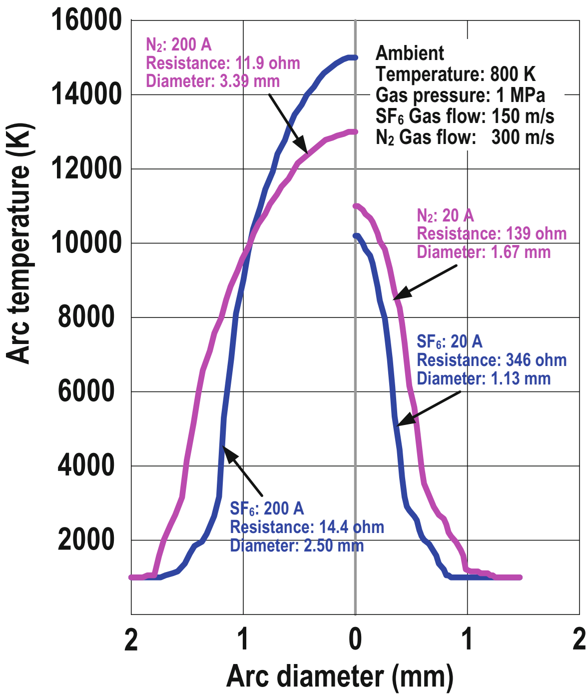


Fig. 3.6 Arc interrupting process of gas circuit breakers. (Kuwahara et al. 1983)

Fig. 3.7 Temperature profiles of SF_6 and N_2 arcs at the currents of 20 A and 200 A



arc increases the temperature in the center of the arc for larger currents. However, the maximum value is kept around 20,000 K due to the larger thermal capacity in this temperature range as described above.

Figure 3.8 shows arc current and voltage behaviors during interruption with SF_6 gas. This behavior can be classified into four different periods: (1) large arc

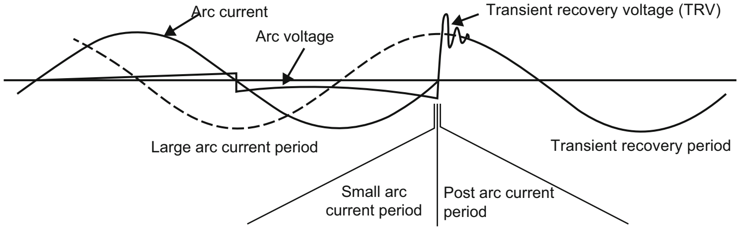
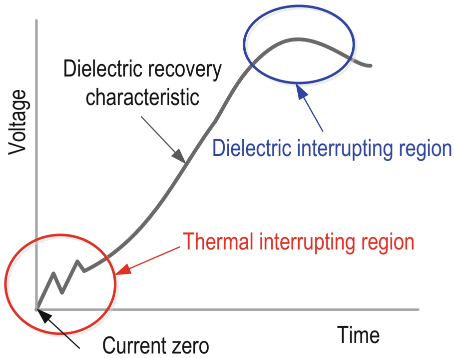


Fig. 3.8 Current interruption process with four different periods

Fig. 3.9 Critical instants to determine the interruption success or failure



current, (2) small arc current, (3) post-arc current, and (4) transient recovery periods.

During the large arc current period, the arc shows high conductivity with a temperature of 15,000–20,000 K. The arc conductivity gradually decreases with a decrease of current during the small arc current period. The arc is extinguished when the cooling due to gas flow is greater than ohmic heating due to residual current generated by the electrical field during the short period (up to a few microseconds) of the post-arc current. Then the dielectric recovery between the contacts competes with the transient recovery voltage (TRV) during the transient recovery period. When the dielectric recovery surpasses the TRV at all times, interruption is successfully completed.

Figure 3.9 shows two critical regions that determine interruption success or failure during the interruption process: the thermal interrupting region and the dielectric interrupting (recovery) region. A circuit breaker must meet the interrupting requirements during both of these two interrupting regions expected in various network conditions.

After current zero, there is residual current which increases the energy of the vanishing arc by ohmic heating. When a circuit breaker cannot provide sufficient cooling ability, a thermal reignition may occur. Figure 3.10 gives an example of current and voltage variations during a successful and a failed current interruption in the thermal interrupting region. When thermal reignition occurs, the residual current through the vanishing arc will increase the temperature, and arc current will be

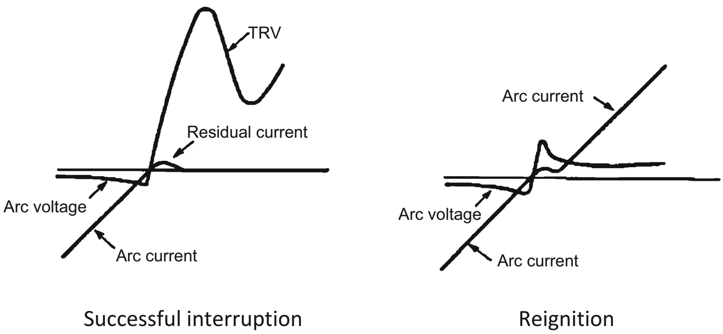


Fig. 3.10 Success and failure (reignition) during the thermal interrupting process

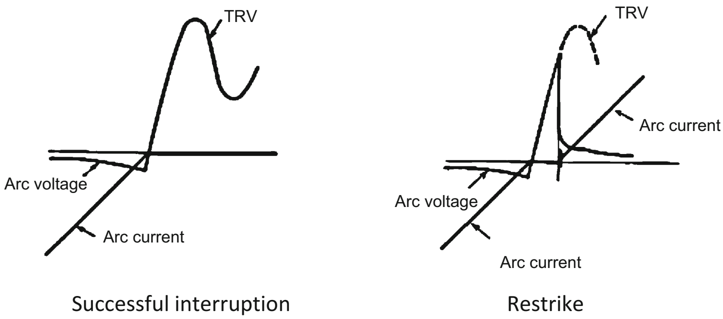


Fig. 3.11 Success and failure (restrike: voltage breakdown) during dielectric interrupting process

reestablished. When a restrike occurs at a current zero, a circuit breaker will have one or two possibilities to interrupt the current at subsequent current zeroes. The recovery voltage during the thermal interrupting region is very small, so the reignition does not generate transients harmful to the system and equipment in the power system.

After the thermal interrupting region, the transient recovery voltage (TRV) is applied between the contacts, while the moving contact is still operating until it comes to a full open position. The dielectric strength across the contacts generally increases with the contact gap. When the TRV exceeds the dielectric strength across the contacts at any moment during the dielectric interrupting region, a dielectric breakdown called restrike will occur. Figure 3.11 shows the comparison of current and voltage variations during a successful and a failed current interruption in the dielectric interrupting region. When the restrike occurs, the arc is immediately restored and the current is reestablished. The restrike may generate transients that could be harmful to the system and equipment in the power system.

Figure 3.12 shows a schematic of dielectric recovery characteristics between contacts of a circuit breaker during no load switching, a small fault current interruption, and a large fault current interruption. When a gas circuit breaker

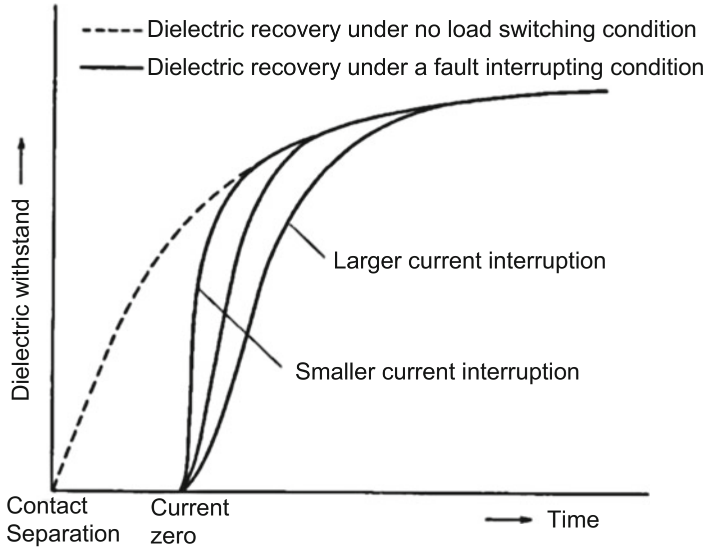


Fig. 3.12 Dielectric recovery characteristics between contacts of circuit breaker

interrupts a low current, the dielectric recovery withstand voltage starts to increase rapidly after current interruption at current zero, as the distance between contacts increases. When a circuit breaker interrupts a large fault current, the dielectric recovery withstand voltage tends to recover slowly as compared with a small current interruption.

Figure 3.13 shows a schematic of the dielectric recovery characteristic in comparison with three transient recovery voltages for different switching duties. For a successful dielectric interruption, the dielectric recovery withstand voltage between contacts of a circuit breaker is required to surpass the transient recovery voltage after current interruption at all times (see the case “a” of Fig. 3.13).

A TRV with a high rate of rise of recovery voltage (RRRV), as shown in case “b” of Fig. 3.13, leads to a dielectric restrike. Such TRVs are typically obtained during transformer limiting faults and series reactor faults. When the RRRV exceeds the rate of rise of dielectric recovery characteristic, a dielectric interrupting failure will happen. On the other hand, a fault interruption in a long transmission line may generate a high TRV peak as shown in case “c” of Fig. 3.13. When the TRV peak exceeds the dielectric recovery characteristic, a dielectric interrupting failure will also happen.

The whole interruption process is successfully completed when both the thermal interrupting and dielectric interrupting regions are successfully cleared. Many interrupting tests are required to confirm both the thermal and dielectric interrupting capabilities in different switching duties expected in power systems. As the initial part of the TRV can influence current interruption, during type tests in a high-power laboratory, it is important to respect a time delay for the recovery

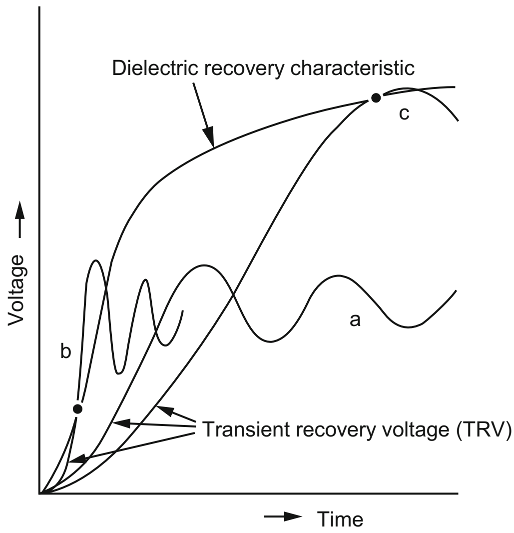


Fig. 3.13 Dielectric recovery characteristics in comparison with transient recovery voltage

voltage after current zero that does not exceed standard values representing network conditions.

Especially in the case of a vacuum interrupter, multiple reignitions and the associated voltage disturbances may be observed as shown in Fig. 3.14, due to their excellent thermal interrupting capability. If high-frequency (HF) current generated after reignition cannot be interrupted, current will be interrupted at the next current zero at power frequency. However, the high-frequency current may be interrupted immediately after a reignition, if a circuit breaker has an excellent thermal interrupting capability. It may generate a repetitive reignition phenomenon, if the dielectric strength is not sufficient for the TRV withstand imposed immediately after current interruption. The multiple reignition overvoltages gradually increase in amplitude, which is repeatedly applied to substation equipment at the load side.

3.6 Interrupting Phenomena with Vacuum

Vacuum circuit breakers are equipped with a couple of disk-shaped electrodes in the vacuum enclosure (vacuum tube) used to extinguish the arc even with a small gap of less than 2–4 mm. Figures 3.15 and 3.16 show a typical cross-sectional view and the configuration of a vacuum interrupter.

While gas circuit breakers use an interrupting media to carry the current, vacuum circuit breakers do not contain any material to sustain the plasma, except for metal vapor emitted from the cathode and anode contact surfaces (they are called cathode and anode spots). The vacuum pressure inside a vacuum interrupter is normally maintained at 10^{-6} bar, which shows excellent dielectric withstands with a small contact gap. The vaporized

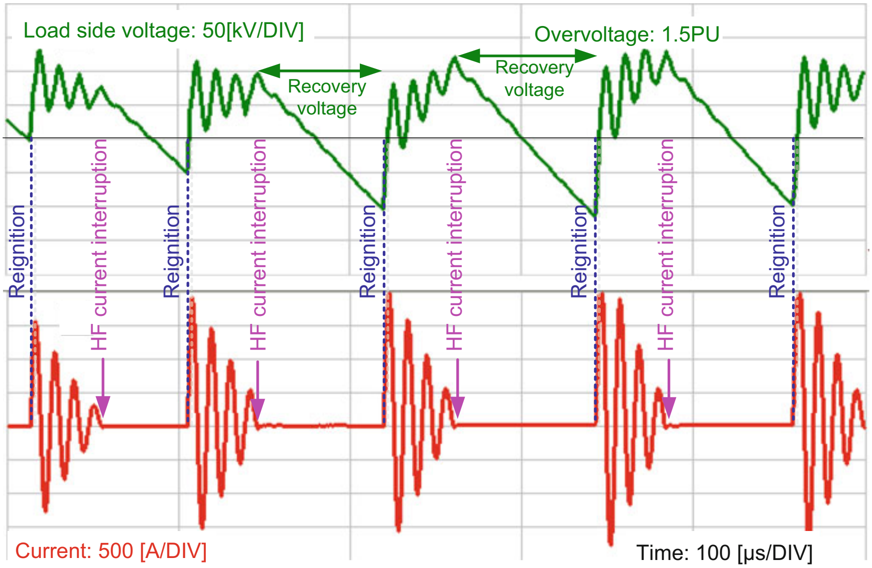


Fig. 3.14 Reiteration of multiple reignitions and high-frequency current interruptions

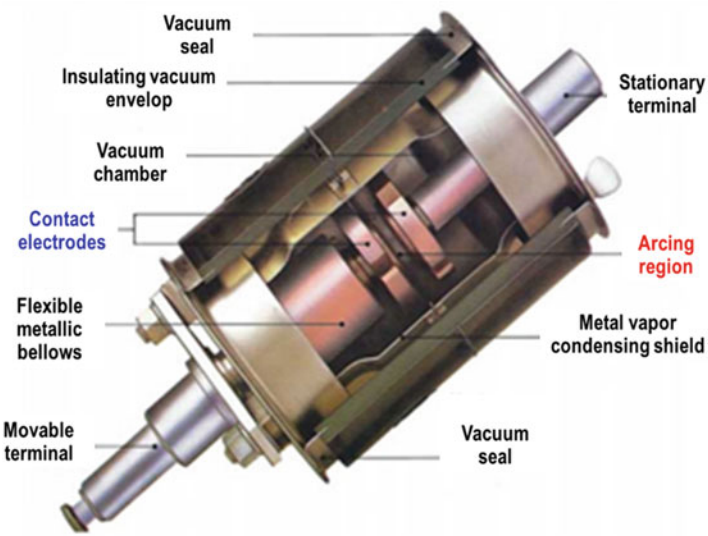


Fig. 3.15 Typical cross-sectional view of a vacuum interrupter

contact material (typically Cu-Cr alloy) plays an important role in switching functions of current carrying and current interruption (insulation) for a vacuum circuit breaker.

The vacuum arc occurs at the cathode spot and carries the current with a high-density plasma. The cathode spots supply the metal vapor and emit the electrons

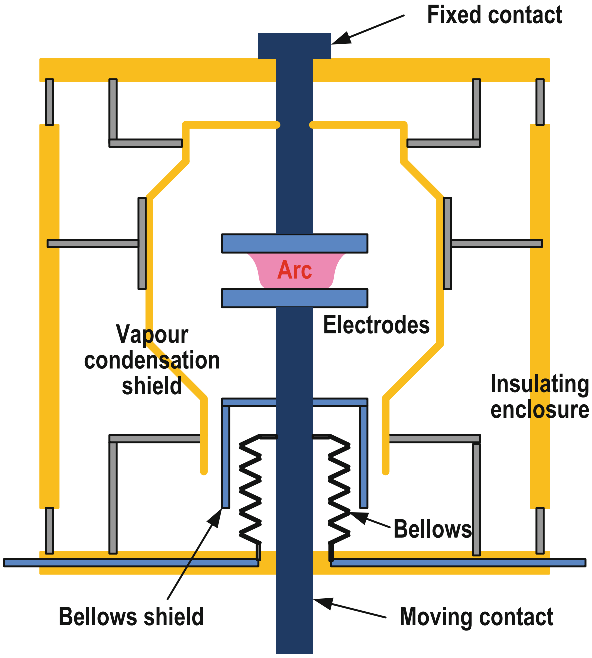


Fig. 3.16 Typical configuration of a vacuum interrupter

that are accelerated in the arc plasma and ionize the other metal atoms by ion bombardment. The newly created ions move toward the cathode and iterate collisions with the metal atoms. During the large current period, the vacuum arc also initiates from the anode spots which are much larger in area than the cathode spots.

Vacuum arcs show two different modes of either diffuse or constricted arcs. The diffuse arc is characterized by a number of fast-moving plasma strings dispersed over the electrodes, which exists independently with many small plasma columns apart from each other carrying current of 30–100 A per each column. The arc voltage of the diffuse arc is relatively low. In contrary, the constricted arc is characterized by a single bulk plasma column similar to an arc observed in gases carrying a large current. The arc voltage of the constricted arc may rise to more than 200 V with an increase of the gap.

The boundary of the two arc modes depends on the current level, the contact gap, the shape, and material of the contact. A low-current vacuum arc less than several thousand amperes exists in the diffuse mode, whereas a high current vacuum arc is shifted to the constricted mode. The diffuse arc with less vapor density shows better interruption capability than the constricted arc, which is enhanced by the application of an external magnetic field.

Figure 3.17 shows a schematic of the arc behavior during current interruption in a vacuum for a half cycle. The arc is initiated in the diffuse mode with a small gap after contact separation. With an increase of the current, the vacuum arc may be shifted to the constricted mode. The constricted arc is a single thick arc carrying a large current with a high plasma density (typically the current is larger than 10–15 kA). It has high atmospheric pressure due to excessive metal vapor with an arc voltage higher than that of the diffuse arc.

When the current decreases, the constricted arc transforms to a diffuse arc composed of many arc columns with cone-shaped plasma directed from the small cathode spot to the anode. During the small current period, the diffuse arc can move very fast on the contact surface. Arc voltage across the contacts becomes very small compared with that of gas circuit breakers, which is about 20 V irrespective of the electrode spacing before the current interruption. Vacuum arc shows no prominent extinction peak due to the existence of fast-moving charged ions and electrons resulting in high conductivity. The number of small arc columns decreases and then disappears at the current zero.

Several measures have been applied to improve the interrupting performance of a vacuum interrupter by suppressing the constricted arcs for higher current levels. The constricted arcs also cause a problem of severe electrode erosion. One of the well-known measures is to reduce local electrode melting by moving the anode spots continuously by application of a transverse magnetic field (TMF) to the arc. Another method is to reduce the plasma density bombarding at the anode spots by spreading

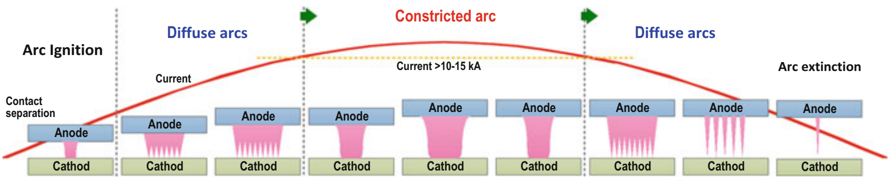


Fig. 3.17 Interrupting process in a vacuum

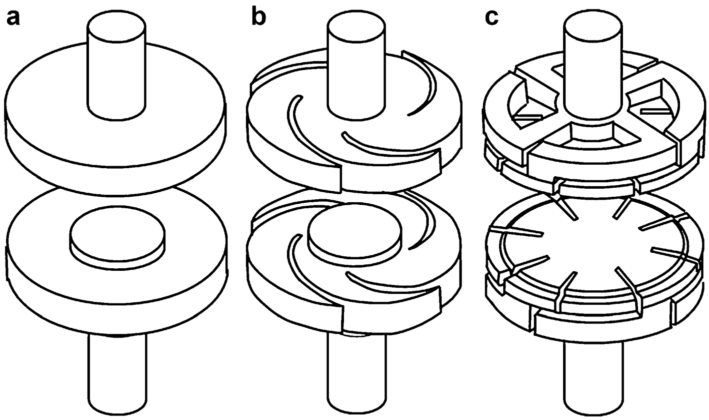


Fig. 3.18 Electrode configurations for vacuum interrupter. (**a**) Plane electrode, (**b**) spiral electrode, (**c**) axial magnetic field electrode with a coil

the arc over the whole area of the electrode in application of an axial magnetic field (AMF) between the electrodes.

Figure 3.18 shows some examples of different electrode configurations. The plane electrode is used for a vacuum interrupter with small interrupting currents. The spiral electrode has several spiral grooves which can normally apply an arc magnetic field in the radial direction. The magnetic field drives the arc to the edge of the spiral fin and avoids excessive local arc erosion. The axial magnetic field electrode consists of several coils behind the electrodes which can apply an arc magnetic field in the axial direction. These special designed contacts along with the radial and axial magnetic fields force the arc to keep travelling on the electrode by its own magnetic field, thereby causing minimum and uniform contact erosion.

A vacuum circuit breaker interrupts the current at current zero, by establishing dielectric strength between the contacts so that reestablishment of the arc plasma after current zero becomes very difficult due to the excellent dielectric strength of a vacuum. Thermal interrupting failure is seldom observed. Since charged particles still remain between the electrodes at current zero, when a recovery voltage is applied between the electrodes, a residual arc current flows because the charged ions and electrons should be removed under the small electrical field after current zero. Even though the residual current tends to be larger as compared with that of SF_6 gas circuit breakers, a large residual current after current interruption in a vacuum interrupter will not affect thermal interrupting performance. The large residual current may be due to the existence of a string current path where the pressure still rises with the metal vapor (high conductivity) immediately after current interruption.

The interruption is successfully completed when the dielectric strength across the contacts always surpasses the recovery voltage after current interruption. Some dielectric breakdown of a statistical nature may be observed since the dielectric strength in a vacuum is strongly affected by the contact surface conditions, and small metal particles can considerably modify the electrical field across the contacts.

The dielectric recovery characteristics during the dielectric interrupting region is important in determining the success or failure of a circuit breaker, especially in case of low-current interruption such as line-charging current switching and capacitor bank current switching.

3.7 Comparison of Dielectric Withstand with Different Interrupting Media

Figure 3.19 shows an example of dielectric recovery characterizes for different interrupting media in the no load condition. This dielectric recovery characteristic is mainly determined by the distance between contacts, the density of the insulating medium in the case of gas, and the opening speed, as well as the configuration of the electrodes. The dielectric strength linearly increases with the

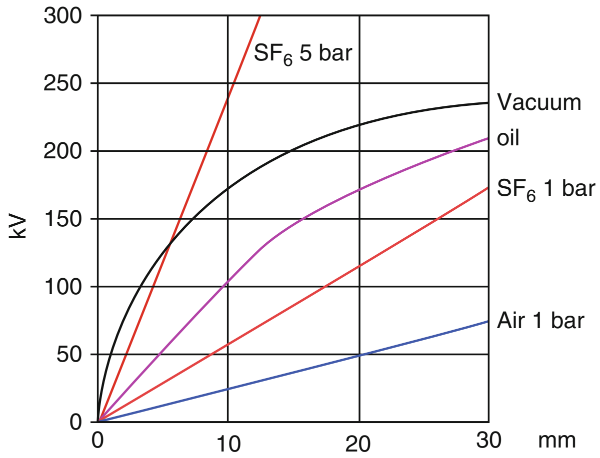


Fig. 3.19 Dielectric performance in vacuum (CIGRE Technical Brochures 589 2014)

contact gap in the case of gas. However in the case of a vacuum, it shows good dielectric strength with a small gap (even 2–4 mm gap) but gradually saturates for a longer gap length.

On the other hand, the density of SF_6 gas in parts inside the enclosure of an interrupter becomes lower after a large current interruption due to the thermal energy exhausted from the arc plasma into the enclosure of an interrupter during the interruption process. This leads to a certain degradation of dielectric recovery characteristics compared to that at no load and small current switching conditions.

3.8 Summary

Interrupting phenomena with different interrupting media are described. The interrupting media can perform a switching function by quickly changing the conductive state by arc generation to the insulating state by arc extinction. In this way, a circuit breaker can interrupt the current and withstand the recovery voltage imposed on the contact gap after the current interruption. The circuit breaker plays an important role to secure other substation equipment in the power system and contributes as a key component to the development of high voltage and large capacity transmission networks.

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Switching Phenomena in Power System

4

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Contents

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Circuit breaker · Transient recovery voltage · Bus terminal fault · Short-line fault · Capacitive current switching · Inductive current switching

4.1 Introduction

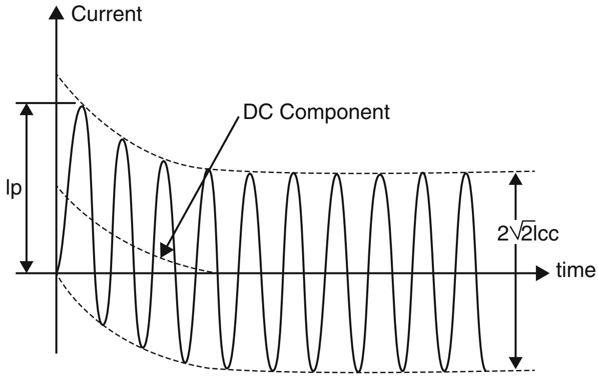
A circuit breaker should be capable of making, carrying, and interrupting the current under both normal and abnormal conditions especially in case of short circuit or fault occurrence. Several short-circuit conditions including a single-phase grounded, three-phase grounded, and phase-to-phase ungrounded fault are expected to occur in power systems. When a circuit breaker interrupt the short-circuit current, different switching phenomena are observed depending on the conditions.

The short-circuit current becomes the maximum value in case of three-phase grounded fault in most of power systems. However, the short-circuit current in case of a single-phase grounded fault is larger than that of three-phase grounded fault in a solidly earthed system where zero-sequence impedance (X_0) is less than positive-sequence impedance (X_1). (The current ratio can be given by I (1-phase)/I (3-phase) $= 3/(2 + X_0/X_1)$, so that when $X_0 > X_1$ the 1-phase fault current is lower than the 3-phase fault current.)

The short-circuit current after a fault occurrence is composed of a decaying DC component superimposed on a symmetrical AC current which is also decaying with time as shown in Fig. 4.1. The AC component decay strongly depends on the reactance in the short circuit including the generator reactance. The DC component is rapidly decayed with the time constant of power system (L/R). The circuit breaker must withstand the electrical and mechanical stresses imposed by the short-circuit current.

A transient voltage is imposed between the contacts (electrodes) of a circuit breaker when it interrupts a current. The transient recovery voltage (TRV) appears immediately after interruption and shows a damping oscillation around the prospective system voltage, and then it approaches to the system voltage (including a slight shift caused by an unbalance in the short-circuit currents among the phases) that oscillates with power frequency as shown in Fig. 4.2. TRV significantly affects the interrupting performance of the circuit breaker. The severity of TRV strongly depends on the prospective system voltage, which differs with system and fault conditions including neutral connection. For example, a first-pole-to-clear factor is 1.3 for effectively earthed neutral system and 1.5 for isolated neutral system in the standards. The amplitude of TRV is also changed with system and equipment conditions.

Fig. 4.1 Short-circuit current



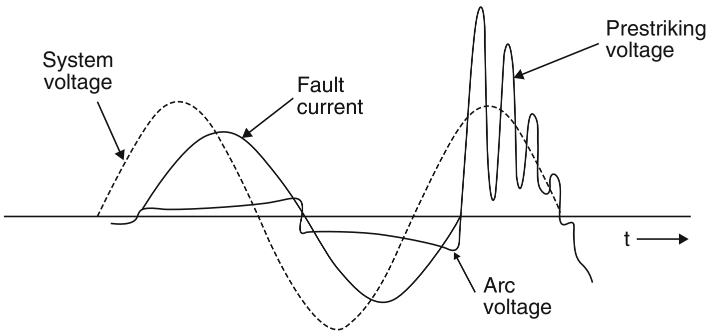


Fig. 4.2 Transient recovery voltage (TRV) and recovery voltage (RV)

This chapter deals with fundamental switching phenomena of circuit breakers depending on the conditions and fault locations in power systems.

4.2 Definitions of Terminology

Recovery Voltage
The power frequency voltage which appears across the terminals of a pole of a switching equipment after the current interruption.

Transient Recovery Voltage (TRV)
A transient recovery voltage for circuit breakers is the voltage that appears across the terminals immediately after current interruption. It is a critical parameter for fault interruption by a circuit breaker; its amplitude and rate of rise of TRV are dependent on the characteristics of the system connected on both terminals of the circuit breaker and on the type of fault that this circuit breaker has to interrupt.

Thermal Interruption/Thermal Interrupting Region
Thermal interrupting period of a circuit breaker within an interval of less than a quarter cycle of power frequency after interruption at current zero, where a very small post-arc current (residual current) is still flowing and putting energy into high ohmic resistance of the vanishing arc plasma. When a circuit breaker cannot provide sufficient fresh gas and cooling, thermal reignition may happen.

Dielectric Interruption/Dielectric Interrupting Region
Dielectric interrupting period of a circuit breaker within an interval of a quarter cycle of power frequency or longer after interruption at current zero, where the transient recovery voltage (TRV) is applied between the contacts. The dielectric strength across the contacts increases with the contact gap. When the TRV exceeds the dielectric strength across the contacts at any moment during the dielectric interrupting region, dielectric breakdown named restrike will happen.

Overvoltage
Any voltage between one phase and earth or between phases having a peak value or values exceeding the corresponding peak of the highest voltage for equipment.

Short-Circuit Current
An overcurrent resulting from a short circuit due to a fault or an incorrect connection in an electric circuit.

Out-Of-Phase Conditions
Abnormal circuit conditions of loss or lack of synchronism between the parts of an electrical system on either side of a circuit breaker in which, at the instant of operation of the circuit breaker, the phase angle between rotating vectors, representing the generated voltages on either side, exceeds the normal value.

Short-Line Fault (SLF)
A short-line fault refers to a fault that occurs on a line a few hundred meters to several kilometers down the line from the circuit-breaker terminal. When a circuit breaker clears the SLF, TRV with a steep rate of rise is observed due to high-frequency oscillation generated by the propagating waves that iterate traveling on the line and reflections between the circuit-breaker terminal and the fault point.

Peak Factor (of the Line Transient Voltage)
Ratio between the maximum excursion and the initial value of the line transient voltage to earth of a phase of an overhead line after the interruption of a short-line fault current. The initial value of the transient voltage corresponds to the instant of arc extinction in the pole considered.

First-Pole-To-Clear Factor (in a Three-Phase System)
When interrupting any symmetrical three-phase current, the first-pole-to-clear factor is the ratio of the power frequency voltage across the first interrupting pole before

current interruption in the other poles, to the power frequency voltage occurring across the pole or the poles after interruption in all three poles.

Amplitude Factor
Ratio between the maximum excursions of the transient recovery voltage to the crest value of the power frequency recovery voltage of that pole.

Minimum Clearing Time
Sum of the minimum opening time, minimum relay time (0.5 cycle) and the shortest arcing time of a minor loop interruption in the phase with intermediate asymmetry that starts with a minor loop at short-circuit current initiation.

Note 1: This definition is applicable only for the determination of the test parameters during short-circuit breaking tests according to test duty T100a.

Note 2: For testing purposes the minimum arcing time found during test duty T100 s is used.

Bus Terminal Fault Interruption
Fault current interruption when a fault is occurred close to a circuit breaker (bus terminal).

Short-Line Fault Interruption
Fault current interruption when a fault is occurred from a transmission line at a distance that ranges from 100 m to a few kilometers from a circuit breaker.

Long-Line Fault (LLF) Interruption
Fault current interruption when a fault is occurred from a transmission line at a distance longer than a few kilometers up to a few hundred kilometers from a circuit breaker.

Transformer Limited Fault Interruption
Fault current interruption when a fault is occurred immediately after a power transformer. The fault location and the circuit breaker are the same side of the transformer or on opposite sides.

Small Inductive Current Switching
Current switching in case of a circuit breaker connected to an inductive load.

Small Capacitive Current Switching
Current switching in case of a circuit breaker connected to a capacitive load.

Insulation Coordination
Selection of the electric strength (LIWV and SIWV requirements) of equipment in relation to the voltages which can impose on the system for which the equipment is intended, taking into account the service environment and the characteristics of the available protective devices such as MOSA arrangements.

Lightning Impulse (LI)
Voltage pulse of a specified shape (assuming a lightning surge) applied during dielectric tests with a virtual front duration of the order of 1 μs and a time to half value of the order of 50 μs.

Note: The lightning impulse is defined by the two figures giving these durations in microseconds; in particular the standard lightning impulse is 1.2/50 μs.

Lightning Impulse Protection Level (LIPL)
Maximum permissible peak voltage value on the terminals of a surge protective device subjected to lightning impulses under specific conditions. Typically, the protection voltage of surge arresters corresponding to the current of 20 kA.

Switching Impulse (SI)
Voltage pulse of a specified shape (assuming a switching surge) applied during dielectric tests, with a time to crest of 100 μs to 300 μs and a time to half value of a few milliseconds.

Note: The switching impulse is defined by the two figures giving these durations in microseconds; in particular the standard switching impulse is 250/2500 μs.

Switching Impulse Protection Level (SIPL)
Maximum permissible peak voltage value on the terminals of a surge protective device subjected to switching impulses under specific conditions. Typically, the protection voltage of surge arresters corresponding to the current of 2 kA.

Very Fast Transient Overvoltage (VFTO)
Very fast transient overvoltage (VFTO) is often generated by operation of a disconnecting switch within GIS installations. It can reach up to 2.6 p.u. or even more at frequencies in the MHz range.

Multi-Bundle Conductors
Overhead power line consists of more than one conductor up to eight conductors is used in power transmission especially for EHV and UHV levels.

DC Component of Current, X/R Ratio
The initial value of the DC component of fault current is dependent on the exact time within a cycle at which the fault takes place and the value of current at that time. The DC component is equal to the value of the instantaneous AC current at fault inception and with opposite polarity. In the worst case, the initial DC offset will be √2 times the symmetrical short-circuit value (RMS). This initial DC component decays over time, eventually reaching zero. The time constant τ is dependent on the system reactance (X) and resistance (R). For a power frequency (f), it is given by:

$$\tau = \frac{1}{2\pi f}\left(\frac{X}{R}\right)$$

Effectively Earthed Neutral System
System is earthed through a sufficiently low impedance such that for all system conditions the ratio of the zero-sequence reactance to the positive-sequence reactance (X_0/X_1) is positive and less than 3, and the ratio of the zero-sequence resistance to the positive-sequence reactance (R_0/X_1) is positive and less than 1. Normally such systems are solidly earthed (neutral) systems or low impedance earthed (neutral) systems.

Non-effectively Earthed Neutral System
System does not correspond to the effectively earthed neutral system. Normally such systems are isolated neutral systems, high impedance earthed (neutral) systems, or resonant earthed (neutral) systems.

Zero-Sequence Impedance
The ratio of the zero-sequence component of the voltage, assumed to be sinusoidal, supplied to a synchronous machine, and the zero-sequence component of the current at the same frequency.

Positive-Sequence Impedance
The impedance offered by the system to the flow of positive-sequence current is called positive-sequence impedance.

Negative-Sequence Impedance
The impedance offered by the system to the flow of negative-sequence current is called negative-sequence impedance.

Secondary Arc
When a grounding fault occurs in the faulty phase of transmission lines, an arc is generated from the faulty location to the ground. After a circuit breaker interrupts the fault current, a small secondary arc current continues to flow at the fault location due to electrostatic and electromagnetic induction. The secondary arc is extinguished when the insulation at the fault location is sufficiently recovered.

4.3 Abbreviations

CB	Circuit breaker
TRV	Transient recovery voltage
ITRV	Initial transient recovery voltage
SLF	Short-line fault
OHL	Overhead transmission line
k_{pp}	First-pole-to-clear factor
k_{af}	Amplitude factor
X_0	Zero-sequence reactance

X_1	Positive-sequence reactance
Z_0	Zero-sequence surge impedance
Z_1	Positive-sequence surge impedance
EHV	Extra-high voltage
UHV	Ultrahigh voltage
MTS	Mixed technologies substation
LIWV	Lightning impulse withstand voltage
LIPL	Lightning impulse protection level
SIWV	Switching impulse withstand voltage
SIPL	Switching impulse protection level
VFTO	Very fast transient overvoltage

4.4 Fundamental Switching Phenomena

A circuit breaker is required to clear any faults that occurred in power system or to interrupt the currents stipulated in the international standards such as IEC 62271-100, even though the standards generally cover 90% of the switching duties expected in the existing power systems in order to provide an economical circuit breaker WG A3.11 (2006a, b).

Figure 4.3 shows several switching duties imposed on a circuit breaker. They are summarized in Table 4.1.

4.5 Bus Terminal Fault Interruption

When a circuit breaker is required to clear a bus terminal fault occurred in a vicinity of a circuit breaker, another circuit breaker located at the remote end of the connected line is required to clear a long-line fault covered in standards by terminal fault test duties T10 or T30.

The fault current and the transient recovery voltage (TRV) imposed on the circuit breaker after a fault clearing vary depending on a fault location in power system. The fault current increases with the amount of currents flowing from the transmission lines and power transformers connected to power generators into a fault point.

When only one current source such as a load transmission line or a power transformer supplies the current to a fault point as shown in Fig. 4.4, the fault current is relatively small, normally less than 10% of the rated interrupting current (corresponding to T10 test duty). The associated TRV generally shows a single frequency with a higher value of TRV peak, which is determined by the amplitude factor in the related circuit. The TRV amplitude factor tends to be larger due to the single frequency contributed by a single current source.

Especially, a fault is generated immediately after a power transformer without any appreciable capacitance between the transformer and the circuit breaker; severe TRV

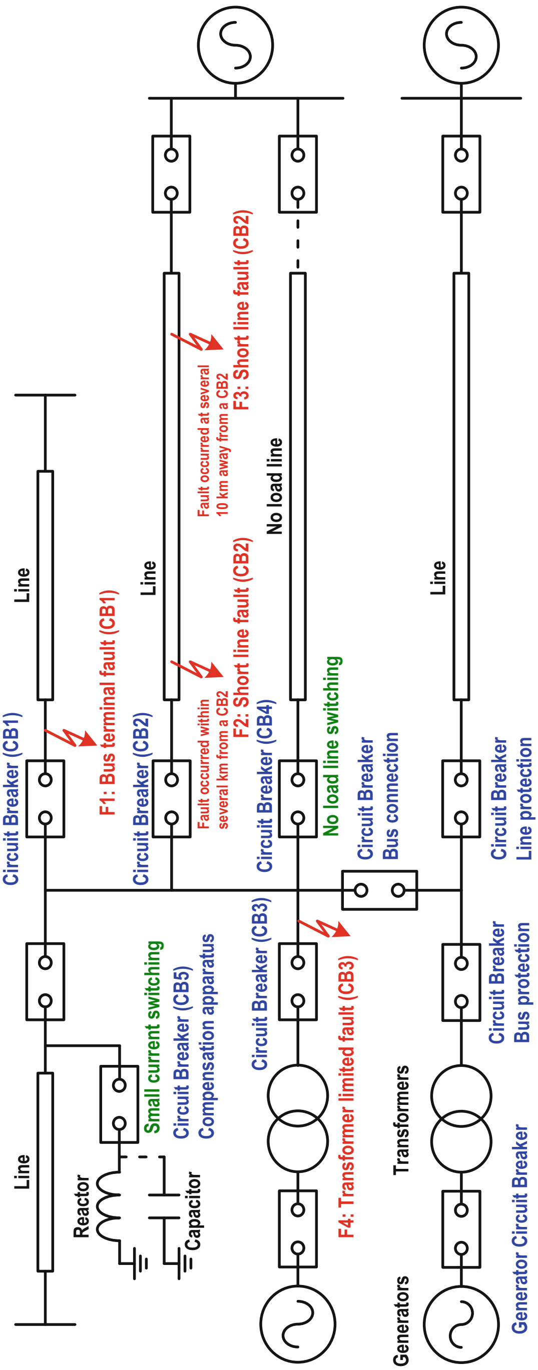


Fig. 4.3 Dielectric recovery characteristics in comparison with transient recovery voltage

Table 4.1 Switching duties in power system

Switching duties	Fault location	Responsible circuit breaker
Bus terminal fault interruption	F1	CB1
Short-line fault interruption	F2	CB2
Long-line fault interruption	F3	CB2
Transformer limited fault interruption	F4	CB3
No-load line switching	–	CB4
A small capacitive current switching	–	CB5
A small inductive current switching	–	CB5

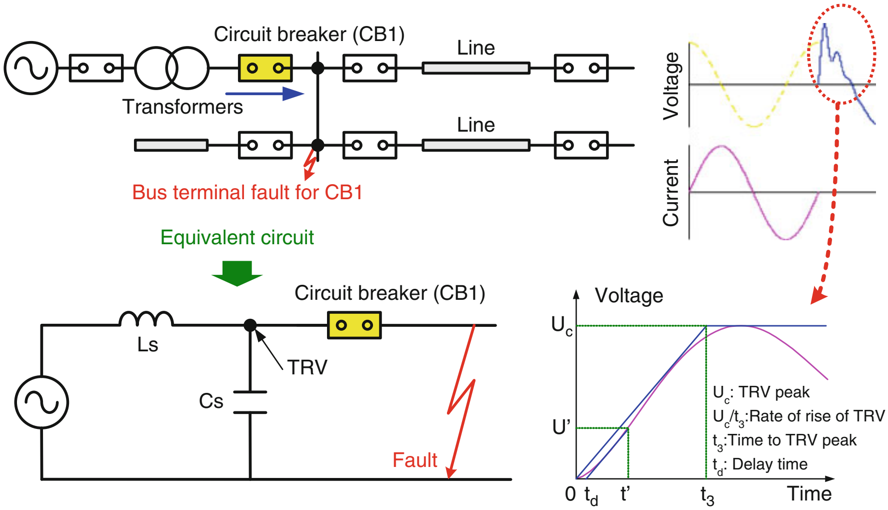


Fig. 4.4 TRV waveform of bus terminal fault corresponding to T10 test duty

may happen, which may exceed the standard RRRV values for T10 test duty. The duty is often called as transformer limited fault interruption (see Sect. 4.9).

Even though a circuit breaker is required to have a sufficient arc cooling capability to deprive the arc energy generated in the interrupter during the arcing time after contact separation, the interrupting capability of a circuit breaker during thermal interrupting region is not severe, because the rate of rise of TRV (RRRV) is relatively smaller than that in case of short-line fault (SLF) interruption. Therefore, the dielectric recovery capability of a circuit breaker, which is required to surpass the TRV at all times, is a primary concern to clear the fault on the T10 test duty. The TRV shows a simple frequency when the current source is limited, which is specified with two-parameter reference line and a delay time in the standard.

When several current sources from load transmission lines or power transformers supply the current to a fault point as shown in Fig. 4.5, the fault current is relatively large, up to about 60% of the rated interrupting current (corresponding to T60 test duty). The associated TRV shows multiple frequencies due to different related circuits

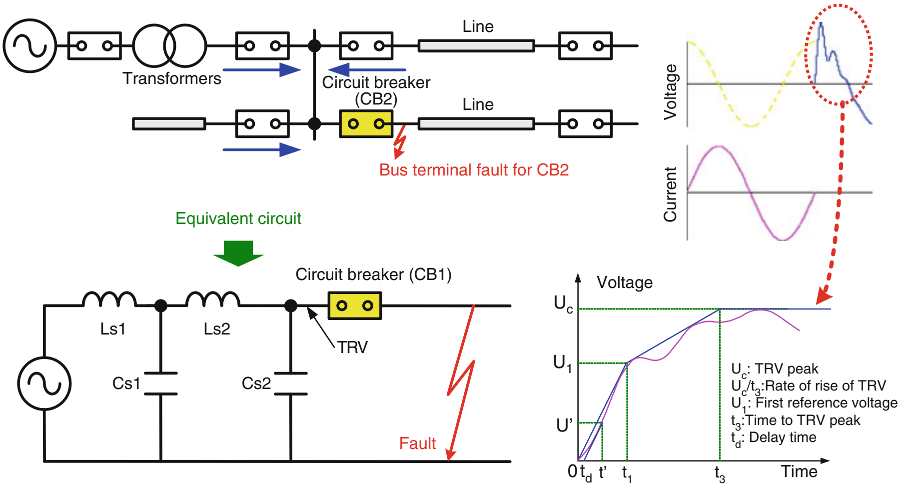


Fig. 4.5 TRV waveform of bus terminal fault corresponding to T60 test duty

corresponding to different current sources. TRV composing of multiple frequencies and different time to the peak due to different current sources tends to reduce the amplitude factor resulting in lower TRV peaks for higher interrupting currents.

Figure 4.6 illustrates an example of power system configuration with several transmission lines, power transformers, and power generators. It shows the amplitude of the fault current and TRV waveforms depending on different fault locations. When a fault is generated at F1, the circuit breaker (CB1) is required to clear the fault current with about 10% of the rated interrupting current of the CB1 mainly fed by one power transformer (the fault current flow is shown in red arrow). TRV after clearing the fault at F1 shows higher TRV peak with a damping oscillation having a simple frequency determined by a circuit condition of one current source.

When a fault is generated at F2, the circuit breaker (CB2) is required to clear the fault current with ranging 30–60% of the rated interrupting current of the CB2 which is fed by several current sources through transmission lines and power transformers (the fault current flow is shown in green arrow). TRV after clearing the fault at F2 shows TRV peak lower than that at F1 with multiple frequencies determined by different circuit conditions of several current sources.

For the most severe case, when a fault is generated at F3 in case that all transmission lines are loaded, the circuit breaker (CB3) is required to clear the fault current with the rated interrupting current of the CB3 which is fed by all current sources in power system (the fault current flow is shown in blue arrow). TRV after clearing the fault at F3 shows lower TRV peak with complex frequencies determined by different circuit conditions of all current sources.

Regarding bus terminal fault interruptions, the standard requires a circuit breaker to interrupt the symmetrical current of 10%, 30%, 60%, and 100% of the rated interrupting current as well as 100% of the current with the standard values of DC component (in asymmetrical current) with the corresponding TRV peaks and

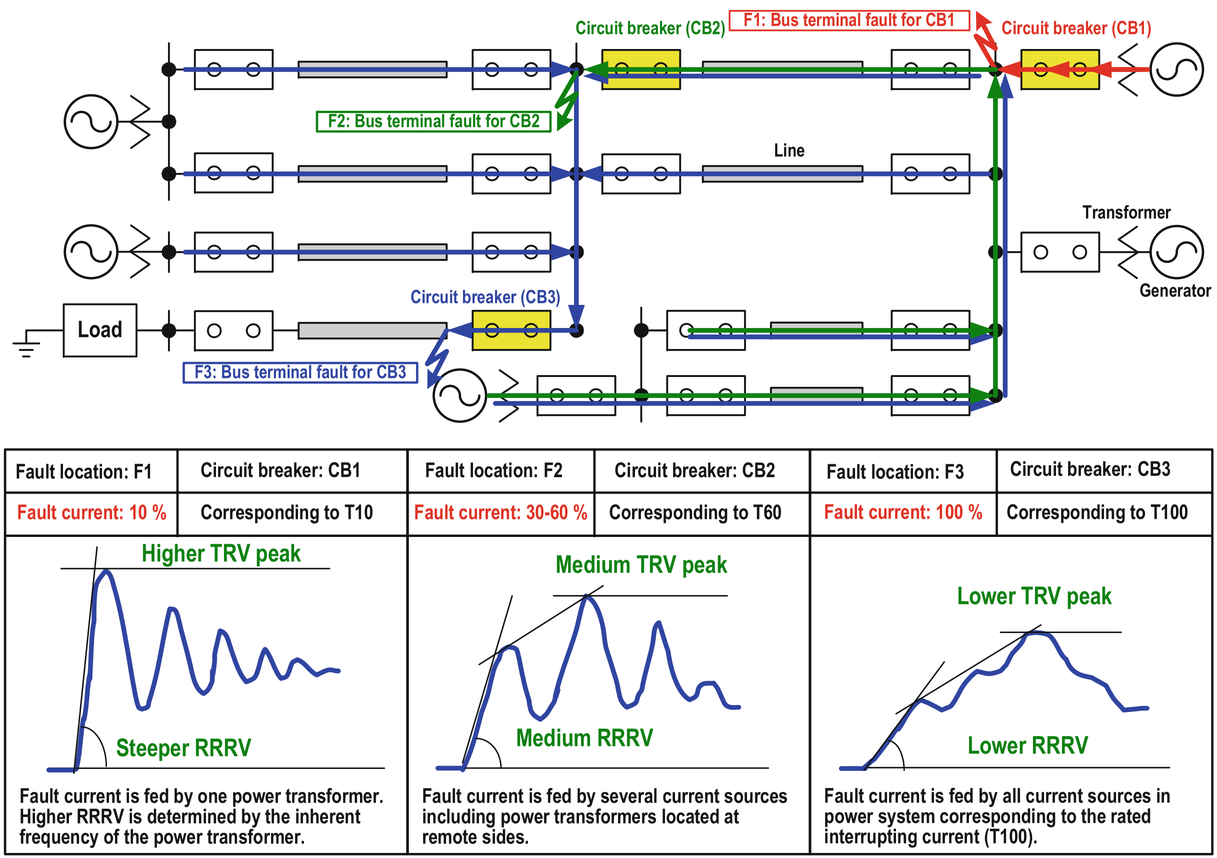


Fig. 4.6 TRV waveform of bus terminal fault depending on fault location

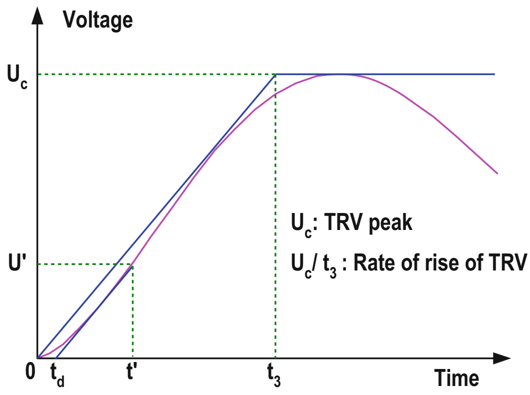


Fig. 4.7 Representation of specified TRV by two-parameter reference line and delay line

RRRVs, respectively. Those testing requirements are classified as the test duties T30, T60, T100 s, and T100a.

For rated voltages equal to or higher than 100 kV, the TRV for terminal fault test duties is described by two parameters shown in Fig. 4.7 for the test duties of T10 and T30 or four parameters shown in Fig. 4.8 for the test duties of T60 and T100.

The peak value of TRV (U_c) applied to a circuit breaker during bus terminal interruption is given by:

$$U_c = U_r \sqrt{\frac{2}{3}} k_{pp} \; k_{af}$$

where,

U_c TRV peak
U_r rated voltage
k_{pp} first-pole-to-clear factor
k_{af} amplitude factor

For a given rated voltage, both the first-pole-to-clear factor and the amplitude factors must be defined for determining the peak value of TRV. The power frequency recovery voltage (U) given by the following equation is a function only of the rated voltage and the first-pole-to-clear factor.

$$U = \frac{U_r \; k_{pp}}{\sqrt{3}}$$

IEC 62271-100 specifies a first-pole-to-clear factor of 1.3 for effectively earthed neutral systems at the rated voltages up to 800 kV, which is calculated from the following equation using the zero-sequence reactance X_0 and positive-sequence reactance X_1.

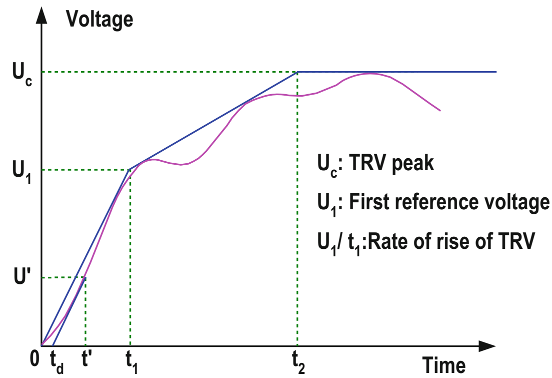


Fig. 4.8 Representation of specified TRV by four-parameter reference line and delay line

$$k_{pp} = \frac{3}{2 + \frac{X_1}{X_0}}$$

In a network with long transmission lines, the first-pole-to-clear factor tends to increase, because the ratio of X_1/X_0 of lines relatively becomes smaller. On the other hand, in the case of a network connected to large power transformers (a star connection with an earthed neutral or a delta connection), the first-pole-to-clear factor becomes smaller and occasionally less than 1.2, because the ratio of X_1/X_0 is equal to or larger than 0.5 ($2X_1 > X_0$). Especially in cases where most of the short-circuit currents are fed through large-capacity power transformers, the first-pole-to-clear factors are smaller, because the zero-sequence impedance is reduced due to the delta connection of large-capacity power transformers (X_1/X_0 approaches unity or X_0 approaches X_1).

The impedance of OH-lines is nearly in reverse proportional to the square of the system operating voltage, so the ratio of line impedance to total transmission system impedance tends to be smaller for a system operating higher voltages. This tendency reduces the zero-sequence impedance in UHV systems (at the rated voltages of 1100 kV and 1200 kV) due to the increasing influence of large-capacity power transformers that have smaller zero-sequence impedance X_0 compared with transmission lines. Accordingly, the first-pole-to-clear factor in UHV systems is defined as 1.2.

The amplitude factor of TRV tends to decrease with the interrupting currents because the superimposed TRVs composing of multiple frequencies and different time to the TRV peak due to different current sources contributing to the bus terminal fault reduce the amplitude factor.

Table 4.2 gives the amplitude factors in IEC 62271-100 for terminal fault interruption by circuit breakers with a rated voltage of 100 kV and above. The amplitude factor is $1.7 \times 0.9 = 1.53$ for test duty T10 at the rated voltages 100 kV up to 170 kV based on the first-pole-to-clear factor of 1.5 with voltage reduction of 0.9 across the transformer. The amplitude factor of TRV for rated voltages higher than 170 kV is 1.76; it tends to increase due to lower losses of power transformers and transmission lines as well as less damping of traveling

Table 4.2 Amplitude factors for terminal fault test duties (* for $U_r > 170$ kV)

Test duty	Amplitude factor
T10	1.7 × 0.9 or 1.76*
T30	1.54
T60	1.50
T100	1.40

Table 4.3 RRRV for terminal fault test duties

Test duty	RRRV (kV/μs)
T10	7
T30	5
T60	3
T100	2

waves. This amplitude factor of 1.76 leads to the same value of TRV peak when multiplied by a first-pole-to-clear factor of 1.3 as would be obtained with an amplitude factor of 1.53 times a first-pole-to-clear factor of 1.5.

Table 4.3 gives the rate of rise of TRV (RRRV) values in IEC 62271-100 for terminal fault interruption by circuit breakers with a rated voltage of 100 kV and above. Similarly the RRRV tends to decrease with the interrupting currents because the superimposed TRVs composing of multiple frequencies and different time to the TRV peak due to different current sources contributing to the bus terminal fault reduce the RRRV.

4.6 Short-Line Fault Interruption

When a fault is occurred from a transmission line at a distance that ranges from 100 m to a few kilometers along the lines, a circuit breaker is required to clear the short-line fault (SLF). When a circuit breaker clears the SLF generated on the line, TRV with a steep rate of rise similar to a sawtooth waveform is observed due to high-frequency oscillation generated by the propagating waves that iterate traveling on the line and reflections between the circuit-breaker terminal and the fault point.

Figure 4.9 shows an equivalent circuit and a voltage distribution when SLF is generated on the line. The circuit breaker is connected to the generator through a power transformer at the source side and connected to the transmission line at the line side, which can be modeled with multiple lattice circuits composing of a reactor and a capacitor shown in Fig. 4.9.

When the circuit breaker interrupts the fault current on the SLF conditions, the voltage of the circuit-breaker terminal at the source side is back to the system voltage at the transformer terminal which causes an oscillation with the power frequency in the source circuit. The source side circuit can be approximated with a lumped circuit

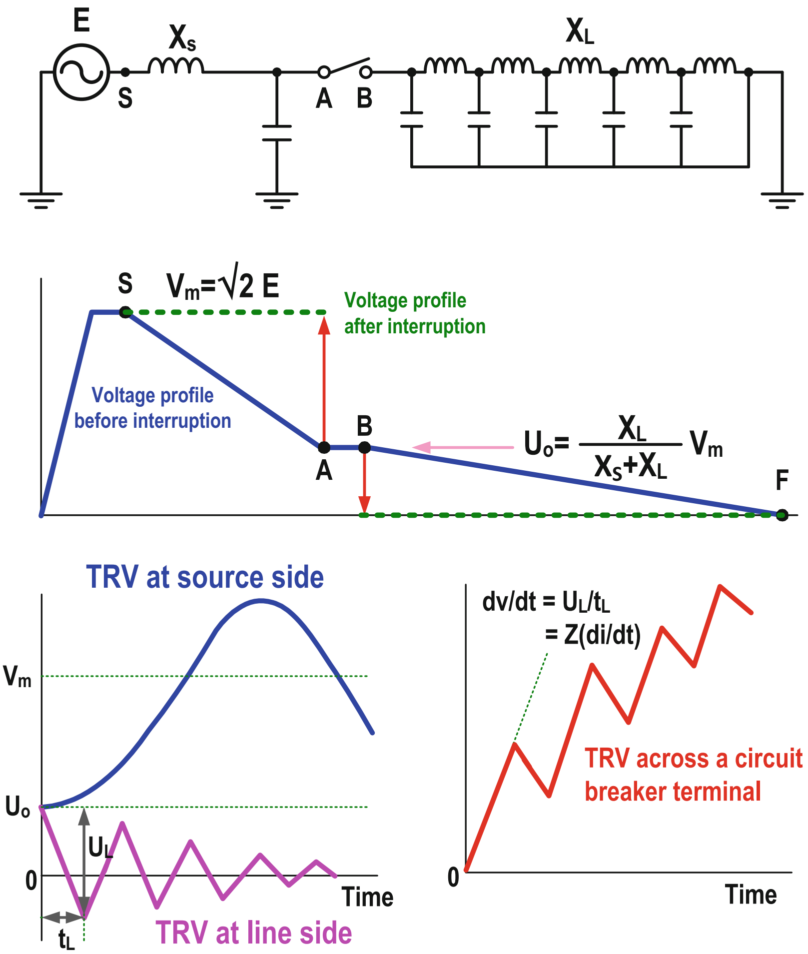


Fig. 4.9 Equivalent circuit and TRV waveforms of short-line fault (SLF) condition

with constant concentrated parameters. The amplitude factor of TRV is similar to the case of the terminal faults.

On the other side, the voltage of the circuit-breaker terminal at the line side is dropped to the grounding levels, which creates another oscillation with a sawtooth (triangular) shape due to traveling and reflection of propagating waves along the line. The line side circuit can be approximated with a small attenuated circuit with distributed parameters.

Figure 4.10 shows a schematic change of the TRV propagation at line side without considering any attenuation of the traveling waves. After SLF interruption, the transients travel along the line in both directions. One is propagating from the breaker terminal to the fault point. The other is doing from the fault point to the breaker terminal with a contact propagating velocity of c, which is about 300 m/μs through a transmission line.

The transient initiated from the breaker terminal (whose voltage is U_0 immediately after interruption) decreases with time and arrives at the fault point (where the voltage is always ground level) with $t = L/c$. Here L is the line length. The transient

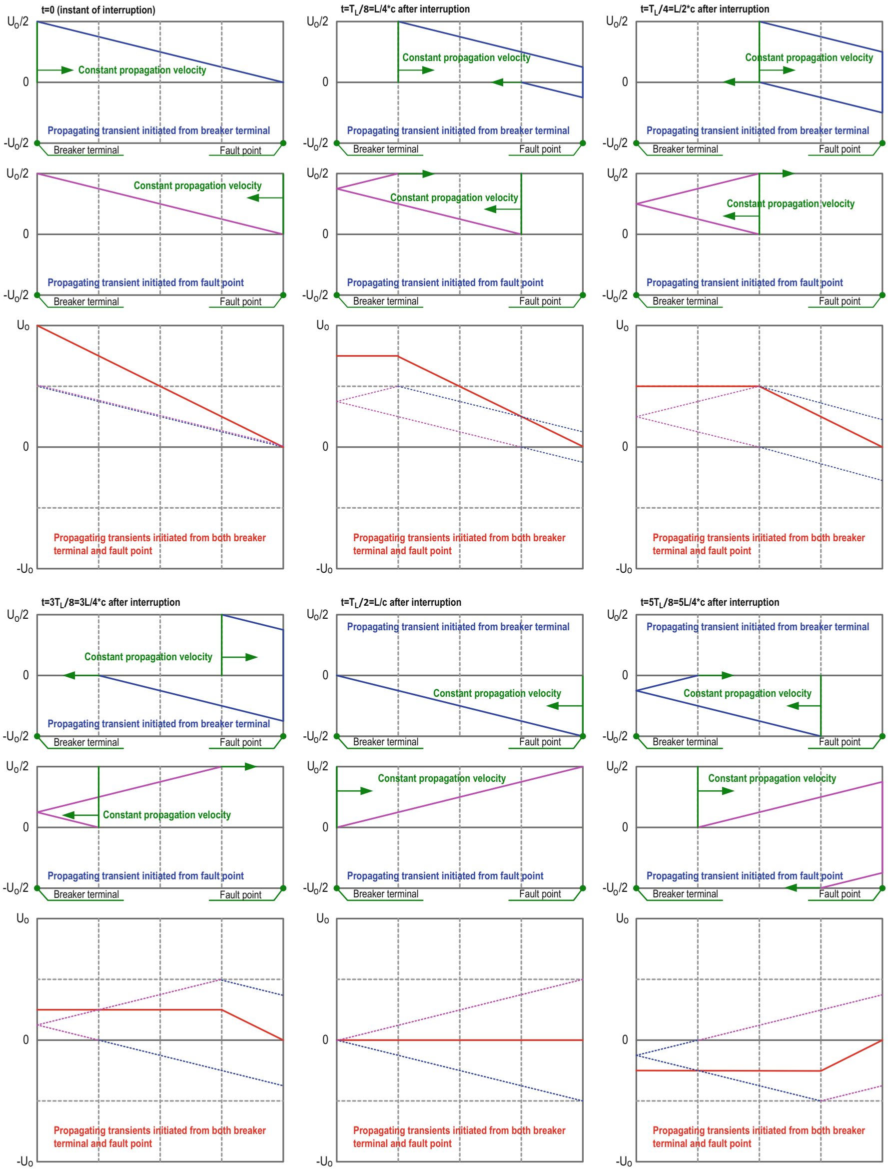


Fig. 4.10 (continued)

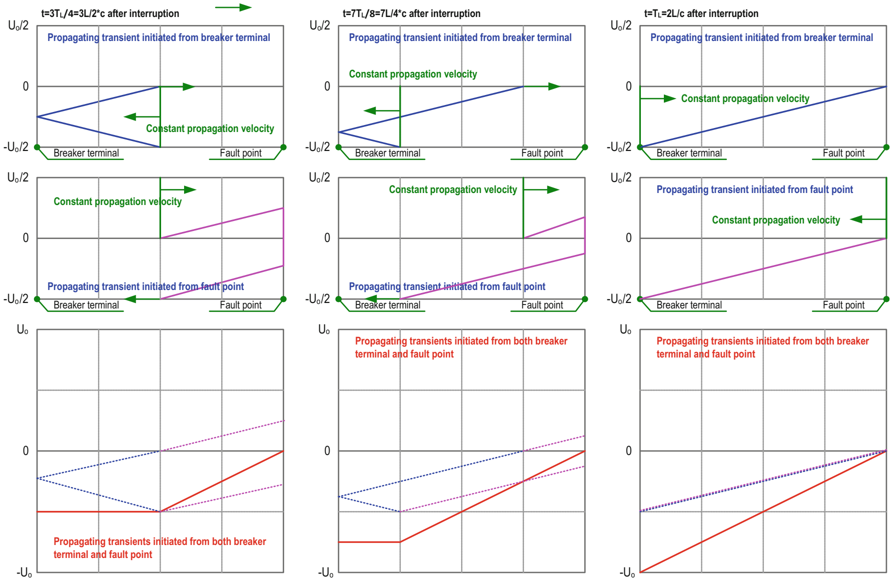


Fig. 4.10 TRV propagation for short-line fault (SLF) condition at line side

reflected at the fault point (discontinuity) and travels back along the line and turns to the breaker terminal at t = 2 L/c with the voltage of – U_0 with the negative polarity, which corresponds to the first TRV peak (U_L).

The transient iterates traveling along the line in both directions and reflections between the breaker terminal and the fault point with the constant propagating velocity, resulting in forming a sawtooth (triangular) shape.

TRV across the circuit-breaker terminals is given with a superimposed waveform of those at both the source side and the line side with the initial rate of rise of TRV given by dv/dt = Z x (di/dt), where Z is the line surge impedance. TRV on the line side increases with the increase of the distance to the fault point, while TRV on the source side decreases.

When a circuit breaker interrupts the SLF, the thermal interrupting performance is a dominant factor to determine an interruption success or failure, because of the severe energy input immediately after current interruption due to higher RRRV. When a circuit breaker cannot provide sufficient coolability for the energy input during the thermal interrupting period, thermal reignition may happen.

The standardized value of Z in IEC 62271-100 and IEEE C37.04 is 450 Ω roughly corresponding to the surge impedance of a single conductor. In EHV and UHV systems, multi-bundle conductors are used, which give lower line surge impedance ranging from 250 to 400 Ω at normal current-carrying condition, which can be given by $(L/C)^{0.5}$ with a larger capacitance to the ground. When a SLF is generated, each conductor in the multi-bundle conductors attracts each other due to Lorentz force which operates the parallel conductors carrying the large fault current at the same direction. Figure 4.11 shows a schematic of multi-bundle conductors at the normal condition and the bundle collision under the fault conditions.

Besides the fault current, the line surge impedance depends on multi-bundle conductor designs (materials, cross section, span, and spacer size) and the mechanical tension applied on the conductors of the lines. Several studies including those of CIGRE WG 13.01 reported the time to require bundle collision. For example, twin conductors with 686 mm^2 in cross section carrying 40 kA collided at 50 ms after a fault occurrence, and quadruple conductors with 810 mm^2 in cross section carrying 30–50 kA collided at 100–200 ms shown in Fig. 4.12. A longer time for bundle contraction is expected for UHV lines due to the increased number of conductors and the larger cross section used. A value of 330 Ω is standardized for the surge impedance of lines in UHV systems.

The severity of SLF test duties depends mainly on the rate of rise of recovery voltage, which is determined by the line surge impedance and slope of the fault current. The equivalent line surge impedance (Z) for each pole-to-clear is given by the following equations, where Z_0 is the zero-sequence surge impedance and Z_1 is the positive-sequence surge impedance.

$$Z_{\text{firstpole}} = \frac{3\ Z_1\ Z_0}{Z_1 + 2\ Z_0}$$

$$Z_{\text{secondpole}} = \frac{Z_1\ (Z + 2\ Z_0)}{2Z_1 + Z_0}$$

$$Z_{\text{thirdpole}} = \frac{(2Z_1 + Z_0)}{3}$$

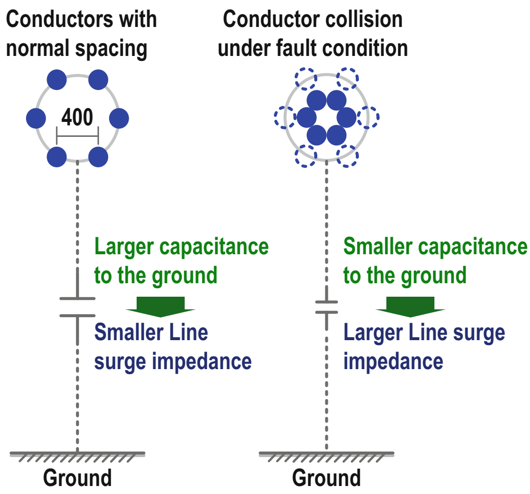
The equivalent surge impedance of the last pole-to-clear is the most severe surge impedance, and therefore the test duties to cover SLF are based on the last pole-to-clear or the interruption of a single-phase-to-earth fault.

In an actual substation, a circuit breaker is connected to the bus terminal using a short line. The surge impedance of the short line is 260 Ω due to larger capacitance to the ground because the short line is normally closer to the ground and often connected to a capacitive voltage transformer, while that of the transmission line is 450 Ω. The short length of this line creates a similar triangular waveform with higher frequency and lower amplitude, which is called an initial TRV (ITRV). ITRV may provide the severe thermal stress on a circuit breaker depending on the condition.

In IEC 62271-100 and IEEE C37.04 Standards, L90, L75, and L60 are the type test duties for short-line fault (SLF) conditions. The fault current is equal to 90%, 75%, and 60% of the rated short-circuit breaking current, respectively. The requirements of SLF on different current levels were originated from the thermal interrupting capability of an air blast circuit breaker, which generates higher residual current (post-arc current) after current interruption as compared with that of an SF_6 gas circuit breaker.

Figure 4.13 shows TRV waveforms calculated for different current levels corresponding to L90, L75, and L60 assuming of 550 kV transmission line with the rated interrupting current of 50 kA and the power frequency of 60 Hz. The line surge

Fig. 4.11 Multi-bundle conductors at normal condition and the bundle collisions under fault condition



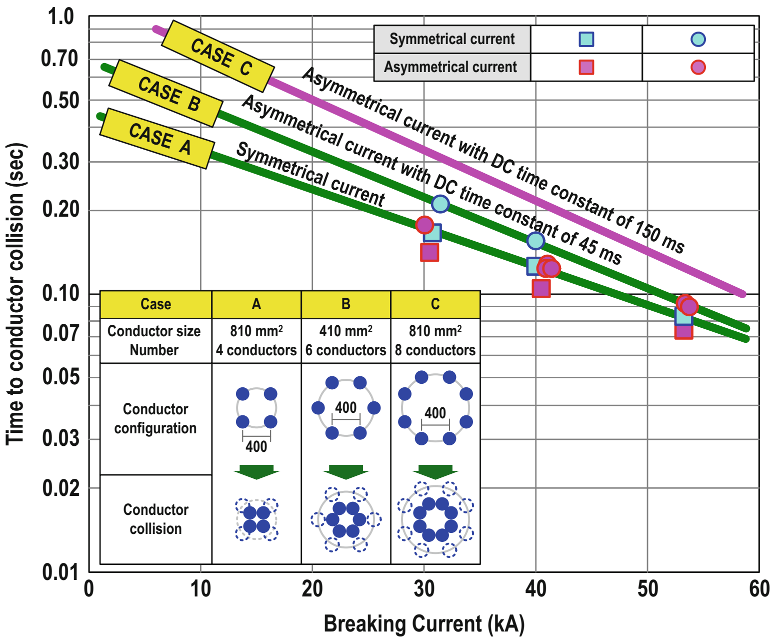


Fig. 4.12 Collision time of multi-bundle conductors

impedance is 450 Ω. TRV shows the higher RRRV and lower TRV peak with higher TRV frequency at the interrupting current of 45 kA (L90), meaning that the fault occurs at 1.3 km away from the circuit breaker. RRRV gradually becomes lower, and TRV peak becomes higher with lower TRV frequency with a decrease of interrupting currents from L75 (a fault is 3.8 km away from CB) to L60 (a fault is 7.5 km away from CB).

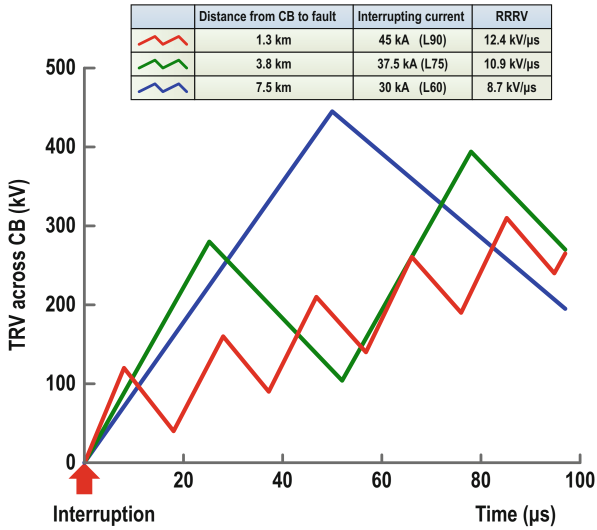


Fig. 4.13 TRV waveform comparison for different interrupting currents corresponding to L90, L75, and L60

Line faults further away show a lower RRRV but also a higher peak of the line side TRV. The further away, the larger the peak. This leads to the phenomenon of long-line faults (LLF) where relatively low fault currents have to be cleared but with considerable high TRV peak values. Normally these peak values are compared with those as specified for the out-of-phase test duty, as will be described in Sect. 4.10.

Figure 4.14 shows the relation of the residual currents and TRV waveforms for different interrupting current levels with air blast breakers and gas circuit breakers, respectively. Air blast breakers tend to flow a larger residual current after current zero as compared with that of gas circuit breakers, which peak roughly corresponds to the TRV peak for testing duty of L60. In contrary, the peak of a smaller residual current with gas circuit breakers roughly corresponds to the TRV peak for testing duty of L90. Therefore the energy input becomes highest for the TRV corresponding to L90 in case of gas circuit breakers and L60 or L75 in case of air blast breakers. Accordingly L60 or L75 requirements may have more severe thermal interruption duties for air blast breakers than L90 requirement.

Figure 4.15 shows the critical interrupting capability for air blast breakers and gas circuit breakers, respectively. While gas circuit breakers have the most severe thermal interrupting duties in case of L90, air blast breakers may have the most severe case in the cases of L75 and L60.

4.7 Capacitive Current Switching

When a circuit breaker connects or disconnects no-load transmission lines, no-load cables, and shunt capacitor banks (as shown in Fig. 4.16), it switches small capacitive currents from several ten to several hundred amperes with 90° advance to the voltage phase. Since the current interruption leaves a reverse charged DC voltage on

Fig. 4.14 Relation between the residual current and TRV with air blast circuit breakers and gas circuit breakers

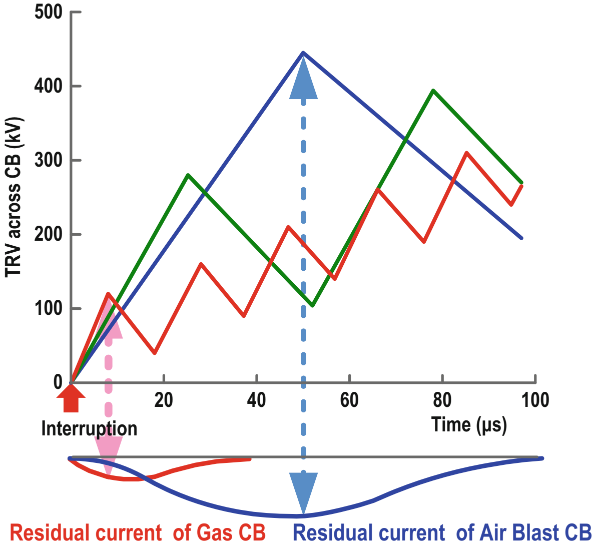
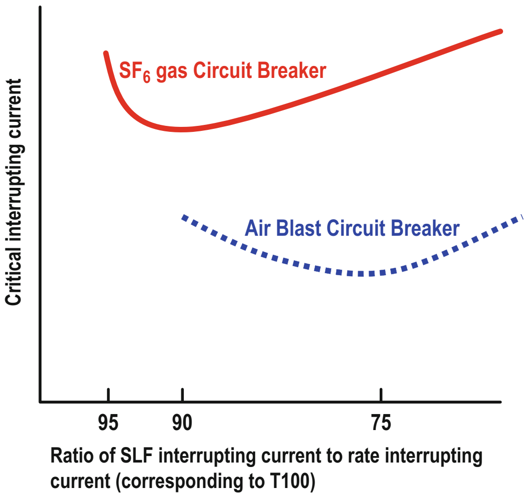


Fig. 4.15 Thermal interrupting capability with air blast circuit breakers and gas circuit breakers for different currents



the load circuit, the recovery voltage across the circuit breaker shows 1-COS waveform as a result of the difference between the AC voltage of the source side and DC voltage at the load side and appears the severe TRV peak which is twice the system voltage peak at a half cycle after interruption, even though the rate of rise of TRV is not severe. Figure 4.17 shows these TRV waveforms: TRV across a circuit breaker, TRV at source side, and TRV at line side.

Since a circuit breaker can interrupt a small capacitive current easily, the dielectric interrupting performance is a dominant factor to determine an interruption success or failure of the small capacitive current switching. The interruption is successfully

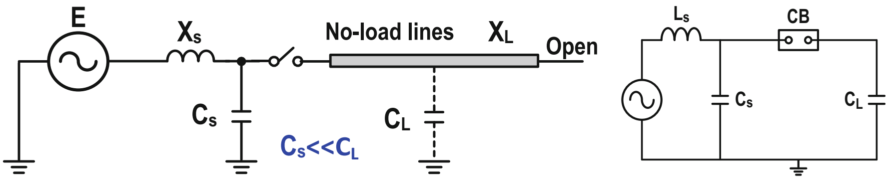


Fig. 4.16 No-load transmission line switching

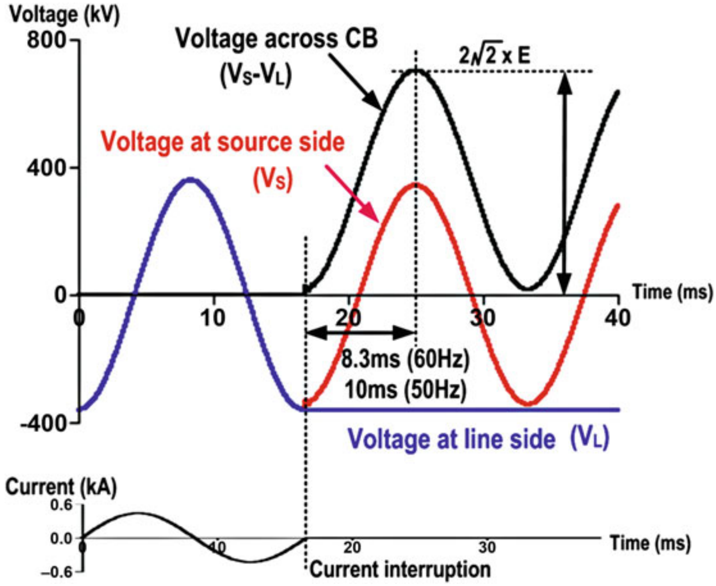


Fig. 4.17 TRV waveforms after disconnecting no-load line

completed when the dielectric strength across the contacts always surpasses the recovery voltage after current interruption.

When TRV exceeds the dielectric recovery performance across the circuit breaker terminals at any moment, a dielectric breakdown occurs. The dielectric breakdowns are classified into reignition and restrike depending on the instant of occurrence. The dielectric breakdown that happens within 1/4 cycle after current interruption is called as a restrike, which will not generate severe overvoltage. However, when it happens after 1/4 cycle after current interruption, it is called as a reignition, which may generate severe overvoltage.

When reignition occurs at voltage peak where the load side voltage (at the line side) keeps –E and the voltage across a circuit breaker is 2E, the load side voltage jumps up to 3E (reverse polarity of remaining DC of E plus TRV peak of 2E) as shown in Fig. 4.18. If the circuit breaker can interrupt the high-frequency current immediately after reignition, the load side voltage on line side remains a DC voltage of 3E. The recovery voltage across the circuit breaker shows COS-1 waveforms with a starting point of -2E and

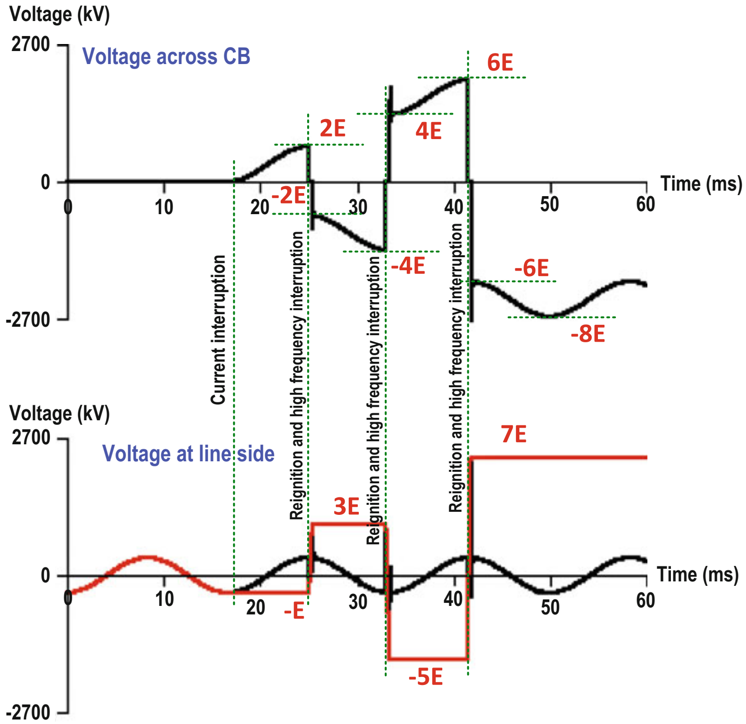


Fig. 4.18 Load side voltage escalation caused by multiple reignitions

attains -4E. Then again if reignition occurs at voltage peak where the load side voltage (at the line side) keeps 3E and the voltage across a circuit breaker is -4E, the load side voltage jumps up to 5E (reverse polarity of remaining DC of 3E plus TRV peak of 2E). If the circuit breaker can interrupt the high-frequency current immediately after reignition, the load side voltage on line side remains a DC voltage of -5E. The recovery voltage across the circuit breaker shows 1-COS waveforms with a starting point of 4E and attains 6E. Then again if reignition occurs at voltage peak where the load side voltage (at the line side) keeps -5E and the voltage across a circuit breaker is 6E, the load side voltage jumps up to 7E (reverse polarity of remaining DC of 5E plus TRV peak of 2E). The voltage escalation due to multiple high-frequency interruptions immediately after reignitions may impose serious stress on equipment in power system.

The energization of no-load transmission or shunt capacitor bank may generate high inrush currents and associated overvoltages depending on the making instants of the voltage across a circuit breaker. Figure 4.19 shows inrush current and associated overvoltage generated when a circuit breaker makes the voltage peak in case of no-load line energization, which may provide excessive mechanical and electrical stresses in the capacitor bank and other equipment in power system and erosion of the

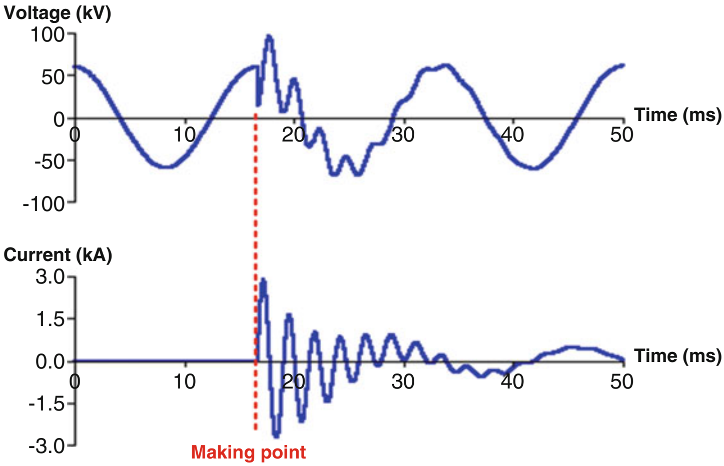


Fig. 4.19 Severe inrush current and associated overvoltage generated when a circuit breaker makes the voltage peak in case of no-load line energization

circuit-breaker contact. The controlled switching can effectively reduce the switching surges in case of no-load transmission or shunt capacitor bank energization.

In an actual substation, a circuit breaker is connected to the bus terminal using a short line. The short length of this line creates an initial TRV (ITRV) waveform with higher frequency and lower amplitude, which is called an initial TRV (ITRV) similar to SLF interruption. Figure 4.20 shows a practical TRV waveform when a circuit breaker disconnects no-load transmission line.

The three-phase switching of no-load transmission lines and no-load cables is a slightly complex nature than shunt capacitor banks, because the capacitance is distributed along the line rather than lumped and involves both line to earth and line-to-line capacitance.

Figure 4.21 shows an equivalent circuit of no-load transmission line or no-load cables, which is characterized by their positive capacitance (C_1) and negative capacitance (C_0). Here $C_1 = C_0$ corresponds to the case of shunt capacitor bank switching with an earthed neutral. TRV will be 1-COS waveform similar to capacitor bank switching but different TRV peak dependent on the ratio of C_0 to C_1.

When the load impedance X_1 is $1/\omega C_1$ in case of capacitor bank switching with an earthed neutral, where $C_1 = C_0$, TRV peak is 2E (E: system voltage peak). The line impedance X_L of no-load transmission is given by:

$$X_L = \frac{1.5X_0X}{1.5X + X_0}$$

where X is $1/\omega(C_1 - C_0)$ and X_0 is $1/\omega C_0$. TRV peak is given by the following equation:

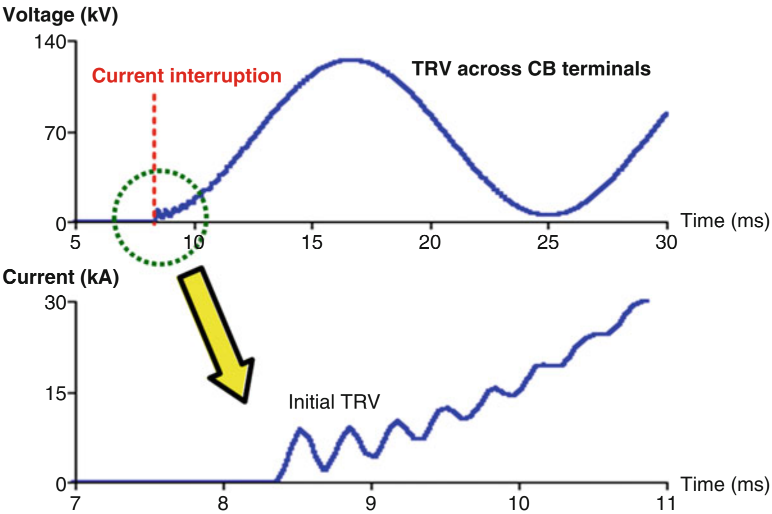


Fig. 4.20 TRV waveforms with ITRV in case of no-load line de-energization

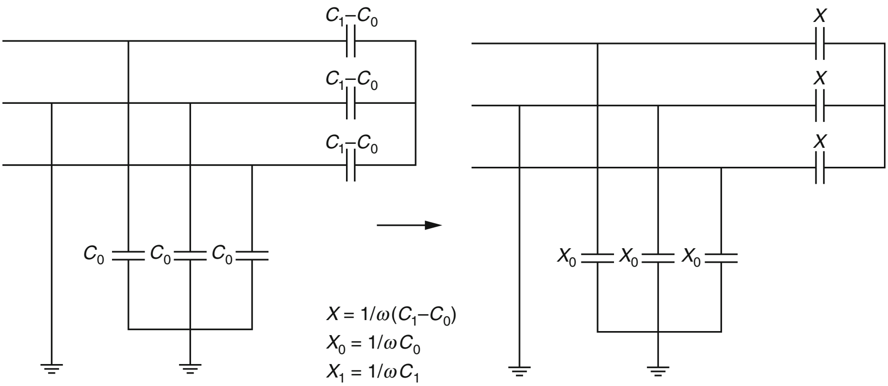


Fig. 4.21 Equivalent circuit of no-load lines and cables

$$\text{TRV peak} = \frac{6\mathrm{C}_1/\mathrm{C}_0}{1 + \mathrm{C}_1/\mathrm{C}_0}$$

Figure 4.22 shows TRV peak as function of C_1/C_0, which is approaching a value of 3. TRV peak is 2.4 E in case of switching no-load overhead transmission line (OHL), where $C_1 = 2C_0$ and 3E in case of switching no-load cable with an isolated neutral, where $C_0 = 0$ approximately.

In some case, a transmission line equips shunt reactor compensation, which connects a shunt reactor bank at the line terminal. TRV at load side of compensated

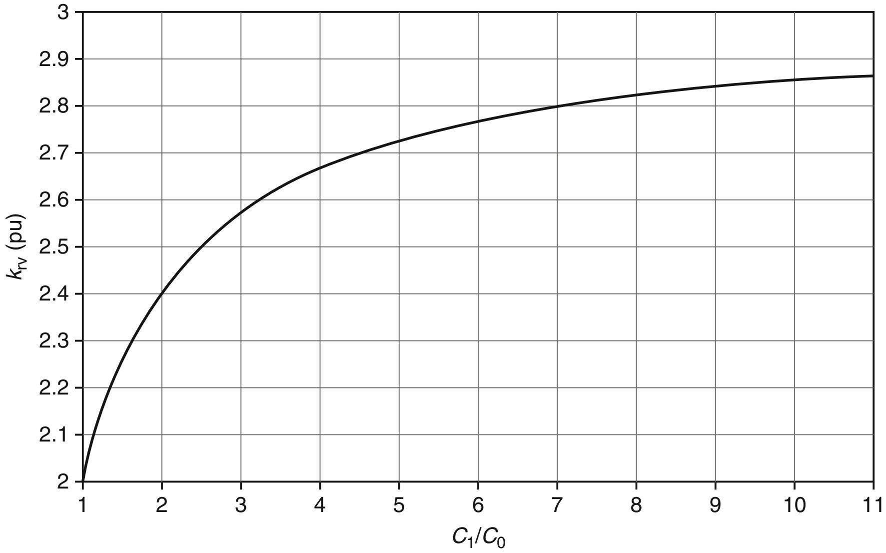


Fig. 4.22 TRV peak of first-pole-to-clear in case of no-load line switching

lines oscillates with the frequency determined by line circuit parameters not keeping a constant value.

The influence of shunt reactors on TRV for a 360 km no-load line switching is calculated with the 550 kV double-circuit transmission line. Figure 4.23 shows an example of TRV waveforms in case of no-load line switching with and without shunt reactors. The TRV frequency is of several tens of Hz, which depends on the inductance of the reactor and the capacitance of the line, and the TRV peak can be considerably reduced in the network when a large shunt reactor is connected. For example, the TRV peak for line charging condition in a 550 kV network and a fault occurring at a remote distance of 360 km is 1018 kV without shunt reactor, while it is reduced to less than 400 kV when a shunt reactor is connected. Therefore, shunt reactors can significantly reduce the first TRV peak for no-load line charging breaking conditions.

4.8 Small Inductive Current Switching

When a circuit breaker opens and closes a shunt reactor banks or unloaded power transformer, it switches small inductive currents of several ten amperes with 90° lagging to the voltage phase. It happens when a circuit breaker is applied to shunt reactor switching, motor switching, and unloaded transformer switching (IEC 62271-110; IEEE Standard C37.015 1993).

Circuit breakers in general have no difficulty interrupting small inductive currents; the current in fact is usually forced to a premature zero by a phenomenon known as current chopping. However, the resultant chopping overvoltages, and

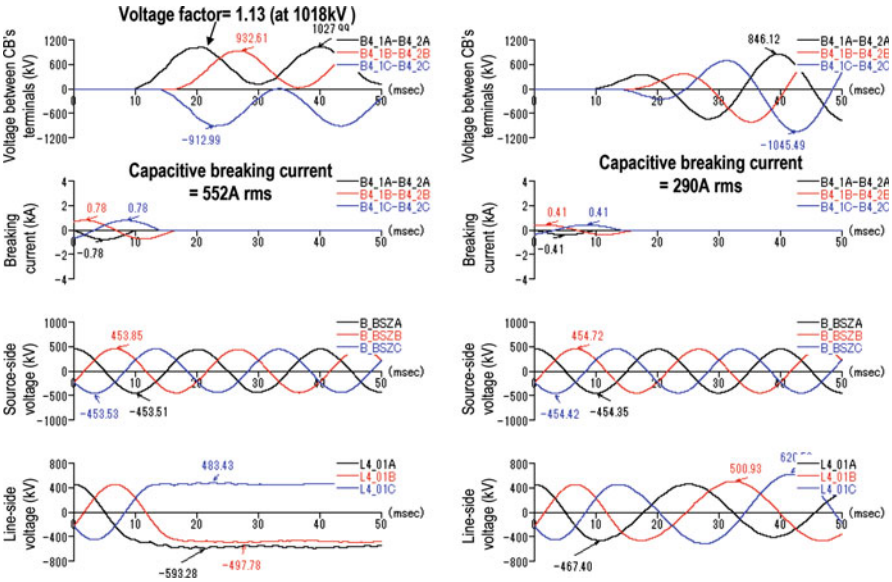


Fig. 4.23 Influence of shunt reactor on TRV for no-load line breaking in 550 kV double-circuit network model using system and equipment parameters in Thailand

subsequent reignition overvoltage may generate severe consequence depending on the circuit-breaker performance and the circuit conditions. The duty is thus very interactive, and due diligence should be exercised in selecting a circuit breaker for this purpose. The general theory of inductive current switching is essentially common to all of the above three switching cases. On this basis, shunt reactor switching is considered in detail and unloaded transformer and motor switching as extensions to that case.

Three are three grounding conditions in case of shunt reactor switching cases depending on the system voltage:

1. Directly earthed shunt reactors usually applied at HV (72,5 kV $\leq U_r \leq$ 245 kV) and EHV (300 kV $\leq U_r \leq$ 800 kV)
2. Neutral reactor earthed shunt reactors usually applied at EHV
3. Unearthed shunt reactors usually applied at $U_r \leq$ 52 kV

All three cases can be readily analyzed by first considering the general case of the neutral reactor earthed shunt reactor and extending it to the other two cases.

Figure 4.24 shows an equivalent circuit of inductive current switching. The inductive switching is generally not a significant testing duty for a circuit breaker. However a circuit breaker with higher thermal interrupting performance may interrupt small inductive current before an inherent current zero (current chopping) and generate the chopping overvoltage, which tends to increase with an increase of chopping current level.

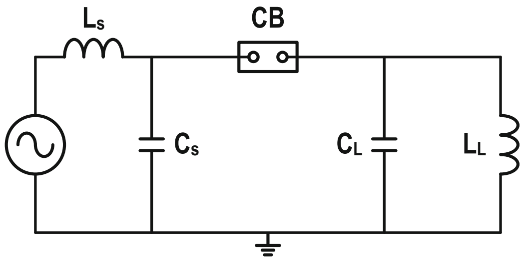


Fig. 4.24 Equivalent circuit of small inductive switching

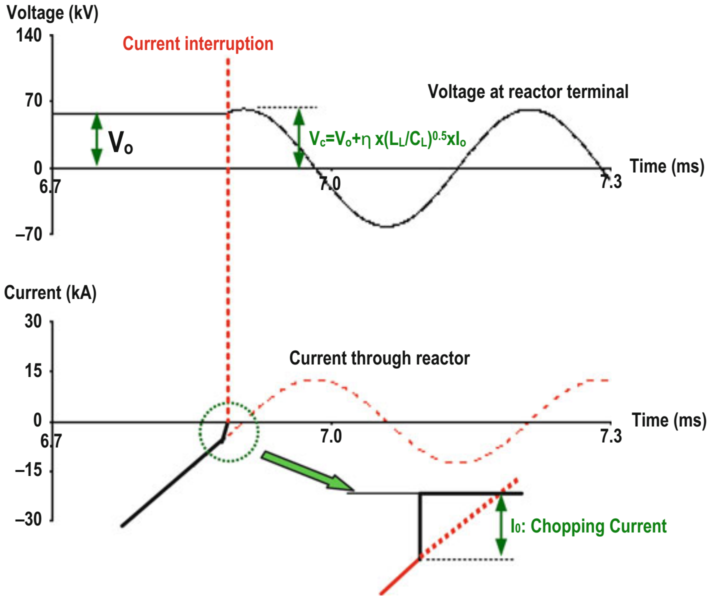


Fig. 4.25 Voltage and current behavior when current chopping occurs in case of small inductive current interruption

Figure 4.25 shows typical voltage and current behavior when current chopping occurs in case of small inductive current interruption. The current chopping sometimes accompanies an expanding high-frequency current oscillation leading to sudden current zero, which is an arc instability phenomena caused by arc characteristic and circuit conditions. The chopping current of a modern SF_6 gas circuit breaker is not higher than 10 A, which generally does not provide severe chopping overvoltage.

Another prominent phenomenon observed after small inductive current interruption is reignition. A circuit breaker can easily interrupt small inductive current even at short arcing time with small contact gap. The dielectric withstand strength of a circuit breaker increases with the contact gap; therefore a small contact gap tends to generate voltage breakdown during TRV period when the TRV exceeds the dielectric withstand across the contact gap. The reignition provokes high-frequency current oscillation and associated overvoltages as shown in Fig. 4.26. The reignition overvoltages may damage the nozzle and contacts of circuit breaker and reactor insulation. The controlled switching is often applied to avoid reignitions during small inductive switching by increasing arcing time.

The first-pole-to-clear representation for the general case is shown in Fig. 4.27. i_c is the chopped current in the first-pole-to-clear, and the second and third poles are considered to be grounded through an infinite bus. Figure 4.28 shows the single-phase equivalent circuit for the first-pole-to-clear that is derived from Fig. 4.27.

In Fig. 4.28, V_o is the peak power frequency voltage across the shunt reactor at the instant of current chopping, and (1 + K) is the first pole factor given by:

$$L' = L\left[1 + \frac{1}{2 + L/L_N}\right] = L[1 + K] \tag{4.1}$$

For directly grounded shunt reactors, $L_N = 0$, $K = 0$, and $L' = L$; for ungrounded shunt reactors, $L_N = \infty$, $K = 0.5$, and $L' = 1.5\ L$.

The energy trapped in L' and C_L at the instant of current chopping will oscillate between the two circuit elements. The suppression peak overvoltage can be calculated by considering the energy balance since the maximum overvoltage will occur when the available energy is stored in the capacitance C_L:

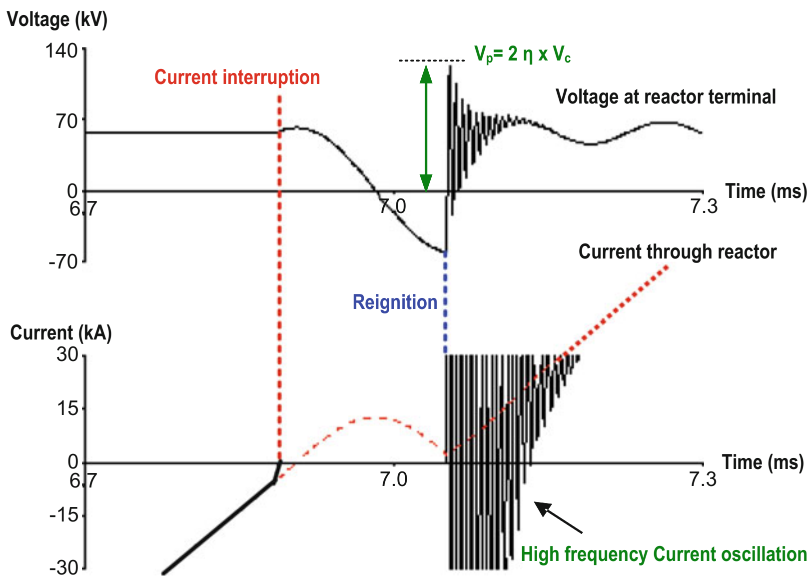


Fig. 4.26 Voltage and current behavior when reignition occurs in case of small inductive current interruption

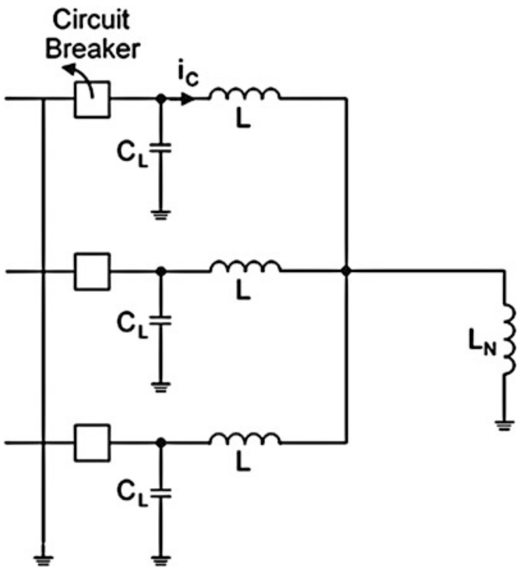


Fig. 4.27 General case first-pole-to-clear representation

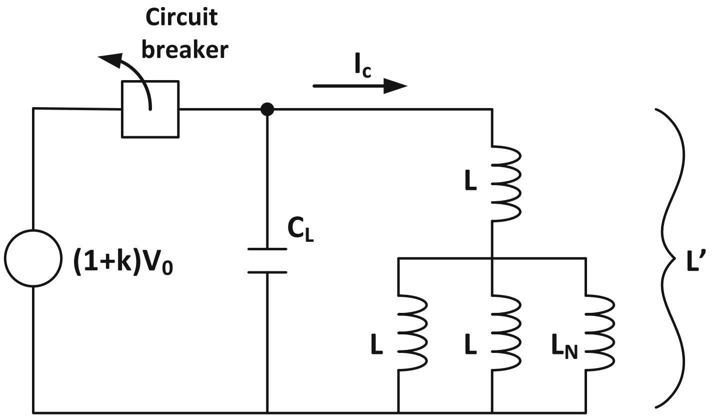


Fig. 4.28 Single-phase equivalent circuit for the first-pole-to-clear

Energy at suppression peak overvoltage = energy at current interruption; therefore.

$$\frac{1}{2}\mathrm{C_L}V_\mathrm{m}^2 = \frac{1}{2}\mathrm{C_L}\left[\left(1+K\right)V_0\right)\right]^2 + \frac{1}{2}i_\mathrm{ch}^2 L' \quad (4.2)$$

where V_m is the peak voltage on the capacitor C_L when all the available energy is stored in the capacitance.

The instant of current chopping is usually taken as occurring at the peak of the voltage across the shunt reactor (V_o), and neglecting arc voltage in Eq. (4.2) can be rewritten as:

$$\frac{V_m}{V_0} = (1+K)\sqrt{1+\frac{1}{(1+K)}\left(\frac{i_{ch}}{V_0}\right)^2\left(\frac{L}{C_L}\right)} = k_a + K \tag{4.3}$$

with (k_a + K) in p.u. The factor (k_a + K) is usually designated k_b. From Eq. (3) the suppression peak overvoltage k_a (refer to Fig. 4.29) can be calculated as follows:

$$k_a = (1+K)\sqrt{1+\frac{1}{(1+K)}\left(\frac{i_{ch}}{V_o}\right)^2\left(\frac{L}{C_L}\right)} - K \tag{4.4}$$

The value of the chopped current is dependent on the capacitance C_t seen from the circuit-breaker terminals including the grading capacitor capacitance C_p, the number N of interrupters in series per pole, and the so-called chopping number λ for a single interrupter, which is a characteristic value of the circuit breaker. The chopping current level is given by:

$$i_{ch} = \lambda\sqrt{NC_t} \tag{4.5}$$

where $C_t = C_p + \frac{C_s C_L}{C_s + C_L}$

The chopping number approach can be applied for all current circuit-breaker types except vacuum circuit breakers, where the basic Eq. (4.4) must be used. The

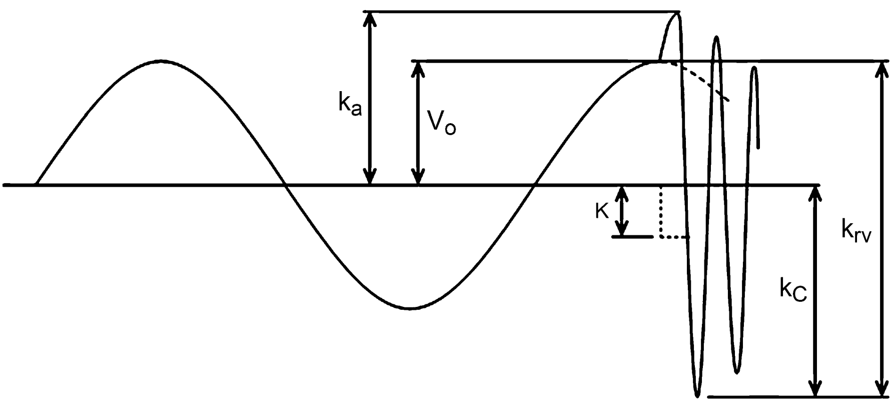


Fig. 4.29 Shunt reactor voltage at current interruption

approach is valid provided that the circuit as seen by the circuit breaker can be considered as an equivalent parallel capacitance in the relevant range of frequencies. Where this is not the case, a computational approach using EMTP or other method is required (Dufournet 1988).

Typical chopping numbers are given in Table 4.4. For gas circuit breakers in particular, current chopping increases with arcing time and likewise the chopping number (Panek and Fehrle 1975).

The maximum value of C_t leading to the highest chopping level and subsequent highest suppression peak overvoltage occurs when $C_s >> C_L$ and C_t is given by:

$$\mathrm{C_t} = \mathrm{C_P} + \mathrm{C_L} \tag{4.6}$$

Substituting for i_{ch} (from Eqs. (4.5) and (4.6)) in Eq. (4.4) gives k_a on a chopping number basis:

$$k_a = (1+K)\sqrt{1 + \frac{NL}{(1+K)}\left(\frac{\lambda}{V_o}\right)^2\left(\frac{\mathrm{C_P}}{\mathrm{C_L}}+1\right)} - K \tag{4.7}$$

A more useful variation of Eq. (4.7) based on the shunt reactor rating Q in VA and taking V_o as the peak value of the system voltage to ground is:

$$k_a = (1+K)\sqrt{1 + \left(\frac{1{,}5}{1+K}\right)\left(\frac{N\lambda^2}{\omega Q}\right)\left(\frac{\mathrm{C_P}}{\mathrm{C_L}}+1\right)} - K \tag{4.8}$$

For directly grounded shunt reactors, $K = 0$ and ka is given by:

$$k_a = \sqrt{1 + \frac{1{,}5N\lambda^2}{\omega Q}\left(\frac{\mathrm{C_P}}{\mathrm{C_L}}+1\right)} \tag{4.9}$$

For ungrounded shunt reactors, $K = 0.5$, $N = 1$, C_P is negligible compared to C_L, and k_a is given by:

Table 4.4 Circuit-breaker chopping numbers

Circuit-breaker type	Chopping number $\lambda AF^{-0.5}$
Minimum oil	5.8×10^4 to 10×10^4
Air blast	15×10^4 to 20×10^4
SF_6 puffer	4×10^4 to 19×10^4
SF_6 self-blast	3×10^4 to 10×10^4
SF_6 rotating arc	0.39×10^4 to 0.77×10^4

$$k_{\mathrm{a}} = 1{,}5\sqrt{1 + \frac{\lambda^2}{\omega Q}} - 0.5 \tag{4.10}$$

k_{a} and the subsequent recovery voltage peak overvoltage k_{c} stress the shunt reactor, the latter being given by (refer to Fig. 4.29):

$$k_{\mathrm{c}} = 2K + k_{\mathrm{a}} \tag{4.11}$$

The transient recovery voltage peak imposed on the circuit breaker is k_{rv} (refer to Fig. 4.29) given by:

$$k_{\mathrm{rv}} = 1 + 2K + k_{\mathrm{a}} \tag{4.12}$$

The influence of the grounding arrangement is reflected in $2K$ factor, the multiplier of 2 being due to the fact that the oscillation is about the shifted neutral point.

When a reignition occurs in the circuit-breaker, the load side voltage rapidly tends to the source side voltage but overshoots producing a reignition overvoltage as shown in Fig. 4.30.

Figure 4.30 shows the case for a circuit with a low source side capacitance, and the only difference for a high source side capacitance is that V'o = Vo, and the initial second parallel oscillation is around the source voltage.

The reignition overvoltage in the worst case (C_{s} very large) oscillates around the source voltage, and its magnitude k_{i} in p.u. to ground assuming damping (β) is given by:

$$k_{\mathrm{p}} = 1 + \beta(1 + 2K + k_{\mathrm{a}}) \tag{4.13}$$

The damping factor β is usually taken as 0.5 based on actual field experience.

The excursion of the reignition transient k_{s} in p.u. is given by:

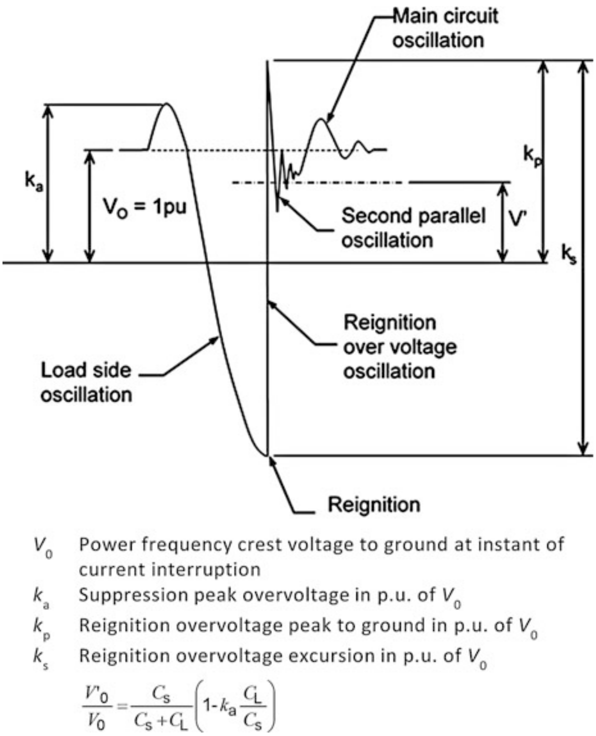
$$k_{\mathrm{s}} = (1 + \beta)(1 + 2K + k_{\mathrm{a}}) \tag{4.14}$$

Reignitions are normal occurrences but may be harmful to the interrupters (Bachiller et al. 1994) and also to the shunt reactor windings.

Figure 4.31 shows an actual 550 kV shunt reactor switching event illustrating chopping and reignition overvoltages. The circuit breaker in this case exhibits an extraordinary number of reignitions as compared to the typical case of reignition at one zero crossing only.

Four oscillation circuits play a role in shunt reactor switching and can be generally described by considering the directly grounded shunt reactor case (refer

Fig. 4.30 Reignition at recovery voltage peak for a circuit with low supply side capacitance



to Fig. 4.31). The first oscillation circuit relates to current interruption and the other three circuits to the reignition process.

A successful shunt reactor current interruption results in a decaying load side oscillation with the trapped energy oscillating between the inductance L and the capacitance C_L (Fig. 4.32). The frequency of this oscillation is:

$$f_L = \frac{1}{2\pi\sqrt{LC_L}} \tag{4.15}$$

and is typically in the range 1–5 kHz for EHV and HV shunt reactors and up to 30 kHz for MV shunt reactors. f_L is the frequency of the circuit-breaker transient recovery voltage whose peak value is given by Eq. (4.12).

When a reignition occurs in the circuit breaker, a first parallel oscillation occurs due to the discharge of capacitance C_P through the circuit breaker (Figs. 4.30 and 4.32). The frequency of this oscillation is given by:

$$f_{p1} = \frac{1}{2\pi\sqrt{L_P C_P}} \tag{4.16}$$

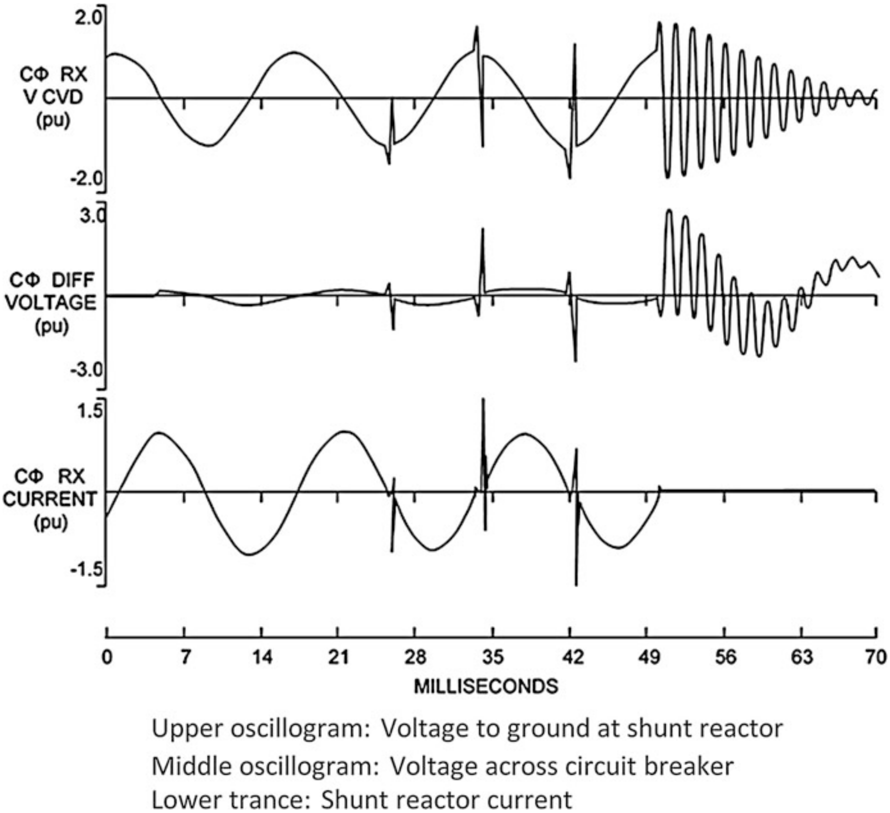


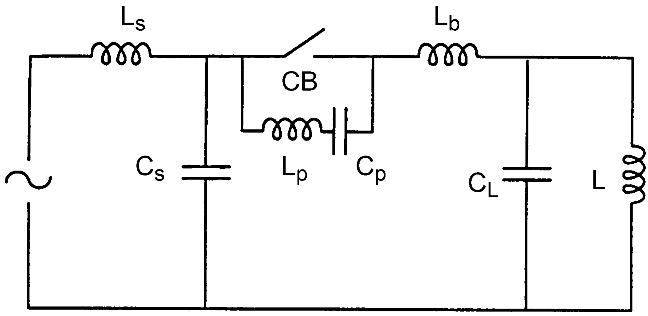
Fig. 4.31 Field oscillogram of switching out a 550 kV 135 MVAR directly grounded shunt reactor

and is typically in the range 1–10 MHz. The circuit breaker will not interrupt the current associated with this oscillation, and therefore it has no significance with respect to overvoltages.

The second parallel oscillation follows the first parallel oscillation involving C_s, C_L, and L_b and results in equalization of the voltages on C_s and C_L (Figs. 4.30 and 4.32). The frequency of this oscillation is given by:

$$f_{p2} = \frac{1}{2\pi\sqrt{L_b\left(\frac{C_s C_L}{C_s + C_L}\right)}} \tag{4.17}$$

and is typically in the range of 50 kHz–1 MHz. This transient voltage is steep and may be unevenly distributed across the shunt reactor winding, stressing in particular the entrance turns of the winding. The reignition itself is particularly hazardous to the entrance turns.



Key

L_s	source inductance	L_b	connection series inductance
C_s	source side capacitance	C_L	load side capacitance
L_p, C_p	first parallel circuit inductance and capacitance	L	reactor inductance

Fig. 4.32 Single-phase equivalent circuit

Under certain circumstances (C_s and C_L of the same order of magnitude), a main circuit oscillation follows the second parallel oscillation (Figs. 4.30 and 4.32). This oscillation is complex and its frequency in its simplest form is given by:

$$f_m = \frac{1}{2\pi}\sqrt{\frac{L_s + L}{L_s L(C_s + C_L)}} \tag{4.18}$$

and is in the range 5–20 kHz.

Some method of overvoltage limitation is usually applied in all shunt reactor switching cases. The various methods and their relative effectiveness are reviewed in Table 4.5.

4.9 Transformer Limited Fault Clearing

One of the most severe fault current interruption duties of a circuit breaker is the clearing of a transformer limited fault (TLF). In Fig. 4.33 the two topology conditions of a TLF are given: the transformer fed fault (TFF) and the transformer secondary fault (TSF). In both conditions the transformer characteristics are the dominant factors that determine the short-circuit current, its AC and DC components, the power frequency recovery voltage (first, second, and third pole-to-clear factor by its neutral treatment; the voltage drop), and the higher frequency TRV (WG A3.28 2014).

Table 4.5 Chopping and reignition overvoltage limitation method evaluation for shunt reactor switching

Overvoltage limitation method	How does the method work	Advantage	Disadvantage
Opening resistor	Resistor causes phase shift of current with respect to voltage resulting in current interruption by resistor switch at lower point on voltage half wave, thus reducing *k*a and consequently *k*rv significantly	Very effective on circuit breakers with very high chopping numbers, i.e., air blast and dual pressure SF_6 circuit breakers	Adds significantly to mechanical complexity and maintenance requirements of the circuit breaker, not viable technically or economically on single pressure SF_6 circuit breakers
Surge arresters to ground at shunt reactor	Limits overvoltage to ground (*k*a) at shunt reactor	Passive	Effective only for circuit breakers producing suppression peak overvoltages in excess of the surge arrester protective level, reignition overvoltages still occur at up to twice the protective level of the surge arrester
Metal oxide varistor (MOV) across circuit breaker	Limits the recovery voltage (*k*rv) across the circuit breaker to the protective level of the varistor and subsequent reignition overvoltages to maximum $1+\beta k$arv where *k*arv is the protective level of the arrester in p.u. of *V*o	Passive, effective for all circuit-breaker types, particularly suitable for use on circuit breakers at $\leq$52 kV, magnitude and probability of reignitions significantly reduced, energy absorbed by surge arrester is minimal	Adds to complexity of circuit breaker, surge arresters must be able to withstand forces associated with circuit breaker operation, some reignitions will still occur albeit at low voltage levels
Surge capacitor	Decreases frequency and thereby rate of rise of the load side oscillation, decreases frequency of reignition overvoltage excursion	May reduce probability of reignitions, reduces frequency of the voltage excursion imposed on the shunt reactor winding, may reduce the value of *k*a for vacuum breakers where chopping current is dependent mainly on contact material	Does not influence *k*a for circuit breakers other than vacuum type, leads to increased chopping current but not necessarily increased suppression peak overvoltages, does not eliminate reignitions, may have the effect of reducing the minimum arcing time such that probability of reignitions is unchanged, require space

(*continued*)

Table 4.5 (continued)

Overvoltage limitation method	How does the method work	Advantage	Disadvantage
Controlled switching	Ensures contact parting with respect to current wave such that interruption occurs at the first subsequent current zero	Eliminates reignitions	Suitable only for mechanically consistent circuit breakers with appropriate minimum arcing times, requires independent pole operation thereby increasing capital cost of the circuit breaker

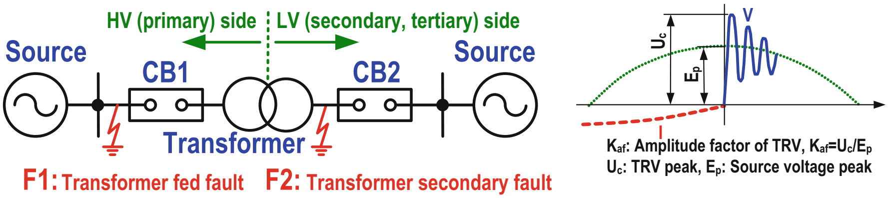


Fig. 4.33 Transient recovery voltage (TRV) for transformer limited faults (TLF)

Due to the dominancy of the transformer impedance, the power frequency voltage drop across the transformer forms the basis to establish the TRV. The higher the TLF current, the lower the voltage drop will be. A fault current of 6.3 kA will cause a voltage drop of roughly 90%, while a fault current of 12.5 kA will show a voltage drop more closer to 70%. In practice 12.5 kA corresponds approximately to 30% of the rated short-circuit current of the circuit breaker.

Depending on the neutral treatment of the network and the involved transformer, the X_0/X_1 ratio will vary within wide bands. But, for effectively earthed networks and transformers with an earthed neutral, the X_0/X_1 ratio will be smaller than 1.0, thus leading to a reducing effect on the first-pole-to-clear factor k_{pp}. In other conditions, though, where transformer neutrals are not (always) connected to earth, k_{pp} may rise up to 1.5. This, however, is an exception, and in general it can be stated that at the transformer side, connected to networks of 100 kV and above, the first-pole-to-clear factor for TLF will be closed to 1.0 or even lower. The first-pole-to-clear factors as specified in the IEC Standard for circuit breakers (1.2 for UHV and 1.3 for EHV) are thus certainly larger than those observed in service conditions. In cases where transformer neutrals are isolated from earth or connected by Petersen coils (resonance earthing), k_{pp} has to be specified as 1.5.

Neglecting the contribution from the supply that is at a much lower frequency, the TLF TRV peak is given by the following equation:

$$U_c = k_p \times k_{af} \times k_{vd} \times \frac{U_r \sqrt{2}}{\sqrt{3}} \tag{4.19}$$

where

U_c is the TRV peak.
k_p is the pole-to-clear factor (k_{pp} for the first-pole-to-clear).
k_{af} is the amplitude factor.
k_{vd} is the voltage drop factor.
U_r is the rated voltage.

When the capacitance to earth of the connection between circuit breaker and transformer is large enough, the frequency response at the moment of fault current interruption (i.e., the TRV as a function of the frequency) will be dominated by this capacitance in parallel to the transformer short-circuit inductance. The TRV as a function of time will appear as a rather simple single frequency response: a damped 1-COS function, described by a two-parameter envelope, as defined in the IEC Standard for high-voltage circuit breakers (IEC 62271-100).

Figure 4.34 illustrates the TRV envelope of TLF conditions, which is covered by terminal fault test duties T10 and T30 corresponding to short-circuit currents of 10% and 30%, respectively, of the rated short-circuit current of the circuit breaker. The time coordinates T_2 are U_c for the peak value and t_3 for the time to the intersection of the line segments constituting the envelope. Figure 4.34 shows the steepness of the TRV expressed as the RRRV, which is immediately imposed after interruption as an important dielectric stress factor for the contact gap. Figure 4.35 provides the ratio between the time to peak T_2 and the time coordinate t_3 as a function of the damping that is expressed as the amplitude factor (k_{af}). A factor of 2.0 means no damping. An amplitude factor of 1.7 covers most of the actual cases (Janssen et al. 2016).

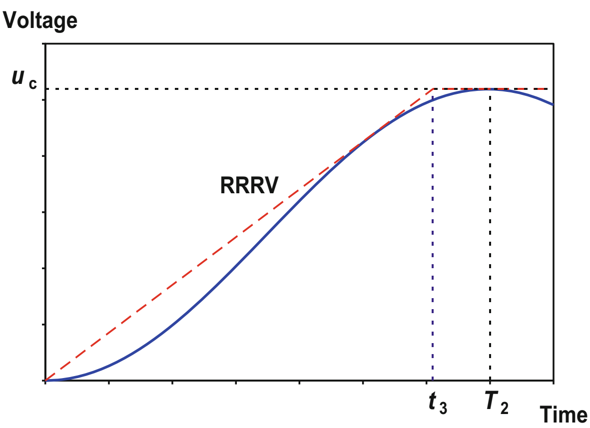


Fig. 4.34 Two-parameter TRV with coordinates

The corresponding rate of rise of recovery voltage (RRRV) can be then calculated from the TRV peak U_c and time t_3 as shown in Fig. 4.34 and Eq. (4.20).

$$RRRV = \frac{U_c}{t_3} \tag{4.20}$$

where t_3 can be derived from T_2, time to TRV peak, as a function of amplitude factor as shown in Fig. 4.35.

Without an external capacitance, the TRV will be determined by the complicated model of a transformer. Several models to describe the transient behavior of a transformer are available. One of the important aspects is that the relevant range of frequencies to estimate the TRV waveform is between about 10 kHz and about 100 kHz, much lower than most transient transformer models refer to, since they address frequencies up to tens of MHz that accompany the internal stresses in the transformer's windings. Frequency response analysis (FRA) measurements are applied to study the very high-frequency models but are also useful for the lower frequency range and to determine TRV waveforms. They are used to get the frequency-dependent ratio between an output voltage and an input voltage in several configurations of shorted LV windings and excited HV phases of a power transformer.

The impedance can also be measured directly by adequate measurement equipment. Figure 4.36 shows the magnitude together with the argument (phase angle shift) of the frequency-dependent transformer impedance.

The FRA measurements show the transformer response in the frequency domain. Multiplying the transformer impedance in the frequency domain with the fault

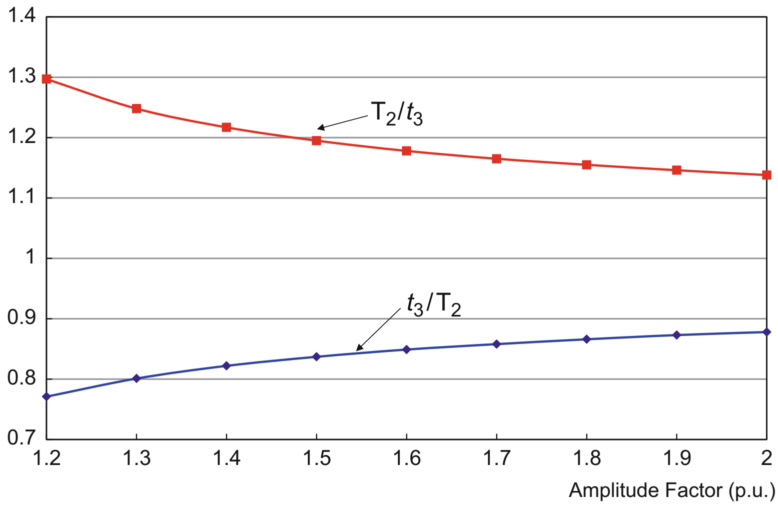


Fig. 4.35 Ratio T_2 and t_3 as function of k_{af}

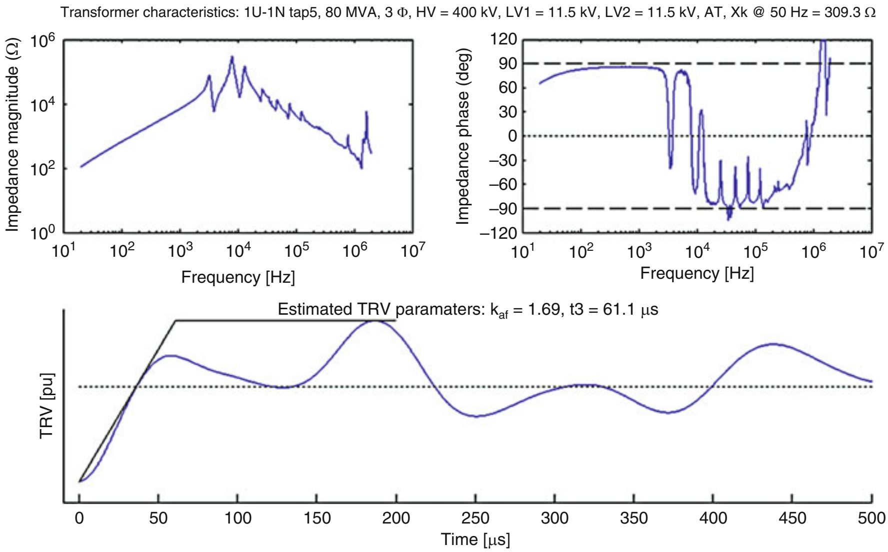


Fig. 4.36 FRA and TRV waveform with a 400 kV 80 MVA transformer

current function in the frequency domain will give the TRV in the frequency domain: TRV(ω) = Isc(ω)*Z(ω). By reverse Fourier transformation, the TRV(t) in the time domain can be calculated. Note that the fault current mentioned here is the so-called injected fault current with a polarity opposite to the actual fault current so that by superposition of actual and injected fault current the net effect gives zero current: the fault clearing. During the relevant part of the TRV, only some ms, the injected fault current can be regarded as a ramp function: I(t) = S*t, or in the frequency domain, I (ω) = S/ω^2. By this characteristic the effect of the higher frequency part of Z(ω) on the TRV(ω) is reduced.

From the FRA measurements shown in Fig. 4.36, one can deduce the short-circuit inductance by fitting a straight line, upward increasing proportionally to the frequency, in the low-frequency range. It is also possible, but less obvious, to determine the surge capacitance by fitting a straight line, decreasing in inverse proportion to the frequency, in the upper range of frequencies. The surge capacitance can be determined in this way, especially for the relevant range of frequencies that is from some tens of kHz to around 100 kHz.

In such a way, a simple single frequency model can be achieved, defined by the short-circuit inductance L and the surge capacitance C. From the crest value of Z(ω), a value for the parallel resistance R can be estimated. From R/√(L/C) = R/Z, the damping of the single frequency response can be calculated, and the peak or amplitude factor k_{ap} can be derived. But also multiple resonances can be derived.

Typical responses obtained by FRA measurements with the first-pole-to-clear at the primary and secondary sides of a 1500 MVA shell-type transformer are also shown in Fig. 4.37.

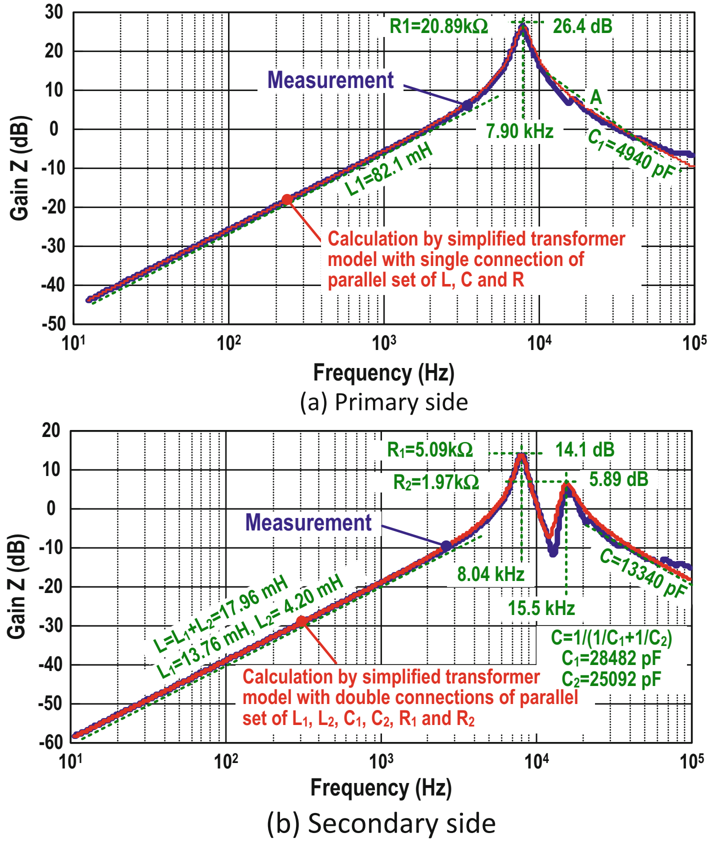


Fig. 4.37 FRA measurement with a 525 kV, 1500 MVA transformer

TRV waveform can be reproduced by a simplified transformer model with a series connection of multiple parallel circuits of L, C, and R based on the FRA measurements. The simplified transformer model for the primary and secondary side can be obtained by the response of the FRA measurement as shown in Fig. 4.38. Frequency responses were also calculated with these simplified transformer models and plotted in Fig. 4.37. Both calculations showed good agreements with the measured FRA characteristics.

Figure 4.39 shows the TRV waveforms reproduced by the simplified transformer models based on the FRA measurements. The calculated TRV waveforms also showed good agreement with the measured TRVs. Thus it is confirmed that the simplified transformer model with a series connection of multiple parallel circuits sets of L, C, and R based on the FRA measurements can reproduce the TRV waveform for TLF conditions very precisely (IEC Std. IEC 62271-100 ed. 2.1 2012).

The minimum amount of capacitance to earth between a circuit breaker and the power transformer has been investigated. Usually the connection is by air-insulated conductors along a minimum distance of tens of meters up to a hundred meter. The

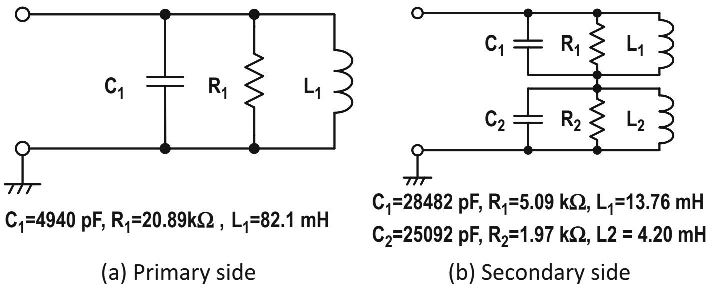
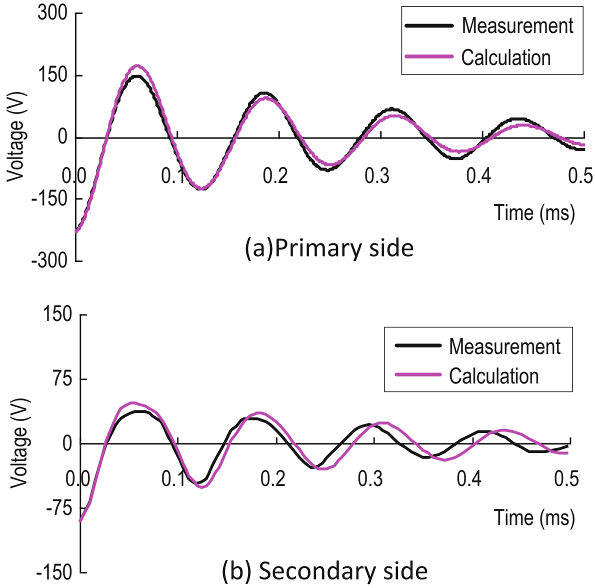


Fig. 4.38 Simplified transformer models for primary and secondary side

Fig. 4.39 TRV reproduced by simplified transformer models



other connected high-voltage equipment is limited and possibly with a rather low capacitance to earth: current transformers, surge arresters, disconnectors, and earthing switches. Typical examples of the external capacitance in air-insulated substations give a minimum value that seems to be from 500 pF to 1000 pF, almost independently from the rated voltage.

A substantial capacitance in comparison to the transformer capacitance will change the TRV waveform. When the external capacitance is included in the FRA measurement, it will result in a shift of the total impedance to the left, i.e., to lower frequencies. In addition, the peak value of the transformer frequency-dependent impedance will become larger, as the quality factor increases. Moreover, while the dominant frequency becomes more salient, the other natural frequencies tend to diminish. Without external capacitance the dominant frequencies tend to have maximum values between 10 and 20 kHz. When a minimum of additional capacitance is added, the dominant frequency is around 10 kHz or less.

The given frequencies (around 10 kHz), the higher quality factors (leading to an amplitude factor about 1.7), the low first-pole-to-clear factor (close to 1.0 and with considerable margin to 1.2 or 1.3), and the voltage drop factor (90% at relatively low fault currents, say 6 kA) and 70% at relatively high fault currents, say 12 kA) form together the basis to define the TRV parameters. Standardization for rated voltages from 100 kV up to and including 800 kV is underway.

4.10 Out-Of-Phase Current Switching

In the IEC and IEEE Standards for high-voltage circuit breakers (IEC Std. IEC 62271-100 ed. 2.1 2012; IEEE Std. C37.09 – 1999, Cor 1-2007 2007), a nonmandatory test duty for making and breaking out-of-phase currents has been specified. The out-of-phase switching duty has been established many decades ago in similar IEC and for both standards. The out-of-phase current and TRV ratings are still based on the original assumptions. Although the ratings are still applicable for transmission systems, the background considerations have to be adapted, since larger out-of-phase angles may be expected than those which can be deduced from the specifications.

There are always small power swings in a transmission network; these can be caused by small transients and the excitation of inherent oscillation conditions between parts of the power system. The actions of large power plants controllers (for instance, power system stabilizers) and HVDC controllers are typically sufficient to dampen the swings and prevent the escalation of such small power swings. In addition, larger but still stable power swings may occur due to larger excitations (sudden loss of a large power plant, a change in system impedances, a jump in system load). When unstable power swings appear, they need a serious intervention by protection and control equipment in the power system. Both stable and unstable power swings are caused by an unbalance in active power (frequency instability), an unbalance in reactive power (voltage instability), a short circuit that has not been isolated quickly enough, or a too large power transfer through a generator or a transmission corridor (angular instability); see Fig. 4.40. Often frequency, voltage, and angular instability coincide. Here out-of-step conditions come into play, and the system will be split due to automatic tripping by protective relays or special protection schemes.

An out-of-step condition is a power swing that will result in a generator or a group of generators experiencing pole slipping for which some corrective action must be taken (IEEE PSRC WG D6 2005). The term is synonymous to unstable power swing (IEEE PSRC WG D6 2005) and loss of synchronism (IEV 60050-448-14-35 1995).

Out-of-phase condition is an abnormal circuit condition of loss or lack of synchronism between the parts of an electrical system on either side of a circuit breaker in which, at the instant of operation of the circuit breaker, the phase angle between rotating vectors, representing the generated voltages on either side, exceeds the normal value (IEEE PSRC WG D6 2005).

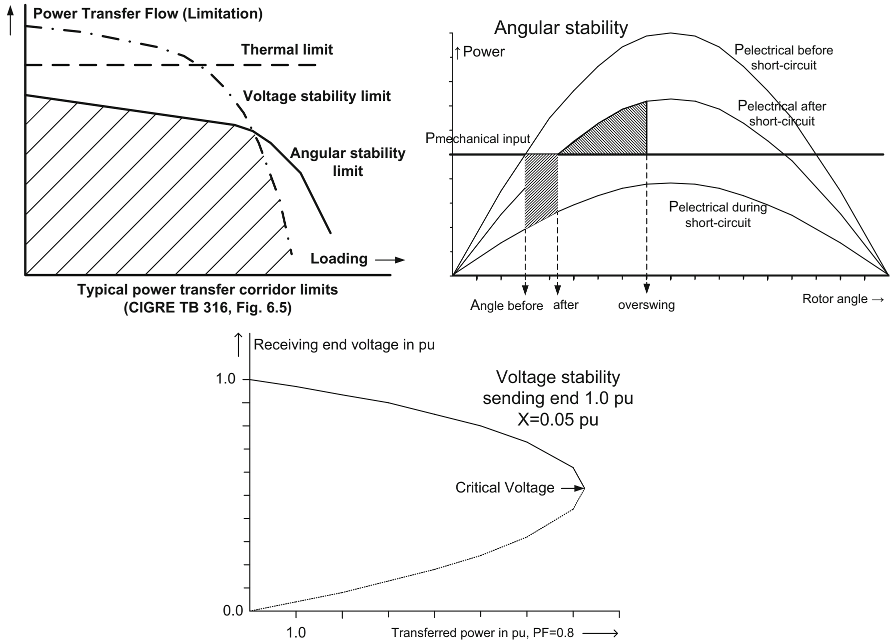


Fig. 4.40 Typical power transfer corridor limits with angular stability and PV-curve (voltage stability)

System separation and large disturbances occur more often than expected (JWG A3/B5/C4.37 2018). They are experienced in all parts of the world and are not restricted to certain types of networks (for instance, radial networks). Although the probability of system separation is smaller in dense meshed networks, a cascading line tripping will change the topology into that of a radial network with identical effects. Per definition, the out-of-phase switching concerns the last line between two parts of a power system to be separated. The risk of out-of-step or out-of-phase conditions should not be ignored and should be taken into account by protection experts as well as circuit-breaker experts.

It should be noted that the amplitude of the out-of-phase current is an important stress factor during the current interruption process, at it directly influences the amount of energy to be absorbed by the arc between the circuit-breaker contacts. The larger the amount of energy, the more difficult it is to withstand the transient recovery voltage immediately after current zero. For transmission circuit breakers, an out-of-phase angle of 180° gives a 40% larger out-of-phase current than an out-of-phase angle of 90° and a 40% larger steepness of the TRV (rate of rise of recovery voltage: RRRV); for generator circuit breakers, an out-of-phase angle of 180° might give a much higher current, up to 80% larger than that occurring in case of an out-of-phase angle of 90°. In the standards the rated (i.e., maximum) out-of-phase current is defined as a percentage of the rated short-circuit current.

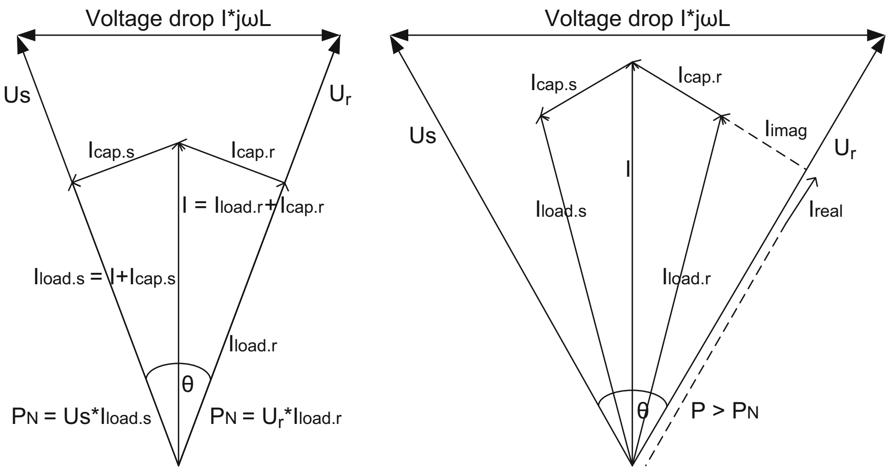


Fig. 4.41 Angle θ along an inductive connection to transfer an amount of active power, being the natural power $P_N = U2/\sqrt{(L/C)}$ (left) of more (right): 30° per 100 km at 5 P_N

System separation goes with a cascading effect of tripping connections, thus with an increase of the impedance between the representative voltages at both sides of the circuit breaker. Therefore, it is quite reasonable that for high-voltage circuit breakers the specified amplitudes of the out-of-phase current are as large as 5% and 25% of the rated short-circuit current of the circuit breaker involved.

Also the larger the out-of-phase angle, the larger and the faster the recovery voltage and the transient recovery voltage. The rate of rise of the recovery voltage can be considered as covered by T30 or by a transformer limited fault test duty, when a transformer forms the dominant impedance. But typical for the out-of-phase TRV is the high amplitude U_c, that is, the largest of all test duties. As such it serves also as a reference for special cases such as long-line fault clearing and the clearing of faults on series compensated OH-lines.

Shortly before the moment of system separation, both parts of the network are connected by a contracted corridor of ultimately one circuit. This condition is similar to a radial network, and the out-of-phase angle is determined by the power flow and the reactance of connecting circuit or circuits in series (see Fig. 4.41). The larger the impedance ωL and the power flow, the larger the angle along the line.

For those large disturbances where detailed information has been published, out-of-phase angles far larger than 90° have been reported. For instance, during the large disturbances in India, July 30 and 31, 2012, the angle between involved regions went from 60° to 260° (system separation around 02:33:15.4 on July 30th), and the angle increased from 90° to 190° at system separation (around 13:00:18 on July 31st) (JWG A3/B5/C4.37 2018; CERC 2012).

The report (CERC 2012) is one of few cases where detailed information is given about the development of the difference in angle between two regions that face a separation. Obviously these angles become large, and consequently the amplitude of the system voltage near the center of oscillation is low. In addition, the large disturbances in the system go with voltage instability problems. At the moment of system separation, large voltage dips, depressed voltages, and dramatic voltage drops have been reported, together with large power flows. For instance, during the separation of the Italian grid from the European continental grid (2003) (UCTE 2004), the voltage fell below 80% of nominal value. This phenomenon has been mentioned in (Meng 2006) as well. The cascading tripping of overhead lines and other components lead to a sudden increase of reactive power consumption and consequently to system voltage depression and eventually collapse.

For high-voltage circuit breakers, this means that large out-of-phase angles most probably coincide with voltage levels far less than the rated voltage of the circuit breaker, even below the minimum acceptable voltage level to grid codes, that is, normally 20% below the rated value. To be precise, to the grid codes the maximum operating voltage is usually 110% of the nominal voltage and the minimum voltage 90% of the nominal voltage (the minimum voltage in extreme conditions is normally specified to be 85% for a certain amount of time and even lower could be indicated for very short time). As the rated voltage of the circuit breaker should be at least the maximum operating voltage in the system, the minimum operating voltage is the rated voltage divided by at least 1.1 and multiplied with 0.9: $\leq$81.8%. Based on 110% and 90%, resp., the next figure shows the actual out-of-phase recovery voltage at minimum operating voltage as a function of the out-of-phase angle (Fig. 4.42). It is compared with the out-of-phase recovery voltage to the standard for high-voltage circuit breakers (IEC Std. IEC 62271-100 ed. 2.1 2012), based on the rated voltage and a first-pole-to-clear factor of 1.3 (effectively earthed networks: blue) and a first-pole-to-clear factor of 1.5 (non-effectively earthed networks, red). From the standard values, it can be deduced that these correspond to an out-of-phase angle of 105° (first-pole-to-clear factor 1.3) and 115°. In Fig. 4.43 these angles are explained together with those of other first-pole-to-clear conditions.

At the minimum operating voltage to grid codes, which is larger than the system voltages reported during large disturbances, the out-of-phase recovery voltage, even for the largest out-of-phase angles, show to be (far) less than or equal to the value used for type testing. As such, actual cases seem to be covered, for smaller out-of-phase angles (up to 90°) up to the rated voltage and for larger angles, large power flows, (up to 180°) up to the minimum operating voltages. This information should be incorporated in (IEC Guide IEC 62271-306).

Conclusions of out-of-phase phenomena:

1. The out-of-phase switching requirements in the standards for circuit breakers seem to be taken from a proposal in a 1952 AIEE paper, where calculations, simulations, and real tests in a power system have been analyzed. The rated out-of-phase currents have been proposed to be 25% of the rated short-circuit current. For economic and statistical reasons, minimum peak values from the TRV analyses have been proposed: a RV of 2.0 p.u. and an overshoot of 25% (U_c is 2.5 p.u.).

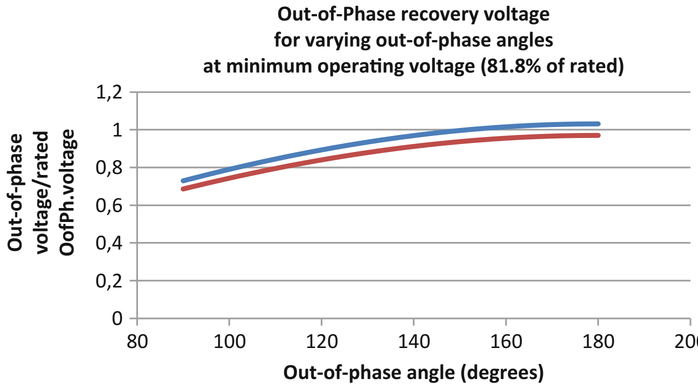


Fig. 4.42 Out-of-phase recovery voltage at 81.8% of the rated voltage as a function of the out-of-phase angle for $k_{pp} = 1.3$ (blue) and $k_{pp} = 1.5$ (red)

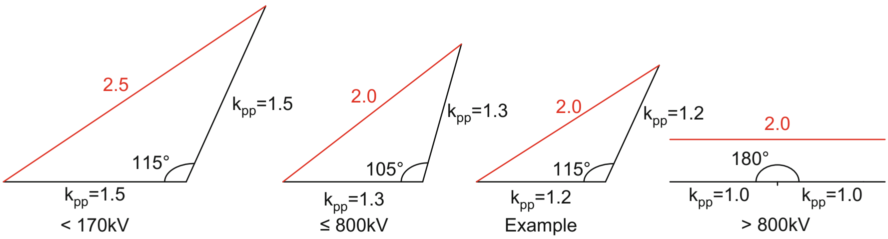


Fig. 4.43 Out-of-phase angles depend on first-pole-to-clear factor k_{pp} (IEC Guide IEC 62271-306)

2. As system separation goes with cascading tripping of overhead lines and thus an increase of the system impedance, a maximum value of 25% of the rated short-circuit current seems to be reasonable, even today. The maximum value of the out-of-phase current is an important parameter for the circuit-breaker capabilities.
3. Large disturbances show out-of-phase angles much larger than the 105° to 115° values associated with the TRV peak values in the standards. This applies both to radial and meshed networks; however, historical events have shown that large out-of-phase angles may occur at the same time as low operating voltages. The combination of a large out-of-phase angle and low operating voltage yields TRV peak values similar to those mentioned in the standards for situations with a relatively low out-of-phase angle and rated voltage (maximum operating voltage).
4. Transmission system circuit breakers used to connect or disconnect conventional power plants may be subjected to out-of-phase switching as well. To disconnect power plants during unstable power swings, the same considerations as for system separation are applicable albeit with care for the possibility that a transformer limited fault test condition has to be specified.

5. To disconnect power plants due to faulty synchronization, similar conditions and requirements as described for MV generator circuit breakers are applicable, and simulations are necessary to judge whether a design can fulfil the duty. Simulations of such events should include the response time of protection systems, the depression phenomenon of the generator voltage, and the acceleration/deceleration of the rotor to identify whether the out-of-phase current and the TRV after false synchronization of generators cover the conditions prescribed by the user, for instance, 180° (JWG A3/B5/C4.37 2018).

4.11 Mechanical Model of Power System Stability

4.11.1 Introduction of Noda Model

Equipment requirements are determined by studying the phenomena in power systems. The engineers involved in equipment design, testing, application, and assessment may often face the need to understand various switching behaviors observed in power systems. An example of a power transmission model as an analogy of a mechanical system is introduced in order to explain the system stability taking a case of out-of-phase condition in this section.

Figure 4.44 shows a simple transmission system with a generator and a load, where the voltage at the generator (V_G) and the voltage at the load center (V_L) are considered to maintain each constant value. The AC power transmission capacity increases with an increase of the system voltage and decreases with an increase of the line reactance (X). The transmission capacity (P) also depends on the difference of the voltage phase angle ($\theta = \theta_1 - \theta_2$) between the generator terminal and the transmission line end.

The transmission capacity is given by the following equation:

$$P = V_G V_L \sin\theta / X$$

Here V_G and θ_1 are the voltage and its phase angle at the generator terminal; V_L and θ_2 are the voltage and its phase angle at the line end. The transmission capacity becomes a maximum when the difference of the voltage phase angle is 90°. Figure 4.45 shows the transmission capacity for different power generations. A

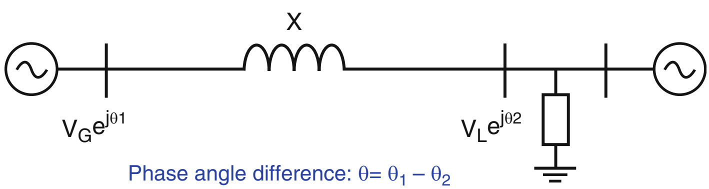
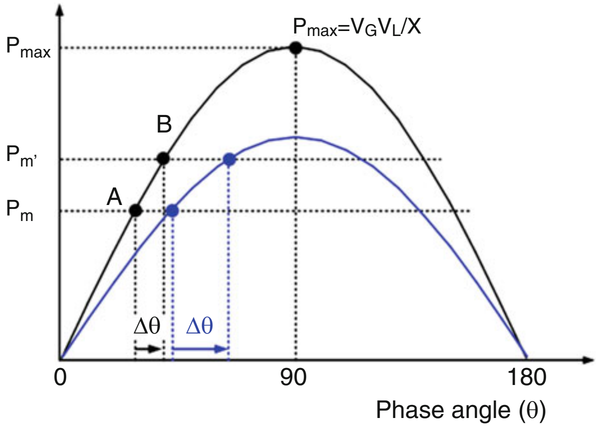


Fig. 4.44 AC power transmission with a generator and a load

Fig. 4.45 AC transmission capacity versus the phase angel (Black: normal state, blue, contingency case)



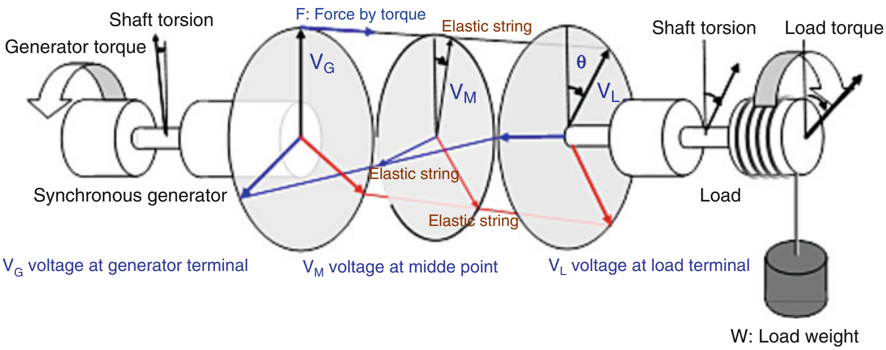


Fig. 4.46 Mechanical model of power transmission with a generator and a load

smaller increase of the phase angle (less than 90°) can increase transmission power from P_m (point A) to P_m' (point B) in the case of a larger power generator.

From Fig. 4.45, it can be seen that the power system can be more stable, when the system is operated in the range of a smaller phase angle difference (less than 90°), because the transmission capacity can increase in case of a demand increase or a contingency case such as loss of one circuit due to fault occurrence (blue line).

4.11.2 Mechanical Analogy of Power Transmission System

Figure 4.46 shows a mechanical analogy of a power transmission system called a Noda model (Hase 2007). In this model, the generator is represented as a rotary torque handle, and the load is shown as a hoist loading with weight (W). The radii V_G, V_M, and V_L of the three disks correspond to the system voltage at the generator terminal, the middle point of the transmission system, and the load terminal, respectively. The three disks are connected with three elastic strings (e.g., rubber wire). The torque power (F) generated by turning the handle at the generator side is transmitted through the elastic strings and winds up at the weight on the load side.

When F and F_0 are the tensions of the elastic strings with length l (the angular difference between the disk at the generator terminal and the disk at the load terminal is θ) and l_o (angular difference is zero), the tension can be expressed as follows, where 1/X is the elastic constant of the string.

$$F - F_0 = \frac{1}{X} \cdot (l - l_0),\ F \cong \frac{l}{X}$$

When F_p is the circumferential component of the tension F, and P is the angular moment of the force as shown in Fig. 4.47, the following equation for an analogy of the transmission capacity is obtained.

$$F_p = F \cdot \cos\alpha = F \cdot \frac{V_L \cdot \sin\theta}{l} = \frac{V_L \cdot \sin\theta}{X}$$

$$P = F_p \times V_G = \frac{V_G \cdot V_L \cdot \sin\theta}{X}$$

Also, when F_q is the radial component of the tension F, and Q is radial component of the force, the following equation is also obtained.

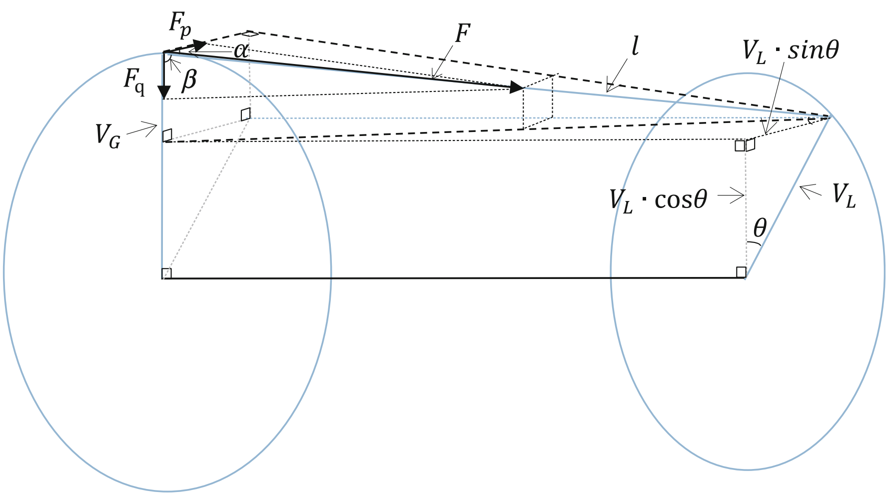


Fig. 4.47 Resolution of the elastic force to circumferential and radial components

$$F_q = F \cdot \cos\beta = F \cdot \frac{V_G - V_L \cdot \cos\theta}{1} = \frac{V_G - V_L \cdot \cos\theta}{X}$$

$$Q = F_q \times V_G = V_G \frac{V_G - V_L \cdot \cos\theta}{X}$$

If the weight (corresponding to the power load P) is increased, the mechanical angular difference (θ) needs to increase resulting in the expansion of the three elastic strings and a decrease in the voltage at the middle point (radius V_M). The mechanical force (Q) compresses the radius V_G corresponding to the reactive power.

Figure 4.48 shows a schematic drawing of three disks and the elastic strings connected to these disks which correspond to small and large line reactance. Therefore, the system stability can be enhanced in the case where the voltage is higher, and the line reactance is smaller resulting in the power system operating at a lower phase angle difference.

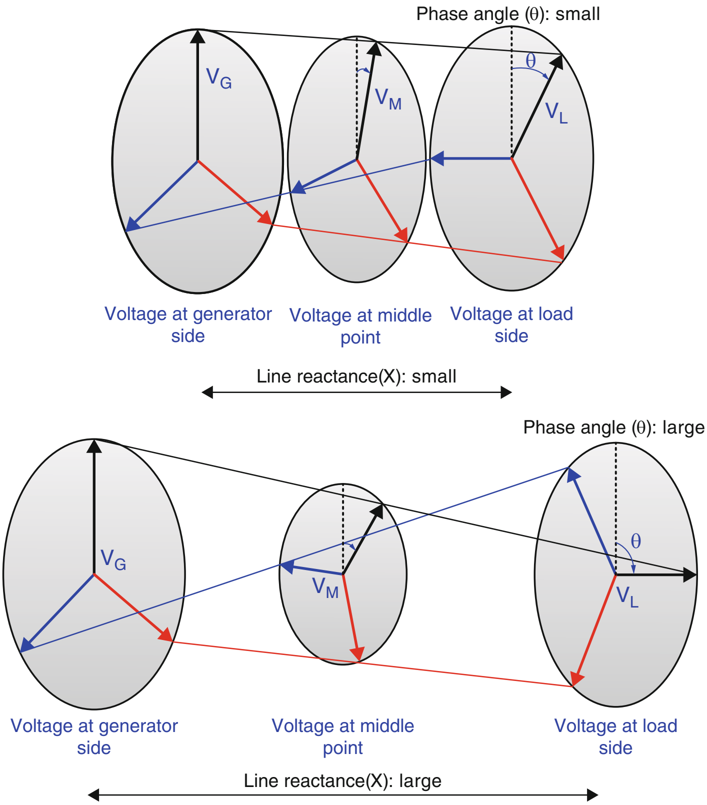


Fig. 4.48 Schematic drawings of three disks corresponding to different line reactance

When the phase angle exceeds the critical condition, the elastic strings are eventually twisted at the middle point as shown in Fig. 4.49, which corresponds to an out-of-phase condition or breakdown at the middle point in the power system.

Figure 4.50 shows an actual demonstration model proposed by K. Noda.

4.11.3 Impact of FACTS on Power Stability

Flexible alternating current transmission systems (FACTS) and series capacitor compensation are often used for a long transmission line to compensate the reactive power. The Noda model can explain the impact of these compensation devices located in the middle of the transmission line by increasing the voltage at the middle point resulting in stable and larger capacity of power transmission as shown in Fig. 4.51.

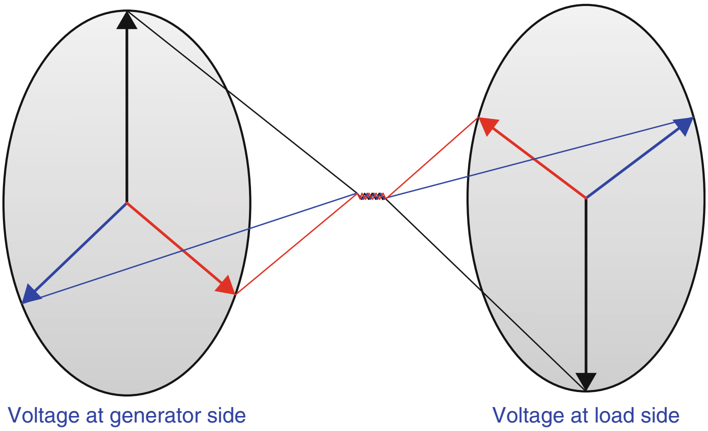


Fig. 4.49 Twisted elastic strings correspond to power system breakdown due to larger phase angle difference (out-of-phase conditions)

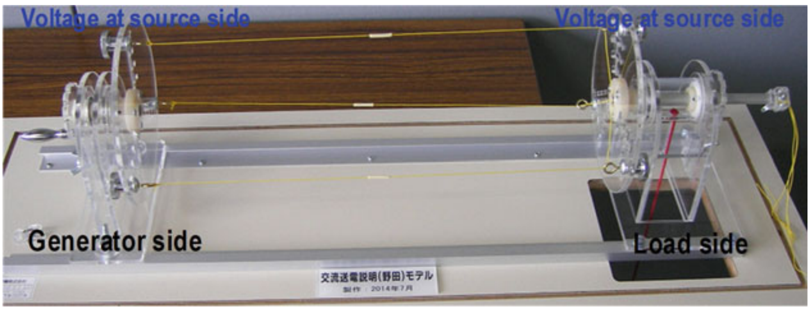


Fig. 4.50 Photograph of Noda model

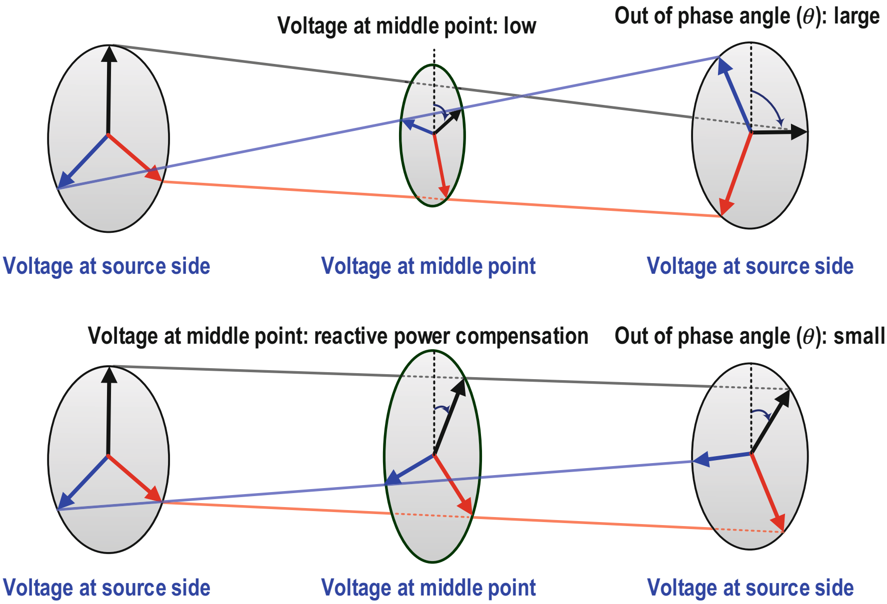


Fig. 4.51 Noda model showing the reactive power compensation

4.12 Difference in Switching Phenomena between 50 Hz and 60 Hz

4.12.1 Power Frequency

Even though the frequency of power systems is operated at 50 Hz in most of the countries, the power frequency of some countries such as the United States and west part of Japan is 60 Hz as shown in the Fig. 4.52. Both frequencies coexist today with no apparent move to worldwide standardization.

Unless some electric appliances may not operate efficiently nor even safely if used on anything other than the intended power frequency. However, most of the substation equipment, especially in the case of a circuit breaker, can be operated at both power frequencies of 50 Hz and 60 Hz.

Strictly speaking, the difference in power frequency affects the performance of substation equipment. In the case of a power transformer, more compact design with the same capacity can be possible for higher power frequency. The impact of power frequency on interrupting performance for different switching duties is given below.

4.12.2 Thermal Interrupting Capability

When a circuit breaker interrupts the same current on the SLF conditions, it requires higher cooling performance (higher thermal interrupting) in case of 60 Hz, because

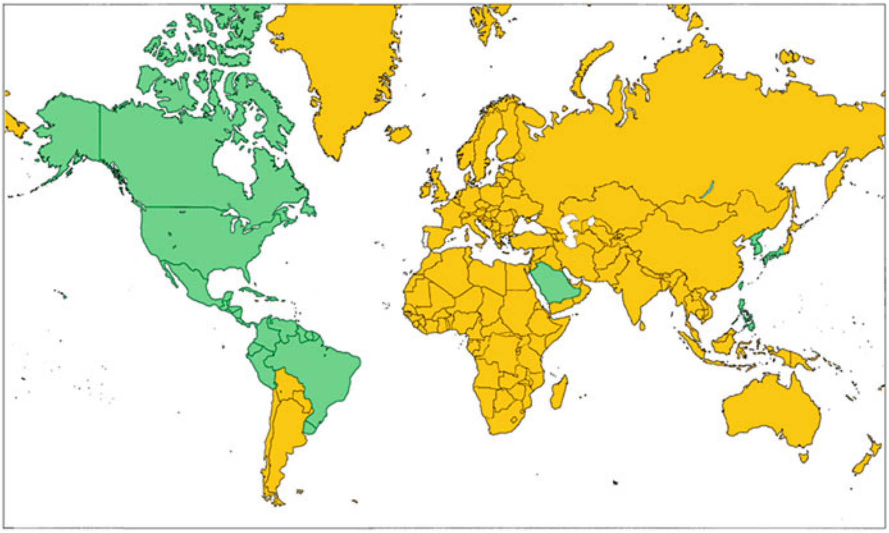


Fig. 4.52 World map of power frequency of 50 Hz (in yellow) versus 60 Hz (in green)

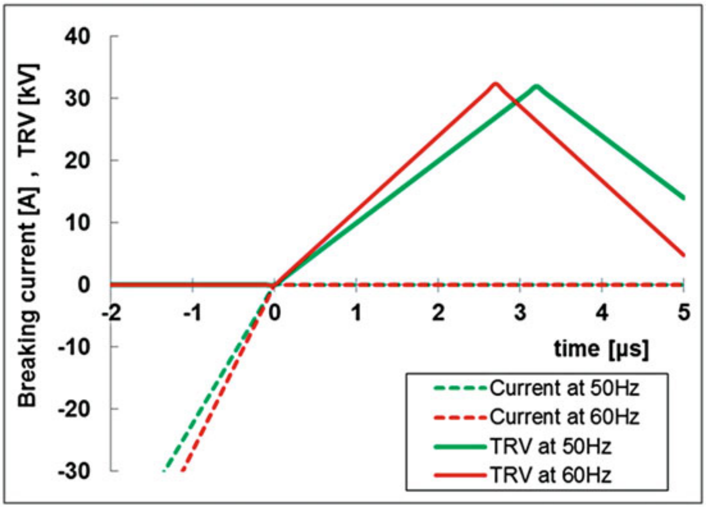


Fig. 4.53 Comparison of (di/dt) at current zero and TRV

the current and voltage slope (di/dt, dv/dt) at current zero becomes 1.2 times higher than that at 50 Hz resulting in higher ohmic heat input around the current zero. Some designs of a circuit breaker employ a larger grading capacitor in case of 60 Hz as compared with the application in 50 Hz, which can enhance the thermal interrupting capability by mitigating the current slope at the current zero (Fig. 4.53).

4.12.3 Dielectric Interrupting Capability

A circuit breaker is required to interrupt the short-circuit current on the BTF conditions at any timing of periodical current zero due to power frequency when it elapses the minimum arcing time after the contact separation. This means that a circuit breaker should have a half-cycle interrupting window at minimum (in case of symmetrical current). The intervals between current zeros are 10 ms at 50 Hz and 8.3 ms at 60 Hz. Therefore a circuit breaker is required to have a longer interrupting window resulting in a longer effective gas flow period in case of 50 Hz (Fig. 4.54).

4.12.4 Capacitive Switching Capability

TRV peaks appear at a half cycle after interrupting the current on capacitive switching conditions, which corresponds to 10 ms at 50 Hz and 8.3 ms at 60 Hz

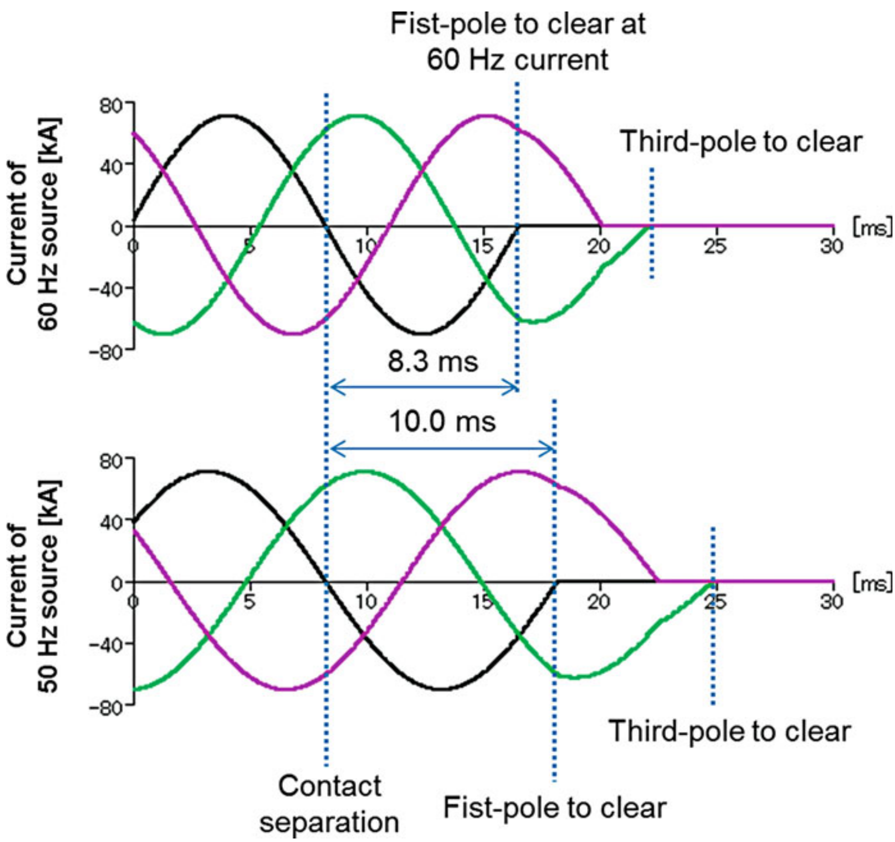


Fig. 4.54 Comparison of the interval between current zero and three-phase currents

from current interruption. Therefore a circuit breaker in case of 60 Hz application is required to have the better dielectric withstand strength recovery between the contacts, which is normally attained by increasing an opening speed of the contact (Fig. 4.55).

4.12.5 Inductive Switching Capability

There is no significant difference in switching performance between 50 Hz and 60 Hz on inductive switching conditions, because TRV is determined by the circuit conditions at load side (not power frequency source side). In addition, the amplitude and the frequency of high-frequency current oscillation and associated overvoltages in case of reignition occurrence do not show any difference between the power frequency of 50 Hz and 60 Hz. Therefore IEC 62271-100 Standard allows that inductive switching tests can be performed either at 50 Hz or 60 Hz.

4.12.6 Current-Carrying Capability

The short-time current withstand test can also be performed either at 50 Hz or 60 Hz, because the energy and mechanical stresses imposed on an interrupter do not show significant difference by considering the current-carrying duration of 1 second, even though the current peak of the first peak is 2.5 times and 2.6 times of root-mean-square value of current for 50 Hz and 60 Hz, respectively. Therefore IEC 62271-100 Standard (IEC 62271-100) allows that short-time current withstand test can be performed either at 50 Hz or 60 Hz.

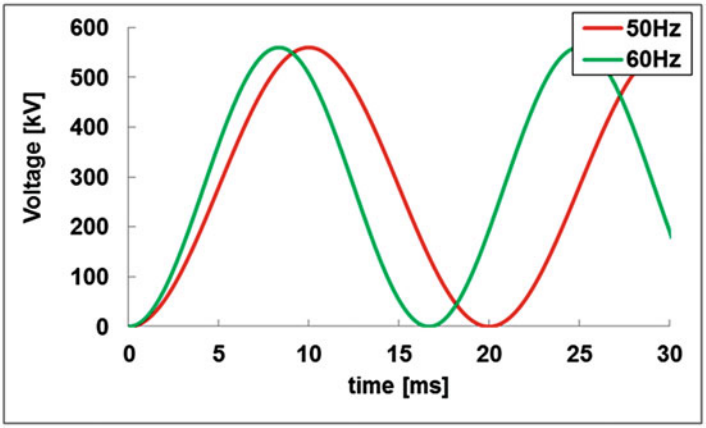


Fig. 4.55 Recovery voltage after capacitive current interruption

In general, a manufacturer provides a circuit breaker applicable both for 50 Hz and 60 Hz despite of the power frequency impacts on the switching performance.

4.12.7 Continuous Current-Carrying Capability

IEC 62271-1 states that tests performed at 50 Hz on switching devices of the open type having no ferrous components adjacent to the current-carrying parts should be deemed to prove the performance of the switching device when rated at 60 Hz, provided that the temperature-rise values recorded during the tests at 50 Hz do not exceed 95% of the maximum permissible values. Accordingly it recognizes the fact that temperature rise is in general slightly higher when carrying a continuous current at 60 Hz.

4.13 Switching Requirements in UHV Transmission

The first commercial operation of a UHV transmission with the rated voltage of 1100 kV AC started on January 6, 2009 after on-site commissioning tests during December 2008 in China. Since then the UHV AC (up to 1200 kV) and UHV DC (up to 1000 kV) networks are steadily extended in some countries such as China and India.

In October 2006, CIGRE SC A3 established the WG A3.22 "Technical Requirements for Substation Equipment exceeding 800 kV" and published some technical documents summarizing the specifications for substation equipment ($\geq$ 800 kV) base on investigations in various UHV and EHV projects (Ito et al. 2007; CIGRE WG A3.22 2008; CIGRE WG A3.22 2011; CIGRE WG A3.28 2014).

In order to minimize the costs and visual impact of UHV transmission lines and substations as much as possible, advanced technological solutions and analytical optimization techniques were introduced. Furthermore, the outcome of the studies in the field of reduced insulation coordination requirements and requirements for some system transients (e.g., TRVs, ITRVs, VFTOs) at UHV levels has an impact on the insulation coordination requirements (distances, dimensions, insulation thickness) for EHV voltages (800 kV, 550 kV, 420 kV).

In the 1970s and 1980s of last century, a few utilities around the world started the first test pilots to explore AC transmission levels above 1000 kV. In the former USSR (Union of Soviet Socialist Republics), a plant has been installed for a long-term test at 1200 kV rated voltage, while in the United States, Bonneville Power Administration (BPA) and American Electric Power (AEP) run pilots at 1200 kV and 1500 kV, respectively. During the 1980s in the former USSR, they even had a pilot plant at 1800 kV rated voltage, and, from 1985 until 1991, they operated a commercial 1200 kV transmission system, existing of 1900 km OH-lines, of which in fact half was operated at 1200 kV. In the 1990s, for 2 years only, in Italy a 1050 kV pilot plant has been in service. And in Japan, since 1996, an 1100 kV pilot is in operation together with 430 km UHV OH-lines (being operated at 550 kV) (CIGRE WG A3.22 2008).

Table 4.6 also shows several specific and distinctive issues observed in UHV AC power systems that may have great impact on substation equipment. In particular, the use of multi-bundle conductors with large-diameter and large-capacity power transformers provides distinctive phenomena for UHV power systems. In addition, the use of higher performance surge arresters (MOSA) with lower protection voltage to effectively limit overvoltages forms an integral part of the design of some UHV systems. The impact of this design approach and its impact on specifications are briefly described.

Table 4.6 Specific issues of UHV AC power systems

Equipment	Phenomena peculiar to UHV	CIGRE investigations
Substation equipment	Increased insulation levels (reduced LIWV/LIPL)	Various mitigation schemes are applied to suppress the SIWV levels as much as possible.
4-legged reactor HSGS	Prolonged secondary arc extinction time due to higher coupled voltage and induced current	4-legged shunt reactor can attain successful auto-reclosing in case of 1LG condition for single circuit.
Surge arrester shunt reactor	Prominent Ferranti effect and TOV due to large capacitance of overhead lines	Severe voltage factor and breaking current for capacitive current switching is not appeared.
Circuit breaker GIS, transformer	Severe VFTO due to geometry and topology of UHV substation	Resistor-fitted DS can effectively suppress VFTO for GIS substation.
Circuit breaker	Large time constant of DC component in fault current due to low losses of transformers and lines	Time constants in the UHV systems are 100 ms for India, 120 ms for China and 150 ms for Japan.
Circuit breaker	Reduced first-pole-to-clear factor due to small zero-sequence impedance in the UHV systems	First-pole-to-clear factors are 1.1 for Japan, 1.2 for India and 1.0–1.23 for China.
Circuit breaker surge arrester	High amplitude factor in TRVs due to low losses of power transformers and transmission lines	RRRV for TLF exceeds the existing standard value. MOSA can suppress TRV peak for terminal faults.
Circuit breaker surge arrester	High TRV peak value for out-of-phase due to low damping of traveling waves	Further investigations are expected to provide some solutions for out-of-phase phenomenon.
Circuit breaker	Reduced line surge impedances due to multi-bundle conductors with large diameter	Line surge impedance is suggested as 330 ohm for 8 bundle conductors designed for UHV OH-lines.
Line substation (AIS)	Possibly reduced corona onset voltage with increased corona losses and audible noise	UHV lines employ 8 conductors with 400–810 mm^2 depending on the allowable level of corona noise.

Technical and economic consequences of insulation levels become increasingly important especially in UHV systems. Optimal insulation coordination can be achieved based on higher performance MOSAs with the V-I characteristic shown in Fig. 4.56.

Studies of the insulation coordination by means of accurate computer-aided simulations are common practice for such projects, while an important aspect of insulation coordination is the utility's policy regarding withstand margins for severe lightning impulse or switching impulse conditions with a very low probability of occurrence.

Suppressing switching overvoltages as much as possible is a prerequisite for air clearances to insulation in order to reduce the heights of transmission towers and the dimensions of open-air parts in substations. As lightning overvoltages dominate the non-self-restoring internal insulation design of substation equipment, it is important to rationalize lightning overvoltages by means of MOSAs arrangement at adequate number of locations, such as at line entrances, busbars, and transformers.

Technical and economic consequences of insulation levels become increasingly important especially in UHV systems, where MOSAs are a key technology to realize rational insulation coordination (Zaima et al. 2007). Table 4.7 illustrates examples of several MOSA arrangements with the corresponding costs and lightning impulse withstand voltages (LIWV) on UHV substation equipment. The arrangement that is composed by two surge arresters per circuit at the line entrance, two per quarter bus, and one per transformer bank is provided as one of the most favorable applications to UHV transmission in Japan.

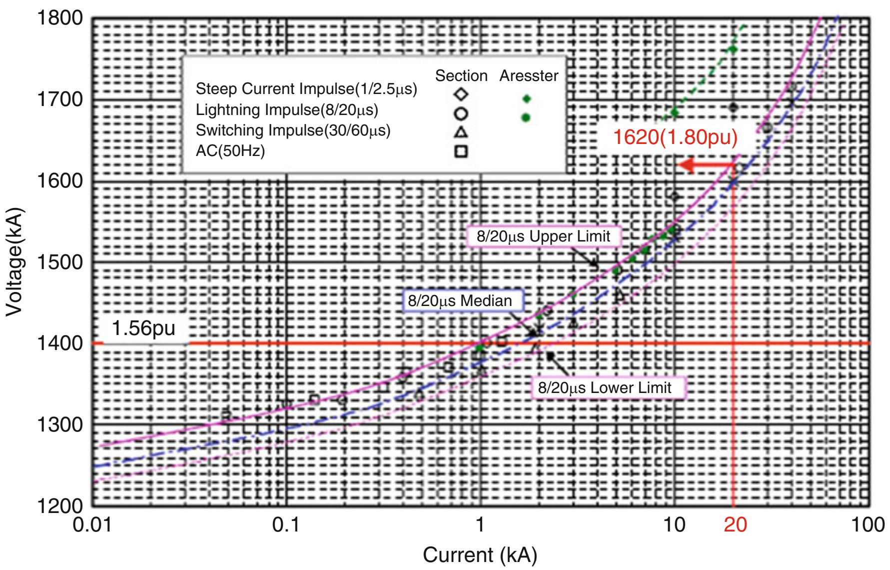
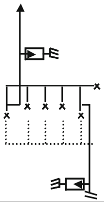
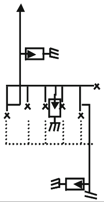
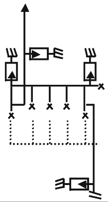
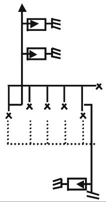
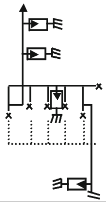
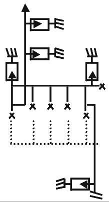


Fig. 4.56 Example of V-I characteristics of higher performance MOSA

Table 4.7 Relationship between LIWV and MOSA layouts

						(:kV)
Layout of Surge Arrester						
Transformer Overvoltage	1950	1943	1895	1943	1938	1896
LIWV	1950	1950	1950	1950	1950	1950
GIS Overvoltage	2898	2854	2730	2628	2506	2208
LIWV	2900	2900	2900	2700	2550	2250
Cost	102%	105%	109%	103%	103%	100%

It is important for EHV and UHV system and equipment to suppress lightning overvoltages effectively by arranging higher performance MOSAs at appropriate locations such as at line entrances, busbars, and transformers. With respect to very fast transient overvoltage (VFTO), these levels are reduced to be 1.3 p.u. or below with application of the resistor-fitted disconnecting switch with a 500 Ω resistor (Kobayashi et al. 2007; Yamagata et al. 2007). This scheme is also effective to suppress electromagnetic interference in the secondary circuit of current transformer (CT), voltage transformer (VT), and protection and control equipment.

Utilities generally use both the analytical and the simplified IEC approaches to evaluate LIWV levels. For the UHV switchgear of 1050 kV, 1100 kV, and 1200 kV, the specified lightning impulse withstand voltages (LIWVs) range from 1.25 to 1.49 times the lightning impulse protection level (LIPL) value as shown in Fig. 4.57.

On the other hand, limiting switching overvoltages as much as possible is a prerequisite for insulation clearances in air to reduce the heights of transmission towers and the dimensions of open-air parts in substations. In addition to the MOSAs, switching equipment equipped with pre-insertion closing/opening resistors is also applied to limit switching overvoltages. Additional MOSAs along the overhead (OH)-lines and controlled switching are options to reduce switching overvoltages even further. The applications of mitigation schemes can vary the SIWV level widely, so simulations are useful to evaluate their effects. Figure 4.58 shows that the UHV system in Japan takes full advantages of these schemes.

Tables 4.8 and 4.9 show examples of the determination process for LIWV and SIWV in China and Korea. The maximum overvoltage calculated in the system is found to be of the same level as the SIPL values.

The short-circuit current observed in UHV system also shows some remarkable features. Large-capacity power generator and large-capacity power transformers lead to a higher X/R ratio, which contributes to the increase in DC time constant in fault currents. EHV and UHV transmission lines employ multi-bundle conductors with large diameter in order to reduce corona noise as well as to increase transmission capacity.

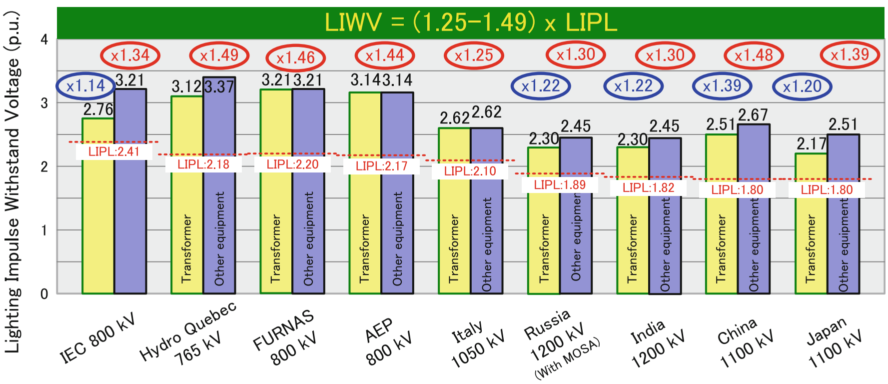


Fig. 4.57 LIWV specifications for transformers and substation equipment

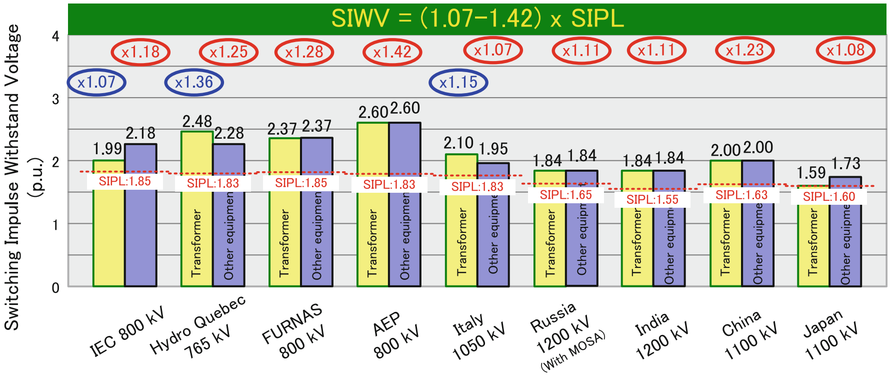


Fig. 4.58 SIWV specifications for transformers and substation equipment

Table 4.8 Example of determination process for LIWV

Country	Korea 800 kV	China 1100 kV (pilot)
LIPL	1310 kV (2.00 p.u.) at 20 kA	1620 kV (1.80 p.u.) at 20 kA
MOSA layout	1 unit for line entrance 1 unit for busbar 1 unit for transformer	1 unit for line entrance 2 units for busbar 1 unit for transformer
Maximum LIWV analysis		1796 kV for transformer 2040 kV for GIS
Acceptable failure rate	0.4 faults/100 km-year-line	0.112 faults/100 km-year-line
Safety factor	–	1.15 for internal insulation
LIWV for transformer	2050 kV (3.14 p.u.)	2400 kV (2.67 p.u.)
LIWV for other equipment	2250 kV (3.44 p.u.)	2250 kV (2.51 p.u.)
LIWV/LIPL	1.72	1.48

Table 4.10 summarizes analytical results of DC time constants calculated using various tower designs with different multi-bundle conductors used in different projects. In IEC 62271-100, a special case time constant is 75 ms for rated voltages 550 kV and above, which corresponds to the medium value of the constants surveyed for 800 kV lines. Since the DC time constant in UHV system has to be larger, the standard time constant of 120 ms is stipulated for UHV.

Transient recovery voltage (TRV) with high amplitude factor is expected in UHV system due to applications of lower loss of UHV power transformers and UHV transmission lines. To define the TRV envelope of UHV circuit breakers, the first-pole-to-clear factor is an important parameter, which is specified to be 1.3 for lower voltage systems with an effectively earthed neutral in IEC 62271-100 Standard. The first-pole-to-clear factor depends on the X_0/X_1 ratio of the system at the location of the circuit breaker. OH-lines give an X_0/X_1 ratio of about roughly 3, while large transformers tend to have a ratio less than or close to 1. As in UHV substations, the short-circuit current will be determined to a large extent by the contribution of the

Table 4.9 Example of determination process for SIWV

Country	Korea 800 kV	China 1100 kV (pilot)
SIPL	1200 kV (1.85 p.u.) at 2 kA	1460 kV (1.63 p.u.) at 2 kA
Resistance for GCB	1000 Ω for closing	600 Ω for closing
Maximum overvoltages	1124 kV for grounding fault 999 kV for closing 1186 kV for opening	1472 kV for opening
Maximum line length	160 km	420 km (tentative)
Flashover probability	0.1%/1 flashover-1000 operation	0.1%/1 flashover-1000 operation
Safety factor	–	1.15 for internal insulation
SIWV for transformer	1500 kV (2.30 p.u.)	1800 kV (2.0 p.u.)
SIWV for other equipment	1425 kV (2.18 p.u.)	1800 kV (2.0 p.u.)

Table 4.10 DC time constant of short-circuit currents in EHV/UHV transmission lines

Maximum voltage	Conductors		DC time constant (ms)
	Size (mm^2)	Bundle	
765 kV (Canada)	686	4	75
800 kV (United States)	572	6	89
800 kV (South Africa)	428	6	67
800 kV (Brazil)	603	4	88
800 kV (China)	400	6	75
1,200 kV (Russian)	400	8	91
1,050 kV (Italy)	520	8	100
1,100 kV (Japan)	810	8	150
1,100 kV (China)	500	8	120

transformers in comparison to the contribution of the OH-lines; the first-pole-to-clear factor tends to be lower than 1.3. The standard value for UHV is stipulated to be 1.2.

Another characteristic not to be overlooked is the equivalent surge impedance of the OH-lines, which is a parameter especially important at short-line faults. The standards take care for the interruption of a single fault to earth and therefore require the equivalent surge impedance of the last clearing pole. Further the interruption of short-line faults goes with frequencies in the kHz range, and the large 8-bundle conductors will not contract completely during the first 100 to 200 ms. Under such conditions the equivalent surge impedance will be much less than 450 Ω, as can be seen in Table 4.11 and Fig. 4.59. Therefore the equivalent surge impedance of UHV OH-lines is reduced from 450 to 330 Ω.

The equivalent surge impedances play also a role in clearing long-line faults (LLF) and out-of-phase currents (OP). MOSAs have an impact to reduce the TRV peak values to a certain level, but the influence of MOSA is much larger at breaker terminal faults (the test duties T100 and T60) and at the interruption of transformer limited faults (TLF–T10).

Table 4.11 Surge impedance of transmission lines

Highest voltage (kV)	Conductor size (mm^2)	Number of conductor	Conditions (TRV frequency)	Z_0 (ohm)	Z_1 (ohm)	Equivalent surge impedance (ohm)		
						First pole	Second pole	Third pole
550 (Japan)	**410**	**6**	Normal conduction (60 kHz)	444	226	270	281	299
			Bundle contraction (60 kHz)	580	355	408	417	430
800 (South Africa)	**428**	**6**	Normal conduction (27.5 kHz)	403	254	290	296	304
			Bundle contraction (27.5 kHz)	509	359	398	403	409
1,050 (Italy)	**520**	**8**	Normal conduction (26.2 kHz)	406	210	250	260	275
			Bundle contraction (26.2 kHz)	532	343	389	396	406
1,100 (Japan)	**810**	**8**	Normal conduction (25 kHz)	476	228	276	289	311
			Bundle contraction (25 kHz)	595	339	396	407	424

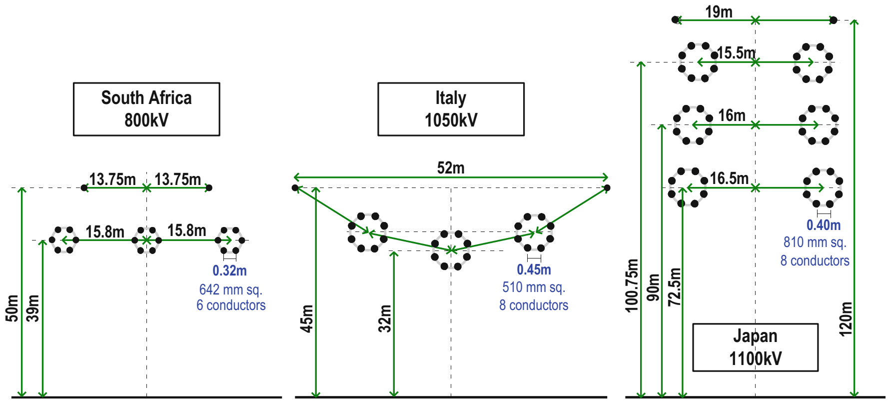


Fig. 4.59 Line configurations used for Table 4.11

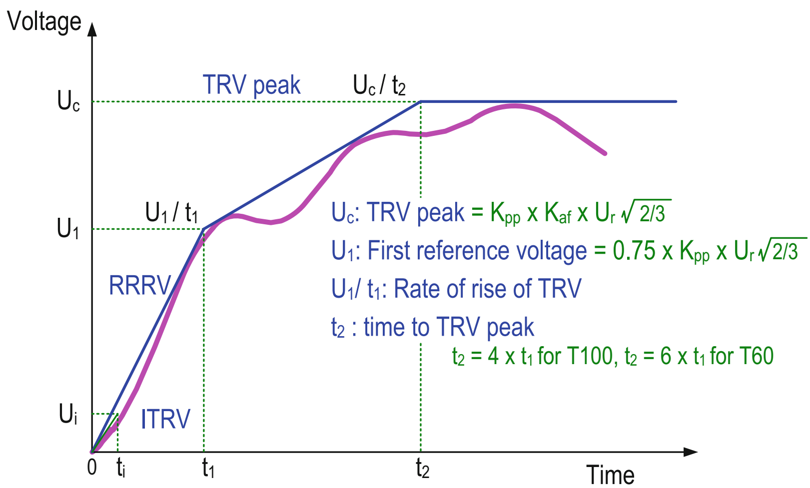


Fig. 4.60 TRV by four-parameter expression

Figure 4.60 shows TRV by four-parameter expression, which applies to the test duties of T60 and T100 (60% and 100% of the rated interrupting current of circuit breakers). The four-parameter TRV consists of three parts: the first part of the TRV up to the U_1/t_1 at the first reference voltage, the third part after the peak value (U_c/t_2), and the second part in between.

Table 4.12 summarizes the standard TRV values for UHV circuit breaker as compared with those for lower voltages including EHV. There are still questions why the proposed value of 330 Ω for the UHV surge impedance could not be adopted for 800 kV as well. Some examples are given in Fig. 4.61.

By means of the value of 330 Ω and information available on the minimum equipment in a UHV substation, it has been concluded that the RRRV, U_1, t_d, and t_{dL}

Table 4.12 TRV parameters of UHV circuit breakers

UHV	First-pole-to-clear factor	Amplitude factor	1100 kV	1200 kV	Rate of rise of TRV	Time to TRV peak	Time to TRV peak
DUTY	K_{pp}	K_{af}	TRV peak (kV)	TRV peak (kV)	RRRV (kV/μs)	t_2	t_3
T100	1.2 (1.3)	1.5 (1.4)	1617	1764	2	$3.0^* t_1$ $(4^* t_1)$	
T60	1.2 (1.3)	1.5	1617	1764	3	$4.5^* t_1$ $(6^* t_1)$	
T30	1.2 (1.3)	1.54	1660	1811	5		t_3 (t_3)
T10	1.2 (1.3)	1.76	1897	2076	7		t_3 (t_3)
TLF	1.2 (1.5)	$0.9^* 1.7$	1649	1799	$(^*)$		$(^*)$
Out-of-phase	2.0	1.25	2245	2450		$1.38^* t_1$ $(2^* t_1)$	

Values ( ) are standards for 800 kV and below

t_1 and t_3 are based on $K_{pp} = 1.2$

$(^*)$: RRRV $= U_c/t_3$ with $t_3 = 6\ ^* U_r/I\ ^{0.21}$ shown in the ANSI C37.06.1–2000 for transformers up to 550 kV

For UHV transformers, RRRV and t_3 are determined by the transformer impedance and its equivalent surge capacitance (specified as 9 nF)

for UHV can be kept the same as specified for the test duties T100, T60, T30, T10, and SLF at lower rated voltages. Even for the ITRV, the value for the busbar surge impedance is proposed to be the same as that for 800 kV (325 Ω instead of 260 Ω for the lower rated voltages), but the time t_i is proposed to be 1.5 μs, as the dimensions of UHV AIS are considerably larger. However, the conditions under which such long t_i may occur may also be applicable to 800 kV.

Based on the information collected so far, it has been proposed to keep the same amplitude factors as for the lower voltages, with the exception of k_{af} for T100, where it is recommended to increase this factor from 1.4 to 1.5. Reasons to do so are on one hand the outcomes from system studies, mainly for the future TEPCO system, and on the other hand the fact that $k_{pp}{}^*k_{af}$ gives the same peak value with the existing IEC parameters as with the proposed values. This peak value for T100 and T60 happens to be about 5% above the clipping level of MOSA, a margin of 5% above SIPL accounts for differences in design.

From simulations it is clear that MOSAs have a reducing impact on the peak values of the TRV, as can be seen in Fig. 4.61.

By means of the equivalent surge impedance seen by the circuit breaker's clearing pole and the number of MOSAs connected at the source side of the circuit breaker (present at the substation), the intersection point with the surge arrester characteristic (s) can be determined, giving the clipping level: see Fig. 4.62.

The ratings for disconnecting switches and earthing switches applied in UHV systems show to be higher than those applied at lower voltages. The specified

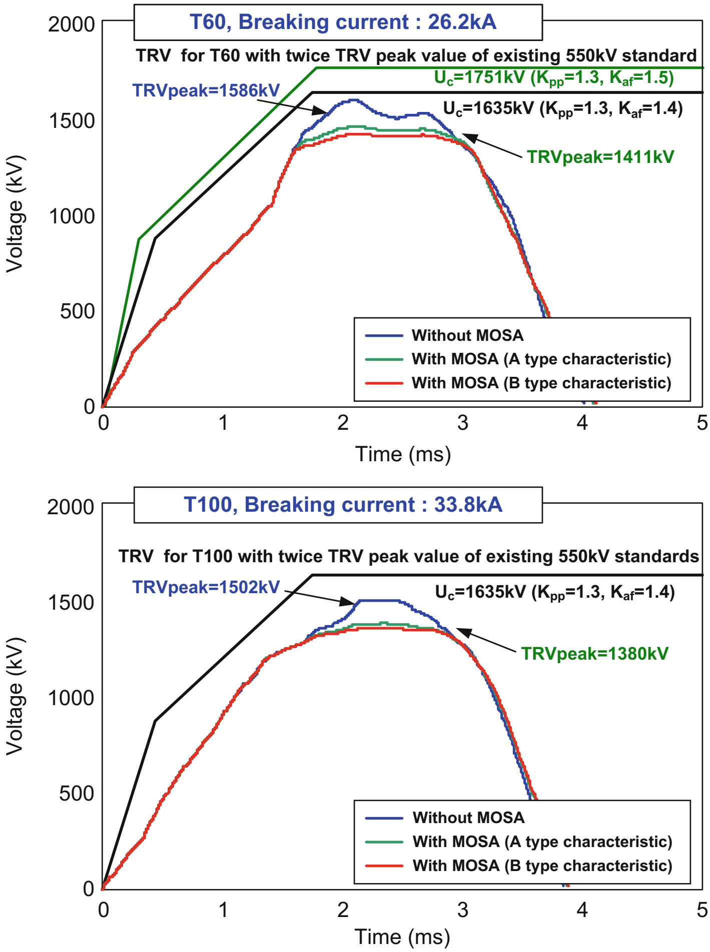
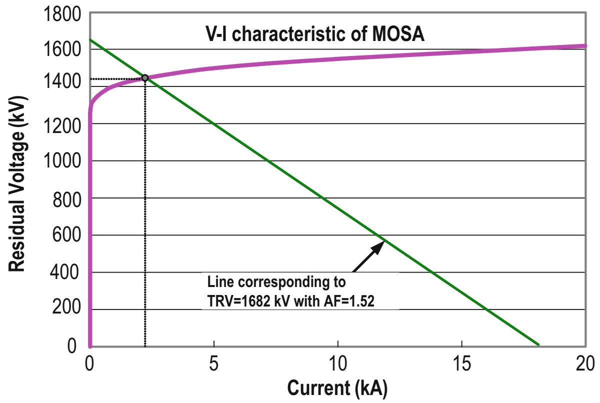


Fig. 4.61 Effect of MOSA on TRV wave-shape (CIGRE WG A3.22 2011)

currents and related voltages for the bus transfer duty and bus-charging current switching duty are relatively high. Figure 4.63 shows the load capacitance and the equivalent length of GIS for different voltage levels depending on the specified bus-charging current. The bus-charging currents, evaluated for several existing UHV substation layouts, reach a maximum value of 0.4 A. Schemes of future UHV substations with maximum busbar lengths up to 200 m allow to conclude that a bus-charging current of 2 A is sufficient also for future applications (Ito et al. 2008).

Bus transfer currents have to be defined in dependence of the actual current ratings, the type of substation, and the maximum loop length. As can be learnt from Fig. 4.64, for GIS, a bus transfer voltage of 80 V belongs to 1,600 A and of 300 V to 8,000 A, while for AIS and MTS, a voltage of 400 V belongs to 1,600 A as well as 4,000 A (Janssen et al. 2009).

Fig. 4.62 Intersection of system response line with MOSA characteristic



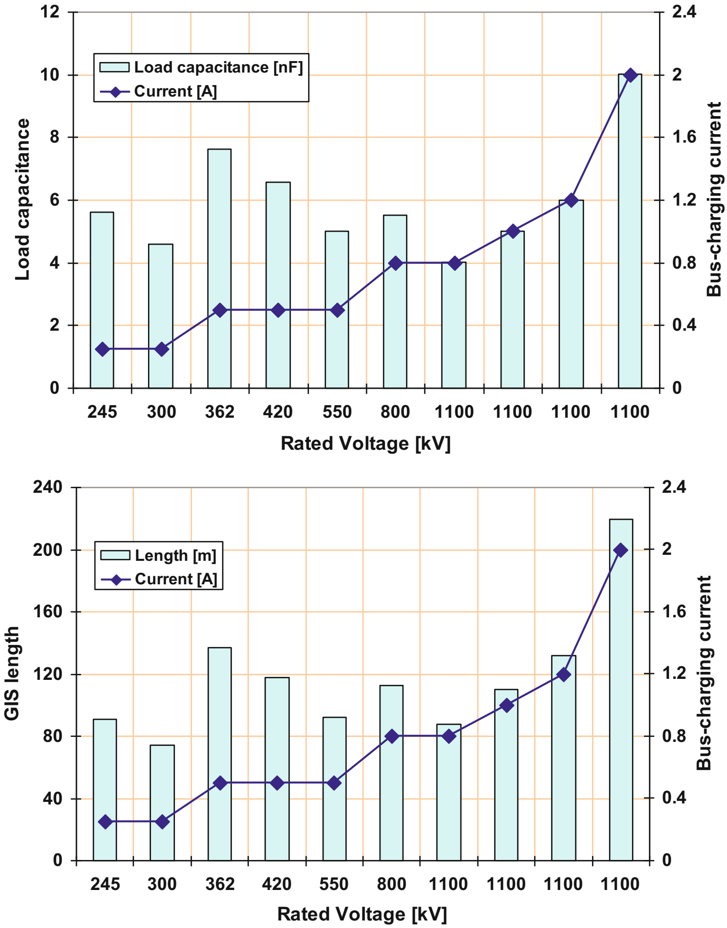


Fig. 4.63 Dependency of bus-charging current, load capacitance, and equivalent busbar length on rated voltage as per IEC 62271-203 (IEC International Standard 62271-203, Edition 1.0 2003)

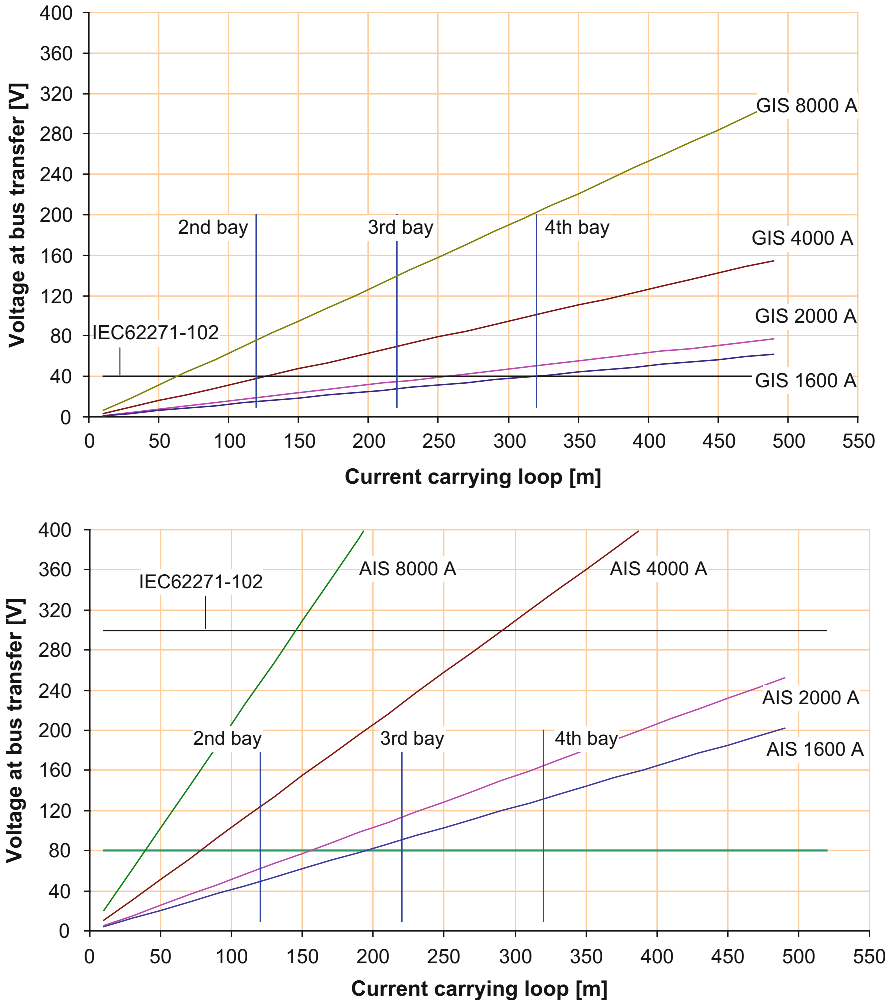


Fig. 4.64 Bus transfer voltage as a function of length of GIS and AIS/MTS current-carrying loop

In Annex C of IEC 62271-102 (IEC International Standard 62271-102, Edition 1.0 2001), electromagnetic and electrostatic-induced currents and voltages are standardized for 550 kV and 800 kV earthing switches, which are designated to be used in circuits with relatively long lines or a high coupling to an adjacent energized circuit (class B earthing switches).

A special topic is the occurrence of VFTO (very fast transient overvoltages) due to the charging and discharging of busbar sections by disconnecting switches in GIS. These switching cause a large number of restrikes and prestrikes, respectively, with high-frequency responses by the traveling waves in the GIS. Such high-frequency voltages may reach amplitudes that could endanger the insulation of the GIS equipment as well as directly connected equipment, such as transformers and shunt reactors.

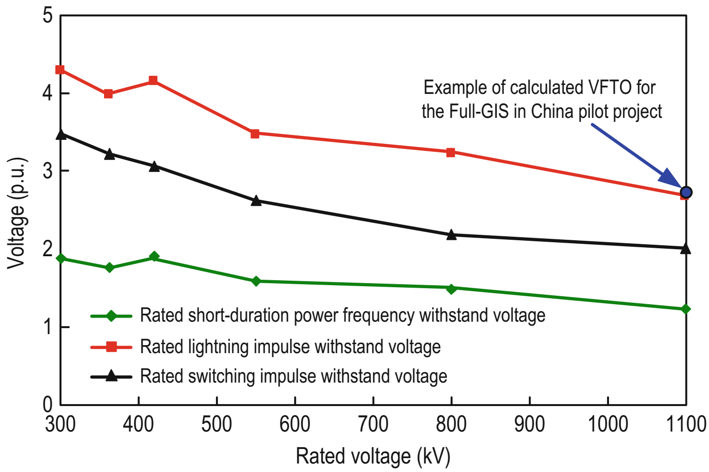


Fig. 4.65 Dependency of VFTO and LIWV of GIS (Janssen et al. 2009)

As shown in Fig. 4.65, this phenomenon is a larger problem at UHV than at 800 kV. When necessary a counter measure is the application of a pre-insertion resistor to the disconnecting switches (Ito et al. 2008; Janssen et al. 2009).

Other dedicated switching equipment in EHV and UHV is used to stimulate secondary arc extinction. When a grounding fault occurs in the faulty phase of transmission lines, an arc is generated from the faulty location to the ground. After a circuit breaker interrupts the fault current, a small secondary arc current continues to flow at the fault location due to electrostatic and electromagnetic induction. The secondary arc is extinguished when the insulation at the fault location is sufficiently recovered.

When single-phase auto reclosure (SPAR) is used, most utilities apply four-leg shunt reactors to limit the secondary arc current, so that it will extinguish within a reasonable short time (mostly within 1 s), but some utilities apply a special scheme to switch off the shunt reactor(s) of a healthy phase (Janssen et al. 2009) or apply TPHSR (three-phase high-speed reclosure) or apply high-speed grounding switch (HSGS) to bypass the secondary arc by a short duration (typically 0.5 s) short circuit, in order to extinguish it. Such solutions are used for UHV, 800 kV, and lower rated voltages. Specifications for the HSGS are now within IEC in the process of standardization. Switchgear for the special switching scheme of a healthy phase shunt reactor is yet to be addressed.

HSGS were applied to both ends of 550 kV transmission line in the United States and demonstrated successful extinction of secondary arc in the field, which corresponds to inductive current switching with 700 A for first switch to open and capacitive current switching with 120 A for second switch (Keri et al. 1983; Hasibar et al. 1981; Agafonov et al. 2004).

In Korea, HSGS are installed at both ends of 800 kV double-circuit transmission lines with line length longer than 80 km (single end of lines with line length shorter

Table 4.13 HSGS requirements

	United States	Korea	Japan	Japan[a]
Highest voltage	550	800	1100	1100
Interrupting current (kA)	700	8000	7000	7830
TRV peak (kV)	260	700	900	570
RRRV (kV/μs)	0.1	1.3	1.15	0.46

[a]Duty for delayed current zero interruption with the arcing time of 80 ms + minimum arcing time

than 80 km) and experienced 22 successful high-speed multi-phase reclosing in the period 2003–2007.

UHV systems in Japan with double-circuit OH-lines with vertical configurations decided to employ HSGS to achieve high-speed single and multi-phase reclosing considering all fault modes such as single-phase line fault to ground (1LG), two-phase faults to ground (2LG), 3LG, and 4LG.

Table 4.13 summarizes technical requirements for HSGS specified for the UHV and EHV systems in the United States, Korea, and Japan.

4.14 Summary

Fundamental switching phenomena appeared in power systems are described, which include bus terminal fault interruption, short-line fault interrupting, capacitive load switching, and inductive load switching. The interrupting current and the associated TRV phenomena across the circuit breaker imposed after current interruption are diversified depending on the circuit (network) conditions, a fault location, and the interrupting performance of the circuit breaker. The circuit breaker in general is required to have a trade-off characteristic for interrupting performance including thermal interrupting performance (required to cope with short-line fault interrupting) and dielectric interrupting performance (required to cape with bus terminal fault interruption and small capacitive load current switching).

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History of Circuit Breakers

5

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Contents

Keywords

Circuit breaker · Oil circuit breaker · Air blast circuit breaker · Gas circuit breaker · Vacuum circuit breaker

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5.1 Introduction

High-voltage (HV) circuit breakers are an indispensable piece of equipment in the power system which perform several functions to make, carry, and break a variety of the AC currents expected in operating and protecting the grid. For instance, a circuit breaker (CB) must cope with the following types of normal current carrying stresses under normal conditions:

- Load currents flowing through overhead lines, cables, transformers, generators, etc.
- Capacitive currents related to unloaded overhead lines, cables, or shunt capacitor banks
- Small inductive currents related to shunt reactors or unloaded transformers

Simultaneously, during abnormal or fault conditions, a CB must cope with the following types of short-circuit stresses:

- Terminal fault currents (single or multiphase terminal faults)
- Short-circuit currents due to faults which occur on an overhead line at a short (short-line faults) or long distance (long-line faults) from the circuit breaker
- Short-circuit currents due to faults generated at a transformer (transformer-limited faults) or series reactor (reactor-limited faults)
- Short-circuit currents due to faults generated at a large generator
- Out-of-phase currents (under the conditions of normal usage)

Since circuit breakers play a primary part of the protection system, the following functions are required for a circuit breaker:

- In the closed position, the CB must be a good conductor.
- In the open position, the CB must be a good isolator between system parts.
- CB must change from a conductor (closed position) to an isolator (open position) in a very short period of time.
- CB must not cause excessive overvoltages during switching.
- CB must be highly reliable in operation.

When short circuit or other events that require some automatic switching action occur, it takes some time to detect the fault. Protection devices typically require time to analyze the system conditions, make decisions, and send a trip command to open or close a particular circuit breaker. This time can be as short as a half cycle or could be a few hundred ms. As soon as a trip command to open or close has been sent to a nearby circuit breaker, no significant time is lost in activating the opening or closing coil of the circuit breaker.

Circuit breakers (CB) are a mechanical switching device, driven by an operating mechanism that, in the closed position, continuously carries the rated nominal current but, when the protective relay described above sends a trip command, has to operate in a very short period of time. During the majority of its lifetime, the CB remains in a static position (either open or closed). In a typical application, the CB may operate less than 1000 times during its life. However, when it is required to open or close, the CB must operate very quickly and very reliably. In certain applications (e.g., shunt capacitor bank switching), the CB can often operate more than 10,000 times during its life. The closing operation of the contacts normally can take up to ~100 ms. The opening time from the instant when an open signal is issued to the CB to the instant of contact separation (contact part) is much faster, typically in the range of 15–40 ms. Modern circuit breakers can have a single breaking unit up to 550/420 kV, while multiple breaking units are required for 1100/800 kV ratings. Some CBs above 245 kV also employ multiple contact break assemblies.

This chapter deals with a history of circuit breakers with different technologies since they were put into service in the early 1900s.

5.2 Definitions of Terminology

Circuit Breaker

A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in power systems from damage caused by excessive currents, typically resulting from an overload or short-circuit conditions. When a fault occurs, circuit breakers quickly clear the fault to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Dead Tank Circuit Breaker

A circuit breaker with interrupters installed inside an earthed metal enclosure. The conductor applied with the system voltage is fed from outside the interrupters through bushings.

Live Tank Circuit Breaker

A circuit breaker with interrupters inside a tank (composed of porcelain or composite insulators) insulated from earth. The conductor can be connected directly with a live part of the breaker terminals.

Gas Blast Circuit Breaker

A circuit breaker in which the arc develops in a blast of gas. When the gas is moved by a difference in pressure established by mechanical means during the opening operation of the circuit breaker, it is termed a single pressure gas blast circuit breaker. When the gas is moved by a difference in pressure established before the opening operation of the circuit breaker, it is termed a double-pressure gas blast circuit breaker.

Sulfur Hexafluoride (SF_6) Circuit Breaker
A circuit breaker in which the contacts are opened and closed in sulfur hexafluoride. Current interruption in a SF_6 circuit breaker is obtained by separating two contacts in sulfur hexafluoride having a pressure of several tenths of MPa. After contact separation, current is carried through an arc and is interrupted when this arc is cooled by a gas blast of sufficient intensity.

Air Blast Circuit Breaker
A circuit breaker in which the contacts open and close in air. Since the air interrupting and dielectric withstand capability at atmospheric pressure is limited, compressed air of several MPa is required for high-voltage applications. The air creates a high arc voltage which can decrease the fault current and assist thermal interruption capability.

Oil Circuit Breaker
A circuit breaker in which the contacts open and close in mineral oil. The "bulk" or dead tank oil breaker has the contacts in the center of a large metal tank filled with oil. The oil serves as an extinguishing medium and provides the insulation to the tank. The live tank or "minimum" oil breaker design has the contacts and arcing chamber inside a porcelain insulator filled with a small volume of oil compared to bulk oil circuit breakers. The arc evaporates the surrounding oil and produces hydrogen and carbon compounds. The process removes the heat from arc and eventually interrupts the current at power frequency current zero.

Vacuum Circuit Breaker
A circuit breaker in which the contacts open and close within a highly evacuated vacuum enclosure. When the vacuum circuit breaker contacts are separated, an arc is generated by the metal vapor plasma released from the contact surface. The arc is quickly extinguished because the metallic vapor, electrons, and ions produced during arcing are diffused in a short time and condensed on the surfaces of the contacts, resulting in quick recovery of dielectric strength.

Contact
Conductive parts designed to establish circuit continuity when they touch and which, due to their relative motion during an operation, open or close a circuit or, in the case of hinged or sliding contacts, maintain circuit continuity.

Main Contact
A contact included in the main circuit of a mechanical switching device, intended to carry the current of the main circuit in the closed position.

Arcing Contact
One of a pair of contacts between which the arc is intended to be established. An arcing contact may serve as a main contact.

Enclosure
A part of switchgear providing a specified degree of protection of equipment against external influences and a specified degree of protection against approach to or contact with live parts and against contact with moving parts.

Operating Mechanism
A part of the circuit breaker that actuates the main contacts. It is often referred to as "operating drive."

Pole
The portion of a switching device associated exclusively with one electrically separated conducting path of its main circuit and excluding those portions which provide a means for mounting and operating all poles together. A switching device is called single-pole if it has only one pole. If it has more than one pole, it may be called multipole (two-pole, three-pole, etc.) provided with an operating mechanism for each pole (independent pole operation, IPO) or to operate multipole together (simultaneous pole operations).

Independent Pole Operation
A circuit breaker with an independent operating mechanism for each pole, which can operate each pole at different instants in the case of controlled switching applications.

Three-Phase Simultaneous (Gang) Pole Operation
A circuit breaker with a single operating mechanism which operates all three poles simultaneously without a time delay between the operations of the individual poles.

Rated Voltage
Rated value of the voltage assigned to a component or equipment by the manufacturer. The specified performance of an equipment in power system is demonstrated at the rated voltage.

Normal Current
Continuous nominal current which the main circuit of a circuit breaker is capable of carrying continuously under specified conditions of use and behavior.

Peak Factor (of the Line Transient Voltage)
Ratio between the maximum excursion and the initial value of the line transient voltage to earth of a phase of an overhead line after the interruption of a short-line

fault current. The initial value of the transient voltage corresponds to the instant of arc extinction in the pole considered.

First-Pole-to-Clear Factor (in a Three-Phase System)
When interrupting any symmetrical three-phase current, the first-pole-to-clear factor is the ratio of the power frequency voltage across the first interrupting pole before current interruption in the other poles to the power frequency voltage occurring across the pole or the poles after interruption in all three poles.

Amplitude Factor
Ratio between the maximum excursion of the transient recovery voltage to the crest value of the power frequency recovery voltage.

Medium Voltage (MV)
MV generally refers to the voltage levels up to and including 52 kV corresponding to distribution systems.

High Voltage (HV)
HV generally refers to the voltage levels higher than 52 kV corresponding to transmission systems.

Arcing Time
The interval of time between the instant of the initiation of the arc in a pole and the instant of final arc extinction in that pole.

Thermal Interruption Process/Thermal Interrupting Region
The thermal interrupting period of a circuit breaker is the time period where the residual current inputs energy into the vanishing arc by ohmic heating. When the arc in a circuit breaker is not sufficiently cooled in this time period, thermal reignition may occur.

Dielectric Interruption Process/Dielectric Interrupting Region
The dielectric interrupting period of a circuit breaker occurs within an interval a quarter cycle of power frequency or longer after interruption at current zero, where the transient recovery voltage (TRV) is applied between the contacts. The dielectric strength across the contacts generally increases with the contact gap. When the TRV exceeds the dielectric strength across the contacts at any moment during the dielectric interrupting region, dielectric breakdown called restrike will occur.

Reignition
Reignition is the resumption of current flow between the contacts of a mechanical switching device within an interval less than a quarter cycle of power frequency after interruption at current zero. A reignition occurring during the thermal interrupting region does not generate voltage transients harmful to the power system.

Restrike
Resumption of current flow between the contacts of a mechanical switching device with an interval a quarter cycle of power frequency or longer after interruption at current zero. A restrike occurring during the dielectric interrupting region may generate transients that could be harmful to the system and equipment.

Transient Recovery Voltage (TRV)
A transient recovery voltage for circuit breakers is the voltage that appears across the terminals of the CB after current interruption. It is a critical parameter for fault interruption by a circuit breaker; its amplitude and rate of rise of TRV are dependent on the characteristics of the system connected on both terminals of the circuit breaker and on the type of fault that the circuit breaker has to interrupt.

Zero Sequence Impedance
The ratio of the zero sequence component of the voltage, assumed to be sinusoidal, supplied to a synchronous machine, and the zero sequence component of the current at the same frequency.

Positive Sequence Impedance
The impedance offered by the system to the flow of positive sequence current is called positive sequence impedance.

Negative Sequence Impedance
The impedance offered by the system to the flow of negative sequence current is called negative sequence impedance.

5.3 Abbreviations

CB	Circuit breaker
EPRI	Electric Power Research Institute
GIS	Gas-insulated switchgear
IPO	Independent pole operation
OCB	Oil circuit breaker
PTFE	Polytetrafluoroethylene
RRRV	Rate of rise of recovery voltage
RV	Recovery voltage
SF_6	Sulfur hexafluoride
TRV	Transient recovery voltage
VCB	Vacuum circuit breaker

5.4 Circuit Breaker

Figures 5.1 and 5.2 show two examples of modern SF_6 gas circuit breakers. Figure 5.3 shows a typical configuration of a SF_6 gas circuit breaker. The circuit breaker (CB) shown in Fig. 5.1 is a dead tank circuit breaker. In the dead tank CB, the conducting (or "live") parts are contained in a metallic enclosure (tank) usually made of aluminum or steel with nonconducting insulators of either porcelain or a composite material. The tank and insulators are sealed and filled with pressurized SF_6 gas which provides electrical insulation between the conducting parts of the interrupter at high voltage and the metallic enclosure (tank) and insulator. The insulator also provides electrical insulation from the top terminals to the tank. Therefore, in this design, the tank is at zero voltage (grounded potential) and can be located close to the ground (hence the name: "dead tank").

Another type of CB has similar internal components, but does not have the tank, but, instead, an external insulator of porcelain or composite material. Therefore, the external portion of this breaker is at full voltage (e.g., is "live") and is insulated from the ground by elevating it so that there is sufficient air insulation between the live circuit breaker components and the ground. This type of circuit breaker is called a "live tank" circuit breaker. An example is shown in Fig. 5.2.

At lower voltages where less power is needed to move the CB contacts, a single operating mechanism can simultaneously drive all three contact pairs. This is commonly referred to as a three-phase simultaneous (so-called Gang) operated breaker. At higher voltages where more power is needed to move the CB contacts,

Fig. 5.1 Typical 145 kV dead tank circuit breaker. (Courtesy of Mitsubishi Electric Power Products)

Fig. 5.2 Typical 800 kV live tank breaker. (Courtesy of GE Grid Solutions)

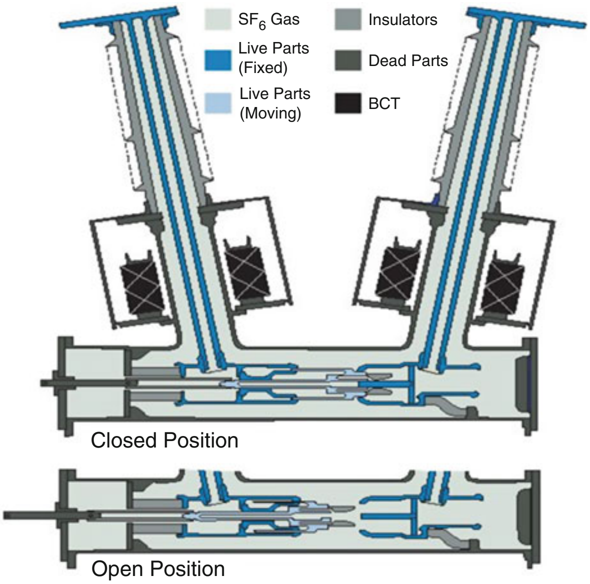


Fig. 5.3 Typical configuration of SF_6 gas circuit breaker

a single independent operating mechanism is generally applied to each pole. The operating mechanisms are synchronized so that the mechanical scattering between poles and between series contact pairs is less than a few ms. In the case of controlled switching applications, an independent operating mechanism for each pole intentionally facilitates nonsimultaneous pole operation of the contacts at a predetermined point in relation to an electrical reference signal for the purpose of reducing switching surges. This type of design is called independent pole operation (IPO) design. For system considerations, some breakers at lower voltages will also use an IPO design so that the operator can operate each pole independently while leaving other poles intact or operate them at different times.

The energy to accelerate the moving parts of the CB and its linkages is stored in a mechanism which uses either spring, hydraulic, or compressed air/nitrogen (pneumatic) systems. The energy is released and transmitted to the CB contacts through a mechanical linkage system, equipped with dampers. An electric coil is energized to initially move a latch or piston in the operating mechanism.

Thus, an open command results in physical separation of the CB contacts within typically 15–40 ms for all three poles simultaneously. But the load or fault current will continue to flow as the electromagnetic force of the power system will not allow a current to be interrupted without being forced to zero. Modern AC circuit breakers require the power frequency current to reach a current zero before interruption occurs. Meanwhile, after contact separation and the next current zero, the current will flow through an electric arc that is established between the contacts at contact separation.

At the first power frequency current zero, the contact gap (i.e., the gap between the contacts of that pole) may still be too small to withstand the recovery voltage and its transients. If the circuit breaker is not able to interrupt the current at the first power frequency current zero after contact separation, the arc will regenerate itself, and the CB pole has to wait for the next current zero opportunity (e.g., a half cycle later in a single-phase circuit). The duration after contact separation to the final interruption is called the arcing time (or arc duration). For fault current clearing, modern HV circuit breakers need an arcing time of 10–20 ms. The time from a trip command to open until fault current interruption in all three phases is, therefore, typically 50–60 ms.

The application of vacuum technology for CB is rapidly increasing especially in medium-voltage power systems and also in transmission voltages above 100 kV. Even though there are still classical technologies such as air blast, bulk oil, and minimum oil circuit breakers in service, the dominant technology today for HV CB is the single pressure SF_6 gas circuit breaker. Therefore, this technology will be used to illustrate the time-dependent phenomena at current interruption (see Fig. 5.4).

In the closed position, the current flows through what are called the main contacts. Usually these consist of a silver-plated contact part (the moving contact) and silver-plated contact fingers (the stationary or fixed contact). Parallel to the main contacts, arcing contacts are installed that guide the current during the process of opening and closing of the contacts. They show a relatively higher resistance but are designed to withstand the electric arc after contact separation. They are designed to separate slightly later than the main contacts during the opening process which allows the

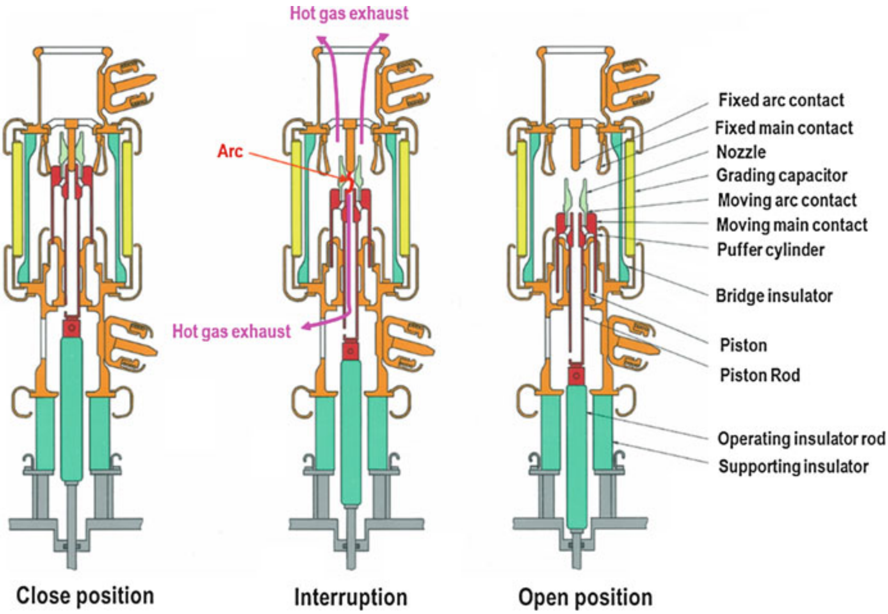


Fig. 5.4 Typical interrupter configuration of SF_6 gas circuit breaker

current to commute from the main contacts entirely to the arcing contacts which leads to a better controlled arc and no wear on the main contacts. During normal operation, the current flows primarily through the main contacts which have a lower resistance.

During opening, the SF_6 gas pressure is built up in a pistonlike structure (a puffer cylinder) by mechanical means and/or heat from the current arc. This SF_6 gas is then directed around the parting contacts in order to cool the electric arc generated between the arcing contacts. Fresh SF_6 gas flow has to be available at the moment of power frequency current zero, so that the hot plasma ions of the arc remnants will recover and the conductive hot gas is removed. The window of opportunity for this to occur is only a few μs before the voltage across the open contacts builds up to a value that can accelerate the remaining ions to energy levels leading to an avalanche effect and reestablishment of the electric arc. This window is called the thermal interruption process, as the possible reignition is caused by a thermal breakdown phenomenon (the acceleration and consequential multiplication of plasma ions). This thermal phase is the first critical period for a successful interruption and occurs during the first few μs after the current zero.

The recovery of the voltage is initially determined by very fast traveling waves in the substation (sub μs time scale) and in the nearby overhead lines (tens to hundreds of μs). Somewhere in the network, the traveling waves will reflect negatively causing a decrease of the transient recovery voltage at the circuit breaker terminals. The well-known sawtooth (triangular) shape of the transient recovery voltage (TRV), caused by the traveling waves, will be somewhat retarded by the substation capacitance.

This results in a time delay characterized by an RC time constant where R is the equivalent surge impedance of the connected overhead lines and C the capacitance of the substation equipment. Usually the time delay is on the order of μs at the bus bar side of the circuit breaker and a fraction of one μs at the line side. It is this initial phase of time that determines whether the cooling of the arc is sufficient to prohibit an avalanche effect or not. After the initial phase, the traveling waves return from the line ends and most of them will show an opposite sign, thus decreasing the recovery voltage. Around the same time, the system natural frequencies start to play a role which determines the further response of the system. Recovery voltages typically show a damped 1-cos wave shape with frequencies of several kHz. It is possible that the contact distance after, for example, 1 ms may not be large enough to create the needed dielectric capability between the contacts to withstand the peak value of the recovery voltage. A dielectric reignition may occur in this situation, and the electric arc will be reestablished. This dielectric phase is the second critical period (called the dielectric interruption process) for a successful interruption with the critical period typically being $\geq$ a few hundred μs (see Fig. 5.5).

After a thermal or dielectric reignition, the circuit breaker pole has to wait for the next power frequency current zero to initiate another attempt to interrupt the current. In the meantime, the other two poles (phases) will face a power frequency current zero and have their opportunity to interrupt the current. For the most part, the first pole to interrupt undergoes the most severe conditions of current to be interrupted and recovery voltage to be encountered. For the second and the last pole, the job is easier. An SF_6 gas circuit breaker is designed to interrupt the current within an arcing window of typically 10–20 ms. Therefore, only a few current zeroes per pole can be handled. In case it is not able to clear at a certain power frequency current zero, it will fail and may explode. Fortunately, modern circuit breakers are designed in accordance with updated standards so that this happens very seldom if at all.

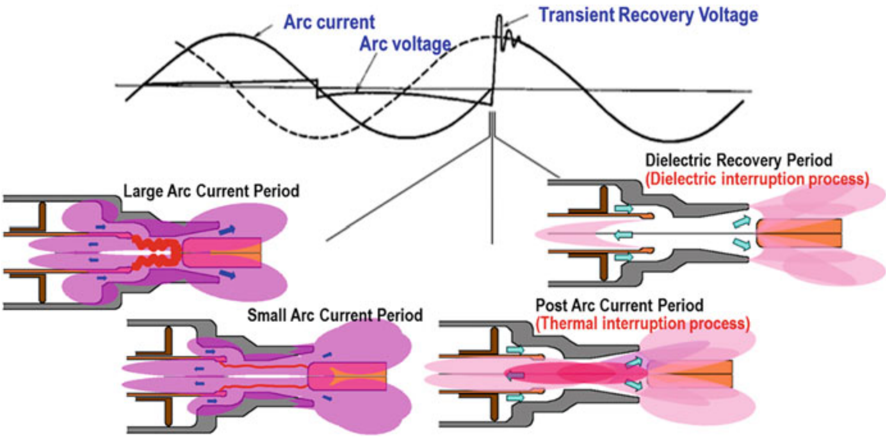


Fig. 5.5 Interruption process with SF_6 gas circuit breaker

The recovery voltage is leading the current to be interrupted by almost 90°. Both are power frequency components: the current being a sine function and the recovery voltage a cosine function. Since modern circuit breakers interrupt at current zero, the recovery voltage jumps from zero before interruption to its peak value. The transient from zero to the peak value is governed by the high-frequency components and is called the transient recovery voltage (TRV). Moreover, the TRV is determined by a more complicated network model at both sides of the circuit breaker with capacitances, natural frequencies between inductances and capacitances, damping, oscillations, and traveling waves (see Fig. 5.6). The TRV applied to the circuit breaker is the difference between the TRVs applied to both sides of the circuit breaker.

The TRV waveform (especially when breaking fault currents) consists of an initial portion, relevant during the thermal phase of the voltage recovery, and a peak value, relevant for the dielectric phase. The key characteristics of the initial portion are the dU(t)/dt and the time delay. For the standards (IEC62271-100 2008) and IEEE Standard C37.09 (1999), TRV waveforms are described by envelopes. These are two-parameter or four-parameter curves, covering more or less a single frequency and a multifrequency system response, respectively. A single frequency system response gives a TRV waveform similar to a damped 1-cos function. A multifrequency response can be seen as a 1-exp function, overlapped by a 1-cos

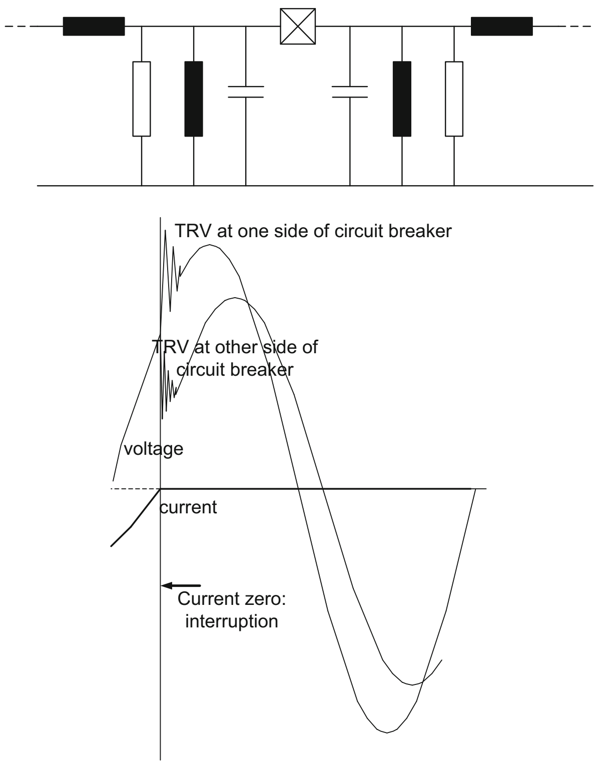


Fig. 5.6 Typical meshed network at both sides of CB with different natural frequencies

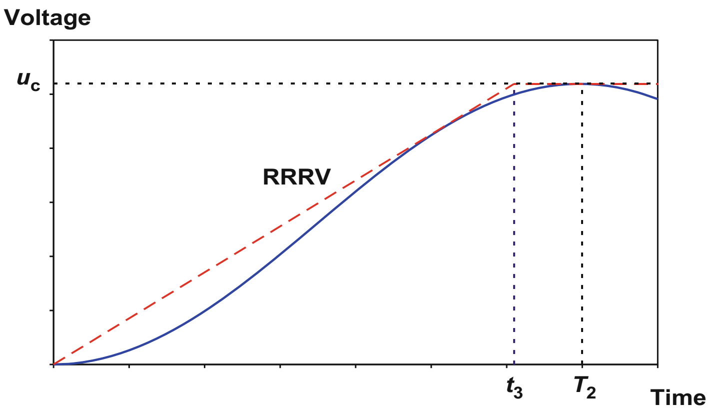


Fig. 5.7 Two-parameter TRV with time coordinates

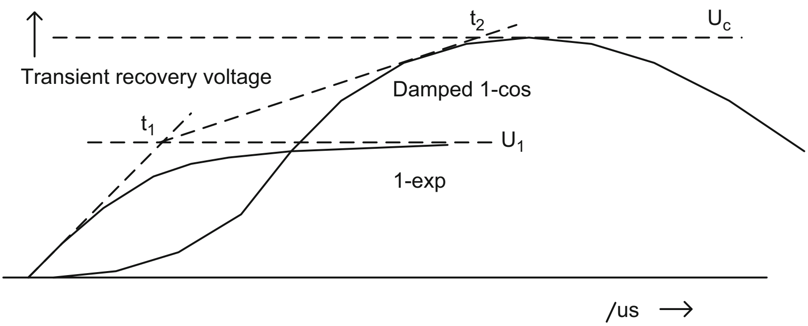


Fig. 5.8 Four-parameter envelope with its coordinates

function. For out-of-phase situations, the four-parameter envelope is used. But first, the two-parameter envelope will be explained.

The two-parameter envelope is defined as the TRV peak value (U_c) with a horizontal line through the TRV peak value and another dotted line through the origin and touching the TRV waveform. The slope of this line is the RRRV (the rate of rise of the recovery voltage). The RRRV is a measure for the TRV steepness dU(t)/dt but is not the same, as can be seen in Fig. 5.7. The two envelope lines of a damped 1-cos function cross at the time coordinate t_3.

The four-parameter TRV is depicted by the values of U_1, t_1 and U_c, t_2 shown in Fig. 5.8. The initial portion represents the traveling waves with $dU/dt = Z^* \, dI/dt$: where Z is the equivalent surge impedance of the system at the location of the circuit breaker. The positive reflections of the traveling waves are covered by the upper part of the damped 1-cos function. Essentially, the 1-exp function represents an overdamped system (low equivalent surge impedance), while the damped 1-cos function (as shown in the two-parameter envelope) represents an underdamped system (high equivalent surge impedance).

From a design aspect, the circuit breaker is required to demonstrate that it can withstand a TRV waveform required for the specified envelope. From an application aspect, the TRV waveforms in service have to show an envelope that lies below the specified envelope. If this is the case, the circuit breaker will perform the required function.

5.5 History of Circuit Breaker Development

Over the last 100 years, electricity has become the world's most flexible and reliable power system. Global demand continues to increase, and, in many countries, the supply of electricity is strongly linked to gross domestic product (GDP) in the country. The infrastructure that enables the safe distribution of electrical power is based upon one specific device which must be extremely reliable: the circuit breaker (CB). The circuit breaker plays what is considered the most important role in the networks which is switching the power system current during both normal and abnormal conditions of the power systems.

The first circuit breakers were built at the beginning of the twentieth century. Since then, the design, manufacturing, testing, and field application of circuit breakers have changed considerably. Water and oil breakers appeared early on in circuit breaker development and worked at very low levels of current and voltage. The contacts in these breakers were embedded in a large tank, filled with the chosen medium. For example, oil circuit breakers rely upon vaporization of some of the oil to blast a jet of oil through the arc. Under these conditions, arc formation led to ionization of the medium and the formation of hydrogen gas. When a current zero was approached (every 10 ms in a 50 Hz or 8.33 ms in a 60 Hz alternating current sinusoidal wave), the high pressure of the vaporized medium compressed the gas-filled arc channel. This caused the medium between the opening contacts to lose most of its conductivity, thereby quenching the arc. Unfortunately, because of the large volumes of medium they required, these devices filled with mineral oils were rather unwieldy, and, if an oil circuit breaker failed, there was a significant risk of explosion and fire. Despite these risks, oil remained a popular medium and oil circuit breakers, based on these cumbersome early devices, were manufactured until the 1980s. As a result of these issues, other types of interrupting media were developed which each had their own advantages and disadvantages. Through its history of development, circuit breakers applied to power systems were broadly classified by the medium used to extinguish the arc. Major circuit breakers applied with different interrupting and insulating media are listed below:

- Bulk oil
- Minimum oil
- Air blast
- Vacuum
- SF_6

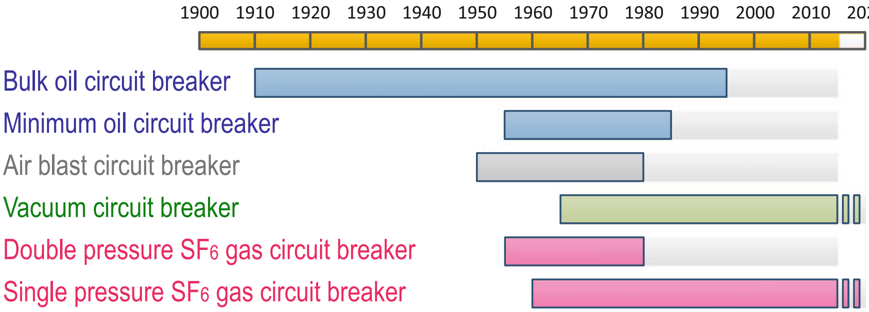


Fig. 5.9 Manufacturing period of circuit breakers with different technologies

The general timeline of commercial production and use of these various types of circuit breakers is shown in Fig. 5.9.

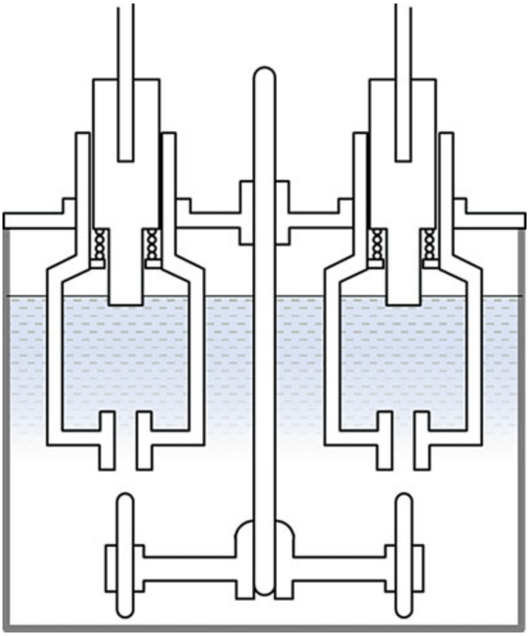
The worldwide experience with circuit breakers over the years in a variety of applications, along with the exchange of this knowledge in CIGRE Study Committee 13 and later Study Committee A3 brought new insights that resulted in new medium- and high-voltage switching equipment. In 1907, the first oil circuit breaker was patented by J. N. Kelman in the United States (Kleman 1907). The equipment was hardly more than a pair of contacts submersed in a tank filled with mineral oil. It was a time of discovery by experiments, and most of the breaker design was done by trial and error in the power system itself. In 1956, the basic patent on circuit breakers employing SF_6 was issued to Lingal et al. (1956). Presently the majority of high-voltage circuit breakers use SF_6 as the interrupting and insulating medium. J. Slepian has done much to clarify the nature of the circuit breaker problem, because the electric arc proved to be a highly intractable and complex phenomenon (Slepian 1929). Each new refinement in experimental technique generated more theoretical problems. The practical development of circuit breakers was, especially in the beginning, somewhat pragmatic, and design was rarely possible as deduction from scientific principles.

A lot of development testing was necessary in the high-power laboratory. A great step forward in understanding arc-circuit interaction was made in 1939 when A. M. Cassie published the paper with his well-known equation for the dynamics of the arc (Cassie 1939; Cassie and Mason 1956). Then, in 1943, O. Mayr followed with the supplement that takes care of the time interval around current zero (Mayr 1943). Much work was done afterward to refine the mathematics of those equations and to confirm their physical validity through practical measurements (Frost and Liebermann 1971). It becomes clear that current interruption by an electrical arc is a complex physical process when we realize that the interruption process takes place in microseconds, the plasma temperature in the high-current region is more than 10,000 K, and the temperature decay around current zero is about 2000 K per microsecond, and the gas movements are supersonic. The understanding of the current interruption process has led to SF_6 circuit breakers capable of interrupting 63 kA at 550 kV with a single interrupting element.

5.6 Oil Circuit Breakers (OCB)

In the late 1800s and early 1900s, the interrupting media of circuit breakers was air, oil, or water. Figure 5.10 shows an example of one of the very early breakers of this vintage. The breaker shown in Fig. 5.11, one of the first oil circuit breakers used, was for application at 40 kV, was installed in 1901, and consisted of two barrels half filled

Fig. 5.10 Early circuit breaker design



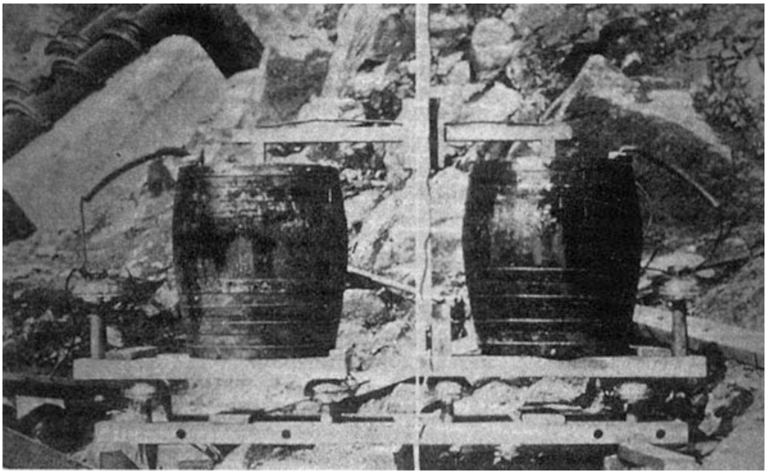


Fig. 5.11 Early 40 kV oil circuit breaker (1901). (Wilkins and Crellin 1930)

with water for performing interruption of 400 A and with oil in the upper section to provide open position dielectric. This performed fairly well until several operations were made over a short period of time resulting in an explosion destroying the adjacent power house (Wilkins and Crellin 1930). Breakers of similar concept, however, performed well and had design improvements over the years. Some of these breakers continued in service through the 1950s.

As demands by utilities for higher voltages and currents increased, the oil circuit breaker became the primary breaker of choice. In the United States, the "bulk" or dead tank oil breaker was the most popular (Prince and Skeats 1931). In bulk oil circuit breakers, the contacts were located in the center of a large metal tank filled with oil. The oil serves as an extinguishing medium and provides the insulation to the tank. In Europe, the live tank oil breaker design (also referred to as minimum oil or sometimes called the oil-poor design) became the most popular. In this design, the contacts and arcing chamber were placed in a porcelain insulator instead of in a bulky metal tank. This was primarily the result of oil being more available in the United States.

The early oil circuit breakers relied solely on the separation of contacts and the long arcing time produced was of little consequence at the time. Oil became the preferred circuit breaker media not only because of its greater insulation compared with air but also for its greater effectiveness in arc extinction. The principle of arc extinction in oil breakers is based on the decomposition of mineral oil into hydrogen (H_2) and methane (CH_4) gas by the arc. When current arcs are generated in the oil, the medium vaporizes and a bubble forms around the arc. This high-pressure gas, which is almost 80 percent hydrogen (H_2), has excellent dielectric properties and a high specific heat constant, inhibits ionization, and moves through the channels surrounding the arc. It enhances convection in the oil, which helps to cool the arc residuals around zero current (see Fig. 5.12). This arc induced-convection principle was later used in the "self-blast" breaker (Baker and Wilcox 1930).

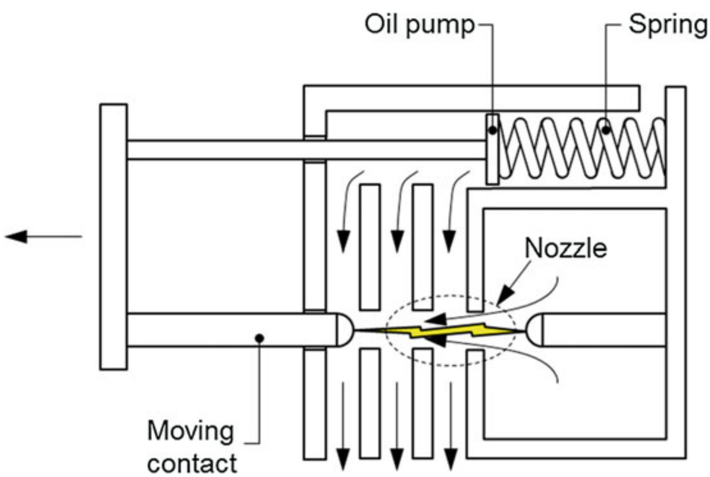


Fig. 5.12 Example of oil circuit breaker with mineral oil convection

In spite of the flammability of both oil and the gases produced by arcing, safe operation is obtained by submerging the contacts in an oxygen-free environment, deep in the oil, and allowing gases to cool as they rise to the surface.

In the early 1920s, engineers began investigation of arc interruption with the intent to provide breakers with higher interrupting capabilities and shorter interrupting times. At Westinghouse in the United States, this investigation was led by research scientist Dr. Joseph Slepian (1929). His work resulted in a detailed scientific explanation of arc behavior based on the ionization of gases both from a theoretical and practical standpoint. During arcing, the current is conducted through the ionization of the interrupting media. At current zero, interruption of the current is the result of deionization of the arc space. One of the basic truths developed in his studies was that the extinction of an arc depended on two factors: the rate of recovery of dielectric strength of the arc space after current zero and the rate at which voltage tending to reignite the arc is applied by the external circuit.

In the late 1920s, this investigation resulted in the development of a deionizing interrupter originally applied to 69 kV oil circuit breakers (OCBs). Eventually, various versions of deionizing grids were applied to oil circuit breakers up to voltages of 345 kV and 63 kA interrupting currents with eight units in series. The interrupter development controlled the arc and enhanced the deionization process resulting in a shorter arcing time and increased interrupting current capability. Figure 5.13 shows a deionizing interrupter assembly for a 69 kV oil circuit breaker (OCB) developed by Westinghouse. It consists of a grid composed of fiber plates each of which were cut to a specific flat geometric configuration which, when assembled one on top of the other, allowed space for the contacts, flow passages for venting gases, segregation of the arc, and oil pockets to provide fresh oil to cool

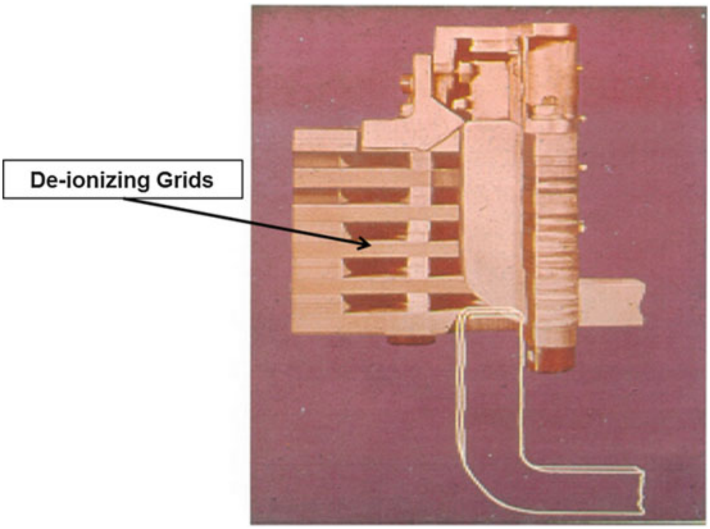


Fig. 5.13 Deionizing interrupter assembly of 69 kV oil circuit breaker

the arc and promote deionization. The fiber plates are unique for this application since the material is “clean burning” meaning that the high temperatures of the arc do not result in carbonization but maintained its insulating characteristics. The decomposition of the fiber also produced gases to enhance the deionization. The use of arc resistant arcing contacts reduced the contamination of the arc space with ionized gases.

At higher voltages and higher interrupter currents, the single break interrupter was modified by adding a second or pressure generating break in series with the main interrupting break. These contacts were located in a separate chamber referred to as an “explosive chamber” and the arc would create pressure to force oil flow into the interrupter grid’s fiber plate paths and into the arcing space enhancing deionization and interruption. As voltages increased, the de-ion interrupter was made as a separate “grid block” assembly that was inserted into the main interrupter tubular support structure as separate units. This resulted in an interrupter that could include several “grid blocks” and associated interrupter contacts in series thus forming a complete multibreak interrupter assembly. Figure 5.14 shows the grid block components assembled in OCB interrupters, which are a lineup of these interrupters for applications at various voltages up to 345 kV and interrupting currents of 63 kA.

During the development of OCBs in the early 1900s, the testing laboratory facilities had limitations in test voltage and current capabilities. Because of this, it was limited in verification of only an individual break’s voltage and current. Testing of higher interrupter break capability with a complete CB has been made possible by modern synthetic testing techniques.

The design of early circuit breakers consisted of two interrupters bridged by a movable metal member (crossarm) for conducting current when the breaker is closed or breaking the circuit and providing a disconnect gap for isolation when the breaker is open. This was an important feature maintained in later model oil breakers. Additionally, there were significant changes in structure, mechanical operation, bushings for insulating the conductors from the grounded tank structure, and current transformers for intelligence.

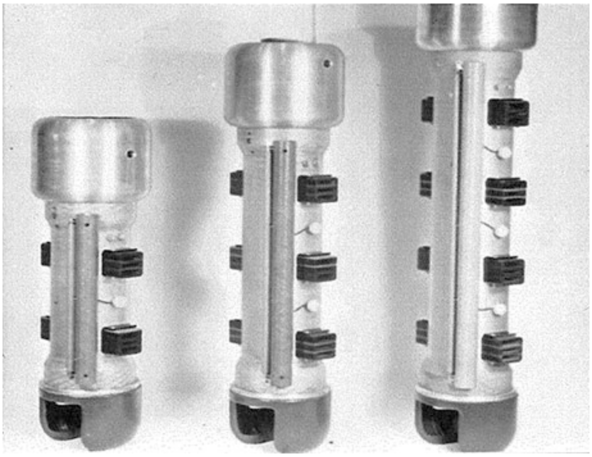


Fig. 5.14 145 kV four-break, 245 kV six-break, and 345 kV eight-break OCB interrupters lineup with 63 kA breaking capability

Figure 5.15 is a cross section of a pole unit of a later oil circuit breaker. As shown, the bushing insulates the conductor from the grounded structure consisting of the tank and also provides support for the interrupters which are bridged by the “crossarm” that is connected to the operating mechanism via the insulated lift rod. The current transformers for protective relaying and metering are mounted around the bushings. Also, note that the interrupter is one of the assemblies shown in Fig. 5.14 employing two “grid blocks.”

Table 5.1 shows the annual progress of OCB interrupting capability with system voltages and interrupting currents. It was deemed that standardization work was

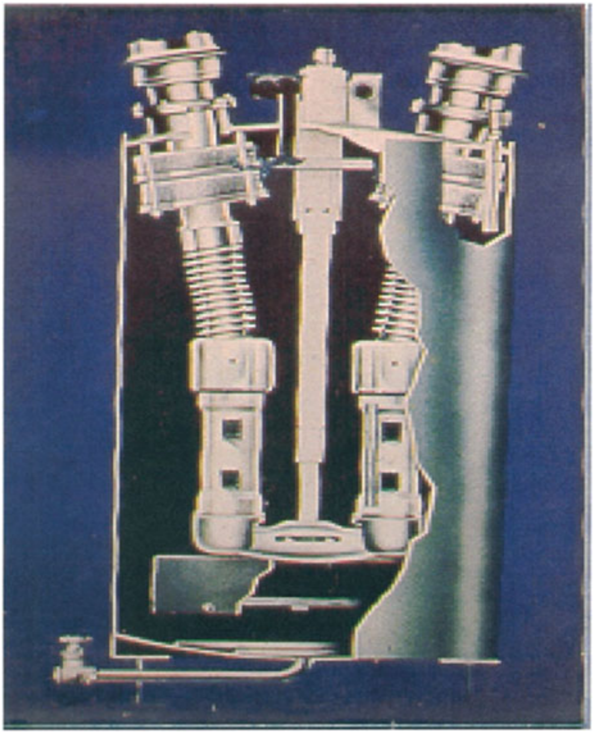


Fig. 5.15 Cross section of later generation of 145 kV 63 kA bulk oil circuit breaker

Table 5.1 Annual progress of OCB capability

Year	Voltage rating (kV)	Current rating (kA)	Three-phase MVA rating (V x I)
1934	287	5	2500
1941	287	7	3500
1945	138	15	3500
1947	230	25	10,000
1949	138	25	6000
1951	161	36	10,000
1954	330	44	25,000
1960	245/362	63	27,000/40,000

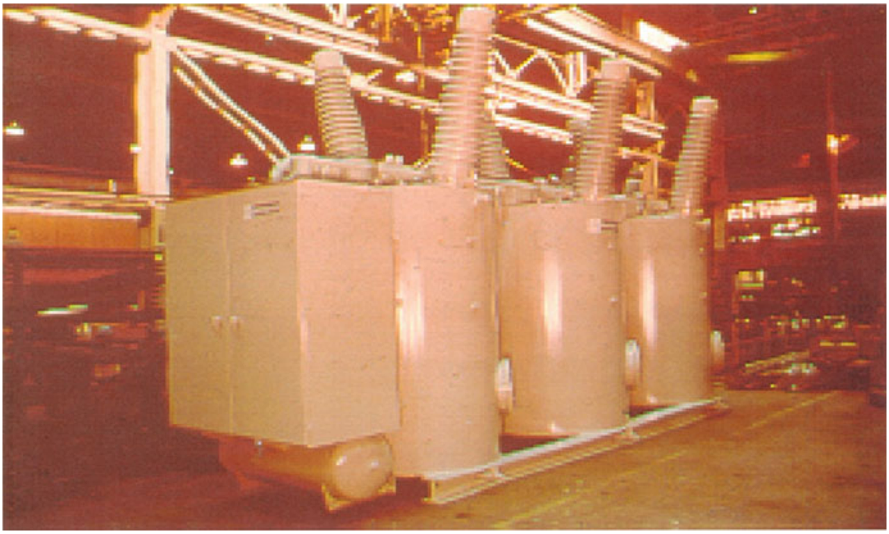
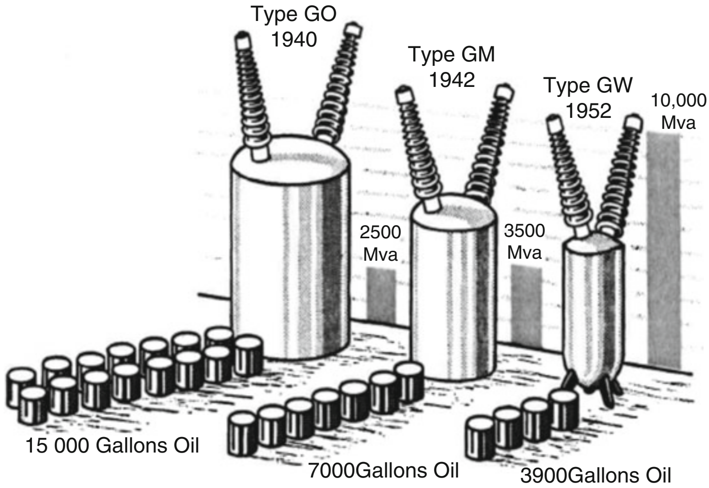


Fig. 5.16 Three-phase bulk oil 242 kV OCBs with dead tanks mounted to steel beam

required to form classes of oil circuit breakers by ratings such as distribution levels from 15 kV to 69 kV and transmission levels of 121–242 kV including 345 kV called extra-high voltage. The 69 kV rating had frame-mounted circuit breakers where the pole unit tanks were supported by a frame with the tanks being lowered for maintenance work. At higher voltages, the pole unit tanks were mounted separately on a foundation or mounted on steel beams as shown in Fig. 5.16.

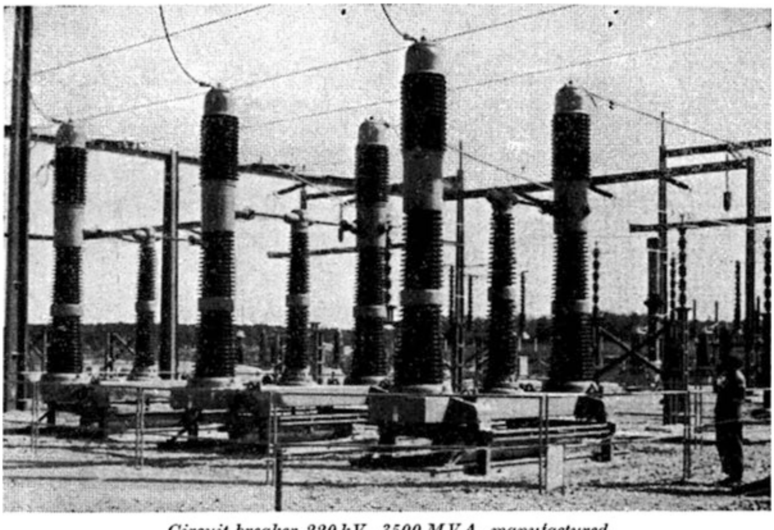
During the popular period for oil circuit breakers, it became desirable to reduce the volume of mineral oil required. This resulted in special tank designs to conform to the voltage gradients around the internal high-voltage components. Figure 5.17 shows the progress made in the effort to reduce the quantity of oil where the amount of oil was reduced by a factor of 4, while the capability was increased by a factor of 4 (2500–10,000 MVA). Of course the live tank-type oil circuit breaker shown in Fig. 5.18 was the most conservative design in quantity of oil filling. However, this type of breaker did not provide the magnitude of interrupting currents required and did not become a major design for the United States market as was noted previously. Minimum oil circuit breakers work best at higher currents that provoke a sharp rise in pressure and strong convection. The interruption of low currents, when the gas quantity released by the arc is lower, has always been a challenge for the design engineers. Minimum oil breakers are sensitive to a dielectric reignition after the interruption of a capacitive current. Oil is a good electrical insulator and when the breaker contacts are open, it isolates the system voltage across the contacts.

Figure 5.19 shows 345 kV oil circuit breakers which was the highest rated voltage achieved for OCBs. This circuit breaker was originally designed for 40 kA interrupting duty but was subsequently modified to meet 63 kA with internal shields to prevent voltage flashovers to the tank wall during interruption.



A "factor of four" figures in recent 230-kv circuit-breaker design
–ratings have increased by four,oil has decreased by almost four.

Fig. 5.17 Progress in 230 kV OCB design efficiency



Circuit-breaker 220 kV, 3500 MVA, manufactured by ČKD-Stalingrad Works.

Fig. 5.18 220 kV 3500 MVA minimum oil circuit breaker

Oil circuit breakers met the needs of electrical transmission systems into the 1980s. Presently, bulk oil and minimum oil circuit breakers still do their job in various parts of the world, but they have left the scene of circuit breaker development. Circuit breakers utilizing sulfur hexafluoride gas are now the breaker of choice

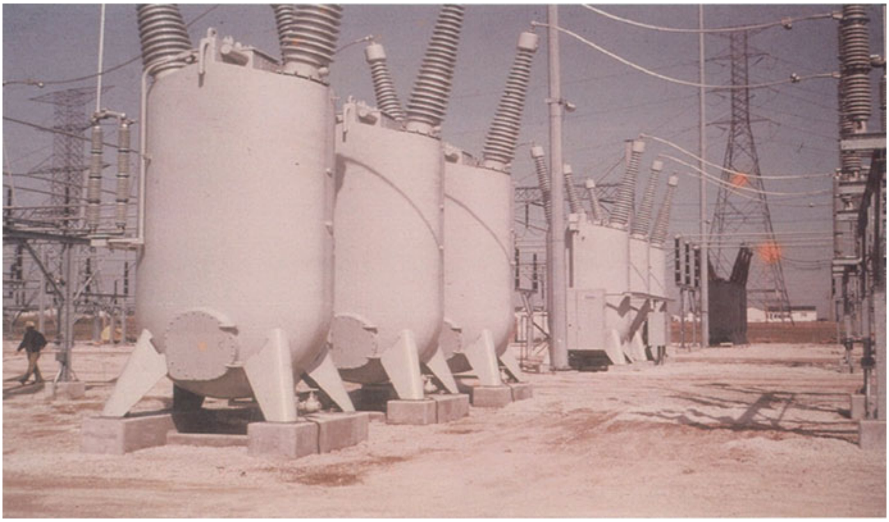


Fig. 5.19 345 kV 63 kA oil circuit breakers

to satisfy the continued demands of higher system voltages, increased short-circuit currents, and frequent capacitance and reactor switching. As of 2016, there remain thousands of oil circuit breakers still in service.

5.7 Air Blast Circuit Breakers

Air is used as a convenient insulator in air-insulated outdoor-type substations and for high-voltage transmission lines. Air can also be used as an extinguishing medium for current interruption. However, at atmospheric pressure, the interrupting capability is limited to low and medium voltages only. Comparable insulation to oil breakers can be achieved using air, but only if it is compressed to several MPa. The use of such high pressures in compressed air blast breakers necessitated a new design of circuit breaker chamber, different from what was developed for oil circuit breakers during the early decades of electrification. The application of air for high-voltage switching equipment was first proposed by the British Electrical Research Association (Whitney and Wedmore 1926). The first design was an interrupter of an axial-blast type. Another design was equipped with metal plates which can split the arc between the plates (Slepian 1929). For medium-voltage applications up to 50 kV, the air blast breakers were normally applied with a magnet in which the arc is blown into a segmented compartment by a magnetic field generated by the fault current. In this way, the arc length, the arc voltage, and the surface of the arc column are increased. Since the arc voltage decreases and limits the fault current, the larger arc column surface improves the cooling of the arc channel.

At higher pressure, air has much more cooling power because the arc is cooled by forced convection as a result of the large pressure difference between the inside of the breaker and the ambient air outside. Air blast circuit breakers operating with compressed air can interrupt higher currents at considerably higher-voltage levels. Air blast circuit breakers using compressed air can be of an axial-blast or cross-blast type. The cross-blast-type air blast breaker operates similar to the magnetic-type breaker: compressed air blows the arc into a segmented arc chute compartment (metal plates). Because the arc voltage increases with the arc length, this is also called high-resistance interruption. It has the disadvantage that the energy dissipated during the interruption process is rather high. In the axial-blast design, the arc is cooled in the axial direction by airflow. The current is interrupted when the ionization level is brought to a low level around the current zero. Because the arc voltage of this type hardly increases, this is called low-resistance interruption. Air blast circuit breakers make a lot of noise during operation, especially when the arc is cooled in free air. This is one of reasons that the application of air blast circuit breakers are limited in high population density areas.

Compressed air has several properties that are beneficial for high-voltage circuit breakers. Air has a high dielectric strength and favorable thermal characteristics that allow for rapid cooling of the arc in the vicinity of the current zero. Air blast (compressed air) circuit breakers use the airflow through nozzles to cool the arc and achieve its deionization. Higher current interrupting performance is achieved by increasing the air pressure (3–5 MPa). In compressed air circuit breakers, the arc is cooled by forced convection caused by the large pressure differences between the inner parts of the breaker and the ambient air outside; a valve opens and compressed air rushes out of the chamber at high speed. A critical design consideration is ensuring that the arc is correctly positioned to benefit from the intense airflow. Various nozzle designs shown in Fig. 5.20 were designed and developed, and, finally, an axial flow, similar to that used in the compression chamber, was chosen.

Air blast circuit breakers that used compressed air as the extinguishing medium had the advantage of high interrupting capability and short interruption times. However, the breaking units (interrupters) had limited dielectric withstand capability which resulted in a circuit breaker for 420 kV requiring up to 6–10 breaking units in series per phase (12 breaking units in series for a 800 kV circuit breaker). The arc extinction requires high air pressure, up to 3 MPa, which means that the risk of leakage is high. Installation, maintenance, and repair are costly in this case.

As early as 1930, a French company "Delle" worked with air blast circuit breakers and minimum oil circuit breakers. The air blast design existed as early as 1930 and was called "Symphaseur" of which one of the best examples was the circuit breakers to protect a testing station which had just been built. The circuit breakers were called the AVP 5/14 but were limited to medium voltage. Extension of this design of air blast circuit breakers to voltages above 66 kV did not occur until about 1955.

From late 1955 to early 1956, a team of the CERDA was working to develop a new cost competitive technology to reach higher-voltage classes. Air blast circuit breakers of this design were put in service from 132 to 420 kV in Europe and

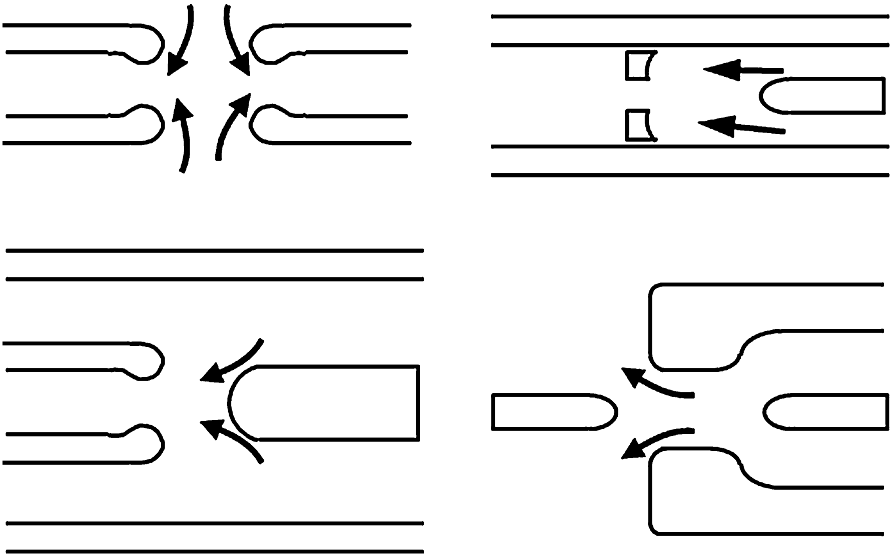


Fig. 5.20 Initial ideas of air blast circuit breaker designs

South Africa. In late 1957, development of circuit breakers of the type AE (air and exhaust) was initiated for a new 525 kV transmission line in Russia, the first in the world. These air blast circuit breakers were delivered in 1960. This design was born a few decades earlier at lower voltages. The AE-type circuit breaker was capable of two interrupting capabilities, 20 and 30 kA, and two standard continuous current ratings: 1250 and 2000 A. Each main chamber or secondary chamber was designed for an elementary rated voltage of 85 kV which required multiple breaking units at high voltage. The development efforts on high-voltage air blast circuit breakers had been focused to increase the unit voltage (to 100 kV per break), leading to less units per circuit breakers.

Based on the good performance of this design of air blast circuit breaker (in addition air does not pollute the atmosphere as other synthetic gases), a new generation of circuit breaker, called the PK design, was designed which simplified the AE design. This design eventually became the first circuit breaker in the world used at 735 kV in Canada and the United States. The design was also used at 138–362 kV as well.

When air blast breakers were introduced, they were used for similar applications as oil circuit breakers. There were several trade-offs between the compressed air breaker and the minimum oil breaker. The oil breaker, especially the self-blast type, had a simple design and could operate under low mechanical power. However, oil is a medium with some difficulties in its handling. It posed a fire risk and necessitated more maintenance. Compressed air breakers, on the other hand, required powerful compressors and were very noisy when operating especially when they vented to the atmosphere. Also, the moisture levels in the compressed air had to be controlled.

In addition, an uncontrolled arc in an air blast circuit breaker could lead to significant damage due to the presence of high O_2 levels. The high pressure could, however, be used to drive the movement of the contacts, and compressed air-based systems were much cleaner and easier to maintain than their oil-based counterparts.

The development of these two breaker principles in parallel polarized opinion, even within the producing manufacturers, and competition between the two camps continued with almost religious zeal. In 1955, some engineers claimed that, “the air blast breaker is better than any other type of breaker for the high voltage level.” As noted above, air blast circuit breakers did become widely used at the very high-voltage levels. Time, however, proved both opinions wrong, and the introduction of sulfur hexafluoride (SF_6) as a viable solution to replace air became more popular than either of its predecessors.

The latest generation of air blast circuit breakers uses pole chambers that are totally and permanently under pressure as shown in Fig. 5.21 Their metal nozzles are of the double-flow type, with gas flow in two directions, and valves located downstream from the nozzles operated by pushrods. This provision helped to reduce the breaking time to two cycles (nominal service frequency) as needed at very high voltages in order to maintain system stability in the event of a fault.

Compressed air/air blast circuit breakers require regular maintenance, especially of their compressor stations. Yet, they have maintained a leading position in terms of high-performance capability over the years of being able to break up to 100 kA at

Fig. 5.21 Latest generation 800 kV air blast circuit breaker. (Courtesy of GE Grid Solutions, produced by Alstom)

high voltage within two cycles, while reducing surges through the use of parallel resistors for opening and closing. The compressed air breaking technique is well suited for operating at very low temperatures because there is no risk of liquefaction of the gas medium. For this reason, air blast circuit breakers are still in use in the northernmost parts of countries such as Canada, especially at very high-voltage ratings (e.g., 765 kV).

5.8 SF_6 Gas Circuit Breakers

The superior dielectric properties of SF_6 were known as early as 1920. SF_6 has a molecular weight of 146 which is five times heavier than air. The dielectric strength at atmospheric pressure is 2.5 times better than that of air and increases rapidly with pressure. At a pressure of 2 bar, it has the same insulating properties as mineral oil. Contamination by air does not alter the insulating properties substantially. The application of SF_6 gas switching equipment was started by Westinghouse in 1953 (Lingal et al. 1953; Lingal and Owens 1953). The first commercial SF_6 gas circuit breaker was used in 1959 (Yeckley and Cunningham 1958). Later extensive research had been conducted by the Electric Power Research Institute (EPRI) in the United States to investigate the interrupting capability with various gas molecules and gas mixtures (EPRI Report, EL- 284 1977; EPRI Report, EL-1455 1980; EPRI Report, EL-2620 1982). They concluded that there are no alternative interrupting media comparable to SF_6 covering the complete high-voltage and breaking current ranges.

SF_6 is well suited for application in circuit breakers because it is an electronegative gas, therefore, having an affinity for capturing free electrons which gives rise to the formation of negative ions with reduced mobility. This property leads to rapid removal of electrons present in the plasma of an arc in SF_6, thus increasing the arc's conductance decrement rate when the current approaches current zero. In addition, the good thermal conductivity of SF_6 during the thermal interruption process contributes to cool the electric arc. SF_6 is an exceptionally stable and inert gas, but in the presence of an arc, it produces some toxic by-products, such as SF_2 and SF_4, which recombine to form nontoxic products immediately after arc extinction. The main stable toxic products that result are metal fluorides which are deposited as white powder and are absorbed in an activated aluminum filter containing aluminum trioxide. $SF_{6,}$ being an inert, stable gas, reduces corrosion of internal metallic circuit breaker parts thus extending operating time and minimizing maintenance. As it is non-flammable, the risk of fire and explosion is also greatly reduced. SF_6 has very good insulating properties, even at relatively low pressure (i.e., 0.5 MPa). This low pressure is crucial because SF_6 would liquefy at higher pressures and be unable to interact with the arc. At normal gas pressures currently in use, operation in the range of -30 °C to -40 °C can be achieved without additional heating. In colder climates, supplemental heating or derating of the circuit breakers may be required due to liquefaction of the SF_6 gas. Also, mixing with another gas (e.g., N_2 or CF_4) can also reduce the liquefaction temperature and allow operation at lower temperatures (<-40 °C) without the use of supplemental heating (Widl et al. 1988; Peelo et al.

2006). For example, the use of a 50:50 mixture of SF_6 and CF_4 is commonly used to achieve operation to −50 °C without supplemental heating. This, however, has an effect on the insulation and interrupting capabilities of the circuit breaker which need to be addressed.

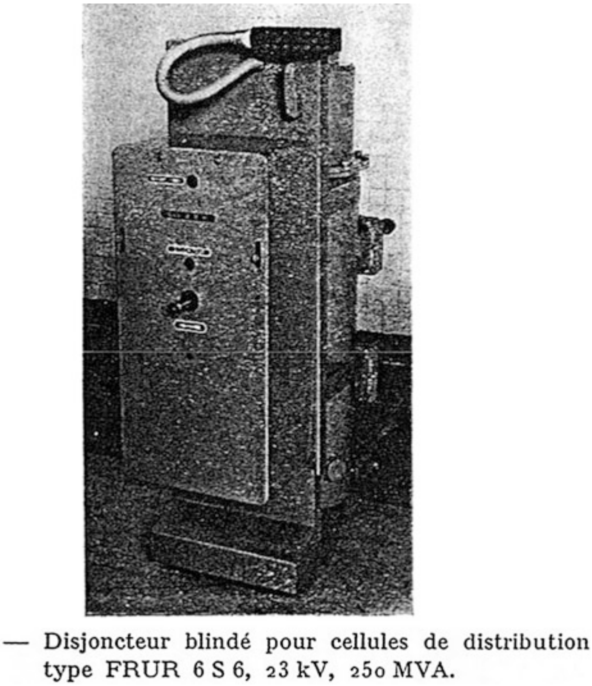
Gas circuit breakers stretch and prolong the arc during the interruption process (sometimes using a magnetic field, sometimes taking advantage of gas flow) and then rely upon the very good dielectric strength properties of SF_6 (rapid switching function from conductive to dielectric states) to quench the stretched arc. In the case of SF_6 technology, the moving contact is connected to a nozzle and a cylinder that forms the piston that compresses the SF_6 gas as the contacts move. When the arc is formed, the cold SF_6 gas, from the dynamically compressed part, can interact with the arc in an axial flow and diffuse its energy. This device combines a number of beneficial features including low maintenance, long-term stability, clean operation, no external compression, and no exhaust noise.

The first development of SF_6 circuit breakers did not begin until the 1940s, but it took until the 1950s before the first SF_6 circuit breaker came to the market. Although the excellent dielectric attributes of SF_6 were known much earlier, the first disclosure of the exceptional properties of SF_6 for current interruption was made in an application for a patent by Lingal, Browne, and Storm in the United States in 1951 (Lingal et al. 1956). In 1953, the first industrial application of SF_6 for current interruption at voltages of 15–161 kV (Lingal et al. 1953) consisted of live switches whose pressurized self-blowing technique was capable of interrupting 600 A currents. The achievement of a high-power, high-voltage SF_6 circuit breaker was first reported in 1956 by Westinghouse. At that time, the breaking capacity was limited to 5 kA at 115 kV (1000 MVA), and the unit consisted of six breaking chambers in series per phase.

Around the same period, in 1957, the French Delle electric factory built a 23 kV, 250 MVA circuit breaker as shown in the Fig. 5.22 for distribution level cubicles followed shortly by a dead tank 25 kV, 200 MVA gas circuit breaker with a self-pressurized insulated nozzle for rail transportation use. In 1959, Westinghouse delivered the first production high-power SF_6 circuit breaker which was capable of interrupting 41.8 kA at 138 kV (10,000 MVA) and 37.6 kA at 230 kV (15,000 MVA) (Yeckley and Cunningham 1958). This tri-pole dead tank SF_6 circuit breaker consisted of three chambers in series per pole which were pressurized at 1.35 MPa for arc clearing and 0.3 MPa for dielectric withstand. The excellent properties of SF_6 described above resulted in the continuous development of the SF_6 technology in the course of the 1960s, and its extended use for the design of circuit breakers with high breaking power under increasingly higher voltages, up to 765/550 kV.

These early designs were descendants of the axial-blast and air blast gas circuit breakers. The contacts were mounted inside a tank filled with SF_6 gas, and, during the current interruption process, the arc was cooled by compressed SF_6 gas from a separate reservoir. This was, therefore, called the double-pressure design (Friedrich and Yeckley 1959; Leeds et al. 1966). Figure 5.23 (a) shows a typical configuration of a CB of the double-pressure type. The liquefying temperature of SF_6 gas depends on the pressure but lies in the range of the ambient temperature of the breaker. This

Fig. 5.22 23 kV 250 MVA vintage gas circuit breaker



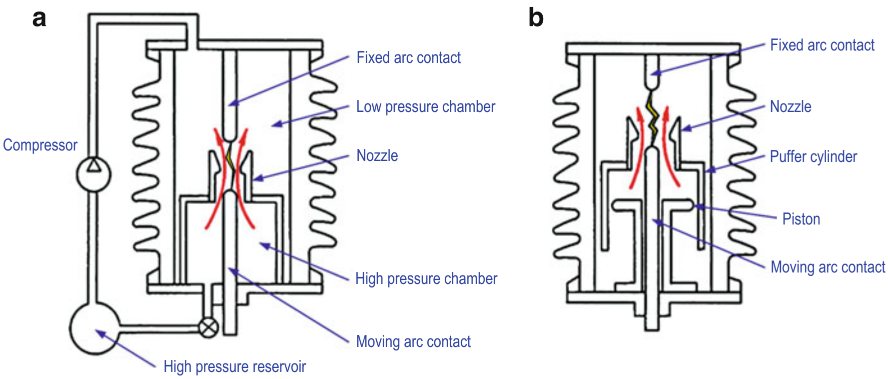


Fig. 5.23 Typical configurations of gas circuit breaker: (**a**) double-pressure type, (**b**) single pressure puffer type

means that the SF_6 reservoir in the double-pressure design needed heating elements to eliminate the possibility of liquefaction at some temperatures which introduced an extra failure possibility for the circuit breaker that could result in the breaker not being able to operate. Although interesting operating performance was achievable thanks to the high gas pressures used, these apparatus could not eliminate a risk of

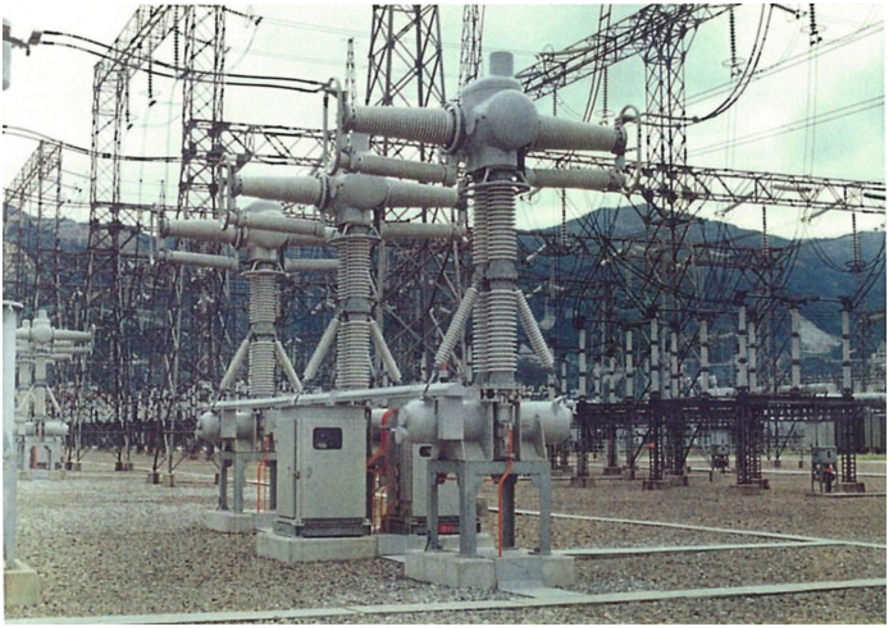


Fig. 5.24 240 kV double-pressure-type gas circuit breaker

liquefaction of the SF_6 gas below 5 °C without additional temperature regulation of their high-pressure vessels. Figure 5.24 shows an example of 240 kV double-pressure-type gas circuit breaker.

In order to solve SF_6 liquefaction under high pressure, a single pressure SF_6 puffer design was developed in the early 1960s as shown in the Fig. 5.23b. Delle first developed medium-voltage levels gas circuit breakers in France and further developed in the 1960s and 1970s for rated voltages higher than 52 kV. The puffer-type CB was also developed for voltage ratings of 34.5–69 kV with breaking currents from 25 to 30 kA in the United States (Easley and Telford 1964). Then the so-called double-pressure-type CB disappeared from the market.

In the puffer gas circuit breaker, the opening stroke driven by an operating mechanism moves a piston rod which also moves the moving arc contacts and a piston, compressing the gas in the puffer chamber and thus causing axial gas flow along the arc channel. The relative displacement of the tubular blasting enclosure and the fixed piston creates a sudden increase of pressure within the cylinder which forces the gas to flow through an exhaust nozzle over the arc and, in so doing, cools the arc. These interrupters are called a dual blast (or gas flow) design because the cooling of the arc, which is crucial to extinguish it, is obtained by a first upward gas blow inside the insulating nozzle followed by a second axial downward gas blow inside the mobile contact. The nozzle must be able to withstand the high temperatures without deterioration and is made from polytetrafluoroethylene (PTFE).

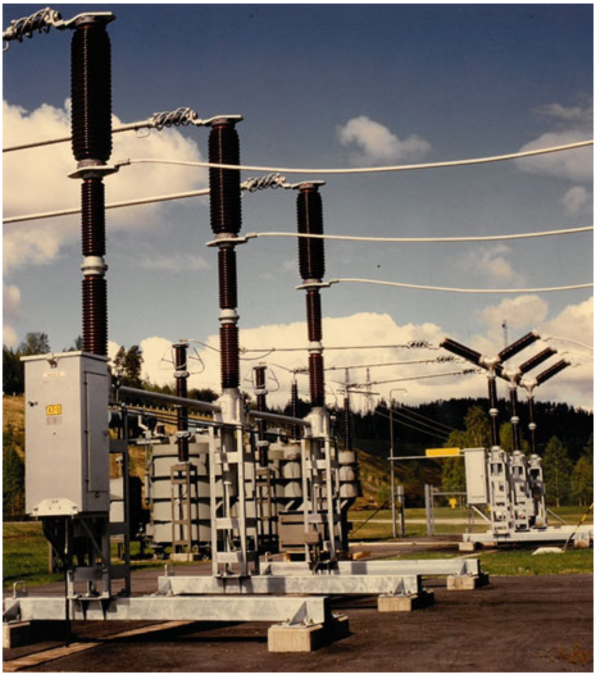


Fig. 5.25 245 kV 50 kA double breaks and single break SF_6 puffer circuit breakers. (Courtesy of ABB, produced by ASEA)

The puffer-type technology including the self-pressurized arc blasting principle was developed from the 1960s to the 1980s to meet the toughest specifications and lead to the development of progressively more efficient apparatus (Spindle et al. 1980).

Figure 5.25 shows the single pressure puffer circuit breakers of two generations with 245 kV 50 kA double breaks (behind) and with single break (forward).

Figures 5.26 and 5.27 show a typical configuration of a 550 kV live tank and dead tank gas circuit breaker with of the single pressure puffer type installed in the United States. Presently, the SF_6 puffer circuit breaker is the breaker type used for the interruption of the highest short-circuit power, up to 550 kV 63 kA per interrupter shown in the Fig. 5.28 (Yamagata et al. 1996). The principles of the puffer interrupter are discussed in more detail below and in ▶ Chap. 6.

Puffer circuit breakers require a rather strong operating mechanism because the SF_6 gas has to be compressed. When interrupting large currents, for instance, in the case of a three-phase fault, the opening of the circuit breaker has a tendency to clog due to the thermally generated pressure, and the operating mechanism (often hydraulic or spring mechanism driven) needs to have enough energy to keep the contacts moving apart at sufficient speed. Strong and reliable operating mechanisms are costly and form a substantial part of the price of a circuit breaker. For the lower-voltage range, self-blast circuit breakers are available on the market. Self-blast circuit breakers use the thermal energy released by the arc to heat the gas and to increase its pressure. After the moving contacts are out of the arcing chamber, the

Fig. 5.26 550 kV live tank SF_6 gas circuit breaker. (Courtesy of Dominion Energy)

Fig. 5.27 550 kV dead tank SF_6 gas circuit breaker with a pneumatic operating mechanism. (Courtesy of Dominion Energy)

Fig. 5.28 550 kV single pressure-type gas circuit breaker. (Courtesy of Chugoku Electric Power)

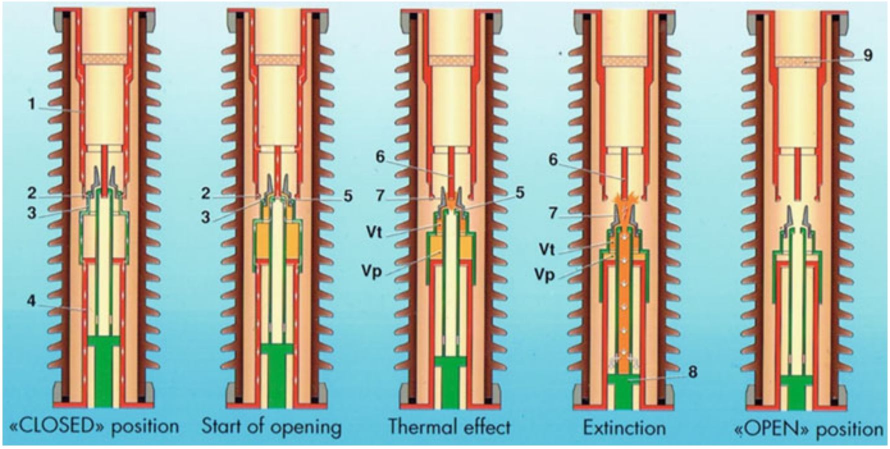


Fig. 5.29 Arc-assisted interrupter with dual puffer cylinders. 1: Current pass at fixed contact side, 2: Fixed main contact, 3: Moving main contact, 4: Current pass at moving contact side, 5: Moving arc contact, 6: Fixed arc contact, 7: Nozzle, 8: Operating insulator rod, *Vt* gas pressure at upper puffer cylinder with fixed volume, *Vp* gas pressure at lower puffer cylinder with compressible volume by a piston

heated gas is released along the arc to cool it (see the Fig. 5.29). The interruption of small currents can be critical for this design because the developed arcing energy is in that case modest, and sometimes a small puffer is added to assist in the interrupting process. The details of this design are discussed in more detail in ▶ Sect. 6.8.

In other designs, a coil carrying the current to be interrupted creates a magnetic field, which provides a driving force that rotates the arc around the contacts and thus provides additional cooling. The first applications of the self-blast features in an SF_6 breaker followed yet another path, as applied in vacuum circuit breakers, using a magnetic field to control the arc. This design is called the rotating arc-circuit breaker. When the contacts are opened, and an arc is formed, a magnetic field builds up due to the spiral form of the electrodes. This causes the arc to rotate at high speed, forcing it to mix with the cold SF_6 medium, which quickly saps its energy. This approach takes advantage of the cumulated expertise and knowledge in multiple phenomena such as arc cooling, gas flow, material ablation, and gas insulation. Thus, the energy required for interrupting short-circuit currents in SF_6 breakers incorporating such expertise is taken partly from the arc itself. This reduces the operational energy requirements to less than half that of a conventional single pressure SF_6 puffer-type circuit breaker. Both self-blast breakers and rotating arc breakers can, therefore, be designed with less powerful (and therefore less expensive) mechanisms and are of a more compact design than pure puffer breakers.

The use of SF_6 as a medium has proved extremely popular with users and engineers. The development of new, yet higher performance SF_6 circuit breaker generations resulted in the supremacy of SF_6 apparatus in the voltage range up to 800/1100 kV. From 1983 onward, numerous achievements paved the way for the overwhelming success of the SF_6 scheme for all types of high-voltage switchgear. Further reduction of the number of interrupting chambers has led to a great simplification of the devices stemming from the decrease of moving parts, seals, etc. This, therefore, resulted in a significantly improved reliability of the apparatus, in addition to the already reported increasing interrupting capacity. Technically speaking, several characteristics of SF_6 circuit breaker technology are responsible for its success:

- Simplicity of the breaking chambers which require no auxiliary compartment for arc quenching
- Autonomy of the devices thanks to a self (single or double)-blasting technique (no compression of the SF_6 gas)
- Opportunity to obtain higher performance levels, up to 63 kA, with a small number of breaking chambers:
  - One chamber to break 63 kA through 550 kV
  - Two chambers for 1100/800 kV circuit breakers
- Successful arc extinction within 2 or 2.5 cycles
- High electrical endurance guaranteeing the normal interruption stresses during a service life of at least 25 years or typically more than 30 years
- Decomposition of SF_6 including charged particles and electrons in conductive states due to arcing quickly recombining to form nontoxic products in the dielectric state reversibly
- High mechanical endurance, especially with a spring operating mechanism guaranteeing 10,000 switching operations
- Reduction of the overall footprint for compact metal clad MV/HV switchgear

- Possibility to equip the chambers with integrated closing resistors and to perform controlled switching operations to reduce switching surges
- Safety of operation
- Lower noise level

5.9 Vacuum Circuit Breakers (VCB)

In the early days of electrical networks, oil and air circuit breakers were the mainstays of switching equipment that performed the task of breaking a circuit. Although they performed this duty well and are still in use today, these types have significant drawbacks which made alternate concepts desirable (oil fires, loud exhaust gas noise, gas leakage, and environmental impacts). The advantages of vacuum as a current interrupting medium were known as early as the 1920s. The first experiments with vacuum interrupters took place in 1926 (Sorensen and Memdenhall 1926). However, commercial application did not occur until the late 1960s because the industry did not have the capability to fabricate the ultrahigh vacuum sealing necessary for long duration application. By that time, metallurgical developments made it possible to manufacture gas-free electrodes and ultra-tight sealing which enabled the first practical vacuum interrupters to be built. After solving these problems, the complicated manufacturing techniques required were the reason vacuum circuit breakers (VCBs) were still not economical for use on the power systems with less maintenance requirements.

VCBs continued to evolve gradually, but it was not until the 1980s, after a series of improvements, that vacuum switchgear was applied on a large scale in electrical networks (Vacuum Arcs Theory and Application 1980; Harris 1980; Yanabu et al. 1989). Since this time, the vast majority of circuit breakers in networks with voltages of up to 40.5 kV are based on vacuum technology. Since the 1990s, VCBs up to 145 kV became available, but these HV VCBs still constitute a small fraction of the HV CB market. It is still not profitable to produce vacuum circuit breakers for applications above 145 kV, since vacuum insulation does not scale proportionally to contact gap length, as SF_6 insulation does. Also higher voltages require larger circuit breakers with corresponding manufacturing difficulties (Slade 1998) although some vacuum breakers are being used at 145 kV.

All of the circuit breaker types discussed in previous sections rely on some kind of extinguishing medium in which the electric arc develops in an interrupter. The vacuum circuit breaker, however, takes a different approach. When current carrying contacts separate in a vacuum container, the arc traces release metal vapor from the metal contacts. It is this metal vapor that provides a conductive medium for arc formation. In addition, vacuum circuit breakers sustain arcing even with very low arcing voltage (as there is nothing to ionize other than the contact material), so at current zero the arc readily quenches, thereby restoring the insulation extremely quickly by diffusion of the remaining post-arc plasma into the vacuum background even at very small gap lengths

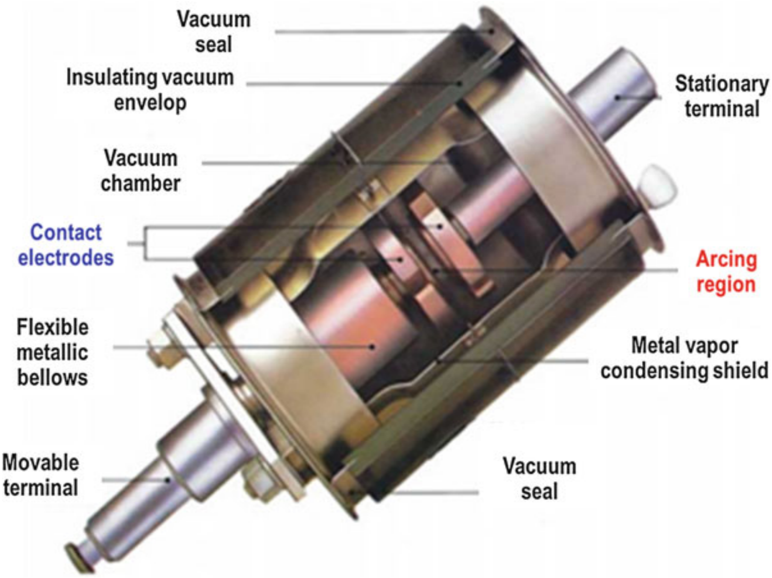


Fig. 5.30 Typical configuration of a modern VCB

(less than 2–3 mm). A description of the key components of a modern VCB is given in Fig. 5.30.

The behavior of interruption processes in the vacuum arc column is best understood as a metal surface phenomenon rather than a phenomenon in an insulating medium. The arc is maintained by ions of metal material vaporized from the cathode. The density of this metal vapor is proportional with the current, and the plasma reduces when the current approaches current zero. At zero current, the contact gap is rapidly deionized by condensation of the metal vapor on the electrodes or condensing shield. When the arc current goes to zero, it does so in discrete steps of a few to 10 A depending on the contact material. For the last current step to zero, a slight chopping of the current can occur. This current chopping, although an issue in the past when it was known to cause high over voltages, in particular, when the vacuum breaker interrupts a small inductive current (e.g., when switching unloaded transformers or stalled motors), is now minimized by a proper choice of contact material, normally a CuCr alloy. The absence of ions after current interruption gives the vacuum breaker a high dielectric withstand capability.

Since there are no mechanical ways to control the vacuum arc, the only possibility to influence the arc channel is by means of interaction with a magnetic field. The vacuum arc is the result of a metal vapor including charged particle (ions and electrons) emission phenomenon which can cause erosion of the contact surfaces leading to degradation of performance and the need for replacement. To avoid uneven erosion of the surface of the arcing contacts (especially the cathode surface) and to avoid concentration of the arc into a single “anode spot” causing gross contact melting, the arc should be kept in a spiraling motion or in a diffuse

Fig. 5.31 Typical vacuum interrupter with axial magnetic field electrode. (Courtesy of Eaton)

mode. The spiraling motion can be achieved by making incisions (or slits) in the arcing contacts. This is known as radial magnetic field arc control. Because the electrodes are spiral shaped, a radial magnetic field is induced in which the arc rotates (thus minimizing the erosion of the electrode surfaces), and the arc is extinguished once the metal vapor recondenses on the electrodes and walls of the vacuum breaker chamber.

Axial magnetic field arc control aims to keep the arc in the diffuse mode, holding the arc stationary, but using the whole inter-contact gap ("diffuse mode"). Axial magnetic fields can also be achieved by applying a horseshoe-shaped iron package located behind the contacts. A typical vacuum interrupter is shown is Fig. 5.31.

The development of more advanced contacts using the benefits of induced magnetic fields in the contact design as well as improved materials increased both the interruption performance and lifetime of vacuum interrupters. The contact designs used in the initial vacuum interrupters were a flat or "butt" style contact design. This design led to a concentrated arc column that resulted in overheating of the contact surface and increased contact erosion. This required a larger contact surface or reduced current to maintain acceptable performance and lifetime.

Radial and axial magnetic field contacts control the arc so that the arc is distributed and overheating is reduced increasing performance and life. Typical contacts are shown in Fig. 5.32 along with typical materials and applications. Butt-type contacts without arc control are usually applied for low current applications (switches, contactors), while the radial field contacts are a better choice for higher current applications and axial magnetic field contacts for applications where low erosion is a requirement as shown in Fig. 5.32. Typical configurations of vacuum interrupters with a brief explanation about the functions of the spiral and axial magnetic field contact designs are shown in Figs. 5.33 and 5.34, respectively.

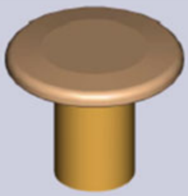
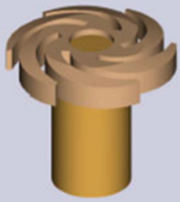
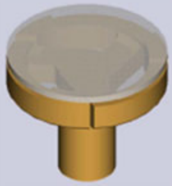
Contact Structure	Flat (Butt) Contact	Spiral Contact	Axial Magnetic Field Contact
Appearance			
Typical Application	•VCB •LBS •Contactor	•VCB (High Current)	•VCB (Low Erosion) •VCB (Low Surge)
Common Contact Materials	•Cu-Cr alloy •Ag-WC alloy •Cu-W alloy	•Cu-Cr alloy	•Cu-Cr alloy •Ag-WC alloy

Fig. 5.32 Typical electrode designs used for VCB

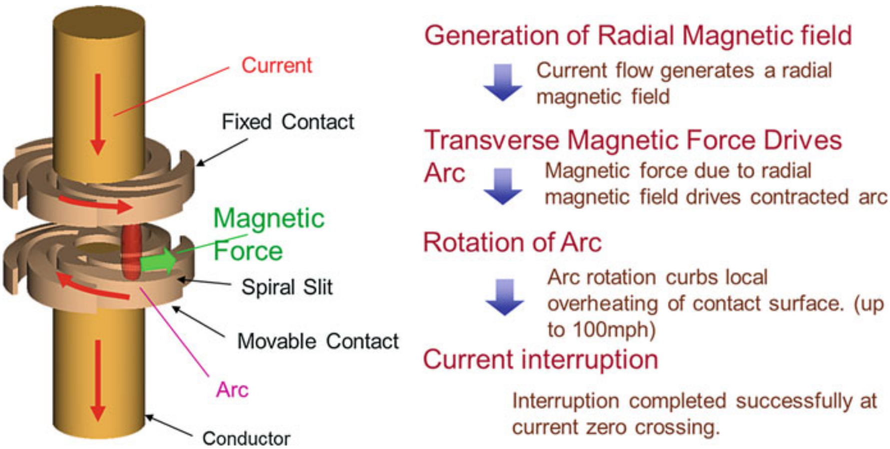


Fig. 5.33 Vacuum interrupter configuration with spiral TMF electrode

Vacuum circuit breakers are typically used in both indoor and outdoor applications. For power circuit breaker applications, three vacuum bottles are installed in a cabinet along with the insulated terminals, internal conductors, and required control systems. Outdoor applications require an external cabinet which protects the breaker from the environment. Indoor breakers can, therefore, be smaller in size. A typical outdoor vacuum circuit breaker is shown in Fig. 5.35.

There is generally less energy required to separate the contacts of a vacuum circuit breaker than for other circuit breaker types. Therefore, the design of the

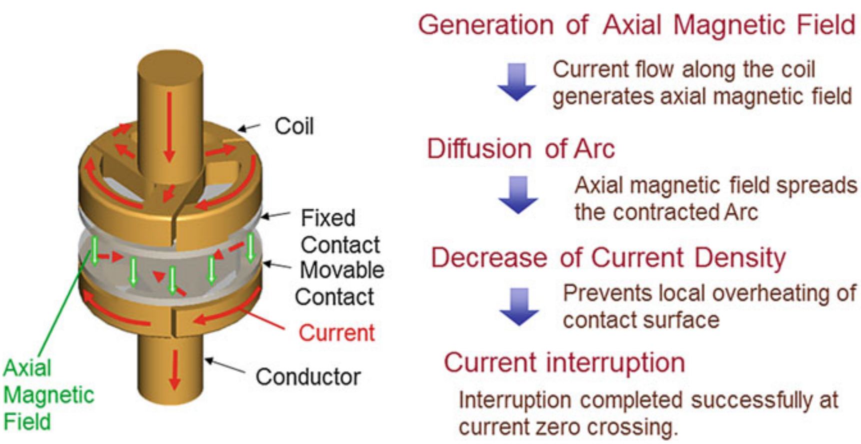


Fig. 5.34 Vacuum interrupter configuration with axial magnetic field electrode

Fig. 5.35 Example of outdoor vacuum circuit breaker. (Courtesy of Mitsubishi Electric Power Products)

operating mechanism usually results in reliable and maintenance-free benefits. Vacuum circuit breakers have become a mainstay for system voltages up to 40.5 kV and short-circuit current ratings up to 63 kA. Vacuum circuit breakers are also applied for transmission levels for 72.5–145 kV ratings. Figure 5.36 shows an

Fig. 5.36 Example of 84/72 kV vacuum circuit breaker. (Courtesy of Mitsubishi Electric)

example of 84/72 kV 2000 A vacuum circuit breaker with a compressed dry air as the insulating media inside the metal enclosure.

5.10 Summary

This chapter describes a historical development of circuit breakers. Water and oil breakers appeared early on in circuit breaker. Oil circuit breakers and air blast breakers enabled EHV transmission networks. Then SF_6 gas circuit breakers realized reliable power systems. Over a half century, alternative solutions instead of SF_6 gas have been investigated due to increasing public concern with SF_6 usage. In addition, HVDC circuit breakers with power electronic devices have been developed up to 500 kV levels, which can potentially interrupt AC current.

CIGRE will investigate the technical trends and facilitate reliable circuit breaker technology.

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Gas Circuit Breakers

6

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6.1 Introduction

Sulfur hexafluoride (SF_6) gas was recognized as an insulating medium having superior dielectric characteristics in the 1920s, and investigations into its interrupting capability started in the 1950s. Industrial production of SF_6 gas started in the United States in 1947, and the application for gas-insulated switchgear with SF_6 was first attempted in 1953 (Lingal et al 1953). A manufacturer in the United States, Westinghouse, produced the first SF_6 gas circuit breaker in the world in 1959. (Leeds et al. 1957). The current interrupting principle has been improved from double-pressure type to single pressure puffer type with various configurations.

Arc discharge occurs between arcing contacts in the interrupter in the enclosure filled with SF_6 gas. The arc plasma generated in SF_6 gas can be changed from conductive to isolating states and vice versa depending on its temperature. The temperature can be controlled by the gas flow from outside the arc. The arc plasma can be a useful electric circuit element capable of so-called "switching function." SF_6 has a unique feature, which can capture free electrons resulting in enhancement of the following reversible chemical reaction during interrupting process. The practical reaction includes the components of the contact and nozzle materials.

$$SF_6 \leftrightarrow SF_4 + SF_2 + F + S + F^+ + S^+ + S^{++} + \ldots + e^-$$

6.2 Definitions of Terminology

Gas Circuit Breaker
The SF_6 gas circuit breaker is an electrical switch using sulfur hexafluoride as insulating and interrupting media. SF_6 gas breakers equip with moving and fixed contacts in an enclosure filled with gas; the gas inside the puffer cylinder is pressurized during the opening operation (heated by arc energy) and blasts high-pressure gas through a nozzle into the arc generated between the contacts to extinguish the arc by cooling.

Transient Recovery Voltage (TRV)
A transient voltage oscillation that appears between the contacts (electrodes) after current interruption, where the contact voltage at source side will oscillate around the source voltage and the contact at line side of a faulted transmission line will oscillate around the ground level.

Residual Current
When the arc current reaches zero, the conductivity in a vanishing arc between the contacts still has a certain value and maintains very small current due to existence of the charged particles. The current after interruption at current zero is called the residual current or post-arc current. The residual current in combination with the transient recovery voltage contributes to energy input due to ohmic heating, which may raise the temperature and increase the conductivity in competition, with the cooling by a gas flow to remove the thermal energy and to reduce the conductivity.

Thermal Conductivity
Thermal conductivity is the property of a material to conduct heat. Heat conduction is primarily evaluated in terms of Fourier's Law. Materials of higher thermal conductivity are readily applied for heat sink. Thermal conductivity of a material may depend on temperature (not required).

Electrical Conductivity
Electrical conductivity is the property of material to conduct current, which is the reciprocal of electrical resistivity. Materials of higher electrical conductivity are readily applied for electric conductors (not required).

Double Pressure Type
Double pressure type mainly establishes the gas pressure (to blast the gas to arc) using an external compressor during the opening operation of the circuit breaker.

Single Pressure Puffer Type
Single pressure puffer type mainly establishes the gas flow (to blast the gas to arc) by increasing the gas pressure in the compressed volume of puffer cylinder by mechanical means during the opening operation of the circuit breaker.

Dead Tank Circuit Breaker
A circuit breaker with interrupters inside an earthed metal enclosure. The conductor applied with the system voltage is fed outside from the interrupters through the bushings.

Live Tank Circuit Breaker
A circuit breaker with interrupters inside a tank (composing of porcelain or composite insulators) insulated from earth. The conductor can be connected directly with a live part of the breaker terminals.

Main Contact
A contact included in the main circuit of a mechanical switching device, intended to carry the current of the main circuit in the closed position.

Arcing Contact
One of a pair of contacts between which the arc is intended to be established. An arcing contact may serve as a main contact.

Enclosure
A part of switchgear providing a specified degree of protection of equipment against external influences and a specified degree of protection against approach to or contact with live parts and against contact with moving parts.

Operating Mechanism
A part of the circuit breaker that actuates the main contacts. It is often referred to as "operating drive." Depending on operating means, they are classified into hydraulic, pneumatic, and spring operating mechanisms.

6.3 Abbreviations

AIS	Air-insulated switchgear
C	Closing operation
CB	Circuit breaker
GIS	Gas-insulated switchgear
O	Opening operation
PTFE	Polytetrafluoroethylene
RRRV	Rate of rise of recovery voltage
SF_6	Sulfur hexafluoride
TRV	Transient recovery voltage

6.4 SF_6 Gas Characteristics

6.4.1 Switching Function of SF_6

In an SF_6 gas circuit breaker, the arc is usually generated in a cylindrical insulating nozzle in order to cool the arc effectively by controlling the SF_6 gas blowing into the arc. The hot gas generated by the arc is then exhausted from the open contact of the interrupter chamber. Polytetrafluoroethylene (PTFE) is generally used for the insulating nozzles, which can control and restrict arc movement inside the nozzle.

The SF_6 arc plasma generated between the contacts of a gas circuit breaker is in a conductive state with charged particles such as ions and electrons. These charged particles are produced from decomposed SF_6 gas as well as contact material due to arc current heating. Radiation heat transfer from the arc to the surrounding materials and evaporation of nozzle materials (loss due to latent heat), along with convection from the turbulent gas flow, and heat conduction will contribute to arc cooling resulting in a change of arc characteristics. Thermodynamic characteristics of SF_6 gas have a strong relation with the excellent arc cooling mechanism (switching function) and reversible interrupting and dielectric withstand capability.

SF_6 has some unique characteristics that make it ideally suited for use as an insulating and interrupting medium in circuit breakers (Frost and Liebermann 1971). This has led to SF_6 becoming the dominant technology for circuit breakers today. Some of the key characteristics of SF_6 which make it an excellent medium for use in circuit breakers are described below.

6.4.2 Gas Density and Its Composition

The dielectric properties of SF_6 are strongly dependent on the gas density. Figures 6.1 and 6.2 show the SF_6 gas density and SF_6 gas composition dependence on temperature respectively. Density follows an ideal gas equation up to 1600 K regardless of the pressure. When the temperature exceeds 1600 K, SF_6 gas density decreases from the values determined by the ideal gas equation (see the Fig. 6.1). This change occurs due to gas decomposition as shown in Fig. 6.2. SF_6 gas shows a clear boundary around 2000 K where gas decomposition is enhanced which results in the generation of charged particles, such as S^+, S^{2+}, F^+, and electrons. When the temperature exceeds 4000 K, SF_6 gas is fully decomposed with many different particles. Electrons account for about 1 percent of all the particles between 8000 K and 9000 K. This can explain the switching function of SF_6 gas showing the conductive and isolative states with this boundary.

6.4.3 Thermal Conductivity and Electrical Conductivity

Thermal conductivity and electrical conductivity affect the heat loss of the arc plasma with a small diameter around current zero, which can strongly affect arc interruption capability. Figure 6.3 shows the thermal conductivity of SF_6 as a function of temperature. When the temperature is raised from 300 K, the first peak of the thermal conductivity appears around 1800 K. On the other hand, electrical conductivity shown in the Fig. 6.4 becomes higher corresponding to an increased

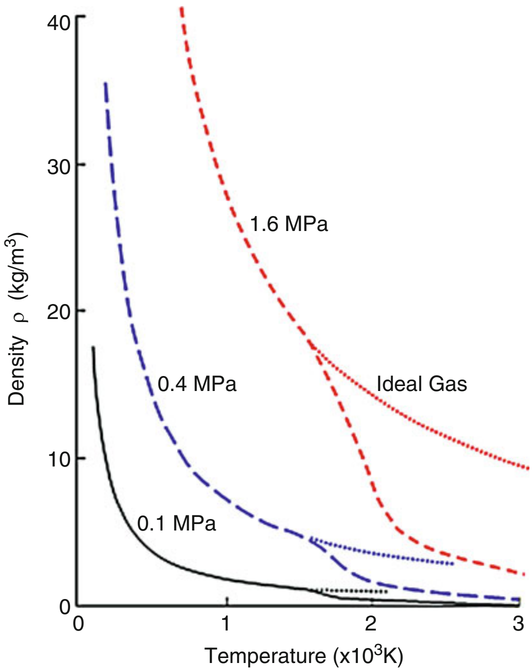


Fig. 6.1 SF_6 gas density

proportion of electrons by ionization. Proportion of the electron becomes 1% of all the particles, and electrical conductivity becomes higher between 8000 K and 9000 K, which is much higher than the temperature (1800 K) where the thermal conductivity shows its peak.

The thermal conductivity generally increases with temperature and has distinct peaks in the area where SF_6 gas is decomposed around 1800–2000 K, which means that the arc shows higher thermal conductivity as well as lower electrical conductivity resulting in good cooling performance when it is close to this temperature region during the small current period.

6.4.4 Specific Heat

The specific heat corresponds to the heat capacity per unit mass of a material. Figure 6.5 shows the dependence of SF_6 specific heat with temperature at a constant pressure of 0.1 MPa. It shows two distinctive peaks around 2000 K and 20,000 K. Figure 6.6 shows the thermal capacity of SF_6 (the product of gas density and specific heat), which also shows higher capacity in the low temperature region (lower than 3000 K) and also around 20,000 K. When the arc temperature increases with an increase of arc current in the lower current region, the temperature stays at 2000 K where the SF_6 gas starts to be

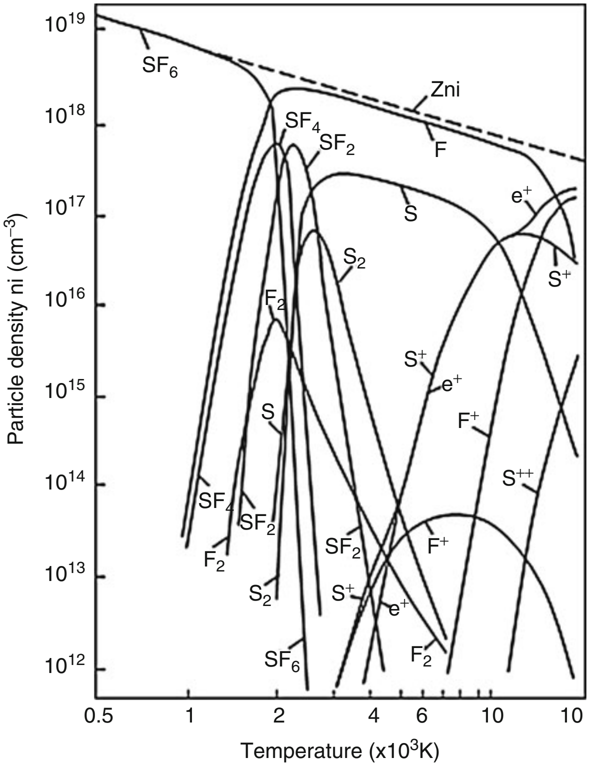


Fig. 6.2 SF_6 gas decomposition. (Frost and Liebermann 1971)

decomposed. In the large current region, the arc temperature stays around 20,000 K due to the larger specific heat in the high temperature region. This is a reason that the core temperature of a large current arc stays around 20,000 K and does not increase much beyond this level.

In order to understand the effective cooling capability due to adiabatic expansion with SF_6 gas, an isentropic cooling process by mixing two different gases is calculated using a large volume ($V_o = 1$) arc at 20,000 K (corresponding to a large current state) and a small volume ($V_d = 0.1$) arc at 1700 K (corresponding to a small current close to current zero) at the gas pressure of 0.6 MPa as shown in the Fig. 6.7. The result after the mixture has a temperature of 2600 K at 0.35 MPa, which is the temperature range having a cooling advantage due to higher heat conduction.

The specific heat ratio (C_p/C_v) of SF_6 is 1.08 which is lower than those of air and hydrogen which is around 1.4. This means that the hot gas with a low specific heat rate, such as SF_6, and requires less heat removal in order to cool it down to the dielectric level when isentropic cooling process with a volume change is considered.

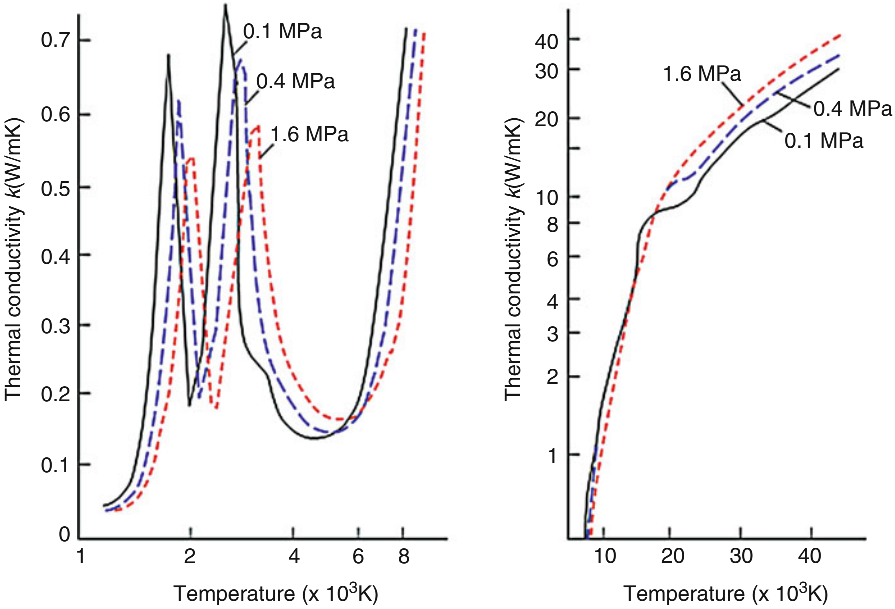


Fig. 6.3 SF_6 thermal conductivity. (Frost and Liebermann 1971)

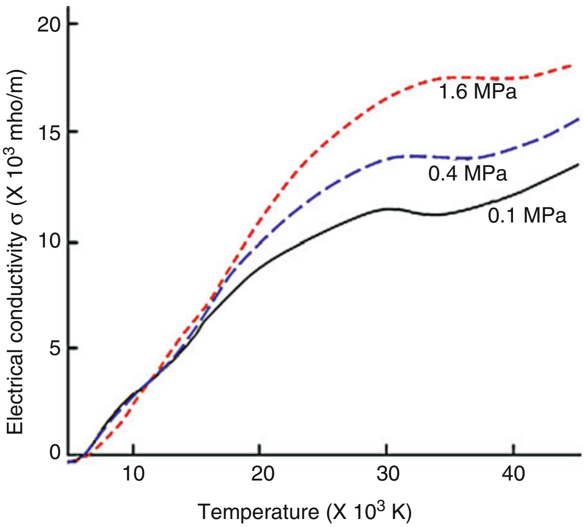


Fig. 6.4 SF6 electrical conductivity. (Frost and Liebermann 1971)

6.4.5 SF_6 Interruption Process with a Gas Circuit Breaker

When it is applied to a circuit breaker, SF_6 has several advantages in its characteristics which create a smaller arc with steeper temperature profiles that can rapidly change from the conductive to the isolative states around current zero. The large

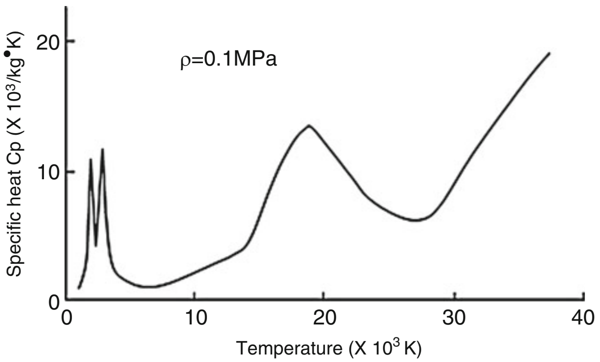
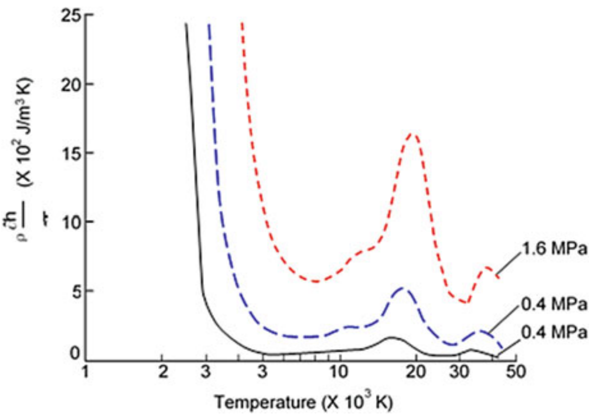


Fig. 6.5 Specific heat dependence on the temperature at 0.1 MPa. (Frost and Liebermann 1971)

Fig. 6.6 Thermal capacity of SF_6 gas. (Frost and Liebermann 1971)



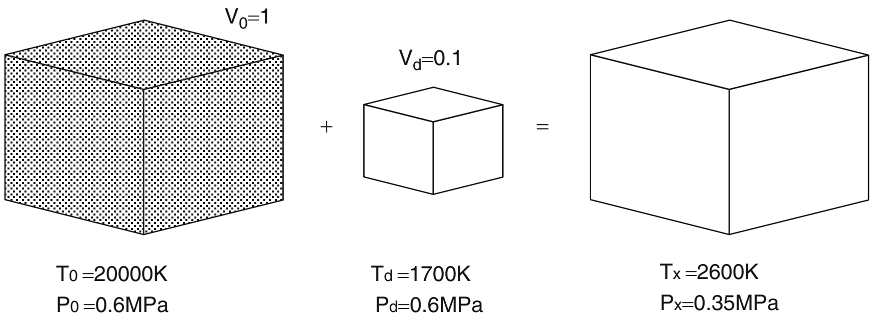


Fig. 6.7 Mixture of SF_6 gas with different temperature and volumes

current interruption process with a modern SF_6 gas circuit breaker is explained below. This process is also shown in Fig. 6.8.

1. The main contact opens first to commutate the interrupting current to the arcing contacts.
2. The arcing contact then opens, and the arc is initiated across the contacts inside the insulating nozzle.
3. A puffer cylinder driven by an operating mechanism compresses SF_6 gas and increases the gas pressure in the puffer cylinder.
4. The arc generated after the arcing contact separation heats up the SF_6 gas inside the nozzle. The arc during a large current period also ablates and vaporizes some of the nozzle insulating materials. Both can contribute to an increase of the gas pressure in the puffer cylinder.
5. When a flow path is sufficiently established, SF_6 gas compressed in the puffer cylinder flows in both directions of the moving and stationary sides through the insulating nozzle which can remove thermal energy from the arc and cool it.
6. When the arc current approaches a periodic current zero with power frequency, the arc diameter continues to shrink and becomes smaller. The maximum temperature of the arc core is also decreasing with the decrease in current. If the cooling capability due to gas flow is high enough compared with the ohmic heating due to the remaining current (residual current), the arc can be extinguished at the current zero.
7. Transient recovery voltage and recovery voltage are imposed between contacts after current extinction. The current interruption process completes when the dielectric recovery characteristics across the contacts surpass the transient recovery voltage throughout the opening process.

Figure 6.9 shows major behaviors of breaking current and voltage with a puffer-type gas circuit breaker. The interrupting process can be classified into four periods depending on the amplitude of the current and the time around current zero

Period	Large current	Small current	Post arc current	Transient recovery
Phenomenon	Large current arc Nozzle ablation Pressure rise	Arc cooling Extinction peak Possible chopping	Residual current Thermal interruption Re-ignition	Restrike Dielectric interruption
Time scale	Up to 100 ms	Up to 100 ms	Up to 1 ms	Up to 1 sec

The arc diameter strongly depends on the instantaneous amplitude of the AC arc current as described in the previous section. In the case of interruption of alternating current, the cross-sectional area of the arc core decreases as current decreases to the current zero point, and the arc is rapidly cooled by the SF_6 interrupting medium

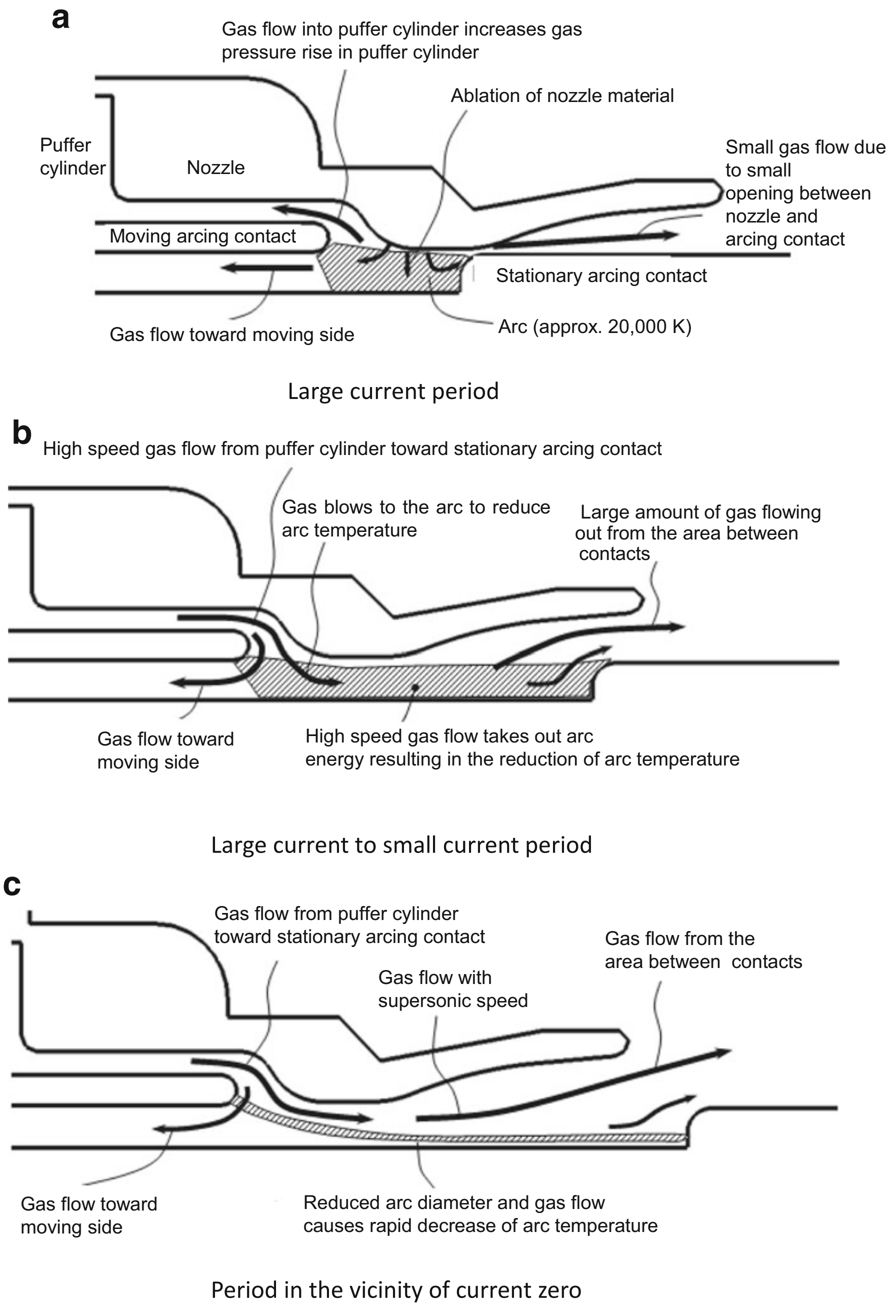
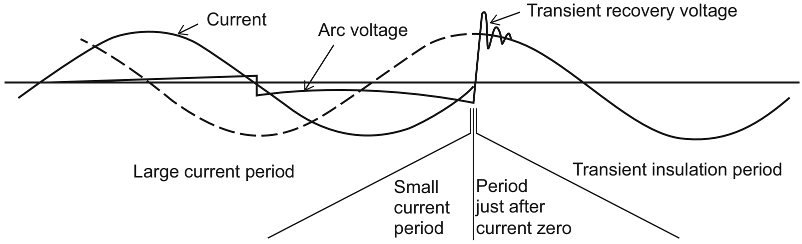


Fig. 6.8 Schematic gas flow in the nozzle during interruption process. (**a**) Large current period. (**b**) Large current to small current period. (**c**) Period in the vicinity of current zero



period	Large current	Small current	Post arc current	Transient recovery
Phenomenon	Large current arc, Nozzle ablation, Pressure rise	Arc cooling Extinction peak Possible chopping	Residual current Thermal interruption Re-ignition	Restrike Dielectric interruption
Time scale	Up to 100 ms	Up to 100 ms	Up to 1 ms	Up to 1 sec

Fig. 6.9 Four distinctive periods at large current interruption

being blown across the arc which then changes the interrupting medium into a dielectric. When the arc quenching capability of the interrupting medium is sufficient, interruption is successful. On the other hand, when the arc quenching capability is insufficient, reignition or restrike occurs between the contacts, and interruption is failed. The process must then wait until the next current zero where interruption is then initiated again.

6.5 Interrupter Principle of Different Types of Gas Circuit Breakers

In an interrupter using SF_6 gas as the interrupting medium, gas flow is created by some means to flow over the arc, which activates the arc cooling due to thermal exchange with the background gas. Typical examples of SF_6 arc quenching arrangements are shown in Fig. 6.10.

Figure 6.10a illustrates a plain break. No explicit gas flow is provided, but the temperature (or density) gradient caused by the arc and gravity cause some gas flow due to natural convection, which in turn affects the temperature distribution and extinguishes the arc. Another example, shown in Fig. 6.10b, utilizes pressure buildup from the arc to provide a pressure rise in the small chamber (with a fixed volume) which causes a gas flow that cools the interrupted arc. In the structure shown in Fig. 6.10c, a high-pressure SF_6 gas is generated by some separately provided means, such as a gas compressor, which is passed over the arc and extinguishes it (called a double pressure type). Figure 6.10d shows an arrangement to generate the gas pressure necessary to build up gas flow by the mechanical motion

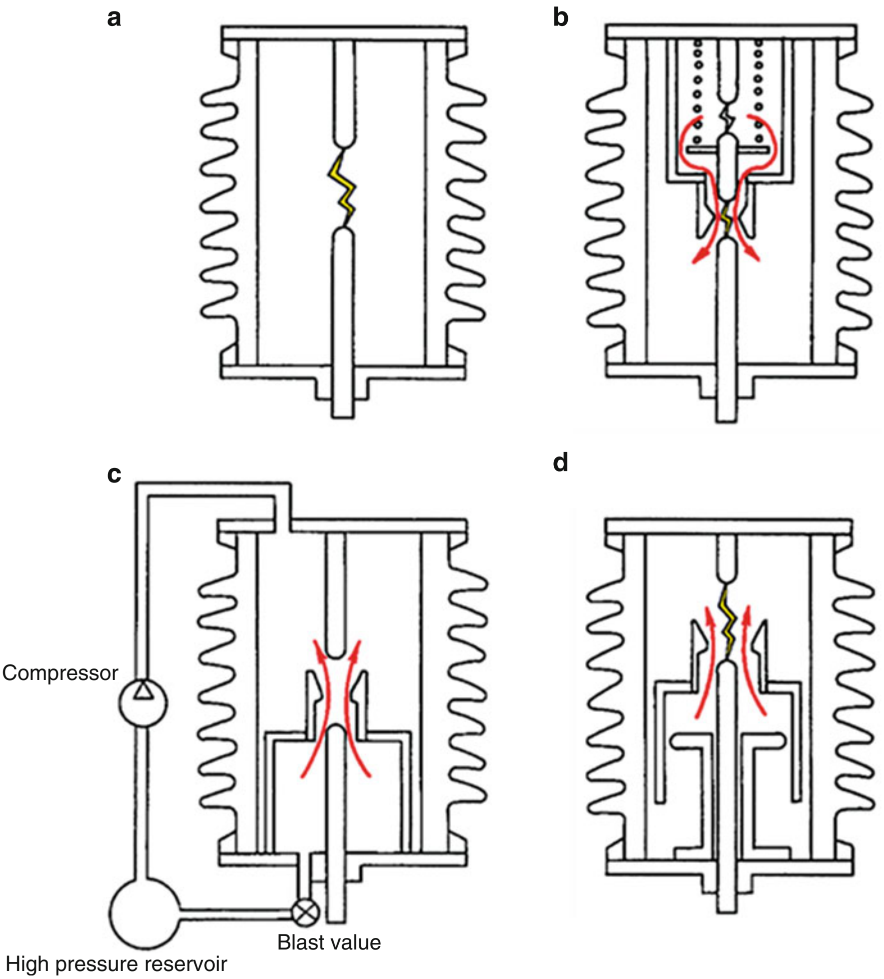


Fig. 6.10 SF_6 arc quenching arrangements. (**a**) Plain break, (**b**) self-blast, (**c**) double-pressure blast, (**d**) puffer-blast

of contact separation of a cylinder. This is called a single pressure puffer-type circuit breaker. Modern circuit breakers use some variation of this basic concept.

The pressure buildup in the puffer chamber and the energy exchange in the arcing space are the important concepts in understanding interruption. The mechanical motion of the arcing contact, especially in the puffer chamber, is affected by the existence of the arc because of the interaction of the pressure buildup in the puffer chamber and the arc current.

Several of the methods of interruption used in SF_6 breakers are described in the next sections.

Experience with SF_6 circuit breakers has shown the importance of high levels of dryness to maintain the insulating properties of the gas. All SF_6 circuit breakers are equipped with adsorbents which will keep the humidity content low. SF_6 gas is normally delivered with very low moisture content, but during commissioning and refurbishments, the circuit breaker can be subjected to moisture that could be absorbed by the gas. To prevent moisture intrusion into the chamber, the circuit breaker chambers should not be opened in humid environments.

6.6 Double-Pressure Type

In this concept, SF_6 gas is pressurized to 1–2 MPa with a compressor, stored in a reservoir tank, and blown across the arc between open contacts with appropriate timing for current interruption. This type of interrupter was put into practical service as 138 kV, 10,000 MVA, two break and as 230 kV, 15,000 MVA, three break gas circuit breakers in 1959 (Leeds et al. 1966, 1970; Yeckley and Cromer 1970). Figure 6.11 shows an 84 kV

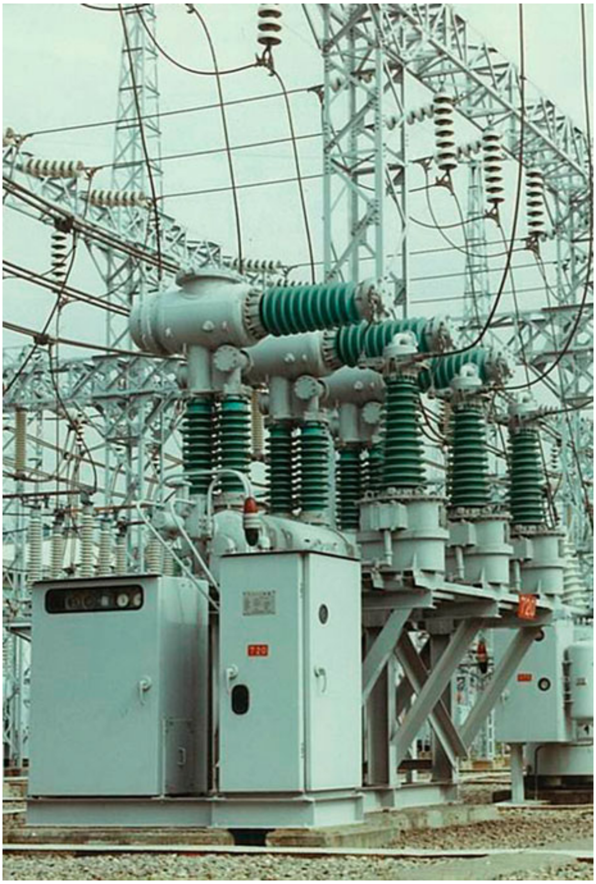


Fig. 6.11 84 kV gas circuit breaker with double-pressure interrupter (1965)

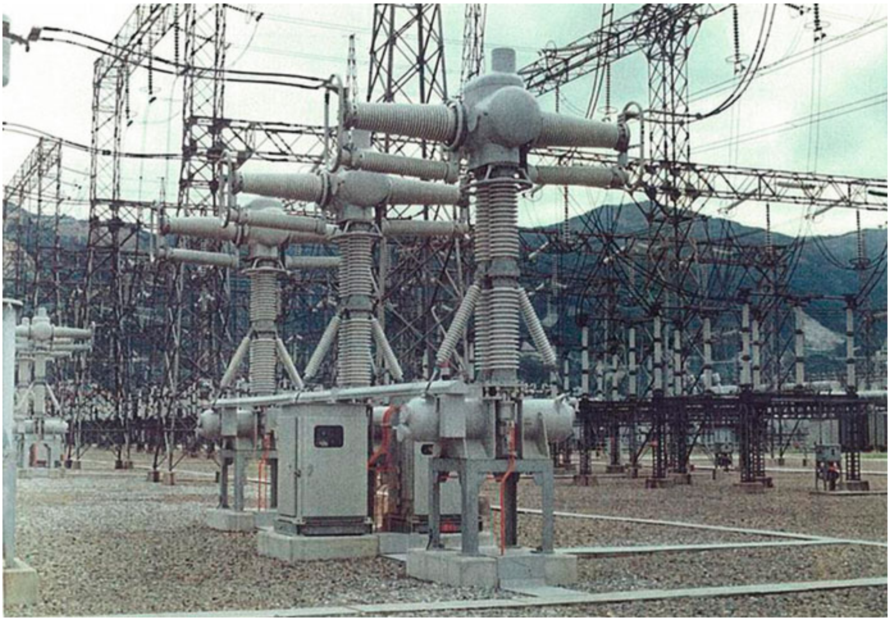


Fig. 6.12 240 kV gas circuit breaker with double-pressure interrupter

500 MVA double-pressure gas circuit breaker first installed in Japan in 1965, and Fig. 6.12 shows a 240 kV gas circuit breaker. The double-pressure interrupter has an advantage that current interruption can be achieved with comparably low operating energy because the required energy for interruption is stored as a high-pressure gas in the reservoir. This is why double-pressure interrupters were mainly used for high-capacity circuit breakers. Double-pressure interrupters had numerous problems due to the need to compress the SF_6 gas and store it in a dry state without leakage. The first circuit breakers applying double-pressure SF_6 had their extinguishing chamber divided into two separate parts with different pressures operating on the same principle as air-blast circuit breakers. The double-pressure concept was dropped in favor of the simpler designs, and currently SF_6 circuit breakers apply a single pressure puffer or self-blast principles.

6.7 Single Pressure Puffer Type

In this design, SF_6 gas is pressurized in a puffer chamber utilizing the opening action of the moving parts of the interrupter and is then blown across the arc between the opening contacts. This type of interrupter was also investigated in the early stage of development in parallel with the double-pressure interrupter because of its simple structure and lack of need for a compressor. Prototype circuit breakers at 115 kV 1000 MV (Cromer and Friedrich 1956) and 46 kV 250 MVA (Yeckley and

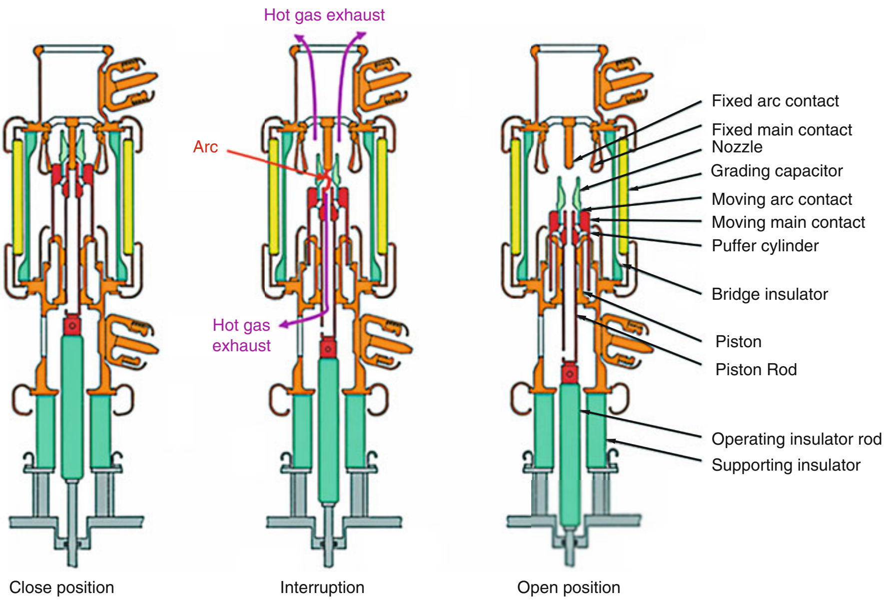


Fig. 6.13 An example of puffer interrupter. (Beige, conducting parts; green, insulating parts)

Cunningham 1958) were developed in 1955, which was earlier than the practical use of double-pressure gas circuit breakers. In the SF_6 puffer interrupter, the gas pressure for the cooling blast is created during the opening stroke in a compression cylinder. In the opening operation, the compression of the gas will start at the same time as the contacts start their motion. The compressed gas is blown out through an insulating nozzle in which the arc is burning. Figure 6.13 shows an example of the key components of a puffer interrupter with a single puffer cylinder. The insulating nozzle is normally made of polytetrafluoroethylene (PTFE). Figure 6.14 shows an example of 550 kV single pressure-type dead tank gas circuit breaker.

One important feature of the puffer design is the current-dependent buildup of extinguishing pressure. During a no-load operation (without arcing), the maximum pressure in the puffer cylinder is typically twice the filling pressure. During interruption, the large current arcing between the contacts blocks the gas flow through the nozzle which causes the puffer pressure to further increase. When the current decreases toward zero, the arc diameter also decreases, which frees more and more space near the exit area for the gas to flow through. A full gas flow is thus established around the current zero, resulting in maximum cooling required for current interruption. The blocking of the nozzle (nozzle clogging) during the high current period gives a further pressure buildup in the puffer cylinder that may be typically several times the maximum no-load pressure. This high pressure in the puffer requires a high operating force of the mechanism. The blast energy is, therefore, almost entirely supplied by the operating mechanism. In order to extinguish the arc (successful thermal interruption), a certain blast pressure is required, which is determined by the

Fig. 6.14 An example of 550 kV single pressure-type dead tank gas circuit breaker. (Courtesy of Dominion Energy)

rate of change of current at current zero (*di/dt*) and the rate of rise of the recovery voltage (*du/dt*) immediately after current zero.

Figure 6.15 shows an example of downsizing evolution for 550 kV single pressure-type SF_6 gas circuit breakers applied for gas-insulated switchgears (GIS). The photographs show four break interrupter installed in 1976, two break interrupter in 1982 and single break interrupter in 1994 with a hydraulic operating mechanism. In accordance with reduction of the number of the breaks, the SF_6 gas volume and its weight used for the circuit breaker portion of GIS can be significantly reduced as shown in the Fig. 6.16.

6.8 Thermal-Assisted Puffer Types

In a thermal puffer interrupter, the SF_6 gas is pressurized in a pressure chamber by the thermal energy of the arc and is blown across the arc between contacts. The thermal puffer interrupter has an advantage that the required operating energy is

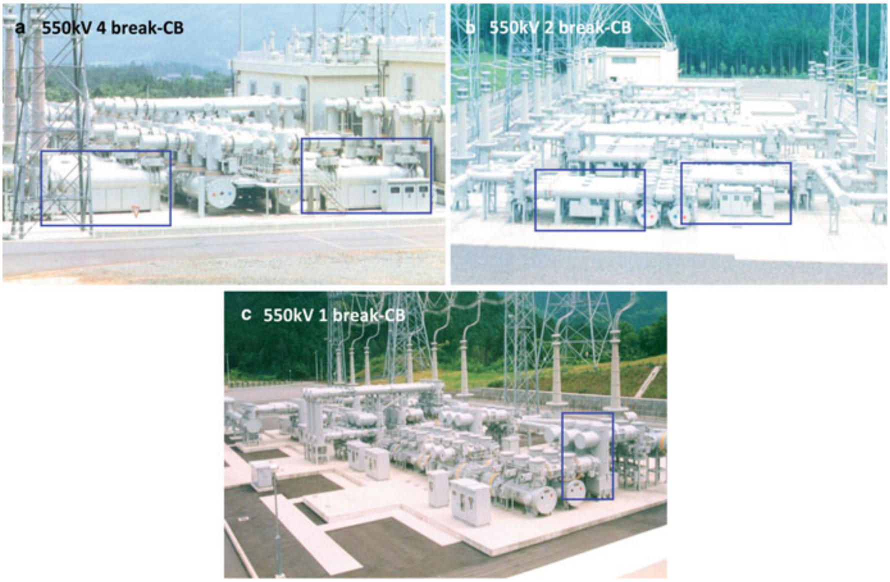


Fig. 6.15 Evolution of 550 kV SF_6 gas circuit breakers. (**a**) Four break (1976), (**b**) two break (1982), (**c**) one break (1994)

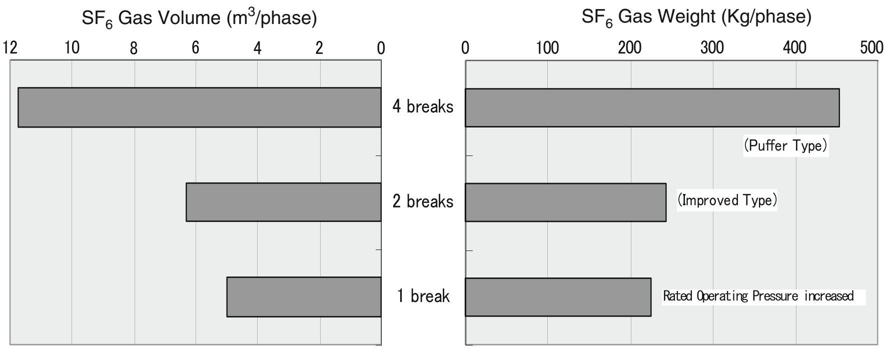


Fig. 6.16 Reduction of SF_6 gas volume of 550 kV gas circuit breaker enclosures

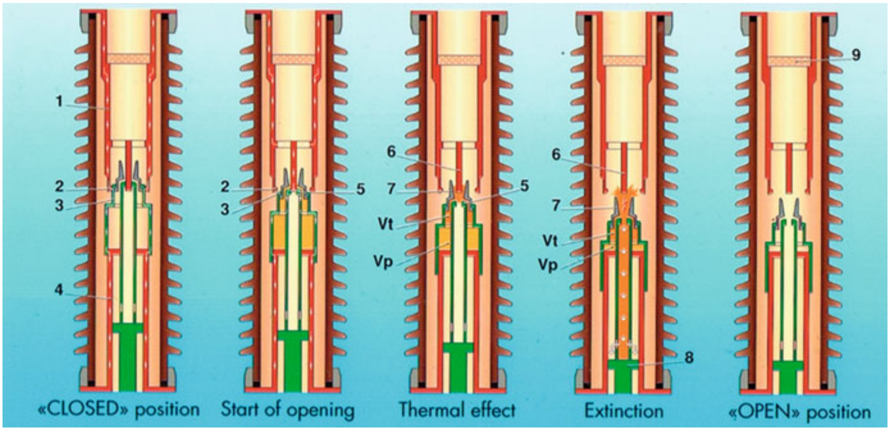
comparably small to build the puffer pressure up required for large current interruption. This is why the thermal puffer interrupter is called a self-blast interrupter. On the other hand, small current interrupting capability becomes lower because the heating of the gas by the arc is reduced.

The period from 1984 to 2000 was marked by the rapid development of computer innovations and modeling tools applied to the design of SF_6 circuit breakers. This enabled the development of new, low-energy operating mechanisms and apparatus making extensive use of the arc energy for switching. Hence, the self-blasting designs became common for large current interruption applications, while the interruption of low currents was still obtained by means of internal gas self-pressure arc quenching in the majority of cases.

Figure 6.17 shows an example of arc-assisted interrupter with dual puffer cylinders.

During the large current period, the arc which is initiated between the metal contacts (5 and 6) transfers much of its energy to the thermal expansion volume (Vt). At a current zero crossing, the ensuing gas overpressure caused by arc clogging of the nozzle is then exhausted through the insulating nozzle (7) and drained into the compression volume (Vp) in the secondary cylindrical compartment at the moving side. This double blast technique provides the necessary cooling of the gas to successfully quench the medium and interrupt the arc. For the interruption of low currents, an extra self-pressure blast is carried out within volume Vp (a puffer), and this compressed gas blow interrupts the arc after exhausting through Vt.

Figure 6.18 illustrates the simulation results of a successful interruption in the case of a fully asymmetric short-circuit current at maximum circuit breaker power capacity (Test duty: T100a), with the evolution of the arc current (I), the displacement of the movable contact (X), and the puffer cylinder pressure (P). During the first part of the operating sequence, the overpressure is mainly produced by compression; next it is primarily due to the thermal expansion of the gas in the thermal volume (Vt).



1: Current pass at fixed contact side, 2: Fixed main contact, 3: Moving main contact, 4: Current pass at moving contact side, 5: Moving arc contact, 6: Fixed arc contact, 7: Nozzle, 8: Operating insulator rod. Vt: Gas pressure at upper puffer cylinder with fixed volume, Vp: Gas pressure at lower puffer cylinder with compressible volume by a piston

Fig. 6.17 Arc-assisted interrupter with dual puffer cylinders. 1, Current pass at fixed contact side; 2, fixed main contact; 3, moving main contact; 4, current pass at moving contact side; 5, moving arc contact; 6: fixed arc contact; 7, nozzle; 8, operating insulator rod. Vt, gas pressure at upper puffer cylinder with fixed volume; Vp, gas pressure at lower puffer cylinder with compressible volume by a piston

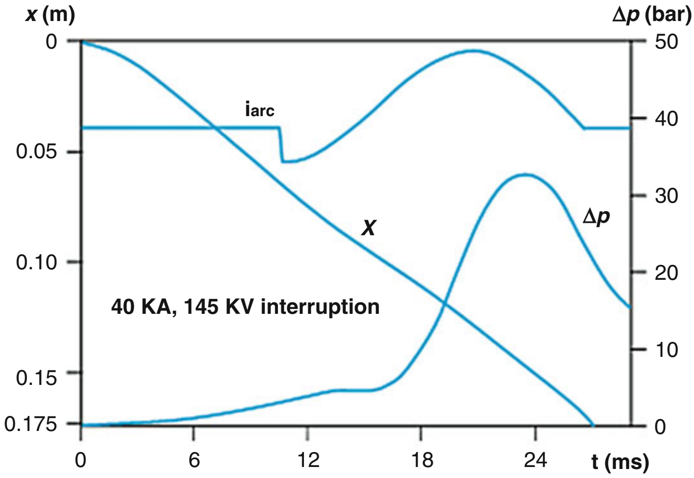


Fig. 6.18 Simulation of pressure rise in case of asymmetric current interruption

The self-blast principles represented a large step forward on the way to reducing the operating energy. The self-blast technology has several designations: auto-puffer, arc-assisted circuit breaker, thermal-assisted circuit breaker, or simply self-blast circuit breaker. Because the blast pressure required for interruption of low currents and low current derivatives (*dI/dt*) is moderate, a small pressure rise independent of the current is sufficient. For higher currents, the energy producing the blast pressure is taken from the arc through heating of the gas.

With the use of a suitable kinematic/automated motion sequence between the circuit breaker pole and its activating device, it is thus possible to achieve a trigger speed high enough to guarantee excellent performance for the interruption of low/capacitive currents and, to a large extent, to maintain this same speed in the event of high short-circuit currents.

Figure 6.19 shows another example of thermal-assisted puffer types equipped with overpressure releasing values for both fixed volume puffer cylinder with the thermal expansion volume (V_t) and compressive volume puffer cylinder with the mechanical compression volume (V_p).

In case of large current interruption, the pressure in the fixed volume (V_t) generated by the arc will be so high that the releasing valves will close, preventing the gas from escaping into the compression volume (V_p). Thus, the overpressure necessary to achieve successful arc extinction is effectively obtained by the optimal use of the arc thermal energy combined with the arc clogging effect that significantly reduces the exhaust of the gases past the nozzle. At current zero, the pressurized gas will flow through the nozzle and extinguish the arc. By avoiding any unnecessary energy expenditure for gas compression, another releasing valve limits the pressure value in the compression volume to that required for the breaking of low short-circuit currents.

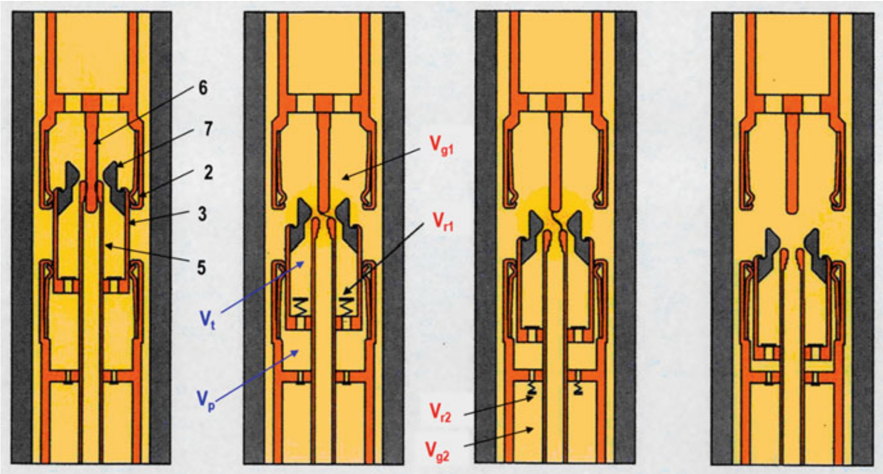


Fig. 6.19 Example of thermal-assisted puffer types equipped with overpressure releasing values for both fixed volume puffer cylinder with the thermal expansion volume (V_t) and compressive volume puffer cylinder with the mechanical compression volume (V_p). 2, fixed main contact; 3, moving main contact; 5, moving arc contact; 6, fixed arc contact; 7, nozzle; 8, operating insulator rod; V_t, gas pressure at upper puffer cylinder with fixed volume; V_p, gas pressure at lower puffer cylinder with compressible volume; V_{g1}, gas pressure outside the nozzle; V_{g2}, gas pressure at rear side of puffer cylinder. Overpressure releasing valves with V_{r1} spring force is closed when $V_t > V_p + V_{r1}$, while the releasing valves with V_{r2} spring force is open when $V_p > V_{r2} + V_{g2}$

On the other hand, in case of small current interruption, typically a few kA, the arc will not have sufficient energy to generate a pressure high enough to close the releasing valve (with spring force V_{r1}) and the interrupter will function as a mechanical compressive puffer interrupter. In this case, the releasing valve opens because of the overpressure buildup in volume (V_p) in addition to the spring force (V_{r1}) is lower than the pressure of the fixed volume (V_t). Arc extinction then occurs as it would in a mechanical compressive type, due to the gas blast coming from the action of the piston mechanisms.

The pressure in the compression volume (V_p) is relatively independent of the current whether the circuit breaker operates as a self-blast interrupter or as a puffer interrupter. It is limited to a moderate level by means of the spring-loaded valve (overpressure releasing valve), which means that the compression energy required from the operating mechanism is limited. Compared with a conventional puffer circuit breaker of the same rating, the energy requirements of the operating mechanism can be reduced to 50% or less.

The issue with this technology is in the low current range where attention must be paid during development to define and insure that the design performs well in the low current range. Improvements to this technology have been made so that self-blast technology has gained high acceptance and is used extensively today, especially for higher kA ratings. A conventional mechanical “pure” puffer interrupters do not have the concern at low currents which some see as an advantage for this design.

6.9 Circuit Breaker Enclosures

There are two basic types of gas circuit breaker structures used today; live tank and dead tank circuit breakers. The insulating housing of a live tank SF_6 circuit breaker is made of porcelain or composite material and is filled with pressurized SF_6 gas. The breaking unit is contained in the insulating material and subjected to full pole potential, i.e., it is “live,” hence the term “live tank” circuit breaker. This assembly is supported by an insulating support column (either porcelain or composite material) which supports the interrupting units in the air. By elevating the interrupting units, the live units are insulated from ground to prevent flashovers from the unit to ground. Figure 6.20 shows an example of 300 kV double-pressure-type, four break, live tank gas circuit breaker, and the Fig. 6.21 shows an example of 420 kV single pressure-type, four break gas circuit breaker. One circuit breaker pole can consist of two or more breaking units in series. The number of breaking units is, therefore, dependent on the system voltage and the requirements on interrupting capability.

Live tank circuit breakers consist of four main components:

- One or more breaking units (interrupters)
- Support insulator
- One or more operating mechanisms
- Support structure (stand)

Dead tank circuit breakers are SF_6 circuit breakers where the interrupting units are housed in a metallic tank (usually aluminum or steel enclosure) and are insulated with SF_6 gas. The SF_6 gas insulates the interrupter from the tank allowing the tank to be at ground potential, hence the name “dead tank.” An advantage of this design is that it can be located on the ground making it more accessible and requiring a smaller footprint. This configuration can be used either in as a stand-alone device in an air-insulated station or in a metal-enclosed gas-insulated switchgear (GIS) including bus and other components which can further reduce the footprint of the substation. The key advantage of GIS substation comes from their reduced overall dimensions which allow them to be installed within urban regions. Thus, the excellent dielectric properties of SF_6 are used to their full extent in dead tank and

Fig. 6.20 300 kV double-pressure-type live tank gas circuit breaker (1966)

GIS substations because the insulation coordination distances required are significantly shorter than for air-insulated switchgear (AIS) substations. Figure 6.22 shows an example of 300 kV dead tank gas circuit breaker with hydraulic operating mechanism, and Fig. 6.23 shows an example of a 145 kV dead tank gas circuit breaker with spring operating mechanism.

Figure 6.24 compares a live tank (four break) and a dead tank (three break) 800 kV gas circuit breakers. The specifications of the dead tank circuit breaker developed in 2000 are 800 kV rated voltage, 63 kA breaking current, and 5000 A nominal current. A live tank interrupter is located at higher position due to air clearance requirement. Figure 6.25 shows an example of 550 kV gas circuit breaker connected with gas-insulated bus bars for GIS.

The major benefits of the successful use of dead tank or GIS technology are:

- Small footprint
- Low sensitivity to environmental conditions
- Personnel safety (live parts are inside a metal enclosure at earth potential)
- No/limited disturbance in the vicinity
- Better anti-seismic performance

Fig. 6.21 420 kV single pressure-type live tank gas circuit breaker. (Courtesy of GE Grid Solutions)

Live tank circuit breakers are used extensively in Europe, while dead tank circuit breakers are commonly used in North America and Japan. The live tank is very similar in concept to minimum oil circuit breakers which were commonly used in Europe, while the dead tank is very similar in concept to bulk oil circuit breakers which were commonly used in North America.

Further, for rated voltages of 145 kV and below, the most economical solution is to house all three phases of the switchgear inside the same metallic enclosure. These enclosures are made of aluminum, a nonmagnetic material and a good conductor which poses no corrosion problem provided the assembly is suitably built. To completely check the switching capacity of three-phase circuit breakers, it is necessary to test them first to assess their phase-to-ground withstand capability and next their phase-to-phase withstand qualification.

6.10 Circuit Breaker Operating Mechanisms

6.10.1 Circuit Breaker Operating Mechanisms

In the early 1900s, the closing operation of a circuit breaker was usually accomplished either by manual operation or a motor drive. Latches were provided to maintain the closed position. Opening operation was accomplished by releasing

Fig. 6.22 300 kV single break dead tank gas circuit breaker (1981). (Courtesy of Kansai Electric Power)

the latch to allow opening from compressed spring energy stored during the closing stroke. Release of the latch could be either manual or electrical. In the early 1920s, 220 kV breakers would have an interrupting time of about 12 cycles comprising 4 cycles until the start of the arc (contact separation) followed by 8 cycles of arcing time. Power systems requirements resulted in the need for higher interrupting capability and shorter interrupting times. Progress in shorter interrupting times resulted in a decrease from 8 cycles to 5 cycles and further decreased to the more common 3 cycle interrupting time of today. In the 1920s, operation of a circuit breaker was typically accomplished with solenoid energy for closing and charging the opening springs. As power systems' performance improved with increased interrupting currents and shorter interrupting times, mechanisms for operation required increased energy and reduction of latch release time. The higher currents also required higher mechanism closing energy resulting from forces caused by prestriking currents in the oil interrupters just prior to contact touch. The area of changes and improvements in the operating mechanism have been in source of the closing energy, the amount of that energy, the speed of closing, the speed of opening, ability to perform multiple reclosing duties, plus reliability and simplicity.

One of the early breaker design requirements was that it had to be "fail safe." This was interpreted to be that it had to be capable of opening in the event of loss of operating energy. This requirement was satisfied by stored spring energy for opening of breakers. As the development of mechanisms improved their reliability, energy

Fig. 6.23 145 kV dead tank gas circuit breaker. (Courtesy of Portland G&E)

sources from compressed air or hydraulics were utilized for both opening and closing of the breaker. Figure 6.26 shows a typical solenoid mechanism. These mechanisms were capable of providing five cycle interrupting times. This is one of the first mechanisms providing a "trip-free" feature. Trip-free is now a standard requirement which permits a breaker to be opened immediately even if the closing operation is in progress, thus resulting in a close-open operation.

The shorter interrupting times and higher currents required increased energy resulting in the development of mechanisms utilizing high-pressure air and subsequently hydraulic mechanisms. The trigger systems for faster release required complete redesigns. Figure 6.27 shows a family of pneumatic mechanisms with air cylinder diameters of 7, 10, and 14 inches with operation at air pressures up to 270 psig. The largest single 14 inch diameter mechanism operated all three phases of a 345 kV oil circuit breaker synchronously. All three of the above mechanisms were mechanically trip-free. Figure 6.28 shows the trip-free operation in which the mechanical linkage disconnects from the closing piston. Mechanisms that used air pressure for both closing and opening operations had valves that provided fast release of the closing air pressure to allow immediate opening air pressure to be applied. These were identified as "pneumatically" trip-free.

Fig. 6.24 800 kV live tank (50 kA) and dead tank (63 kA) gas circuit breakers. (Courtesy of ABB)

There are different types of operating mechanisms, e.g., spring-, hydraulic-, and pneumatic-operating mechanisms and combinations of these technologies (hydraulic-spring or pneumatic-spring). Recently electromagnetic repulsion operating mechanisms or digitally controlled motors have come into use. Operating mechanisms have developed correspondingly regarding the arc extinction technologies for circuit breakers. Earlier pneumatic- and hydraulic-operated mechanisms were typical for higher interrupting currents, but there is a general trend toward spring-operated mechanisms.

The pneumatic-operated mechanism uses compressed air as energy storage and pneumatic cylinders for operation. Solenoid valves allow the compressed air into the actuating cylinder for closing or for opening operation. The compressed air tank is replenished by a compressor unit. The use of pneumatic operating mechanisms is decreasing due to several reasons such as initial cost, maintenance works, and a loud noise during the operation. Due to the high operating pressure, there is always a risk of leakage of air, particularly at low temperatures. There is also a risk of corrosion due to humidity in the compressed air.

The hydraulic mechanism usually has one operating cylinder with a differential piston. The oil is pressurized by a gas cushion in an accumulator, and the operating cylinder is controlled by a main valve. The hydraulic mechanism has the advantages of high energy and silent operation. However, there are also some disadvantages. There are several critical components which require specialized production facilities. The risk of leakage cannot be neglected as the operating pressure is in the range of 30–40 MPa (300–400 bar). It is necessary not only to check the pressure as such but also to supervise the oil level in the accumulator or, in other words, the volume of the

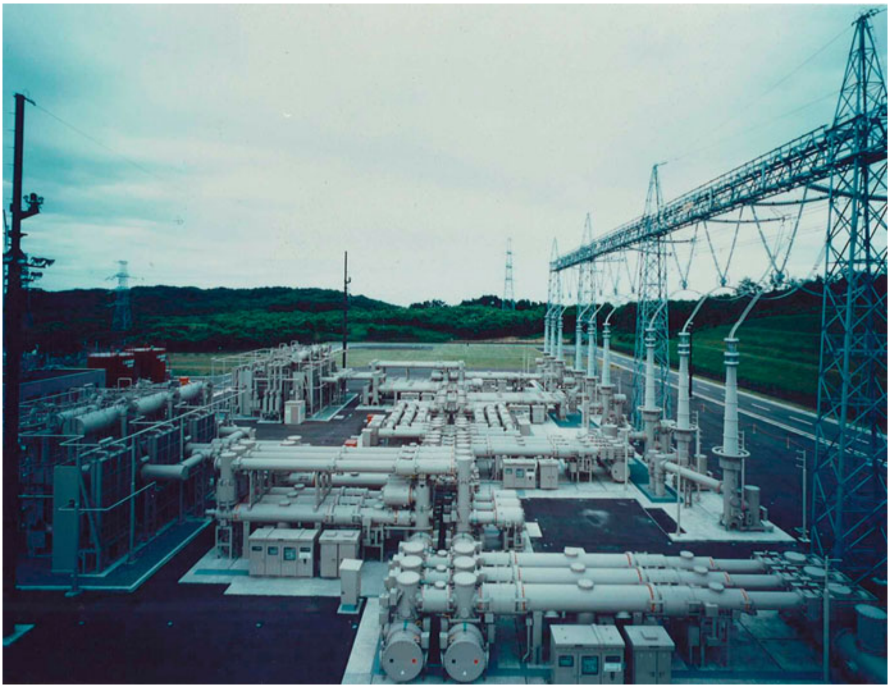


Fig. 6.25 550 kV dead tank gas circuit breakers for GIS. (Courtesy of Tohoku Electric Power)

gas cushion. Large variations in temperature lead to variations in operating time. Until recently, several manufacturers used hydraulic mechanisms for their SF_6 circuit breakers. However, with the introduction of self-blast circuit breakers, the requirement of high energy for operation is decreasing, and the hydraulic mechanisms are losing ground to spring-operated mechanisms (50% of circuit breakers were applied with spring-operated mechanisms according to the last CIGRE reliability survey in 2004–2007).

The hydraulic-spring-operated mechanism is an operating mechanism combining hydraulics and springs. Energy is stored in a spring set that is tensioned hydraulically. A differential piston powered by oil that is pressurized by the spring package is used to operate the circuit breaker during opening and closing operations. In addition to the types of operating mechanisms mentioned above, there are other alternatives, e.g., a design which basically applies the same technology as the pneumatic mechanism but with SF_6 gas instead of air. Another design is the magnetic actuator mechanism, which is applied only for certain medium-voltage circuit breakers.

In the spring mechanism, the energy for open and close operation is stored in springs. Once the mechanism's control system receives an open or close command, the energy stored in the spring is released and transmitted through a system of levers and linkages to the moving contacts which move to the open or closed position. In most designs, the closing spring has two tasks: to close the contacts and, at the same

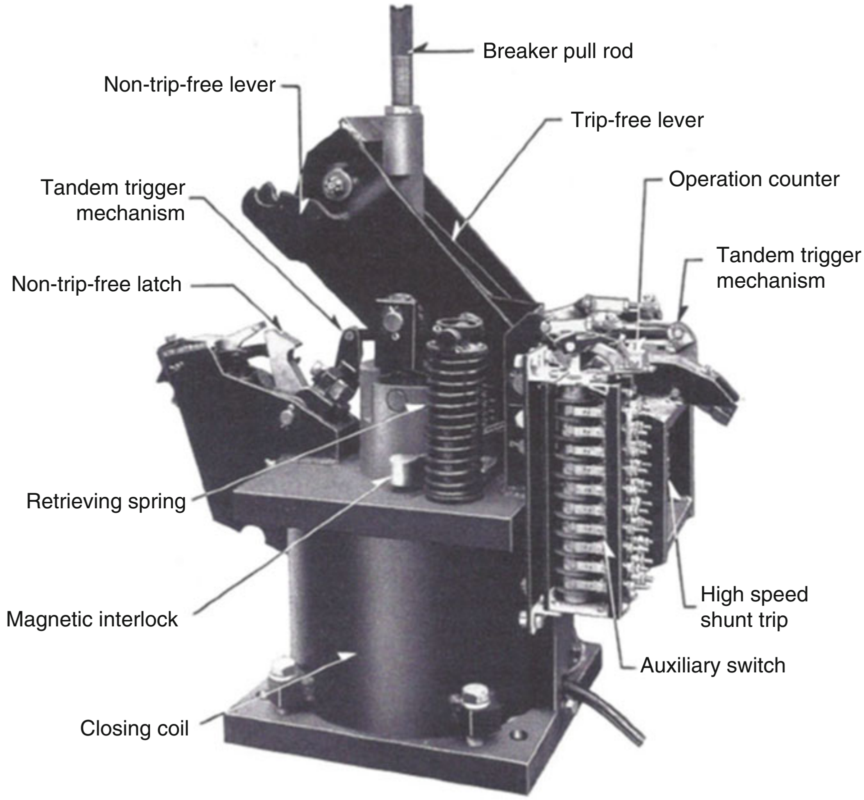


Fig. 6.26 Early solenoid operating mechanism (circa 1938)

time, to recharge the opening spring(s). Thus the criteria stated above are fulfilled; the circuit breaker in the closed position is always ready to trip. The advantage of the spring-operated mechanism is that the system is purely mechanical; there is no risk of leakage of oil or gas, which could jeopardize the CB's reliability.

A well-balanced latching system provides stable operating times even after long interval from the last operation. Furthermore, the spring system is less sensitive to variations in temperature than pneumatic or hydraulic mechanisms. This ensures stability even at extreme low and high temperatures. The spring mechanism has fewer components than hydraulic and pneumatic mechanisms, which also improves its reliability.

6.10.2 Control Systems of Operating Mechanisms for a Circuit Breaker

Circuit breakers are operated by control devices, or command modules, which provide the energy required to perform either opening (O) and closing (C) operations, operating sequences such as open-close (OC) "orders" or combined,

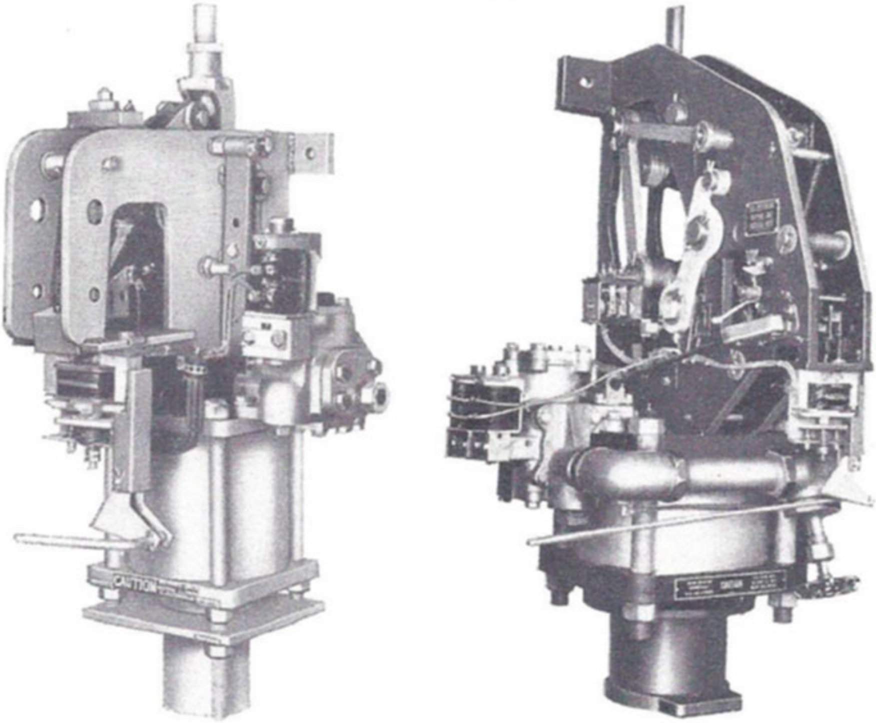


Fig. 6.27 Family of pneumatic mechanisms used for oil circuit breakers

programmed sequences of operations (e.g., OCO). The command module must be able to ensure the required operation or the full sequence of operations of the circuit breaker is accomplished in all normal operating conditions, that is, for opening or closing in the event of short-circuit currents and at high and low temperature conditions. These systems transfer the energy from the mechanisms described above to the actual movement of the breaker components.

In addition, its response time must be short enough to achieve a present time interval (time interval between the moment when the opening order is given and the moment of current break in the final phase) which is requested, typically 3, 2, or 1 power frequency cycle.

Short-circuit-type tests are used to check the capability of the CB to properly handle its nameplate short-circuit rating. The operation is achieved after an order (electric pulse) activates a solenoid that is used to release the energy contained in springs or in a fluid under pressure (air, gas, or oil). The order is given by relays that are part of the network protection which are powered by measurement transducers. The electrical components of the controls are planned to operate within a preset supply voltage range.

6.10.3 Spring Operating Mechanism

Figure 6.29 is an example of helical spring operating mechanism in a triggered position with a compressed closing spring and a released opening spring. An electric motor provides the force needed to compress the closing spring after a closing operation. At the end of compression, the closing spring is kept under tension by a

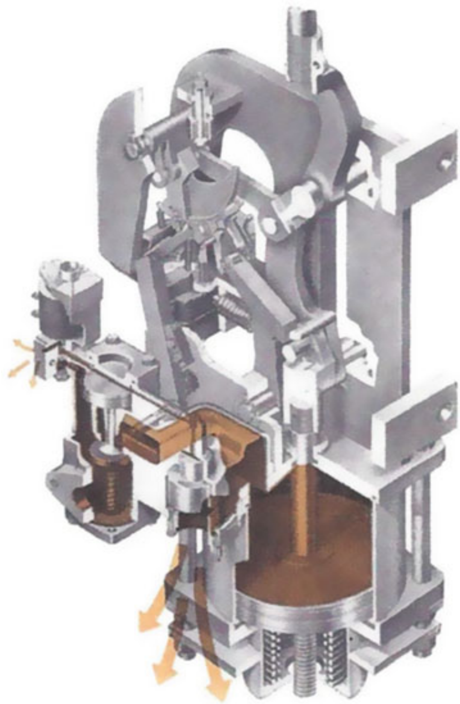


Fig. 6.28 Trip-free mechanism

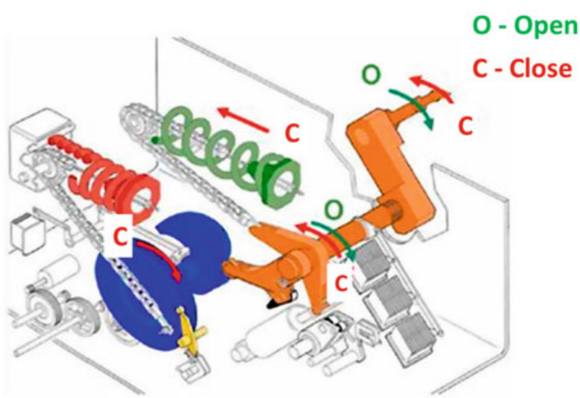


Fig. 6.29 Example of spring operating mechanism. (Courtesy of GE Grid Solutions)

cog on a gear mechanism. The release of the cog causes the closing spring to expand to its normal idle state, thus turning the CB in its closing position while also compressing the opening spring. It is then possible to trigger the circuit breaker. Spring operating mechanisms are now applied for high-voltage circuit breakers up to 800 kV level since they contribute to achieving the most economical apparatus for energies below 8000 J. Their use in high-voltage circuit breakers has been made possible through the development of following techniques for low operating energy conditions:

- Weight reduction of the circuit breaker moving parts
- Larger energy spring operation mechanisms
- Optimization of the kinematic/automated motion sequence that links the interrupting chambers to the actuator modules

6.10.4 Torsion Bar Spring Operating Mechanisms

Spring operating mechanisms applied with a torsion bar have been used to develop higher interrupting capabilities up to 550/420 kV while also providing benefits of increased mechanical reliability and reduced maintenance requirements. The torsion bar mechanisms shown in Fig. 6.30 were applied for 362 kV 63 kA single break gas circuit breakers in 2002 and 245 kV 80 kA in 2003 and 550 kV 63 kA in 2016, which employed compact, small mass interrupters with high interrupting performance as well as a unique torsion bar spring operating mechanism.

A spring operating mechanism stores mechanical energy in the solid spring. Since the operating characteristics of spring operating mechanisms are less affected by the change of ambient temperature and loss of mechanical pressure, they show inherently superior in long-term reliability. There are two important issues that need to be considered in the design of a spring operating mechanism; friction of the sliding

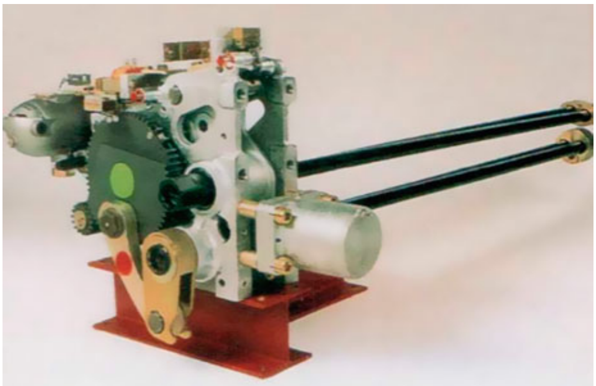
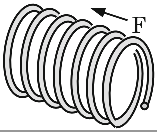
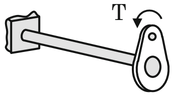


Fig. 6.30 Spring operating mechanism with a torsion bar. (Courtesy of Mitsubishi Electric)

Table 6.1 Comparison between a helical spring and a torsion bar

	Helical spring	Torsion bar spring
Shape		
Volume	100%	10%
Mass per unit stored energy	100%	65%
Energy consumed for spring movement	25%	0%
Energy consumed for interrupter movement	75%	100%

parts (e.g., a trigger, a spur gear, and a latch) and reduction in size of the mechanism while maintaining significant stored energy. Lubricating material, such as sulfur molybdenum, is thermally applied on the sliding parts to optimize long-term mechanical performance by reducing friction and preventing rust. To eliminate maintenance, grease is also added to these sliding parts. Special mechanical endurance tests to confirm the change of operating characteristics when greases are removed, as well as extended mechanical endurance tests of exceeding 10,000 operations (for example, 30,000–50,000 operations). The use of a torsion spring divided into two bars makes it possible to design a compact operating mechanism with large stored energy. Table 6.1 compares the advantages of a torsion spring bar in comparison with a helical spring.

Due to unique advantages of the torsion bar spring mechanism, the mechanism does not require lubrication during its life. Recommended maintenance is limited to visual inspection and a check of basic parameters (e.g., coil gaps, opening and closing times, mechanism and interrupter travel, etc.) after 2000 operations, which is the base requirement in the ANSI and the IEC standards. This makes the mechanism essentially mechanically maintenance-free.

6.10.5 Hydraulic Operating Mechanisms

Until the middle of the 1980s, hydraulic operating mechanisms were the most commonly used especially for large current interruption. There are two main types:

- Hydraulic engaging and spring trigger/releasing mechanism
- Hydraulic engaging and releasing mechanism (double action)

Hydraulic operating mechanisms allow very fast speeds and current interruption within in two power frequency cycles. They can deliver very important energy bursts, larger than 8000 J. These energy values were required in order to achieve high performance levels. Hydraulic command modules are still used for very high performance apparatus and often for generator circuit breakers. Their reliability has

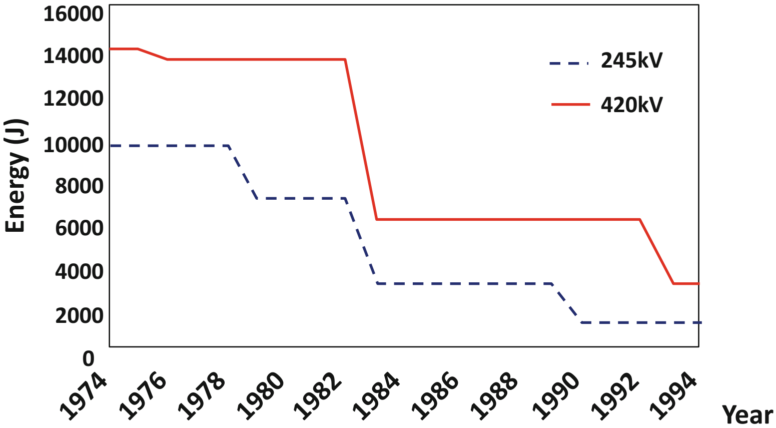


Fig. 6.31 Evolution of required mechanism in 1970–1994 at 245 kV and 420 kV circuit breakers

been increased through the development of a new type of system that uses no high-pressure tubing.

6.10.6 Evolution of Mechanical Energy

Figure 6.31 summarizes the evolution of the tripping (opening) energy at 245 kV and 420 kV circuit breakers over 20 years, from 1974 to 1994. It shows that the required energy has been divided by a factor of 5. The figure highlights the progress that has been made in the field of SF_6 circuit breakers.

6.11 Circuit Breaker Controls

Circuit breakers are generally operated with operating mechanisms, which release energy to the mechanical drive system to move the contacts. The energy required to operate the circuit breaker contacts is provided by various means as described above (e.g., spring, pneumatic pressure, hydraulic pressure, motor, etc.) which are generally charged using motors or rectifiers. The breaker is operated by receiving an external command from an external relay or an operator which actuates the mechanism to change the position of the contacts. The external command is processed by the circuit breaker control circuit to provide the proper action to activate the circuit breaker. The circuit breaker control circuit is the electrical system required to ensure that the circuit breaker responds correctly, safely, and reliably to external commands. This includes operating facilities such as operating coils as well as monitoring facilities such as condition and position indication.

When an external operating command is sent to a circuit breaker, the circuit breaker control system is required to determine whether the circuit breaker is ready to perform the required operation. If so, the control system is responsible for implementing the required action. Conversely if the circuit breaker is not able to complete the requested operation, the control system must prevent (“block” or “lockout”) the requested operation. To achieve this, the control circuit monitors several conditions, such as operating energy, gas density, and the open-close position of the circuit breaker, in order to determine the operational capability of the circuit breaker at any given instant. In addition, the control system is required to monitor critical parameters and provide an alarm to the operator if these are changing such that they may cause the circuit breaker not to function in the future. This alarm function allows the operator to take action in a timely manner and prevent the circuit breaker from being unable to perform its function; a condition which may arise if changes in key parameters go unnoticed and uncorrected. In summary, the control circuit is required to supervise the operating conditions of the circuit breaker, prevent operation if the circuit breaker is outside its operational capabilities, and execute operating commands when it is safe to do so.

Control circuits vary for a variety of reasons including specific requirements in different countries, specific operator or system requirements, the type of operating mechanism, control voltage, control time, redundancy of the system, etc. However, all control circuits can be identified as having two main functions, these being:

1. Control of the circuit breaker
2. Monitoring of the condition of the circuit breaker (including auxiliary circuits) in order to:
   - Ensure safe operation of the circuit breaker
   - Provide information on the status of the circuit breaker to the operator

By reviewing typical control circuit schematics from a variety of suppliers, the various vendors from different countries, CIGRE WG A3.12 developed a common logic for circuit breaker control circuits (CIGRE WG A3.12 2007). This logic is more or less consistent regardless of the details of the schemes and the components used. This logic has been translated into a block diagram showing the essential functions of the control circuit which is shown in Fig. 6.32. The specific components of this “standard” control schematic are described below. This basic schematic is appropriate for both single pole or three pole (independent pole operation or “IPO”) tripping and closing. The components are related to the numbers shown in the schematic in Fig. 6.32.

1. Circuit breaker main contacts: The main contacts of the circuit breaker (not part of the control circuit).
2. Drive or operating mechanism: The mechanical device which releases the energy to move the main contacts (open and close) (not part of the control circuit).
3. Energy charging system: The device which provides energy to the operating mechanism in advance of operation to assure that the circuit breaker has adequate energy to close and/or open. In the case of hydraulic, spring, or pneumatic energy storage systems, this is an electric motor or a motor-operated pump or compressor.

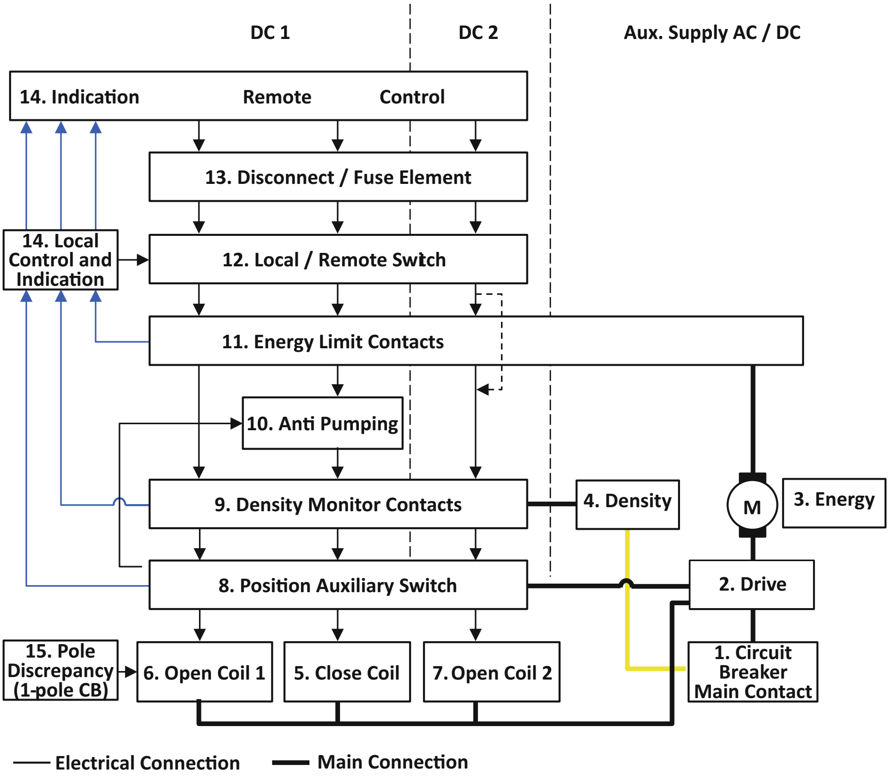


Fig. 6.32 Generalized circuit breaker control schematic

4 and 9. Density monitor and density monitor contacts: These devices provide the means for supervision of the insulation and/or arc extinguishing media; typically SF_6 in modern circuit breakers (in some cases, mixed gas technology is used to eliminate the need for heaters at low temperatures). Temperature compensated pressure switches are commonly used which operate auxiliary relays to prevent the tripping or closing of the circuit breaker if the SF_6 gas density in the enclosure falls below critical levels. There are two functions that are performed by these switches and contacts:

- To provide a warning or alarm in case of reduced SF_6 gas density in the enclosure before the lockout level is reached. This is an alarm only and provides time for the operator to correct the problem before the circuit breaker locks out and is not functional.
- To interlock or prohibit operation of the circuit breaker when the SF_6 gas density reaches a level ("lockout level") where it will not operate safely. Typically the operator has the option of requiring the circuit breaker to automatically trip and lockout when this level is reached ("forced trip") or

having the circuit breaker lockout in the current position. The former option carries some safety risks.

5. Close coil: These are solenoid devices which are energized in the event of a valid closing signal being received by the circuit breaker. Energization releases the mechanism thereby closing the main contacts of the circuit breaker. Once the circuit breaker reaches the closed position, auxiliary switch contacts in the closing circuit open and de-energize the closing coils. Typically, there is only one closing coil in the control circuit.

6 and 7. Open coils: These are solenoid devices which are energized in the event of a valid opening signal being received by the circuit breaker. Energization releases the mechanism thereby opening the main contacts of the circuit breaker. Once the circuit breaker reaches the open position, auxiliary switch contacts in the trip coil circuits open and de-energize the trip coils. There are typically two trip coils that operate from independent power supplies. The operation of only one trip coil is sufficient to operate the circuit breaker. Two coils are provided in order to minimize the risk of a failure to trip.

8. Position auxiliary switch: These contacts, which are driven by the operation of the circuit breaker, are used to interrupt the current of the close and trip coils to de-energize them when the operation is complete. They are also used for indication and monitoring of the circuit breaker position and to interlock control and protection operations at the bay or station level to prevent an incorrect switching operation. These switches can be used for any function where the position of the circuit breaker is a required parameter.

10. Anti-pumping: Anti-pumping refers to the prevention of a reclosing operation in the situation where a previous close command is still applied to a circuit breaker that has been opened. This prevents the circuit breaker from repeatedly closing and opening. Typically the close command energizes an anti-pumping relay via an auxiliary switch contact (a normally open (NO) contact). One contact of the anti-pumping relay interrupts the circuit to the close coil. A second contact is used to latch or "seal in" the anti-pumping relay until the close command is removed from the circuit.

11. Energy limit contact: The energy limit contacts are set to operate when the stored energy in the mechanism is depleted either by operation or losses. Typically they start a motor in order to restore the energy of the mechanism to its normal operating level, e.g., spring position and hydraulic/pneumatic pressure. For spring mechanisms, recharging is typically after every close operation, while other mechanism types may be able to perform several operations before recharging is required. Pneumatic and hydraulic systems have a switch which monitors the pressure and energizes a compressor when it falls below a critical level. When the energy level is restored, a switch opens, which stops the motor. The motor typically has protection against thermal overload and a time limit relay, which will stop the motor (or a motor-operated pump or compressor) in the event of a malfunction. The switches or contacts monitoring the stored energy, therefore, perform the following functions:
   - Lock out the close operation if the circuit breaker does not have enough energy to close and reopen safely.

- Lock out the open operation if the circuit breaker does not have enough energy to open safely. This is typical for hydraulic or pneumatic circuit breakers but not for spring operation where a successful closing charges the opening spring(s).
- Control (start and stop) the charging circuit of the energy storage device (e.g., spring).

12. Local/remote switch: This is a selector switch which allows the operator to interrupt remote control and only operate the circuit breaker locally. This is a safety feature to prevent remote operation of the circuit breaker while it is being serviced.
13. Disconnect/fuse element: These devices are used to interrupt the power to the control system during maintenance work or during a fault to the control circuit. Disconnection is typically provided by knife switches or removable fuses/links which provide visual confirmation that the control circuit is open and which may be locked open to prevent unauthorized reinstatement. Where protection against short circuit is required, mini circuit breakers (MCB) may be used as an alternative to simple fuses.
14. Local control and indication: This function provides an indication of the position of the circuit breaker and the status of the local/remote control facility. These indicators are for maintenance or emergency operations (depending on local safety rules).
15. Pole discrepancy/pole disagreement circuit: For independent pole operation (IPO) circuit breakers (one mechanism for each phase); it is possible for one phase of the circuit breaker to not have the same position (open or close) as the other phases. This situation is called pole discrepancy or pole disagreement and can result in an unsymmetrical primary current. Auxiliary switch contacts in each phase are used to energize a time delay relay in the event that a pole discrepancy occurs. Assuming the discrepancy condition is persistent, after the preset time delay, an attempt will be made to trip all phases of the circuit breaker. In the event that the pole discrepancy was due to a failure to close of one pole, this trip is likely to succeed. However, if the initial discrepancy was due to a failure to open, the failed pole is unlikely to respond to subsequent opening commands and opening of other circuit breakers may be necessary. The preset time delay is normally between 1.5 and 5 s. The time depends on the specific grid conditions and how long the primary circuit could have operated asymmetrically (should be longer than one phase auto-reclose time and shorter than the negative phase sequence protection of generation).
16. Heating: Space heaters are often provided in each of the operating mechanisms and control housings to reduce condensation.

6.12 Summary

The third international reliability survey on SF6 gas circuit breakers (CIGRE WG A3.07 2007) generally reports excellent service experience at all ratings and shows SF_6 circuit breaker failures due to insufficient interrupting capacity are currently rare. The majority of the failures reported are of mechanical natures, which is why efforts are made to improve the overall reliability of the operating mechanisms. Because of the fact that puffer circuit breakers require high operating energy, the manufacturers were forced to use either pneumatic mechanisms, hydraulic mechanisms, or higher-energy spring mechanisms. Self-blast or combined puffer interrupters have become very common in the industry due to this consideration. However, puffer interrupters (sometimes referred to as "pure puffers") are still used due to their higher margins at lower short-circuit currents and high reliability with long lifetime.

SF_6 circuit breakers have become the dominant technology at high voltages and have largely displaced all other technologies. Vacuum breakers are showing some limited use at 145 kV at present, but SF_6 is the dominant technology especially at higher ratings. Nowadays there seems to be no comparable interrupting media with a performance equivalent to that of SF_6 and resulting in a compact and long-term reliable circuit breaker. Nevertheless SF_6 is recognized as a greenhouse gas with high global warming potential (GWP). Although some potential alternative gases have been proposed, it seems some difficulties to find a substitute solution with the same capabilities and the same footprint as SF_6 technology. CIGRE is continuing to look at this subject and will monitor any progress it in the future (Siegar et al. 2017).

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Vacuum Circuit Breakers

7

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Contents

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7.1 Introduction

Vacuum circuit breakers are generally operated with an operating mechanism with smaller operating energy as compared with those of other types of circuit breakers, because the vacuum interrupter employs disc-shaped "butt" contacts instead of finger-shaped contacts often used for SF_6 gas interrupter.

All other types of circuit breakers rely on some kind of extinguishing mediums such as oil, air, and SF_6, where the electric arc develops in an interrupter. However, the vacuum circuit breaker has a unique feature that the vacuum arc is maintained by ionized metal vapors supplied from the cathode in the negative polarity. In addition, vacuum circuit breakers sustain arcing even with very low arcing voltage and restore the insulation quickly by diffusion of the remaining post-arc plasma into the vacuum background even at very small contact gap lengths after arc quenching, virtually independent of the rate of rise of the transient recovery voltage.

The first serious demonstration of switching in vacuum already took place in 1926 (Sorensen and Memdenhall 1926). Despite that switchgear designers were fascinated by the great advantages of excellent vacuum capability for many years, commercial application of vacuum circuit breakers did not occur until the late 1960s, mainly because the industry did not have the capability to fabricate the ultrahigh vacuum sealing necessary for long-duration application. The practical development of vacuum circuit breakers (Cobine 1963; Harris 1980; Greenwood 1994) required far more time and research effort than other types of interruption technologies in spite of the rather simple concept.

First of all there were some problems associated with the production of high-degree degassed contact materials, called gas-free contacts. Degassing is required to prevent deterioration of the initial vacuum due to the release of gases that are normally trapped inside the metals. These gases accumulate and affect the vacuum during arcing.

Another problem was the lack of proper technology to weld or braze the external ceramic and glass envelopes to the metallic armatures, i.e., ceramic-to-metal seals, necessary to maintain the high vacuum during a lifetime of around 30 years in a hermetically sealed interrupter. An additional weakness of early vacuum interrupters was the occurrence of severe surge voltages due to current chopping when pure copper or the refractory metals tungsten or molybdenum were used as contact material to capture the gas escaping from the contacts during arcing. Another difficulty to overcome was that the highly clean surfaces of the contacts produced strong welds in vacuum, often with normal contact pressures and in a no-load situation.

Besides the mechanical simplicity vacuum interrupters do not contain gases or liquids, they are not flammable and do not emit flames or hot gases. Due to the absence of inelastic collisions between the gas molecules, vacuum has the fastest dielectric recovery strength after arc interruption at current zero. This means that there is no avalanche mechanism to trigger the dielectric breakdown, as occasionally observed in gaseous media.

Because of its small contact gap, short arc length, and very low arc voltage, the arc energy released in vacuum is approximately one-tenth of that in SF_6, and even less than in oil. The low arc energy keeps the contact erosion to a minimum. Operation of vacuum circuit breakers requires relatively smaller operating energy, and this allows the use of simple spring operating mechanisms being both reliable and silent.

The advantages offered by vacuum circuit breakers were the driving force in overcoming technological problems. By the end of the 1950s, after long-lasting efforts to develop a vacuum circuit breaker, the products started to appear in practice. Advances in plasma physics and developments in contact metallurgy and ceramic welding provided solutions needed for the vacuum interrupter to become a reality. Finally, in the year 1962, the General Electric Company brought the first commercial vacuum circuit breaker on the market, and since then it has been firmly established as a reliable option for current interruption especially in MV networks.

Vacuum circuit breakers continued to evolve and are gradually applied on a large scale in electrical networks (Garzon 1997; Slade 2008; CIGRE TB 589 2014). Since the 1990s, VCBs up to 145 kV became available, but these HV VCBs still constitute a small fraction of the HV circuit breakers. It is still not profitable to produce vacuum circuit breakers for applications above 145 kV, since vacuum insulation does not scale proportionally to contact gap length, as SF_6 insulation does. Higher voltages require larger circuit breakers with corresponding manufacturing difficulties (Yanabu et al. 1989).

In this chapter, the interrupting and switching phenomena with a vacuum interrupter are described in detail.

7.2 Definitions of Terminology

Circuit Breaker

A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in power systems from damage caused by excessive currents, typically resulting from an overload or short-circuit conditions. When a fault occurs, circuit breakers quickly clear the fault to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Vacuum Circuit Breaker
A circuit breaker in which the contacts open and close within a highly evacuated vacuum enclosure. When the vacuum circuit breaker contacts are separated, an arc is generated by the metal vapor plasma released from the contact surface. The arc is quickly extinguished because the metallic vapor, electrons, and ions produced during arcing are diffused in a short time and condensed on the surfaces of the contacts, resulting in quick recovery of dielectric strength.

Arcing Time
The interval of time between the instant of the initiation of the arc in a pole and the instant of final arc extinction in that pole.

Medium Voltage (MV)
MV generally refers to the voltage levels up to and including 52 kV corresponding to distribution systems.

High Voltage (HV)
HV generally refers to the voltage levels higher than 52 kV corresponding to transmission systems.

Disruptive Discharge
Phenomenon associated with the failure of insulation, in which the discharge completely bridges the insulation, reducing the voltage between the electrodes to zero or nearly to zero. The term “sparkover” is used when a disruptive discharge occurs in a gaseous or liquid dielectric. The term “flashover” is used when a disruptive discharge occurs over the surface of a solid dielectric in a gaseous or liquid medium. The term “puncture” is used when a disruptive discharge occurs through a solid dielectric.

Non-sustained Disruptive Discharge (NSDD)
NSDD refers to a self-restoring discharge that sometimes occurred up to 1 s after current interruption especially observed with a vacuum interrupter. NSDD associated with current interruption does not result in the resumption of power frequency current or, in the case of capacitive current interruption, does not result in significant discharge of the main load. Note that it is difficult to distinguish the phenomenon between a self-restoring NSDD and a restrike (not restoring breakdown).

Thermal Interruption Process/Thermal Interrupting Region
The thermal interrupting period of a circuit breaker is the time period where the residual current inputs energy into the vanishing arc by ohmic heating. When the arc in a circuit breaker is not sufficiently cooled in this time period, thermal reignition may occur.

Dielectric Interruption Process/Dielectric Interrupting Region

The dielectric interrupting period of a circuit breaker occurs within an interval, a quarter cycle of power frequency or longer after interruption at current zero, where the transient recovery voltage (TRV) is applied between the contacts. The dielectric strength across the contacts generally increases with the contact gap. When the TRV exceeds the dielectric strength across the contacts at any moment during the dielectric interrupting region, dielectric breakdown called restrike will occur.

Reignition

Reignition is the resumption of current flow between the contacts of a mechanical switching device within an interval less than a quarter cycle of power frequency after interruption at current zero. A reignition occurring during the thermal interrupting region does not generate voltage transients harmful to the power system.

Restrike

Resumption of current flow between the contacts of a mechanical switching device with an interval, a quarter cycle of power frequency or longer after interruption at current zero. A restrike occurring during the dielectric interrupting region may generate transients that could be harmful to the system and equipment.

Current Chopping

Current chopping in circuit breakers is defined as switching phenomena where the current is forced to create a current zero and interrupt before the periodical current zero at every half cycle of the AC current. Current chopping is predominant while the circuit breakers interrupt a small inductive current when switching shunt reactor or unloaded power transformer. The circuit breakers with higher thermal interrupting capability tend to show more prominent chopping phenomena.

Transient Recovery Voltage (TRV)

A transient recovery voltage for circuit breakers is the voltage that appears across the terminals of the CB after current interruption. It is a critical parameter for fault interruption by a circuit breaker; its amplitude and the rate of rise of TRV are dependent on the characteristics of the system connected on both terminals of the circuit breaker and on the type of fault that the circuit breaker has to interrupt.

Diffuse Arc

Vacuum arc mode is characterized by a number of fast-moving plasma strings, which exists apart from each other carrying the current of 30–100 A each dispersed over the electrodes.

Constricted Arc

Vacuum arc is characterized by a single bulk plasma column similar to an arc observed in gases, potentially carrying a large current.

Gettering
A getter is the chemical capture or the deposit process of reactive material that is equipped inside a vacuum apparatus in order to maintain the vacuum quality. When reactive particles collide the getter material, they combine with it chemically or by absorption. Getters are generally constructed of materials such as zirconium and aluminum or barium and nickel.

Global Warming Potential (GWP)
Global warming potential (GWP) is a relative value to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWPs are based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO_2), as well as the decay rate of the ability of each gas. The GWP of the greenhouse gases has different global warming values over time periods. For most greenhouse gases, the GWP declines as the time horizon increases due to natural decomposition. For example, methane (CH_4) has a potential of 34 over 100 years but 86 over 20 years. However, sulfur hexafluoride (SF_6) with stable properties is reported to have a GWP of 23,500 over 100 years but 16,300 over 20 years.

7.3 Abbreviations

AMF	Axial magnetic field principle
CB	Circuit breaker
GWP	Global warming potential
HV	High voltage
MTTF	Mean time-to-failure
MV	Medium voltage
NSDD	Non-sustained disruptive discharge
RMF	Radial magnetic field principle
RRRV	Rate of rise of recovery voltage
RV	Recovery voltage
SF_6	Sulfur hexafluoride
TMF	Transversal magnetic field principle
TRV	Transient recovery voltage
VCB	Vacuum circuit breaker

7.4 Fundamental Features of Vacuum Circuit Breakers

7.4.1 Introduction

The basic component of the vacuum circuit breaker consists of a vacuum interrupter, often named *vacuum bottle, an operating mechanism, metal (dead tank type) or porcelain (live tank type) enclosure, and control circuits.* The vacuum interrupter has a vacuum-tight container or enclosure made of ceramic and metal parts that are hermetically sealed together. It is completely evacuated to maintain a high vacuum. The internal pressure in the bottle is less than 10^{-2} Pa. Inside the interrupter, a pair of electrode contacts is mounted. The contacts are separated by moving one electrode (at moving side) using a metal bellow because no gasket would be sufficiently tight for maintaining the required vacuum quality. The arc is maintained by metal vapor supplied from the contacts and elongated during contact separation extinguishing at a current zero, and the vapor particles condense on the solid surfaces.

The dielectric recovery characteristic of a vacuum interrupter is highly influenced by the creation of *anode spots,* which depend on the type of material and its composition. The anode spots are relatively large "pools" of molten metal region created by a large current. If they have too big region and do not solidify sufficiently at current zero, they continue to emit vapor and impair dielectric recovery. Therefore, arc control devices in the contact surface are designed to prevent a large anode spot formation. For this purpose, the arc should be kept diffuse in order to minimize the energy input per square millimeter, or it has to be forced into circular motion in order to minimize energy input and energy density on the same small area of the contacts during the interruption process.

Since there is no mechanical mechanism to control the vacuum arc, the only way to influence the plasma column between the contacts is by means of interaction with a magnetic field. Many solutions have been proposed to realize this, but the two most practical methods are:

- Interaction between the arc current and the radial magnetic field
- Application of an axial magnetic field created by a coil, which is either an integral part of the contact component inside the interrupter or mounted outside the interrupter

The interrupting capability of a vacuum interrupter is also related to the surface area of the contacts. Larger contacts combined with an axial magnetic field have better capability to interrupt high current. The rated normal current is also related to the surface area of the contacts. Thus, the contact area should be large enough to absorb the arc energy without becoming excessively heated, and in closed position, it has to provide enough contact points of sufficient area to give low enough energy dissipation during passage of the rated normal current in addition to effective heat sink through the contact rods.

The interrupting capability of a vacuum interrupter depends on the contact gap, the surface area of the contacts themselves, and the space between the contacts and the vapor shield.

Because of the high dielectric strength of vacuum, a vacuum interrupter can be designed quite small in terms of internal dimensions; however, dielectric strength must also exist outside the interrupter. Therefore, it is largely the external dielectric strength that determines the length of the insulating part of the interrupter. Some interrupters have been specially designed for immersion in SF_6, and these could be

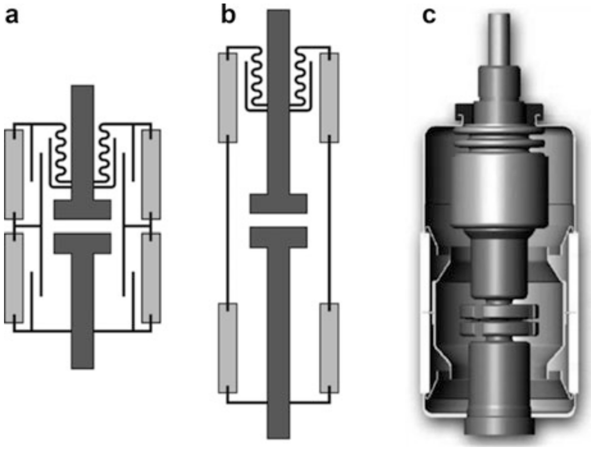

Fig. 7.1 Vacuum interrupter designs: (**a**) shorter with larger diameter; (**b**) longer with reduced diameter; (**c**) cross section of a vacuum interrupter of the design shown in figure (**a**). (Kapetanovic and Smeets 2011)

considerably shorter in length than interrupters for use with dry air external insulation. Figure 7.1 shows two common designs of the vacuum interrupters.

In design Fig. 7.1a, the contacts are surrounded by a central metal vapor condensation shield, which serves to protect the inside walls of the insulating ceramics, so that they do not become conductive by condensed metal vapor since it is insulated from the contact potential. The two end shields also prevent metal vapor to be reflected back from the end plates to the insulating cylinders. In most designs, the central shield is electrically floating because of the dielectric-stress management (Greenwood 1994). Figure 7.1c shows an example of the cross-sectional view of this vacuum interrupter (Christian et al. 2003).

The vapor shields also serve another function: relief of the electrical stress on the joints where the ceramic is attached to metal. These so-called triple junctions, insulator, conductor, and vacuum, can be the source from which discharges originate and lead to a breakdown. Minimizing the stress at triple junctions reduces the probability of breakdown.

Design Fig. 7.1a has a length somewhat greater than its diameter. It has relatively short contact stems, which simplifies the mechanical and thermal design.

Design Fig. 7.1b shows an alternative configuration, in which the diameter of the vacuum interrupter has been reduced at the expense of the length. The central shield becomes a part of the envelope (with a floating potential), and the insulation is split in two equal parts located at both ends of the interrupter. An additional shield is placed to protect the bellows against molten particles released from the contacts, which may cause a puncture of the bellows.

It is important that the central shields have sufficient heat capacity and thermal conductivity to absorb the heat flux without too much temperature rise during the current interruption.

Vacuum technology has been proven to be very suitable for MV applications. Commercial HV interrupters for 72.5 kV and 145 kV are available on the market, but they have not found widespread use yet outside Japan. New HV vacuum circuit

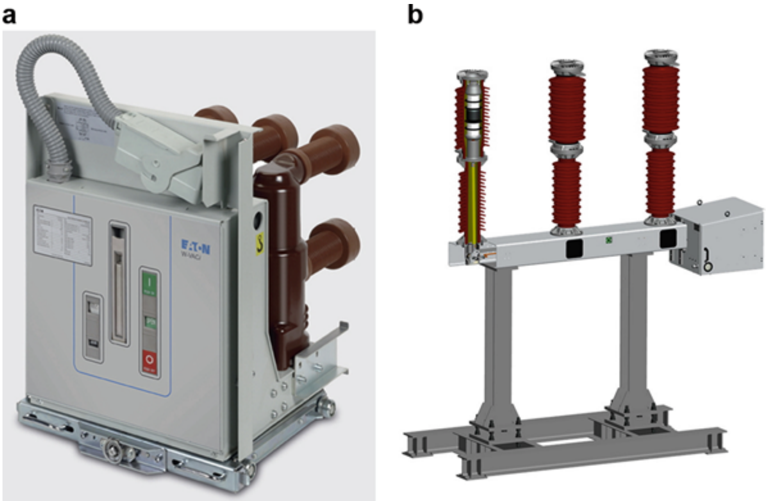

Fig. 7.2 Vacuum circuit breakers: (**a**) 24 kV indoor circuit breaker. (Courtesy of Eaton Electric); (**b**) live-tank 72.5 kV circuit breaker. (Courtesy of Siemens)

breakers are reaching the market rapidly (CIGRE TB 589 2014). Figure 7.2 shows typical examples of vacuum circuit breakers.

7.4.2 Vacuum Arc Control by Magnetic Field

There are no mechanical ways to cool the vacuum arc, and the only possibility to influence the arc column (or strings) is by means of interaction with a magnetic field. Such a magnetic field can be realized through the contact geometry creating the path of the current through the contact configuration. A very efficient way to improve the high current breaking capability by direct magnetic interaction with the arc is to adapt the contact geometry.

Two different principles are used in order to avoid vacuum arc constriction when breaking high currents:

- *Radial magnetic field* (RMF) *principle*, also named *transversal magnetic field* (TMF) *principle*, where the constricted arc column is forced by a self-generated radial magnetic field to rotate rapidly across the outer part of the contact surface circumference
- *Axial magnetic field* (AMF) *principle,* where due to the self-generated axial magnetic field, the vacuum arc stays in a diffuse mode

Both radial and axial magnetic fields are created by special current paths provided in the structure below the contact surface or by the contacts themselves.

7.4.2.1 The Radial Magnetic Field (RMF) Principle

The constricted arc can be regarded as a conductor through which a current flows parallel to the contact axis. If a radial magnetic field is applied to this conductor, the resulting electromagnetic (Lorentz) force will cause rotation of the arc across the contact surface.

Figure 7.3 shows examples of spiral-type contacts employed with RMF and AMF principles, respectively. These contacts generate a radial magnetic field that causes an azimuthally directed electromagnetic force to act on the vacuum arc. The contracted arc rotates across the contact surface at a speed that can be as high as 400 m/s (Dullni 1989). The speed of the constricted arc is limited because charge carriers have to be produced. Since the vacuum arc in the constricted mode behaves like a high-pressure arc, metal vapor can approach atmospheric pressure. Consequently, the surface temperature of the anode is approximately equal to the boiling temperature of the contact material. An upper boundary to the speed is estimated from the time the arc needs to heat up the surface of the contact, in order to obtain metal vapor of sufficient density. This high speed ensures less contact erosion and melting, and it also significantly improves the current-interrupting capability.

A certain trade-off of the slot width for the spiral-type contacts is necessary (Picot 2000). If the slot width is too large, the arc cannot cross it, and it can make the arc stationary and thus overheat it, since the arc is in the constricted mode. If the width is too small, the slot may be filled by fused contact material debris, thus modifying the current path. It leads to reduction of the radial magnetic field and immobilization of the arc.

Even being mobile, the rotating vacuum arc remains constricted. Therefore, the energy brought by the arc causes overheating and considerable melting of the contact material. The high pressure at the arc roots expulses the molten contact material in the form of droplets. This process is a means for cooling the contact. The energy is taken away with the expelled material, which then condenses on the surrounding walls. It leads to relatively high contact erosion.

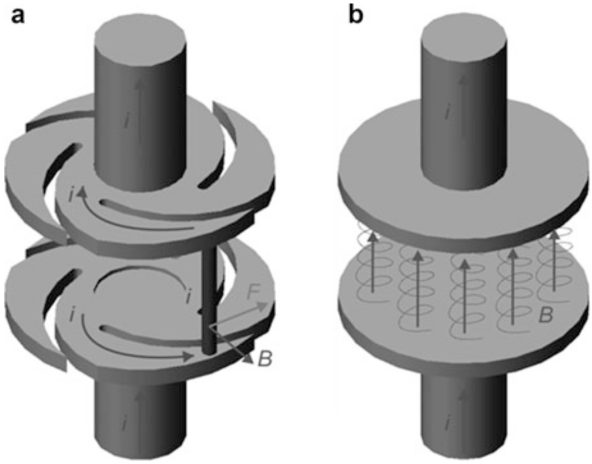

Fig. 7.3 (**a**) Radial magnetic field contacts, (**b**) axial magnetic field contacts (i, current; B, magnetic flux density; F, electromagnetic force). (Kapetanovic and Smeets 2011)

The main advantage using the radial magnetic field contacts lies in its simple physical structure. Another advantage of the spiral contacts is that in the closed position, the current can flow directly via the stem, thereby ensuring lower power losses for normal current carrying.

Radial magnetic field contacts can ensure an improvement of the current-interrupting capability up to 50 kA. For a further increase of the capability from 63 to 80 kA, an axial magnetic field contacts can be used.

Another variant of arc control with the radial magnetic field (RMF) principle is to apply contrate or cup-shaped contacts, as shown in Fig. 7.4. In this case, because the current has to follow the given path, the radial magnetic field is generated below the contact surface at a certain angle to the axis of the contacts. There are no discontinuities (slits) in the contact surface to hamper the motion of the arc.

7.4.2.2 The Axial Magnetic Field (AMF) Principle

The interrupting capacity of vacuum interrupters can also be increased by using contacts that generate an axial magnetic field (see Fig. 7.3b). When a magnetic field is applied in the direction of the flow of current in the arc, the mobility of charged carriers perpendicular to the flow is considerably reduced especially in case of the electrons, which have a much smaller mass than the ions. The electrons gyrate around the magnetic field lines so that the arc contraction is shifted toward higher current. The arc maintains its diffuse mode, which ensures that only a small amount of energy reaches the contacts. This is reflected in the arc voltage that is significantly lower in comparison with the arc voltage measured in the case of radial magnetic field (RMF) contacts.

Application of axial magnetic field (RMF) contacts leads to smooth and stable behavior of the arc voltage. Very low arc voltage of approximately 60 V at a short-

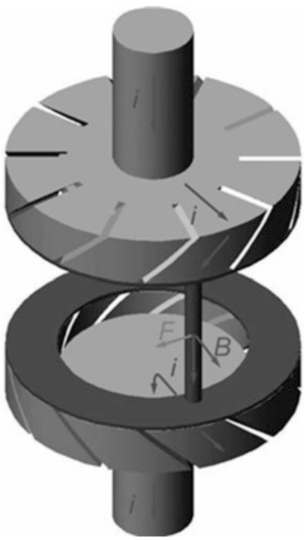

Fig. 7.4 Schematic view of contrate contacts designed to create a radial magnetic field (RMF) for arc control. (Picot 2000)

circuit current of 63 kA (Fink et al. 1998) indicates that the arc is forced to stay in diffuse mode even around the arc current peak.

In contrast with the smooth arc voltage of the axial magnetic field (AMF) contacts, the radial magnetic field (RMF) contacts show a typical shape of the rotating-arc voltage, representing the high-speed motion of the vacuum arc during the large current conditions.

Vacuum arc behavior under an axial magnetic field makes the AMF contacts best suited for very high short-circuit currents (>50 kA). The AMF contacts can shift the contraction of the arc toward higher currents. Since the arc is kept as diffused mode, the contact erosion is drastically reduced. For this short-circuit current range, the more complex AMF contacts that are superior to the conventional RMF contacts are preferred. They also provide advantage when the vacuum interrupters with the AMF contacts are applied in power systems with the rated frequency of 16.7 Hz, e.g., for railway power networks. Due to the long arcing times that occurred in power systems with lower power frequency, vacuum interrupters with the AMF contacts are installed at the current levels up to 31.5 kA.

At larger contact distances, however, as applied, for instance, in vacuum interrupters for higher voltages, the effect of the axial magnetic field (AMF) loses its strength.

The main design parameters that determine the dimensioning of axial magnetic field (AMF) contacts are the size and phase relation of the axial magnetic field with the current. In the ideal situation, the goal is to have no phase displacement between the high current and the magnetic fields that it generates. However, because of the inherent losses in the contact system, such an ideal case will always be out of reach. An important parameter is the value of the eddy currents produced in the contact by the changing magnetic flux density. These eddy currents are responsible for both the phase displacement and the reduction of axial magnetic field. The eddy currents become smaller if the surface is divided into two sectors with different directions of the magnetic flux density. This is because only the areas enclosed by the eddy currents, which passed through in one direction due to the magnetic lines of force, are concerned. Such systems are termed the *bipolar AMF contact systems,* contrary to the classical *unipolar AMF contact systems.*

In many axial magnetic field contact systems, the axial magnetic field (AMF) is commonly generated by a coil using the current pass located behind the contacts (see Fig. 7.5).

Another alternative of generation of axial magnetic field (AMF) is the application of C-shaped, “horseshoe”-type, alternately laminated iron plates behind the contacts as shown in Fig. 7.6. By a proper design, substantial axial field components can be generated in this application. This method of axial magnetic field generation takes advantage of the fact that, with a proper dimensioning of the iron package, the magnetic field lines tend to close by crossing the contact gap to the opposite package, rather than to close in a circular way to the same package.

Figure 7.7 also shows another solution of axial magnetic field (AMF) generation by using the current through a coil outside the interrupter.

Since convection is not an option in vacuum, the only practical way of dissipating the generated heat is through conduction via the copper conductors. As a result, the power losses during service reduce the normal current capability.

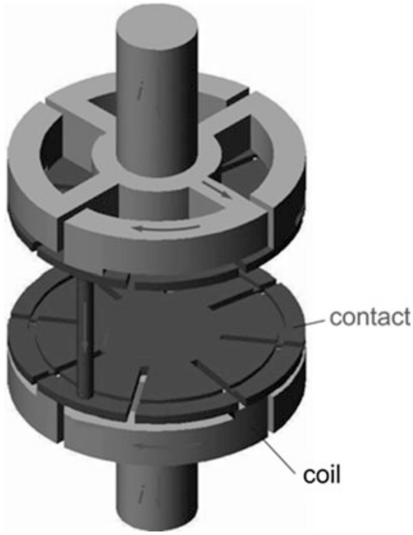

Fig. 7.5 Generation of axial magnetic field for arc control by coil (circular current pass segments) directly below the contacts (Kapetanovic and Smeets 2011; Picot 2000). (Courtesy of Schneider Electric)

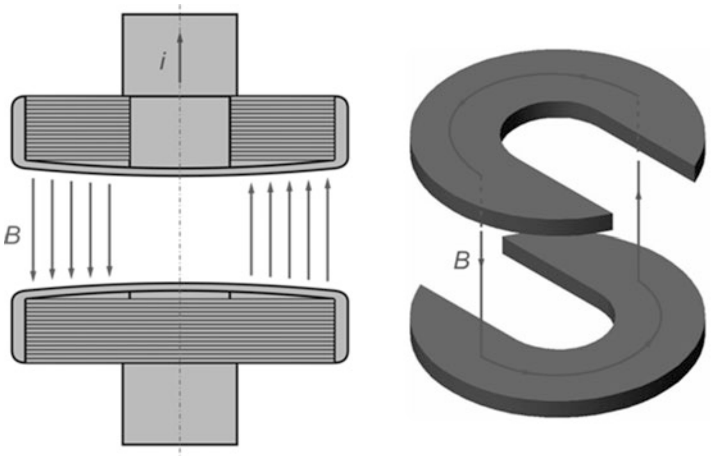

Fig. 7.6 Generation of axial magnetic field for arc control by iron "horseshoe" packages below the contact surfaces (Kapetanovic and Smeets 2011; Eaton Corporation). (Courtesy of Eaton Electric)

7.5 Contact Material for Vacuum Interrupter

7.5.1 Requirements

The successful operation of vacuum circuit breakers depends to a considerable extent on the properties and processing of the contact materials. Contact materials for vacuum application must satisfy a number of different requirements that are sometimes contradictory to each another:

Fig. 7.7 Generation of axial magnetic field for arc control by an external winding (Kapetanovic and Smeets 2011; Picot 2000). (Courtesy of Schneider Electric)

- Good dielectric compatibility with vacuum
- High purity
- Low gas content
- Mechanical strength
- Low contact resistance
- High electric conductivity
- High thermal conductivity
- Low tendency to weld and low weld-break forces
- Low current-chopping level
- Low arc voltage
- Favorable thermionic emission characteristics
- Ample generation of plasma during arcing
- Rapid recovery of dielectric strength after arc extinction
- Low and uniform erosion due to arcing
- Adequate gettering effect

No pure metal has the properties required to make it suitable for use in vacuum interrupters, but composite materials or alloys of two or more metals can potentially satisfy the various requirements. The gettering effect is a special requirement for vacuum interrupters in order to maintain their vacuum quality. It is generally constructed with a metal shield made of zirconium and aluminum or barium and nickel which can capture or deposit reactive materials inside a vacuum interrupter. When reactive particles collide with the getter material, they combine with it chemically or by absorption.

The vacuum environment offers definitely advantages to the contact materials: there is no ambient gas to contaminate the contact surfaces by oxidation or in another way, and therefore, contact materials that are not suitable for applications in gas circuit breakers can be considered. Clean contact surface also helps to maintain a stable contact resistance throughout the lifetime of a vacuum switching device. The clean contact surfaces, however, can result in severe contact welding.

One of the fundamental problems that remain is the contradiction of requirements for a low current-chopping characteristic when interrupting small inductive currents in combination with a high resistance to arc erosion, which essentially limits the breaking capability of vacuum circuit breakers. The contradictory requirements involve the vapor pressure of the contact material.

Namely, vapor pressure of a good contact material must be:

- High metal vapor pressure enough in order to sustain the arc as close as possible to periodical current zero of the AC current to reduce the chopping current, however
- Not too high metal vapor pressure, in order to avoid continuation of emission after current zero that might result in reignition of the arc

Contact materials for applications in vacuum can be classified in pure metals and alloys.

7.5.2 Pure Metals

Pure copper (Cu) appears to meet most of requirements for use in vacuum interrupters. It has good thermal and electric conductivity and reasonably good dielectric compatibility with vacuum and is quite good in interrupting high currents. However, it has the major disadvantage of forming very strong welds, which are the result of diffusion between the solid-state lattices when two clean surfaces are pushed together and heated. Refractory metals offer good dielectric strength; their welds are brittle and thus are easy to break. However, the main disadvantages of the metals with refractory characteristics are their very efficient thermionic emission, which limits their interrupting capability. They possess low electric conductivity and high chopping levels.

Soft or mechanically weak metals can also be ruled out because of the fact that they are incapable of withstanding the shock of rapid closing of contacts in the normal operation of vacuum interrupters.

7.5.3 Alloys

Since an acceptable compromise contact material cannot be found among pure metals, much effort has been put into the development of suitable contact materials,

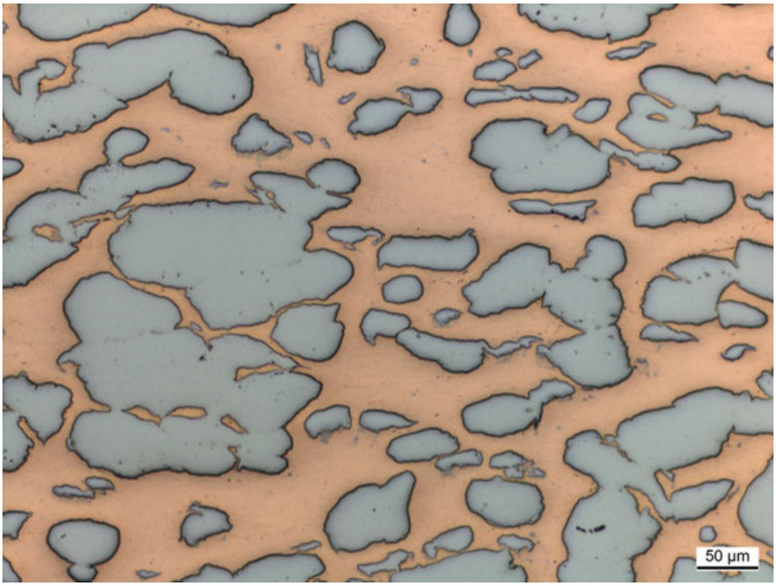

Fig. 7.8 CuCr (75:25) contact material. (Courtesy of Plansee Powertech AG)

and various alloys have been investigated to study their suitability for vacuum-interrupter applications.

Copper-chromium (CuCr) contacts have found wide usage in vacuum circuit breaker applications. One example is shown in Fig. 7.8. A proportion of approximately 25% by weight of chromium in copper has been shown to be particularly suitable (Garzon 1997). It is impossible to employ conventional melting techniques in order to manufacture CuCr material with composition of approximately 50% since chromium and copper are not mutually soluble, even in the liquid state.

There are two powder metallurgy methods that are suitable for manufacturing the CuCr material: (1) densification (sintering and repressing) of CuCr powder mixtures and (2) infiltration of liquid copper into a porous sintered chromium matrix. It has been verified by tests that the interrupting capability of CuCr contacts produced by the infiltration technique is superior to that produced by the densification technique.

During switching, CuCr composite materials exhibit exceptional good melting and solidification characteristics, providing the superiority as a contact material for vacuum interrupters. When subjected to arcing, a CuCr contact surface has several advantages to produce flat shallow pools when melting and to a smooth surface finish when solidifying again.

Due to their shallow depth, the melted pools solidify very rapidly, which quickly reestablishes the dielectric strength of the contact gap. The absence of peaks and troughs on the contact faces ensures that the CuCr material maintains a constant high dielectric withstand strength at very small gaps. This enables the overall size of the vacuum interrupters to be reduced. At the same time, the volume of contact material can be minimized, since – when the contact gap is small – a large proportion of the material vaporized in the arc condenses on the contact surfaces and becomes available again.

The high chromium content also reduces the maximum chopping current for about three times – from approximately 16 A for Cu alone to less than 3 A for CuCr material.

7.6 Reliability of Vacuum Switchgear

Due to difficulties encountered during the production technology that has to assure tightness during decades of operation, it was not until the late 1960s that commercial application of the vacuum-based switching became available on a large scale. Since then, the application of vacuum switchgear for a very wide variety of switching applications in the range up to 40.5 kV has developed fast. Nowadays, vacuum switchgear has a dominant position in MV systems. It has a market penetration that is estimated to be in (Garzon 1997; CIGRE TB 589 2014):

- North America and Japan: close to 70%.
- Northern Europe: about 80%.
- Southern Europe: not specified, but there is a general trend away from SF_6 to vacuum interrupters.
- China, India, and Southeast Asia: tending toward 85%.
- South America, Africa, Middle East, and Russia: tending toward 80%.

Manufacturers have proven ability to produce highly reliable vacuum switchgear. For example, the reliability data on vacuum circuit breaker collected in the United States, 1991–1994, have been reported in (Briggs et al. 1998; Hale and Arno 2000). They show a *mean time-to-failure* (MTTF) up to/at least several tens of years. Manufacturers currently claim MTTF values of 40,000 vacuum-interrupter years (Renz et al. 2007).

7.6.1 Electrical Lifetime

Vacuum switchgear provides very long electrical life because of its low arc voltage and the low erosion of the contacts (Reuber et al. 2003). Usually, electrical life is limited by contact erosion and deposition of metal vapor on the interrupter's interior ceramics.

Contact erosion rate is proportional to the charge passed through the arc since arcing activity in fact removes mass from the contacts. For the cathode, a number of approximately 10 μg/C of charge is often quoted for the rate in a diffuse arc (Slade 2008). Slots (narrow opening) in the contact, such as those used in radial magnetic field, usually increase the erosion rate since metal vapor disappears through these slots and is not returned to the contact surface, and this is why radial magnetic field contacts have a shorter electrical life span than axial magnetic field contact systems (Slade and Smith 2006).

From extrapolations based on measurements, several hundreds of thousands of switching operations under load current condition are estimated in order to erode 3 mm of contact material (Schlaug et al. 2006). The loss of a layer of 3 mm of contact material is often taken as an end-of-life criterion. The lifetime of a vacuum interrupter is determined by its mechanical lifetime rather than by the electrical lifetime. With respect to fault-current interruption, there are estimates that vacuum circuit breakers can perform at least 30 interruptions of the rated short-circuit current.

7.6.2 Mechanical Life

Vacuum circuit breakers designed for MV applications make low contact strokes (in the 10 mm range), they have low moving masses (Dullni et al. 1999) (in the kilogram range), and they therefore benefit from low operating energy of operating mechanism.

The mechanical life of vacuum interrupters is limited by the bellows that enable motion of the moving contact through the vacuum-sealed enclosure. The lifetime of the bellows is a function of the number of its contractions, its diameter, the extent of its expansion, and the acceleration of the movement, but it can be designed for several tens of thousands of operations (Slade 2008).

7.7 Breaking Capacity

7.7.1 Interrupting Capability

Vacuum switching shows a unique feature of very rapid dielectric recovery. This is of great advantage to thermal interrupting capability to interrupt the currents with very high value of di/dt and TRVs with very high value of RRRV. This property is exploited in vacuum generator circuit breakers (Smeets et al. 2009) where high di/dt and RRRV occur in the same switching duty. The applications in transformer-limited fault (Smeets et al. 2007a) interruption may also create severe RRRV. Recently HVDC circuit breakers with current injection scheme were developed by the application of a vacuum interrupter utilizing the excellent capability to interrupt the very high value of di/dt *(500–1000 A/microsecond level)* (Tahata et al. 2014).

The drawback of this excellent interrupting performance is that vacuum circuit breakers are also capable to interrupt high-frequency current after a reignition or a restrike. Because vacuum circuit breakers attempt to interrupt the current repeatedly, the recovery voltage increases after every attempt (*multiple reignitions*, *multiple restrikes*). In some cases, very high overvoltages are generated, and protection is necessary (Schoonenberg and Menheere 1989).

Because of this property, vacuum circuit breakers are sometimes called “hard-switching devices.” SF_6 circuit breakers, which generally need more recovery time, may fail to interrupt reactive load currents instead of doing many attempts before succeeding but have a lower tendency to generate overvoltages.

A strong point of vacuum interruption is the capability to break currents without external means, such as pressure built-up inevitable in SF_6 circuit breakers. A stationary open gap of vacuum circuit breakers has a good inherent interruption capability, as demonstrated by the non-sustained disruptive discharges (NSDD). This partly compensates for the lack of reproducibility of dielectric withstand in certain conditions. Stationary open gaps in SF_6 circuit breakers will not interrupt current above a certain level after late or otherwise unexpected breakdown.

Because a vacuum gap is in principle always ready to interrupt and no extinction pressure needs to be built up mechanically, the minimum arc duration, or *minimum arcing time,* is significantly shorter than in SF_6 circuit breakers, i.e., several milliseconds in vacuum against 10–15 ms in SF_6 circuit breakers.

7.7.2 Dielectric Withstand Capability

Dielectric withstand capability is strongly influenced by the contact surface condition and the presence of particles inside the interrupter. Thus, the arcing history is of importance for the capability. This is also reflected in the conditioning of the vacuum gap by applying voltage. As a stage in the manufacturing process, all vacuum interrupters are preconditioned by high AC voltage (Ballat et al. 1993). The intention is to increase the breakdown voltage by removing the surface irregularities and other electric-field electron emitters through breakdowns under controlled conditions. If this procedure is optimized, the initial breakdown voltage can be increased three to four times by the conditioning process (Ballat et al. 1993). When the energy in the conditioning discharge is too high, the energy in the breakdown can create new or more intense field electron emitters that have a net effect of de-conditioning (deterioration). Therefore, the energy in the HV generator, released at the moment of breakdown, is of importance in the conditioning process (Leusenkamp 2012).

Because breakdown in vacuum is basically determined by the surface condition, the (microscopic) geometry of which depends on the arcing and switching history, the dielectric performance of a vacuum gap is less predictable than that of an SF_6 gap (Betz and König 1998; Nitta et al. 1974), where breakdown is basically governed by the gas (gas pressure and gap distance). This implies that vacuum gaps have a finite probability of breakdown at relatively low voltage and it makes the design of vacuum interrupters for disconnector applications a challenge (Hae et al. 2013; Schellekens et al. 2010).

7.7.3 Current-Carrying Capability

Vacuum circuit breakers have butt contacts. This implies that the contact resistance is relatively high, especially after contact surface modification by high current arcing. This limits the rated normal current that can be handled. In order to reduce the contact resistance and to counteract the "popping" caused by "blowoff" electromagnetic forces that try to open the contact under high current conditions, additional contact closing force must be applied by a set of springs that are energized by the mechanism during the closing operation. A strong point of vacuum interrupter contacts is their insensitivity to contact oxidation or to contamination by products inside the interrupter's enclosure.

A design challenge is that the transfer of heat, generated at the contact interface, cannot take place by convection (forced convection heat transfer), such as in SF_6 interrupters. This implies that the heat has to be conducted by the supporting contact stems to the external environment. Radiators (heat sink) are sometimes provided to the contact stems in order to increase the rated normal current. This limits the rated normal current, especially for high-voltage applications where the interrupters are long because of the requirements of the external dielectric strength.

Even without an arc, contacts in vacuum tend to weld upon closing, which is a natural interaction of clean metallic surfaces being pressed together. In the presence of a prestrike arc, welding can be much more severe due to the thermal energy of the arc. The operating mechanism must be designed to be able to break the weld.

7.8 Vacuum Quality

A major requirement set for vacuum interrupters is to provide a high vacuum (10^{-1} to 10^{-5} Pa) over a long lifetime, which is usually required from 20 to 30 years. This ensures a high breakdown strength for short gaps and half-cycle interruption of power currents throughout the lifetime of a vacuum circuit breaker.

In order to fulfill this requirement, the material used for vacuum interrupters should meet the following conditions:

- The materials utilized in the interior of the interrupter must be extremely pure and free of microporosity, ruptures, and other defects.
- The contact material has to be totally degassed by heating it in a vacuum furnace to release and remove any gaseous impurities.
- The ceramic-to-metal seals must have an extreme airtightness.
- The getter material should be mounted inside the vacuum interrupter to capture the free gaseous particles that may remain after assembly.

The experience of vacuum circuit breakers used in MV systems shows that loss of vacuum by leakage is an extremely improbable event. Recently, loss of vacuum has been a subject of renewed interest. The primary reason is the fact that many MV devices installed in the field have lifetimes in excess of 30 years. Customers started asking whether they can extend the life of these devices. In the reference (Falkingham and Reeves 2009), the authors conclude that the experience with the vacuum interrupters has been excellent in the range of 12–38 kV.

In rare cases, where vacuum circuit breakers fail, it is normally related to loss of vacuum. The experience at MV levels shows that vacuum interrupters can operate in excess of 30 years (Renz et al. 2007). However, the same authors report, after a study of over 200 elder interrupters, that for interrupters older than 30 years, the mean time-to-failure drastically drops from 40,000 vacuum-interrupter years to just over 400 vacuum-interrupter years, due to loss of vacuum (Reeves and Falkingham 2013).

In most practical cases, switching with vacuum circuit breakers often improves the vacuum quality. The vacuum arc itself exhibits a pumping effect since the metal vapor plasma jets, emitted from the contacts, trap the particles of the residual gases and embed them in thin film layers deposited on the surfaces of the contacts, shields, etc. Therefore, operation of the interrupter involving an arc is beneficial in improving the quality of vacuum inside the device.

At the production stage, the pressure is ensured to be below 10^{-4} Pa, whereas 10^{-2} Pa is the limit that still ensures switching ability. Therefore, the margin of the initial state of the vacuum pressure is rather high, and the getter material helps the interrupter to stay within the required (ultra-) high vacuum state.

In the case of vacuum circuit breakers, continuous supervision of the vacuum quality inside the interrupting unit is possible by the following methods (Parashar 2011):

The first approach predicts failure by monitoring the actual vacuum inside the vacuum interrupter. This method uses either the Penning or the Pirani principle which requires a vacuum gauge to be permanently fixed to the vacuum interrupter.

The second approach detects a failure of the vacuum. This can be incorporated in the design of the circuit breaker as used in some vacuum contactors and uses the atmospheric pressure on the bellows as part of a balance of forces when the contactor is closed. For example, if one pole has lost vacuum, then the unit cannot close. Continuous monitoring can be achieved via a partial discharge detector, which is actually not yet widely used.

Another possibility to give real-time information about the status of the vacuum is a fiber-optic system that conducts light in case of normal state of vacuum and blocks the light in case of loss of vacuum.

In service, it is not common to have any vacuum-quality measurement or detection system for indication of loss of vacuum, because a vacuum-quality monitoring system is in general less reliable than the vacuum interrupter itself. This means that adding these vacuum measurement or loss-of-vacuum detection systems may reduce the reliability of the vacuum circuit breaker.

There are several vacuum-integrity monitoring devices on the market that test the voltage withstand capability of the interrupter in open position.

Note 1: Penning principle is one of vacuum pressure measurements by detecting the ionization current under the influence of combined electric and magnetic field.

Note 2: Pirani principle is one of vacuum pressure measurements by monitoring the heat loss to a low-pressure environment of a heated wire.

7.9 Vacuum Switchgear for HV Systems

7.9.1 Introduction

Excellent service experience of vacuum circuit breakers in MV power systems obviously resulted in exploration of possibilities to develop vacuum switchgears for transmission voltage levels. Another major driver is the search for alternatives for SF_6, which is a predominant interrupting medium in HV power systems but one of the greenhouse gases with high global warming potential (GWP). CIGRE investigated the service experience of HV vacuum circuit breakers and summarized the state of the art regarding the impact of the application of vacuum switchgear at voltages above 52 kV (CIGRE TB 589 2014).

There are basically two ways to increase the dielectric strength of the vacuum gap to the value needed for insulation at transmission levels.

One is to increase the contact distance in a two-contact configuration. However, the breakdown voltage U_b of vacuum gaps is not proportional to the gap length d (as it is in gases) but typically follows the relation:

$$U_b = A \cdot d^{\alpha}$$

where α is a parameter smaller than one and A is a constant. The explanation is that breakdown in vacuum is a surface effect (Latham 1981), completely governed by the contact surface condition. In SF_6, breakdown is merely a volume effect that scales linearly with the gap length. The breakdown process is then mainly determined by the insulating medium and its pressure rather than by the contact configuration and condition.

Figure 7.9 shows an example of dielectric recovery that characterizes for different interrupting media with no load condition. The dielectric strength linearly increases with the contact gap in case of gas; however, that in a vacuum shows good dielectric

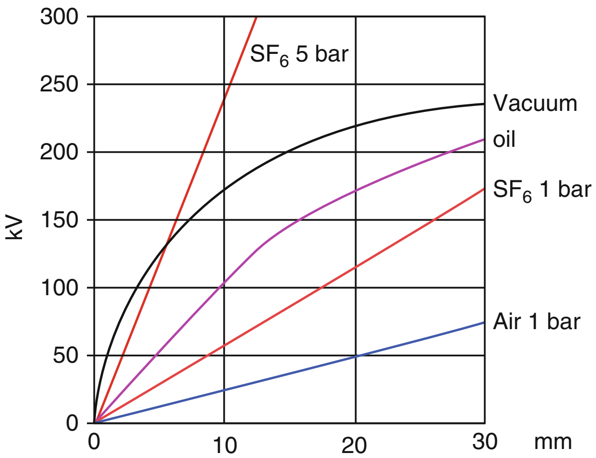

Fig. 7.9 Dielectric performance in vacuum. (CIGRE TB 589 2014)

strength with small gap (even 2–4 mm gap) but gradually saturates for a longer gap length.

The other way is to place two or more gaps in series (multibreak circuit breakers that typically ensure the uniform voltage distribution across all breaks during normal and switching system operation with grading capacitor), and in case of ideal voltage sharing between the gaps, the necessary withstand voltage level can be achieved with a total contact distance smaller than it would be with a single gap.

These two solutions coexist in the market at voltages above 72.5 kV.

7.9.2 Development of HV Vacuum Circuit Breakers

The first reported commercial development of transmission vacuum circuit breakers was in the United Kingdom in 1968 where eight vacuum interrupters were connected in series in a circuit breaker for 132 kV (see Fig. 7.10) (Falkingham and Waldron 2006). The breaker has been in service for more than 40 years.

In the mid-1970s, in the United States, a series arrangement of four vacuum interrupters per pole (Shores and Philips 1975) was used as retrofit kit for bulk oil circuit breakers up to a system voltage of 145 kV (Slade et al. 1991), and further plans were made for up to 14 break interrupters for 800 kV.

Simultaneously with this multi-gap/multibreak approach, Japanese researchers developed and commercialized single-break vacuum interrupter units up to 145/168 kV (Umeya and Yanagisawa 1975).

In 1986, two types of vacuum circuit breakers were published (Yanabu et al. 1986): a single-break 84 kV vacuum circuit breaker (Figs. 7.12 and 7.13) with a rated breaking current of 25 kA and a prototype vacuum circuit breaker for the 145 kV voltage level (Saitoh et al. 2002).

Commercial single-break vacuum circuit breakers are available up to 145 kV, and commercial double-break dead-tank-type vacuum circuit breakers are developed up to 168 kV (see Fig. 7.11) (Matsui et al. 2006) and 204 kV.

China took a strong lead in research and development of HV vacuum circuit breakers. Single-break designs up to 252 kV (Wang et al. 2006) and futuristic conceptual designs of modular EHV circuit breakers (Homma et al. 2006) for 550 kV level and even for 765 kV (Liu et al. 2004) have been published.

7.9.3 Actual Application of HV Vacuum Circuit Breakers

In total, approximately 8300 units of vacuum circuit breakers with rated voltages of 52 kV and above were delivered to the market by five manufacturers in Japan from the late 1970s to 2010 (Ikebe et al. 2010). Roughly 50% were delivered to power utilities and 50% to industrial users. Cubicle-type GIS (C-GIS) represents 50% of the HV vacuum circuit breaker application, mainly by industrial users.

One of the reasons of the rather frequent use of HV vacuum circuit breakers in Japan is that utilities acknowledge the advantages of less maintenance (compared

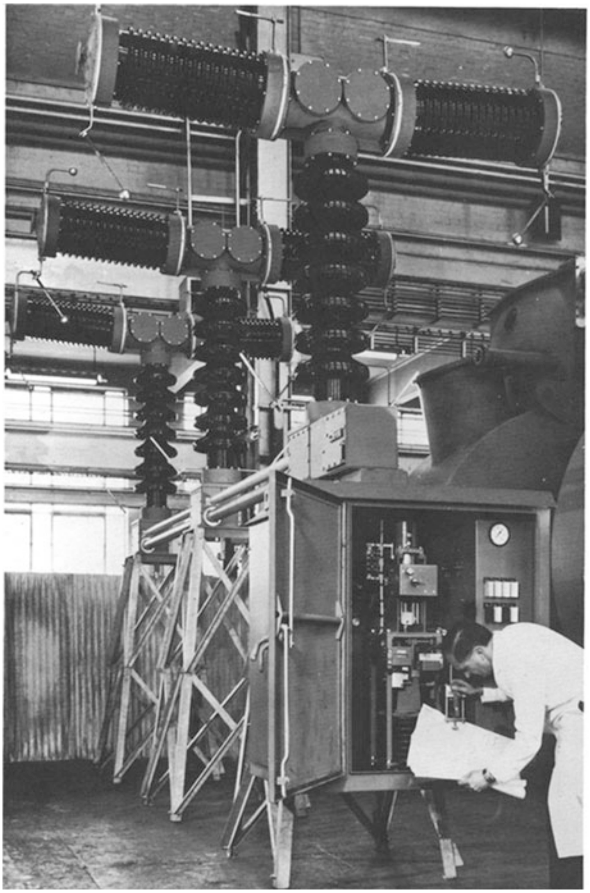

Fig. 7.10 138 kV vacuum circuit breaker. (CIGRE TB 589 2014)

with SF_6 circuit breakers), the excellent frequent-switching performance, and the suitability for rural distribution systems.

The reliability of HV vacuum circuit breakers appears to be comparable to SF_6 circuit breakers. A Japanese survey on the failure rate of HV vacuum and SF_6 circuit breakers installed in 72.5 kV transmission networks was conducted in cooperation with a Japanese utility (CIGRE TB 589 2014). Mechanical failure of the operating mechanism was the main cause of major failures. There were no troubles caused by overvoltages arising from HV vacuum circuit breakers. The quantity of failures, however, is too low to identify a trend regarding service years.

Up to the present, most research and development efforts devoted to HV vacuum circuit breakers are concentrated in East Asia. Japanese companies showed the feasibility of mature products already 20 years ago, however, predominantly applied on their internal market where HV vacuum circuit breakers take a certain share in special applications.

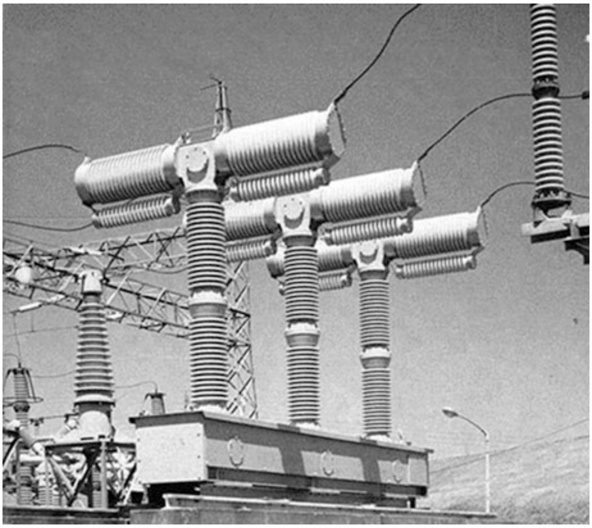

Fig. 7.11 168 kV 40 kA vacuum circuit breakers in 1972. (Courtesy of Meidensha)

Fig. 7.12 72/84 kV dead-tank vacuum circuit breaker with dry air as external insulation. (Courtesy of Meidensha)

In China, there are significant developments, and application on a large scale on 72.5 and 126 kV is foreseen in the near future.

Research and development work in Europe has been reported since the mid-1990s (Giere et al. 2002; Schellekens and Gaudart 2007; Godechot et al. 2008). Companies in Europe are now bringing HV vacuum circuit breakers on the market and have started pilot projects to gain experience in the field (Brucher et al. 2012; Newton and Renton 2013). In the modern generation of HV vacuum circuit breakers, SF_6 is tended to avoid as outside insulation media of the vacuum interrupter, and instead, nitrogen or dry air is preferred.

Some manufacturers in the United State although having an early track record of HV vacuum circuit breaker development did not commercialize the HV vacuum circuit breaker technology. However, products for load switching, notably capacitor

Fig. 7.13 72/84 kV 31.5 kV 2000A dead-tank vacuum circuit breaker with dry air as external insulation. (Courtesy of Mitsubishi Electric)

banks, with multibreak vacuum interrupters in series (up to 9 interrupter units per phase) emerged already long ago as HV switches up to rated voltages of 242 kV. Vacuum switchgear is occasionally seen as an option in HV disconnectors for increasing their switching capability.

Experimental ("hybrid") designs with SF_6 and vacuum interrupters in series have been reported as well (Smeets et al. 2007b; Cheng et al. 2010). The idea is to use the very fast recovery of a vacuum interrupter to withstand the initial TRV (such as appears in short-line fault interruption), whereas an SF_6 interrupter with a reduced amount of SF_6 should withstand the peak value of the transient recovery voltage.

7.9.4 X-Ray Emission

X-ray emission is generated in vacuum devices because electrons, accelerated by the electric field in the gap, collide with the metal target contact. In this process, electromagnetic radiation is generated, the energy of which is determined by the voltage across the gap and the intensity of which is determined by the electron current. The biological effect of X-ray radiation on human tissue is expressed as equivalent radiation dose. Its SI unit is the sievert [Sv]; 1 Sv = 1 J/kg.

To benchmark X-ray dose limits, the natural background radiation dose rate of about 0.3 μSv/h can be considered. Investigations show (Renz and Gentsch 2010) that the X-ray dose rate of interrupters up to rated voltages of 36 kV remains within the limits of 1 μSv/h, even during application of power frequency test voltages, much higher than the rated voltage. It depends on the design and on the contact surface roughness, but the dose rate of X-rays emitted by vacuum interrupters seems to be within the limit of 1 μSv/h up to a rated voltage of 145 kV (Yan et al. 2012).

7.9.5 Comparison of HV Vacuum and HV SF_6 Circuit Breakers

There exists general consensus among specialists that applying vacuum technology for HV switchgear is already successful for fault-current interruption (CIGRE TB 589 2014). Interruption of very high fault current even in combination with very high value of rate of rise of TRV by vacuum circuit breakers has been demonstrated and in this context may be even superior to SF_6 circuit breakers. This can be particularly useful in the application of, for example, transformer- and reactor-limited faults. Recently HVDC circuit breakers with current injection scheme for current zero creation have been developing using a vacuum interrupter with its excellent thermal interruption capability (CIGRE JWG A3/B4.34 2017).

Figure 7.14 shows the interruption power of air-blast, vacuum, and SF_6 circuit breakers per break (Glaubitz et al. 2014). The interruption power of SF_6 puffer circuit breakers per break surpassed that of air-blast circuit breakers around 1970 and significantly advanced in the 1980s and 1990s. SF_6 puffer circuit breakers at 245 kV 40 kA and 300 kV 50 kA were developed with a single break in the early 1980s, followed later by 420 kV and 550 kV 63 kA single-break circuit breakers, and 800 kV, 1100 kV, and 1200 kV circuit breakers with two breaks per pole were achieved in the mid-1990s. Highly reliable and compact designs lead to the dominance of SF_6 puffer circuit breakers over the complete transmission voltage range up to EHV/UHV.

Comparing the interruption capacity of vacuum circuit breakers to the development of SF_6 breakers, it is clear that a large gap has to be bridged in order to come even near the interruption power of the largest SF_6 circuit breakers. Nevertheless, up to voltages of 145 kV, both technologies can coexist, even in SF_6-free GIS

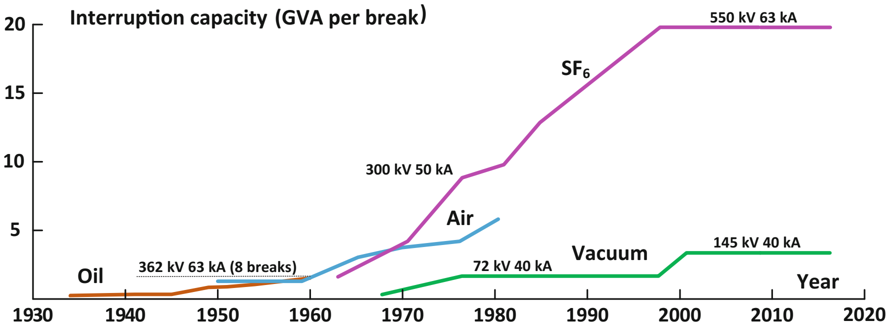

Fig. 7.14 Interruption capacity per break of vacuum circuit breakers compared with other technologies including SF_6 circuit breakers

technology (http://www.siemens.com/innovation/en/home/pictures-of-the-future/energy-andefficiency/power-transmission-environment-friendly-high-voltage-switchgear-unit.html).

The main driving force for the development of HV vacuum circuit breakers is the absence of SF_6 gas as well as the reduced maintenance (of the interrupter) and high electrical endurance. In turn, the lack of practical methods to monitor the vacuum quality in service is seen as a disadvantage.

The main challenge for HV vacuum switchgear is in the capacitive and inductive load switching duties. Capacitive switching is influenced by the inherently wide variation of vacuum in breakdown statistics, which becomes significant for frequently switching capacitor banks. Testing statistics show that capacitor bank switching, especially in case of large inrush currents, at higher voltages is associated with an increasing occurrence of late breakdown (Smeets et al. 2012). A special design of a HV vacuum interrupter may sometimes be advisable for switching of single capacitor banks.

In shunt reactor (inductive load) switching, the number of reignitions (not the probability of reignition) can be large compared with SF_6 circuit breakers. Protective measures when switching small HV reactors, especially when directly connected to the circuit breaker, are sometimes recommended. Alternatively, designs that are optimized for shunt reactor switching may be used. The chopping current level of (HV) vacuum circuit breakers do no differ essentially from those of SF_6 circuit breakers (Tokoyoda et al. 2013).

In comparison with SF_6 circuit breakers, from a merely technical point of view, vacuum has the following strong features (CIGRE TB 589 2014):

- Vacuum interrupters do not contain greenhouse gas inside.
- Vacuum circuit breakers are disposable at the end of life without special issues.
- No site risk for contamination in case of an explosive failure.
- Vacuum interrupters are sealed for life (no gas handling infrastructure or interrupter maintenance).
- Lower operation energy may imply simpler drives and reduced maintenance.
- Very fast dielectric recovery after interruption.
- Short arcing times make design of a two-cycle circuit breaker feasible.
- Vacuum circuit breakers can interrupt current after a late restrike.
- Restrikes and reignitions typically do not damage interrupter internal parts.
- Vacuum interrupters function electrically independent of low ambient temperature (there is no liquefaction).
- Frequent switching capability even short-circuit interruption (electrical endurance).

The weaker points of vacuum switchgear for application at the transmission voltage levels are the following:

- Costs are probably higher than that of SF_6 technology for the same ratings (at least to date).

- Limited HV service experience resulting in unknown lifetime.
- Difficulties for higher normal current-carrying performance due to limited heat convection out of the vacuum interrupter.
- No practical way to monitor vacuum quality in service.
- Multiple breaks per pole are generally applied at the rating of 145 kV and above, often even at lower voltages.
- Dielectric performance of vacuum interrupters is sensitive to switching history or contact surface conditions and has significant scatter.
- Special designs or protection devices may be necessary in certain reactive switching applications (shunt reactor, capacitor bank switching).

7.10 Summary

Vacuum circuit breakers have several technical advantages such as excellent thermal interrupting capability, frequent switching capability, and less maintenance works due to smaller operating energy for the mechanism. Vacuum circuit breakers show good service experience especially in MV networks (both power systems and industrial applications) and are also applied to transmission voltages up to 145/168 kV levels.

The dielectric withstand strength in a vacuum shows good dielectric strength with small gap but gradually saturates for a longer gap length. This characteristic brings multibreak designs for higher-voltage applications and increases its cost compared with SF_6 technology.

Recently due to growing environmental concerns, cost-effective and maintenance-free vacuum solutions to cover the complete transmission voltages (EHV and even UHV) are highly expected in power systems.

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Generator Circuit Breakers

8

Daisuke Yoshida and Marta Lacorte

Contents

Keywords
Generator · Synchronization · Generator circuit breaker · Step-up transformer

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8.1 Introduction

A power plant is required to supply the energy produced by power generators in as stable and efficient method as possible. A circuit breaker is used to connect the generator to the network and to separate the generator from the network. Figure 8.1 shows two different layouts of a power plant. The circuit breaker which connects and disconnects the generators in the power plant is located either at the high-voltage (HV) side of the step-up transformer (HV synchronization of the generator with HV circuit breaker) or at the medium voltage (MV) side between the generator and the step-up transformer (MV synchronization of the generator with MV circuit breaker). In the latter case, the MV circuit breaker is called a generator circuit breaker because special duties and capabilities are required.

The generator circuit breaker is used to synchronize the generator to the grid and to protect the generator in case of fault occurrence but also to prevent excessive stresses to the power equipment including the generators for long duration due to external short-circuit faults that may damage the generator. The generator circuit breaker, when existing, will also decrease the duration of the generator short-circuit stresses in case of a fault that occurs on the MV side of the step-up transformers. In case of false synchronization, the generator circuit breaker could also provide subsequent tripping. Sometimes the HV circuit breaker could be tripped when it is energized in false synchronization conditions as well.

Each layout has both pros and cons. Furthermore, the best technical and economical solution may vary depending on the number of generators and step-up power transformers in addition to the power capacity and system voltage ratings.

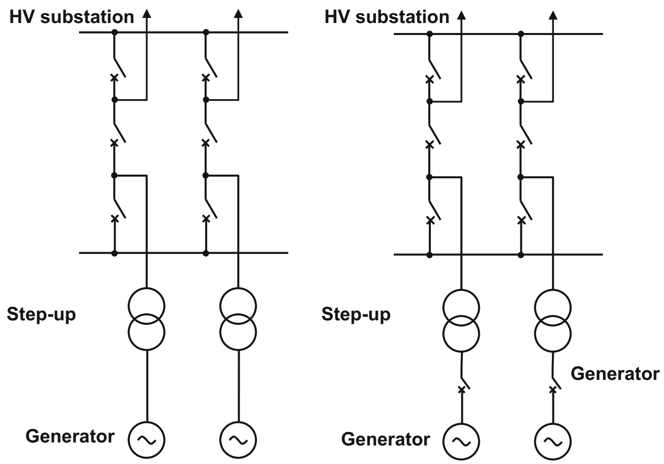


Fig. 8.1 Power plant layouts with direct connection. (*Left*) The generator is synchronized at the HV side of the step-up transformer; (*Right*) the generator is synchronized at the MV side of the step-up transformer with generator circuit breakers between the generators and the step-up transformers

As already described, generator circuit breakers are located between a generator and the MV side of a step-up transformer. The power plant with generator circuit breakers can provide a clear advantage in the circumstances prevailing in thermal power generation stations. Figure 8.2 compares simplified single-line diagrams of a thermal power station with/without generator circuit breakers (Brown and Koeppl 2004).

In a power generation station with a generator circuit breaker (Fig. 8.2a), the generator is switched on and off by means of the generator circuit breaker. The unit auxiliaries are supplied at all times from the unit transformer, even during the starting up and shutting down of the generator. The station transformer can, therefore, either be completely omitted or derated as an emergency shutdown transformer. The circuit breaker on the high-voltage side of the step-up transformer is normally operated only in case of longer out-of-service periods.

In a power station without a generator circuit breaker (Fig. 8.2b), the generator is switched on and off by means of the HV circuit breaker located at the HV side of the step-up transformer. This configuration, without the generator circuit breaker, brings a certain operation restriction because the unit auxiliaries cannot be supplied from the unit transformer unless the generator is synchronized to the high-voltage system. During the starting-up and shutting-down periods, the unit auxiliaries must, therefore, be transferred (using rapid changeover equipment) to an alternative power source. Usually this source can be supplied by a station transformer that is connected directly to the high-voltage system.

In case of a power plant with generator circuit breakers, a fault can be cleared in a shorter period, typically 3–5 cycles, when the fault occurs between the generator circuit breaker and the step-up transformer or HV circuit breakers, which can reduce the electrical stresses imposed on the power equipment including the generators. On the other hand, in case of a power plant without a generator circuit breaker, the fault

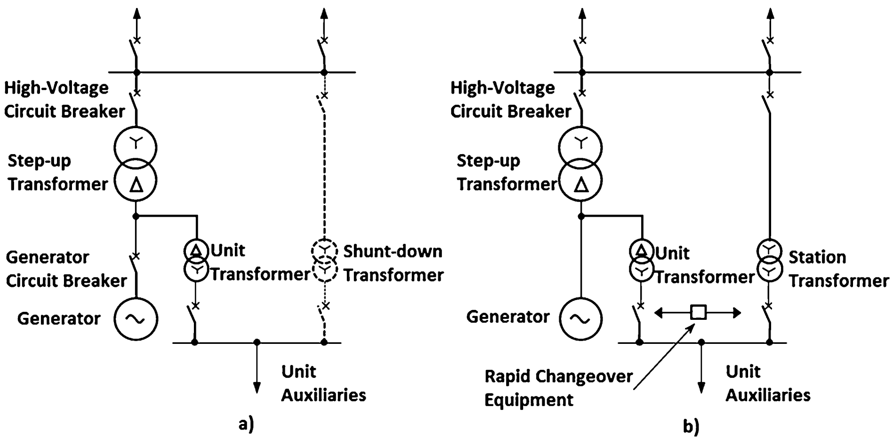


Fig. 8.2 Single-line diagrams of a typical thermal power plant with (**a**) and without (**b**) generator circuit breaker

current may continue to flow for a longer period, up to several dozen seconds, until the energy of the generator is completely discharged, which may cause significant damage on the power equipment.

An auxiliary power source is required which supplies power for the secondary and auxiliary equipment of the generators such as an oil pump and an exciter, when starting the generator. In case of a power plant without a generator circuit breaker, an additional step-down station transformer (which has the same voltage ratings as that of the step-up transformer) and HV circuit breakers connected to the station transformer are required to supply power for the secondary and auxiliary equipment.

To the contrary, in case of a power plant with generator circuit breakers, a small unit transformer can be connected to the step-up transformer which supplies power for the secondary and auxiliary equipment in the open position of the generator circuit breakers (before starting the generators). Therefore, the power plant with generator circuit breakers enables a compact station layout by eliminating the additional step-down station transformer and its HV circuit breakers. The power plant with generator circuit breakers also provides a benefit of being able to connect several units of generators to a single step-up transformer as shown in Fig. 8.3.

Hence, the application of a generator circuit breaker can reduce and minimize a faulted part or out-of-service part of the generator circuit (system) to be separated from the healthy power system in case of a fault occurrence as well as some maintenance work, which results in improvement of the availability of the power system operating with a healthy condition.

The generator circuit breaker can provide other benefits to make the transformer and generator protection levels much broader and flexible. Consequently, the presence of the generator circuit breaker increases the availability of the power generation plant. However, of course, the initial investment may increase. Technical and economical assessments to decide the power plant configuration with or without generator circuit breakers must be evaluated using the Life Cycle Cost methodology.

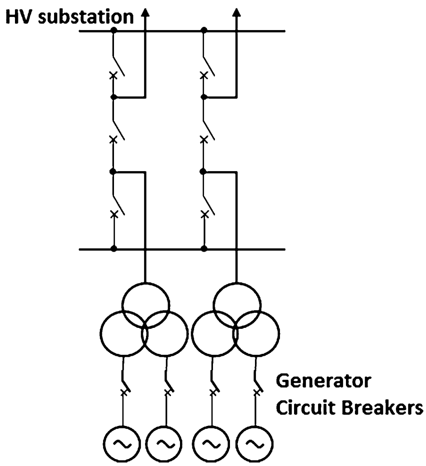


Fig. 8.3 Power plant layouts with generator circuit breakers

8.2 Definitions of Terminology

Circuit Breaker
A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in power systems from damage caused by excessive currents, typically resulting from an overload or short-circuit condition. When a fault occurs, circuit breakers quickly clear the fault to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Gas Circuit Breaker
A SF_6 gas circuit breaker is an electrical switch using sulfur hexafluoride as the insulating and interrupting media. The SF_6 gas breakers consisting of moving and fixed contacts in an enclosure filled with gas pressurize the gas inside the puffer cylinder during the opening operation and blast high-pressure gas through a nozzle into the arc generated between the contacts to extinguish the arc by cooling.

Air-Blast Circuit Breaker
A circuit breaker in which the contacts open and close in air. Since the air interrupting and dielectric withstand capability at atmospheric pressure is limited, a compressed air to several MPa is required to high-voltage applications. The air relatively creates high arc voltage, which can decrease the fault current and assist thermal interruption capability.

Vacuum Circuit Breaker
A circuit breaker in which the contacts open and close within a highly evacuated vacuum enclosure. When the vacuum circuit breaker separates the contacts, arc is generated by the metal vapor plasma released from the contact surface. The arc is quickly extinguished because the metallic vapor, electrons, and ions produced during arc are diffused in a short time and condensed on the surfaces of the contacts, resulting in quick recovery of dielectric strength.

Transient Recovery Voltage (TRV)
Transient voltage oscillation which appears between the contacts (electrodes) after current interruption, where the contact voltage at the source side will oscillate around the source voltage and the contact at line side of a faulted transmission line will oscillate around the ground level.

Generator Circuit Breaker
A generator circuit breaker is directly connected to the terminal of a generator with MV ratings with special requirements and is commonly applied to a station with multiunit generators where a number of relatively small generators are connected to a common bus. The other side of the generator circuit breaker is connected to a step-

up transformer and HV circuit breakers. The current interrupting capability of the generator circuit breaker attains up to the 250–300 kilo-ampere level required for some applications. A major advantage of the generator circuit breaker is that it can be interrupted in 5–7 cycles, or currently 3–5 cycles, after fault occurrence and then isolate the generator. Other advantages include the elimination of transfer of auxiliary loads and improved reliability when the generator is synchronized with the system.

Peak Factor (of the Line Transient Voltage)
Ratio between the maximum excursion and the initial value of the line transient voltage to the earth of a phase of an overhead line after the interruption of a short-line fault current. The initial value of the transient voltage corresponds to the instant of arc extinction in the pole considered.

First-Pole-To-Clear Factor (in a Three-Phase System)
When interrupting any symmetrical three-phase current, the first-pole-to-clear factor is the ratio of the power frequency voltage across the first interrupting pole before current interruption in the other poles to the power frequency voltage occurring across the pole or the poles after interruption in all three poles.

Amplitude Factor
Ratio between the maximum excursion of the transient recovery voltage to the crest value of the power frequency recovery voltage.

Subtransient and Transient Reactance of the Generators
At the moment the fault occurs, substantial high current flows through the generator for a few cycles after the fault occurrence, and then the fault current rapidly decays. The lower generator reactance observed by the fault current during this initial period (typically from 0 to 6 cycles) is called subtransient reactance. After the subtransient period elapses, the fault current decreases slowly after a comparatively longer period of time. The generator reactance observed by the fault current during this period (typically from 6 cycles to a few seconds) is called transient reactance. Finally the short-circuit current becomes steady, and the generator reactance observed by the steady fault current (after a few seconds) is called steady-state reactance.

8.3 Abbreviations

AC	Alternating current
CB	Circuit breaker
DC	Direct current
RRRV	Rate of rise of recovery voltage
SF_6	Sulfur hexafluoride
SFC	Static frequency converter
TRV	Transient recovery voltage

8.4 Generator Circuit Breaker Requirements

Generator circuit breakers are generally applied at the outlet of high-power generators (100–1800 MVA) in order to protect the power equipment including the generators. Generator circuit breakers typically have some special requirements such as current carrying capabilities from 6.3 kA to 40 kA and short-circuit breaking capacities ranging from 63 kA to 300 kA.

Figure 8.4 shows a typical example of cross-sectional view of SF_6 puffer-type generator circuit breaker, which is composed of a gas circuit breaker (CB), a disconnecting switch (DS), an earthing switch (ES), current transformer (CT), voltage transformer (VT), metal oxide surge arrester (MOSA), and operating mechanisms.

8.4.1 Operating Duties

Generator circuit breakers are fundamentally applicable for all kinds of power generation plants such as fossil-fired, nuclear, gas turbine, combined-cycle, hydro, and pumped storage power plants as well as for retrofit in existing power stations without generator circuit breakers.

Fig. 8.5 presents a single-line diagram of a typical generator circuit with the generator circuit breaker in a power plant.

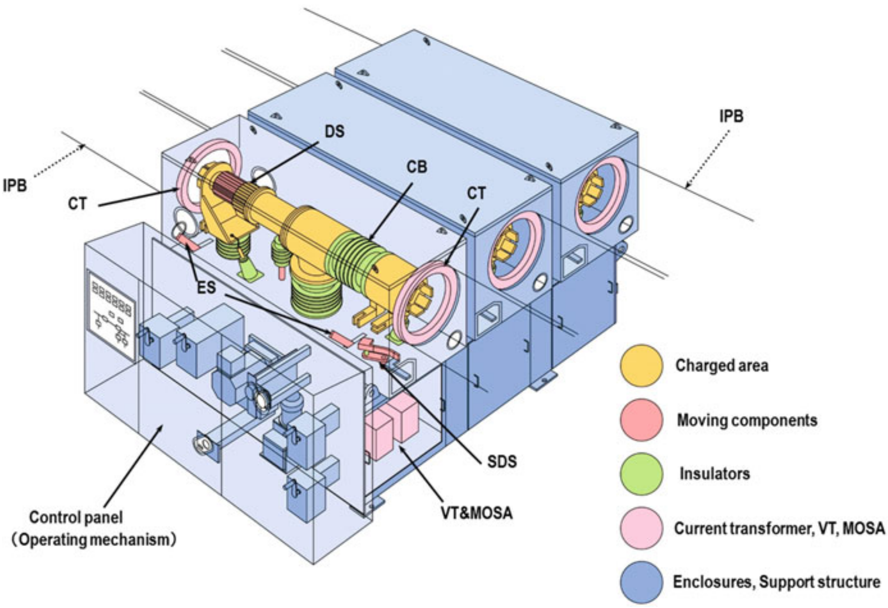
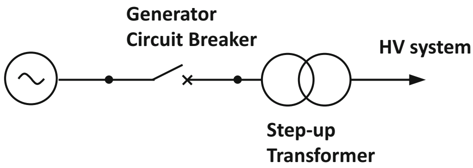


Fig. 8.4 Typical structure of SF_6 puffer-type generator circuit breaker. (Courtesy of Mitsubishi Electric)

Fig. 8.5 Typical single-line diagram generator circuit in a power plant



The generator circuit breaker must be able to perform the following operation duties:

- Synchronize the generator with the system voltage at the HV side
- Separate the generators from the HV system (switching off the unloaded or lightly loaded generators)
- Interrupt load currents (up to the full-load current of the generators)
- Interrupt system-fed short-circuit currents
- Interrupt generator-fed short-circuit currents
- Interrupt current under out-of-phase conditions (up to an out-of-phase angle of 180°)
- Synchronize the generator-motor with the HV system when the machine (generator unit) is started in the motor mode (in case of pumped storage power plants, there are different synchronization methods such as a static frequency converter (SFC) starting or back-to-back starting)
- Close on and interrupt the starting current of the generator-motor when the machine is started in the motor mode (in pumped storage power plants, with asynchronous starting)
- Interrupt generator-fed short-circuit currents at frequencies below 50/60 Hz (in gas turbine, combined-cycle, and pumped storage power plants, depending on the start-up supply)

There are several synchronization methods in the case of pumped storage power plants.

The static frequency converter (SFC) starting scheme mainly consists of a thyristor converter connected to a unit transformer at the HV side and an inverter connected to a generator. The inverter starts the generator from low power frequency and gradually increases it up to the rated power frequency. Then the generator is excited to produce the power which may have a different phase angle from that in the network. The generator is synchronized with the HV network by either a generator circuit breaker or a HV circuit breaker, at the instant when the phase difference between the generator and the HV network is minimized.

For another example, a back-to-back starting scheme can be used in a power plant with several generators. The power source produced by the generator operating at nominal condition is used to start the halted generator up to the rated power frequency. The generator is synchronized with the HV network with either a generator circuit breaker or a HV circuit breaker.

The requirements imposed on generator circuit breakers are greatly different from the requirements imposed on general purpose circuit breakers applied in transmission and distribution systems. The generator circuit breakers are required to have larger continuous current carrying capability, load current switching capability, and short-circuit current capability as compared with those required for general circuit breakers.

8.4.2 Continuous Current Carrying Capability

The rated nominal current of the generator circuit breaker is the highest value of the generator load current and is calculated by:

$$I_{\text{nominal}} = \frac{\mathrm{S}}{\sqrt{3} * \mathrm{U}_{\min}}$$

where S is the rated power of the generator and $\mathrm{U}_{\min}$ is the minimum operating voltage of the generator.

The rated power of the generator in a large power plant can reach thousands of MVA. Consequently, the nominal current that the generator circuit breaker should be able to carry can reach up to 50 kA, often demanding forced cooling (Smeets and Zehnder 2006). This is the biggest challenge of generator circuit breakers; the heat transfer from the conductor path to the environment must be enhanced in order to minimize power losses.

8.4.3 Load Current Switching Capability

When a generator circuit breaker interrupts the load current, two circuits located at both terminals of the generator circuit breaker oscillate independently, providing a TRV as a result of the voltage difference between the terminals. At first, the voltage waveform at the generator side appears with a relatively lower rate of rise of recovery voltage (RRRV) due to the existence of distributed capacitances and impedance.

8.4.4 Short-Circuit Capability

In the case of a fault occurrence close to a generator, a generator circuit breaker encounters two distinctive situations, either of the so-called generator-fed short-circuit current or system-fed short-circuit current. Figure 8.6a shows the system-fed fault current where the generator circuit breaker is required to break fault current that is fed by the system through the step-up transformer. Figure 8.6b shows the

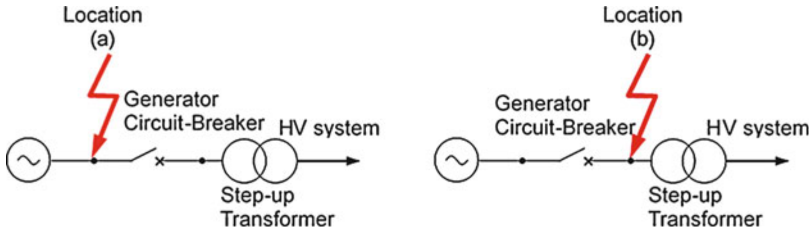


Fig. 8.6 Short-circuit conditions for generator circuit breakers. (**a**) System-fed fault current. (**b**) Generator-fed fault current

generator-fed fault current where the generator circuit breaker is required to break fault current that is fed by the generators.

The largest short-circuit current will occur when the current flows from the system through the step-up transformer and through the generator circuit breaker to the fault location at the generator side of the circuit breaker. The fault short-circuit current consists of a (constant) AC component and a decaying DC component that depends on the exact moment of the fault occurrence with respect to the voltage waveform. When a fault occurs at a voltage peak, there will be no DC component, while a fault that occurs at a voltage zero will show a large DC component with the same amplitude as the AC component. A large DC time constant is expected due to the existence of the step-up transformer.

In general, the system-fed fault current is higher than the generator-fed fault current due to the fact that the sum of the short-circuit reactance of the transformers and the system at HV side is lower than the subtransient and transient reactance of the generators.

(a) **System-Fed Fault Current**

When the fault current is supplied through the step-up transformer, the symmetrical AC and DC component of the short-circuit current can be calculated by:

$$I_{\mathrm{sym}} = \frac{\mathrm{U_{max}}}{\sqrt{3} \times \left(\mathrm{X_t} + X_{\mathrm{sym}}\right)}$$

$$I_{DC} = \sqrt{2} \times I_{\mathrm{sym}} \times e^{-t/\tau}$$

$$\tau = \frac{\mathrm{X_t} + \mathrm{X_{sys}}}{\omega \times \left(\mathrm{R_t} + \mathrm{R_{sys}}\right)}$$

where $\mathrm{I_{sym}}$ is symmetrical AC component of the short-circuit current, defined as the rated short-circuit current of the generator circuit breaker; $\mathrm{U_{max}}$ is the maximum voltage before a fault occurrence; X_t and R_t are the reactance and resistance of the transformer, respectively; X_{sys} and R_{sys} are system reactance and resistance, respectively; ω is angular power frequency; and τ = time constant decay of the DC component.

As an example, the asymmetry becomes 75% at the instant of contact separation in case of a typical sum of the relay time and opening time of 38 ms and a typical time constant of 133 ms. The ratio of the maximum asymmetrical short-circuit current (peak factor) at a half cycle to the rated short-circuit current of the generator circuit breaker is given by $I_{peak}/I_{sym} = \sqrt{2}\times(e^{-t/t} + 1) = 2.74$.

Therefore, typically closing, latching, and current carrying capability of the generator circuit breaker is considered to be 2.74 times rated short-circuit current. The peak factor with the DC component is an important characteristic, since a circuit breaker is designed to consider the electromagnetic force applied by the maximum short-circuit current with the maximum asymmetry, for example, in case of contact separation under the short-circuit current.

Unlike the case of general circuit breakers, the maximum transient recovery voltage (TRV) stress for a generator circuit breaker appears for the maximum short-circuit current stress. The very high RRRV may be generated by the impedance of the step-up or auxiliary transformer.

The neutral of the generator is not solidly grounded; thus, the phase-to-ground fault current is not significant. The severe TRV may occur after the interruption of a symmetrical current. At the interruption of the short-circuit current with maximum asymmetry, the transient oscillation of the recovery voltage will be very small or even negligible since at the moment of short-circuit current interruption, the normal frequency voltage value may be very small or zero.

The first-pole-to-clear factor (k_{pp}) at interrupting symmetrical three-phase current is the ratio between power frequency voltage across the first interrupting pole before the current interruption in the other poles and the power frequency voltage occurring across the poles after interruption in all three poles.

The first-pole-to-clear factor can be calculated by:

$$K_{pp} = \frac{3Z_0}{2Z_0 + Z_1}$$

where Z_0 is equivalent zero-sequence impedance of the three-phase circuit and Z_1 is equivalent positive-sequence impedance of the three-phase circuit.

In case of the step-up transformer with a star connection, the star point of the stator winding of the generator is usually grounded through a high resistance. Therefore, the zero-sequence impedance, Z_0, of such a system is much higher than the positive-sequence impedance, Z_1.

The first-pole-to-clear factor for a generator circuit breaker is 1.5.

The amplitude factor k_{af} is the ratio between the maximum excursion and the initial value of the transient recovery voltage. Standard value for generator circuit breakers is 1.5 without considering any capacitance connected at the terminals of the generator circuit breaker (IEEE C37.013a 2007).

One particularity in case of small generator application is the fact that there is often a cable connection between the circuit breaker and the step-up transformer when the generator rating is smaller (less than 100 MVA). The TRV is then greatly influenced by the characteristics of this cable connection (length, surge impedance, etc.). More than 70 simulations have been done to cover many cases of applications for different rated maximum voltages, short-circuit current ranging from 7 kA and 45 kA and cable capacitances up to 12,000 pF. The IEEE standard was amended in 2007 to include medium-sized (10–100 MVA) generator applications considering the cable connection described above.

(b) **Generator-Fed Fault Current**

The generator-fed short-circuit current usually has a lower AC component than the system-fed short-circuit current. On the other hand, it should consider the severe interruption with delayed current zeros. The DC time constant of the generator is generally very large resulting in the relatively slow decay of the DC component. Consequently, the decay of the AC component may cause the fault current in that particular poles will not cross the zero. A general circuit breaker cannot interrupt the current without periodical current zeroes.

The standard DC time constant is given to be 133 ms considering these situations. The asymmetrical component of the generator-fed short-circuit current can be calculated by the subtransient and transient time periods of the generators. The decay time constant of the DC component is defined by:

$$T_a = \frac{\mathrm{X}_{\mathrm{d}}^{''}}{\omega \cdot R_a}$$

where X_d" is subtransient reactance and R_a is armature resistance of the generator. The DC component at the instant of contact separation could be higher than the peak value of the asymmetrical component (the amplitude of AC component).

According to IEEE C37.013 (2007), a survey with many different generators showed that the degree of the asymmetry could be 110% at maximum in case of the fault with the maximum short-circuit current. The asymmetry degree as well as the symmetrical component of the generator-fed short-circuit current can be determined by the operating conditions of the generator, for example, unloaded or supply power conditions with lagging power factor (overexcited mode) or leading power factor (underexcited mode) prior to fault occurrence.

The magnitude of the symmetrical component in case of generator-fed short-circuit current is typically about 80% which is lower than that of the magnitude of the symmetrical component in case of system-fed short-circuit current. However, the degree of asymmetry component in case of generator-fed short-circuit current is higher due to higher X/R ratios.

The maximum required degree of the asymmetry is 130% of the peak value of symmetrical current in case of the generator-fed short circuit, while the value is about 75% in case of the system-fed short circuit (see Fig. 8.7 in case of arcing contact parting time around 35 ms). Higher asymmetry may often cause delayed current-zero phenomena, as shown in Fig. 8.8.

Additional resistance in series with the armature resistance reduces the time constant of the DC component, forcing a faster decay of the DC component. Such additional resistance includes the arc resistance of circuit breaker after contact separation in addition to the resistance by the arc generated at the fault location. Figure 8.9 shows the effect of the arc resistance on DC component, symmetrical component, and total asymmetrical short-circuit current (Smeets et al. 2014).

Some old-generation generator circuit breakers equip an opening resistor, which can contribute a rapid decay of DC component due to additional resistance. However, it is well recognized that recent generator circuit breakers based on SF_6 technology without an opening resistor have enough arc resistance to decay the DC component of the short-circuit current during a fault interruption and prevent delayed current-zero phenomena.

Dictated by the (relatively large) inherent capacitance of the generator, the rate of rise of recovery voltage (RRRV) in case of generator-fed fault is about half the value as compared with those in case of the system-fed fault.

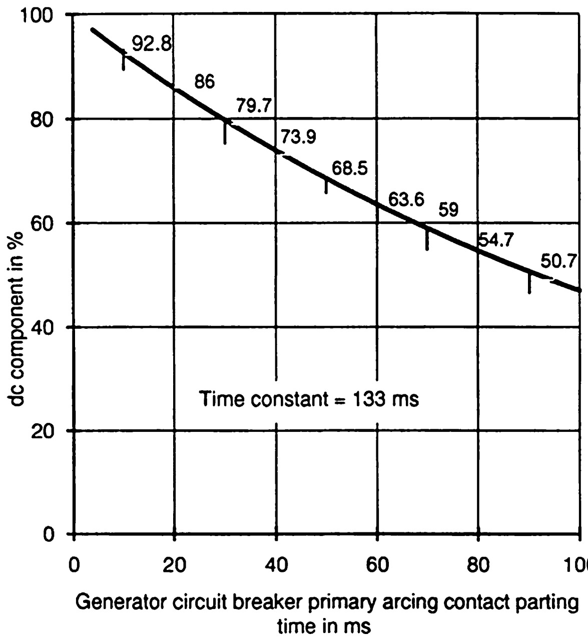


Fig. 8.7 DC component in percentage of the peak value of the symmetrical system-fed short-circuit current

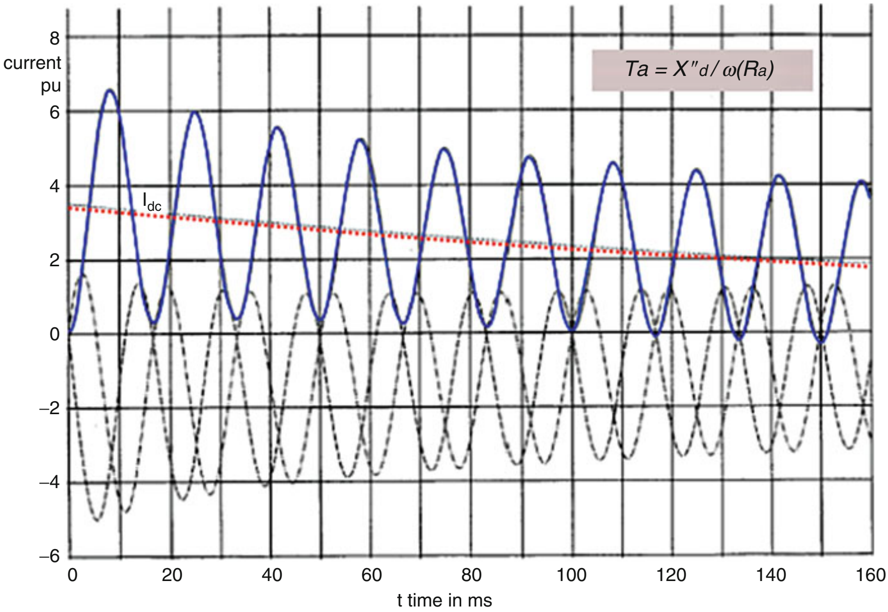


Fig. 8.8 Generator-fed short-circuit current under delayed current zeros

(c) Out-of-Phase Condition

The term out-of-phase is typically used by circuit breaker experts for whom switching under out-of-phase conditions covers conditions with angles exceeding normal values (e.g., the phase angle difference of 90°), while out-of-step includes a phase difference of more than 180° of one or more generators or between interconnected power system networks. Out-of-step covers the case of generators or parts of power systems that lose stability. After a pole slip of one or more generators, these generators may recover and run further synchronized with the power system (synchronous restoration), but most probably they will be automatically disconnected from the power system.

The specified out-of-phase current in the standard is 50% of the rated system-fed fault current, and the recovery voltage is corresponding to an out-of-phase angle of 90°. The standard requires only an out-of-phase current making capability under full phase opposition conditions, but not break capability. However, for cases where out-of-phase switching is of special importance in power system, the out-of-phase current and recovery voltage have to be specifically calculated and specified, taking account of a phase angle difference of 180°. Examples of the out-of-phase currents and recovery voltages for actual service conditions were simulated and statistically evaluated as function of the out-of-phase angle (IEEE 1982; CIGRÉ Technical Brochure 231 2003; CIGRÉ Technical Brochure 716 2018).

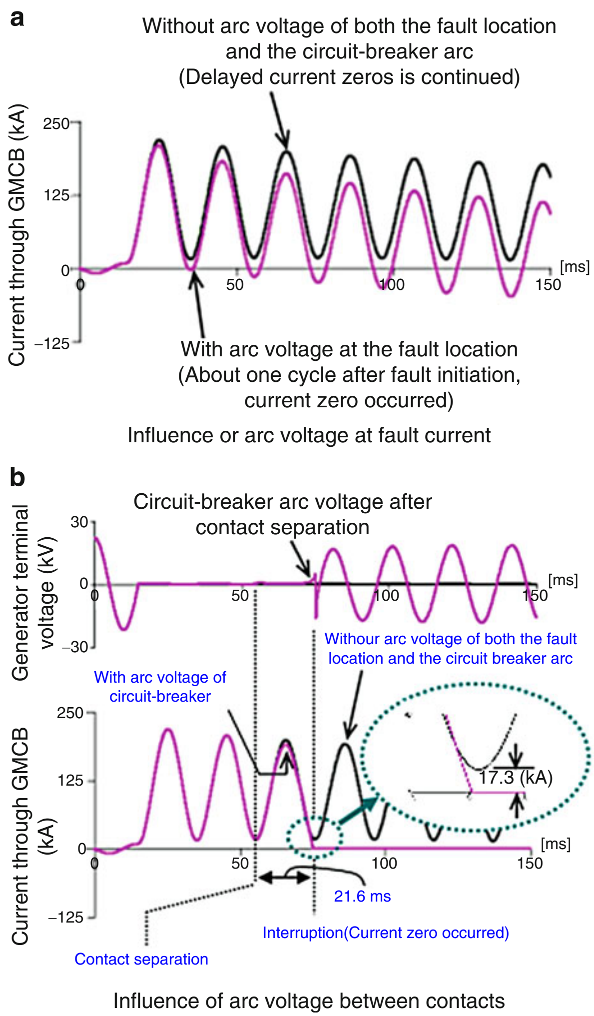


Fig. 8.9 Impact of the arc resistance of generator circuit breaker on DC component, symmetrical component, and total asymmetrical short-circuit current. (Otani et al. 2015)

The out-of-phase switching test duty consists of a closing operation, immediately followed by an opening operation (C-O operation), which is repeated after 30 min. This test has to be performed twice, once with a symmetrical out-of-phase current (no DC component) and once with an asymmetrical current (75% DC component at contact separation). The survey (IEEE 1982) indicates that the asymmetry of the current at an out-of-phase angle of 90° is typically 115% and it could exceed 130% at lower out-of-phase angles. In general, the AC component of the out-of-phase current tends to increase with the out-of-phase angle, whereas the degree of asymmetry of the out-of-phase current tends to decrease with the out-of-phase angle. Wrong settings of synchronization apparatus and manual synchronization may lead to false synchronization which may give an immediate tripping command.

8.5 Testing Requirements

HV circuit breakers designed and tested in accordance with IEC 62271–100 "High-voltage switchgear and controlgear – Part 100" do not cover the requirements for generator circuit breakers. Apart from the very high nominal current carrying capacity, the faults imposed on generator circuit breakers have special characteristics.

The IEC 62271-100 explicitly excludes the requirements for generator circuit breakers. IEEE C37.013a "IEEE Standard for AC High Voltage Generator Circuit Breakers Rated on a Symmetrical Current Basis" has been generally accepted to cover the requirements for generator circuit breakers, and recently IEC/IEEE 62271-37-013 Ed. 1.0 "Alternating-current generator circuit-breakers" was published in 2015.

High-power testing with generator circuit breakers requires some extreme testing conditions. Magnitude of the short-circuit current and asymmetry of the current along with very steep rate of rise of TRV are the main challenges to perform the short-circuit tests. Preparation of cooling air with stabilized temperature is required in addition to large continuous test current for temperature rise tests (Smeets et al. 2010, 2014).

8.5.1 Short-Circuit Making and Breaking Tests

Direct test methods are normally applied in some laboratories with test conditions up to 17.5 kV and 80 kA. Synthetic test methods are also applied to obtain higher-voltage and larger current conditions. Large magnitude of the test current (above 700 kA peak) requires a precise control of the extreme electromagnetic forces on the conductors due to short-circuit current. Single-phase synthetic test method is typically used for the tests with SF_6 as well as air-blast technologies with the rated breaking currents of 100–300 kA (for generators with the order of 1000 MVA and above) which can impose TRV on one pole. Since three-phase current tests can verify the interactions between the phases as well as between interrupters and mechanisms correctly, single-phase current tests require the verification considering the influence under the three-phase current including the travel characteristic of the contact of the circuit breaker driven by a single common operating mechanism. This is often confirmed by comparison of the travel characteristics recorded between the direct three-phase make and break test at full current and these characteristics during the single-phase test.

In the synthetic tests, one synthetic unit normally supplies a steep TRV to the first clearing pole, and the other unit is used for arc prolongation. Such a test circuit is essential to produce a realistic arc duration in the synthetic tests. Whereas a capacitor bank of the synthetic unit is very well suited to supply the adequate TRV, in some cases it cannot maintain an adequate recovery voltage for a sufficient long time. A new type of hybrid (single phase) circuit was developed and tested to combine advantages of direct and synthetic circuits. Figure 8.10 shows the proposed hybrid

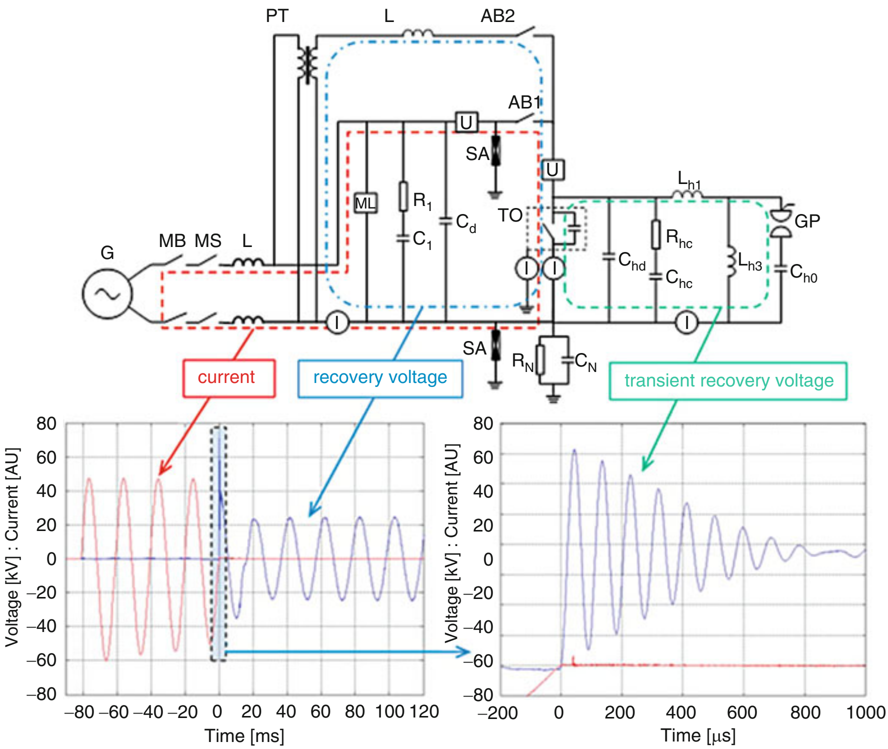


Fig. 8.10 Layout and functionality of hybrid synthetic-direct test with full-power generator circuit test (Smeets et al. 2014)

test circuit, with the functionalities of each of the relevant parts: current circuit (red), TRV circuit (green), and RV circuit (blue) along with typical waveforms realized with the generator circuit breaker.

Test circuit to realize generator-fed short-circuit current with delayed current zeros was proposed using two short-circuit generators and reactors (Otani et al. 2015). Figure 8.11 shows a simplified test circuit along with examples of voltage and current waveforms observed during short-circuit test. Two short-circuit generators feed the asymmetrical current with a delayed current zero which can be generated by decreasing the AC component of the current from the generator Ge2 which is realized by closing the switch Cs at the instant of the current peak.

8.5.2 Temperature Rise Tests

An air cooling system is required to conduct a temperature rise test with large-capacity generator circuit breakers. Figure 8.12 shows a test setup for the temperature rise test using the generator circuit breaker with the rated continuous current of 50 kA. The test object is connected to isolated phase bus ducts on both sides. On

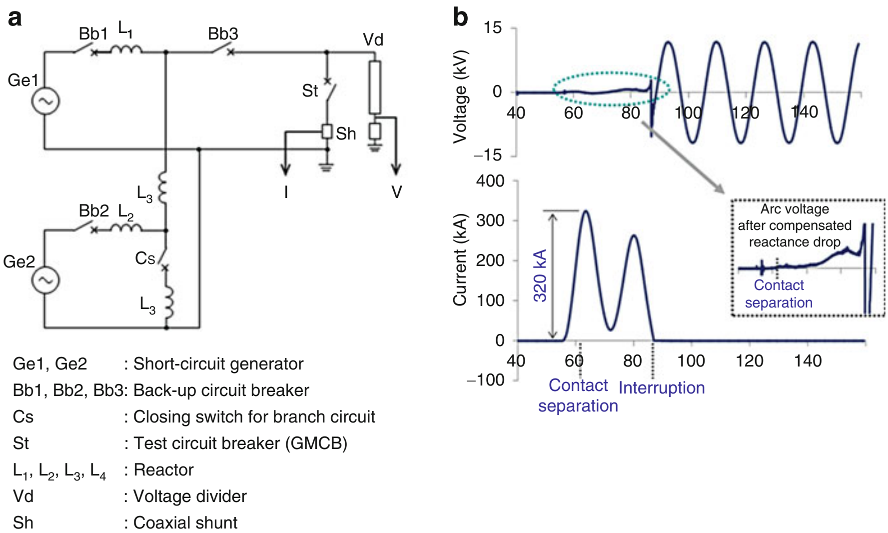


Fig. 8.11 Simplified test circuit and tested waveforms of the short-circuit test with delayed current zero. (**a**) Test circuit. (**b**) Voltage and current waveforms

their ends, tubes for the inlet and outlet of the air cooling system were installed. Water-cooled air handlers were used to blow the air through the system and to stabilize the temperature. The three-phase current is injected using current supply transformers located at one end of the bus duct.

8.6 History of Generator Circuit Breaker

The generation power plants first installed a generator circuit breaker between the transformer and generator. However, the technical limitation at that time made difficulties to use it with an increase of the generation capacity.

In the 1960s, the first generator circuit breaker with air-blast technology was installed in a power plant to meet the requirement with the higher-rated power. The generator circuit breaker was consisted of an air-blast arching chamber, a disconnector, and opening resistors. The opening resistors were used to prevent from occurring the delayed current zero phenomenon and also to mitigate the rate of rise of TRV.

In the late 1970s, the first generator circuit breaker with SF_6 technology was developed without applying the opening resistors. Enhanced interrupting and insulating performance with SF_6 technology was realized to design a compact generator circuit breakers with larger short-circuit performance exceeding 200 kA. Figure 8.13 shows examples of generator circuit breakers with air-blast, SF_6 gas, and vacuum technologies, respectively.

CIGRE Session report (Palazzo et al. 2012) shows an example of the reliability results of the generator circuit breakers with different technologies. They reported

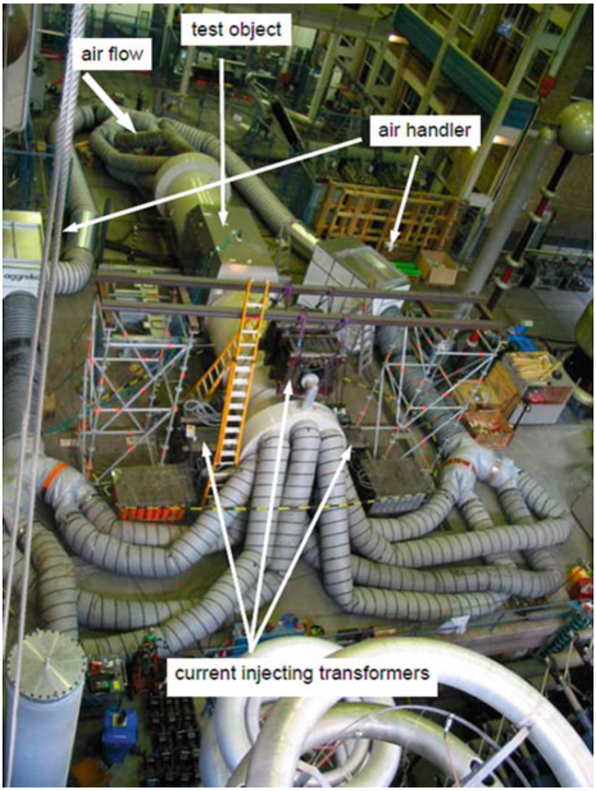


Fig. 8.12 Test setup of the temperature rise test with generator circuit breaker (Smeets and Zehnder 2006). (Courtesy of DNV-GL KEMA Laboratories)

that the old designs such as air-blast type showed higher failure frequency than the modern design of SF_6 puffer type.

8.7 Structure of Generator Circuit Breakers

8.7.1 Fundamental Configuration

A principle of a generator circuit breaker is quite similar to that of a high-voltage live-tank circuit breaker. Each of the three interrupters has an external insulator of porcelain or composite material, which maintains sufficient air insulation between the live circuit breaker components and the ground. The moving parts of the interrupters are mechanically connected to operating mechanism(s). Fundamental configuration of the generator main circuit is common, so a generator circuit breaker is normally integrated with a disconnecting switch, earthing switches, surge arrestor, surge capacitor, and voltage and current transformers into one unit. Figure 8.14 shows a typical diagram of the generator circuit breaker bay, and Fig. 8.15 shows an example of a complete generator circuit breaker (Otani et al. 2015; CIGRÉ Technical Brochure 716 2018).

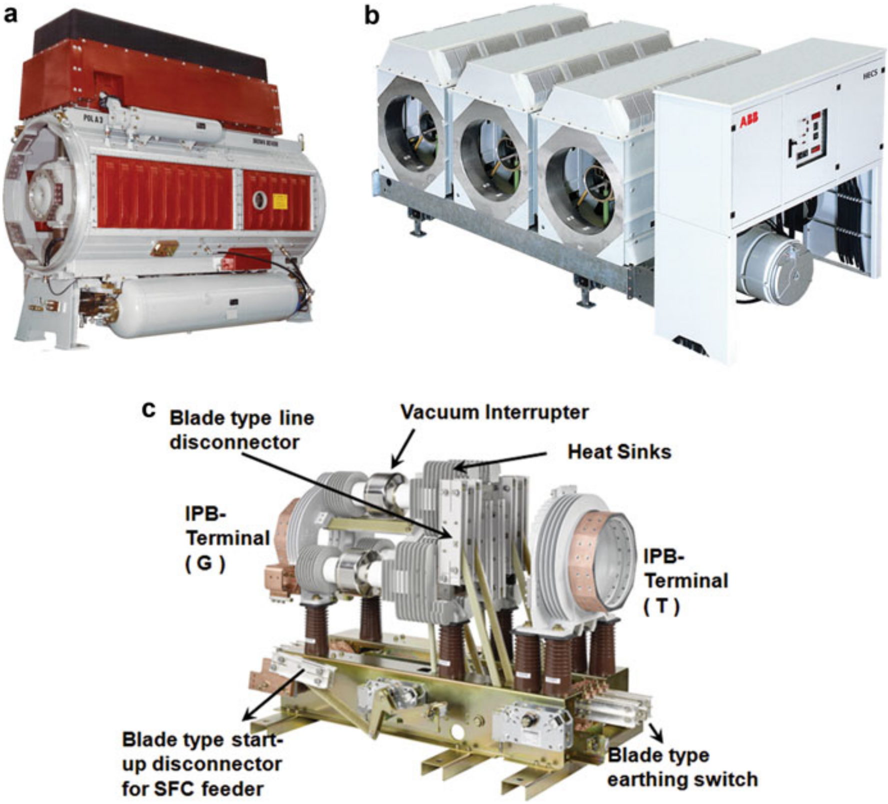


Fig. 8.13 Generator circuit breakers with different technologies. (**a**) Air-blast-type generator circuit breaker. (Courtesy of ABB). (**b**) SF_6 gas-type generator circuit breaker (ABB n.d.). (Courtesy of ABB). (**c**) Generator circuit breaker with vacuum interrupter (Leufkens et al. 2018). (Courtesy of Siemens AG)

8.7.2 Interrupter

A generator circuit breaker applied with SF_6 technology requires larger operating energy as compared with those of general HV circuit breakers in order to cope with a repulsion force due to higher puffer pressure built up during the large short-circuit interruption.

The reduction of operating energy was mainly achieved by the utilization of arc energy to heat the gas and to secure the required puffer pressure. The self-blast interrupter described in the circuit breaker chapter (see the ▶ Chap. 5) is generally applied for the generator circuit breaker. Figure 8.16 shows an example of the cross-sectional view of the self-blast interrupter. The energy released by the arc leads to a rapid pressure and temperature rise in the heating volume between the arcing contact and the piston. The puffer pressure built up by arc can blow a gas flow to extinguish the arc at a

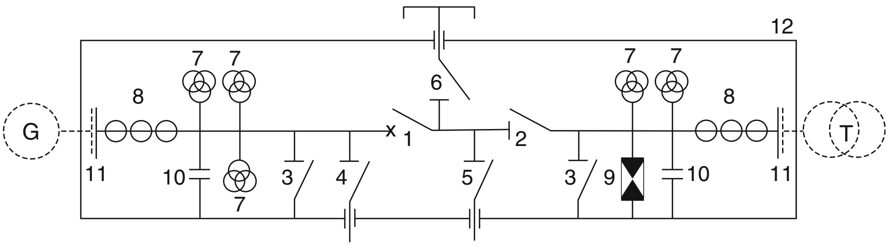
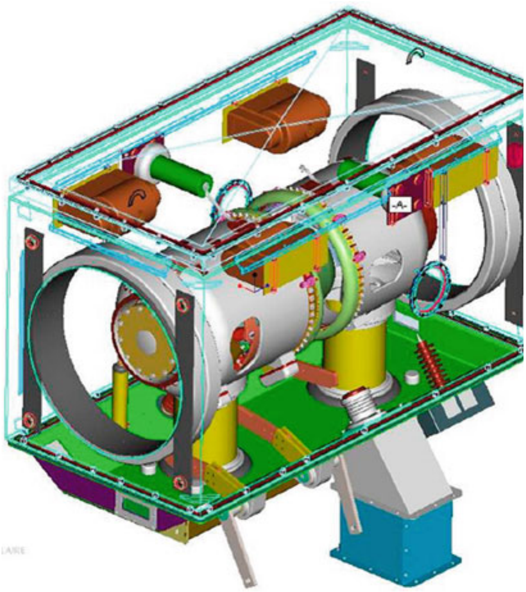


Fig. 8.14 Typical single-line diagram of a generator circuit breaker bay. 1, circuit breaker; 2, disconnecting switch; 3, earthing switches; 4, starting switch (SFC); 5, starting switch (back to back); 6, short-circuiting switch/breaking switch; 7, voltage transformers; 8, current transformers; 9, surge arrester; 10, surge capacitors; 11, terminals; 12, enclosure

Fig. 8.15 Example of a complete generator circuit breaker. (Courtesy of GE Grid Solutions)



periodical current zero. For a relatively low current interruption, a mechanical piston can build up the necessary puffer pressure to extinguish the arc with smaller currents.

8.7.3 Cooling Technology

Large current carrying requirement for a generator circuit breaker makes it essential to equip with a cooling system to remove the heat in the main current carrying pass in order to minimize the power loss.

The nominal carrying current from a generation power plant reaches to 40 kA, which requires a forced cooling device for the isolated bus conductor to avoid too large bulky design.

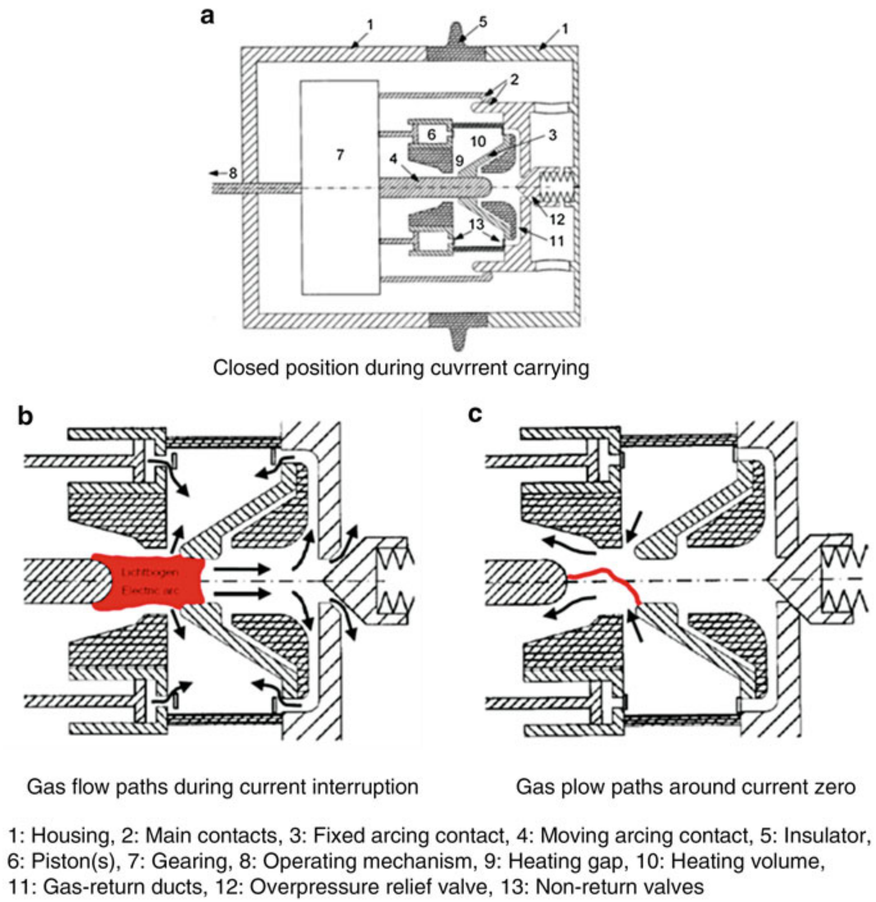


Fig. 8.16 Cross-sectional drawing of thermal arc-assisted interrupting (Otani et al. 2015). (**a**) Closed position during current carrying. 1, housing; 2, main contacts; 3, fixed arcing contact; 4, moving arcing contact; 5, insulator; 6, piston(s); 7, gearing; 8, operating mechanism; 9, heating gap; 10, heating volume; 11, gas-return ducts; 12, overpressure relief valve; 13, nonreturn valves. (**b**) Gas flow paths during current interruption. (**c**) Gas plow paths around current zero

A common cooling method is to apply a longitudinal airflow within the isolated phase bus conductor, even though the previous designs used a water cooling system.

In the past, generator circuit breaker's cooling system used even water. Recently some different cooling methods such as natural convection cooling system and an external fan cooling system are also used for generator circuit breakers. Figure 8.17 shows an example of the generator circuit breaker with an external fan cooling system. Figure 8.18 shows an example of the generator circuit breaker with external radiators outside the cubicle connected to the SF_6 interrupter.

Fig. 8.17 Generator circuit breaker with an external fan cooling system (ABB n.d.). (Courtesy of ABB)

Fig. 8.18 Generator circuit breaker with external radiators (Dufournet and Willieme 2002). (Courtesy of GE Grid Solutions)

8.8 Summary

A generator circuit breaker is directly connected to the terminal of a generator with 100–1800 MV ratings, which is commonly applied to a station with multiunit generators where a number of relatively small generators are connected to a common bus. The other side of the generator circuit breaker is connected to a step-up transformer and HV circuit breakers. The current interrupting capability of the generator circuit breaker attains up to 300 kilo-ampere level and the nominal current carrying capabilities from 6.3 kA to 40 kA. A major advantage of the generator circuit breaker can be interrupted in 5 to 7 cycles or currently 3–5 cycles after a fault occurrence and then isolate the generator. Other advantages include the elimination of transfer of auxiliary loads and improved reliability when the generator is synchronized with the system.

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Disconnecting Switches and Earthing Switches

9

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Contents

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9.1 Introduction

A disconnecting switch (disconnector) is a mechanical switching device which energizes and de-energizes parts of an electrical circuit. Earthing switch is a mechanical switching device which earths parts of an electrical circuit.

Disconnecting switches are primarily used to visualize whether a connection is open or closed. Figure 9.1 shows some examples of disconnecting switch. Different from circuit breakers, disconnectors do not have current interrupting capability. Therefore, a disconnecting switch cannot be opened when it is conducting a current and when a recovery voltage builds up across the contacts after opening. A disconnecting switch can interrupt a small current when, after opening, a negligible voltage appears over the contacts.

Earthing switch is predominantly used to make parts of the circuit including equipment safe to access by bringing them to earth potential. Earthing switch may be associated with a disconnecting switch or be independent of a disconnecting switch.

This chapter deals with design, requirements, and field experience of disconnecting switches and earthing switches.

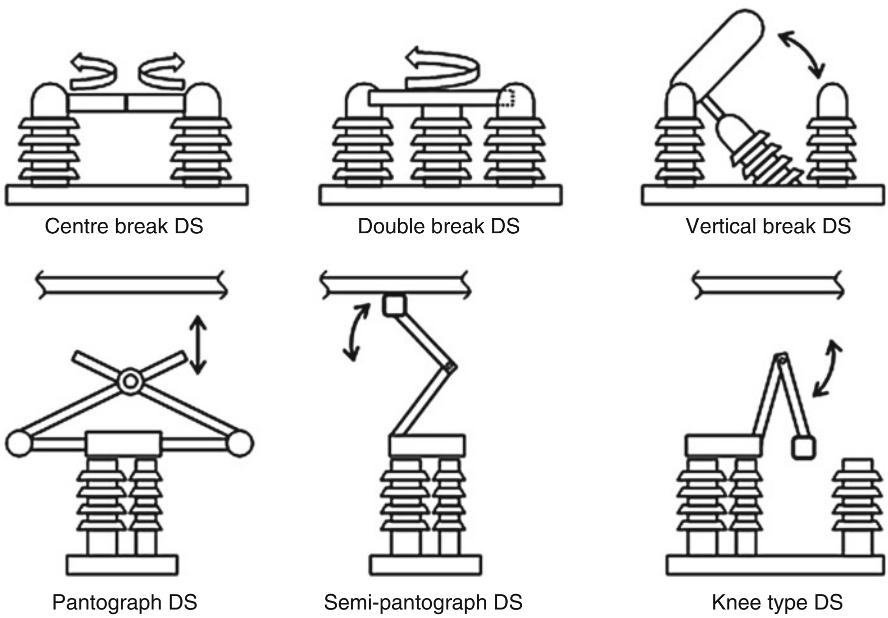


Fig. 9.1 Different designs of air-insulated disconnecting switches

9.2 Definitions of Terminology

Gas Circuit Breaker

The SF_6 gas circuit breaker is an electrical switch using sulfur hexafluoride as insulating and interrupting media. SF_6 gas breakers consist of moving and fixed contacts in an enclosure filled with gas; the gas inside the puffer cylinder is pressurized during the opening operation and blasts high-pressure gas through a nozzle into the arc generated between the contacts to extinguish the arc by cooling.

Disconnecting Switch

Switching equipment capable of opening and closing a circuit with either negligible/ leakage current is opened or made or without significant change in the voltage across the terminals of each of the poles of the disconnecting switch. It is also capable of carrying currents under normal circuit conditions and carrying for a specified time currents under abnormal conditions such as those of short circuit.

Earthing Switch

An earthing switch for the purpose of earthing/grounding and insulating a circuit.

Contact

A contact intended to carry the current in close position and withstand the operating voltage in open position.

Enclosure

A part of switchgear providing a specified degree of protection of equipment against external influences and a specified degree of protection against approach to or contact with live parts and against contact with moving parts.

Operating Mechanism

A part of disconnecting switch and earthing switch that opens and closes the contacts. It is normally motor driving or manual operating spring operating mechanisms.

Clearance

The distance between two conductive parts of equipment along a string stretched the shortest way between these conductive parts. Air clearance refers to the distance in air between two conductive parts of air-insulated equipment.

Loop Switching

Current commutation from one current carrying path to another parallel path. The commutation relies on the arc voltage and resistance between the contacts of a disconnecting switch. Loop switching is referred to bus-transfer switching in IEC terminology on assumption that it will only occur between buses within a substation.

International Electrotechnical Vocabulary (IEV)
International Electrotechnical Vocabulary (IEV) is Electropedia produced by the IEC, which defines important technical terms used in power system.

9.3 Abbreviations

AIS	Air-insulated switchgear
C	Closing operation
CB	Circuit breaker
DS	Disconnecting switch (disconnector)
ES	Earthing switch
GIS	Gas insulated switchgear
IEC	International Electrotechnical Commission
IEV	International Electrotechnical Vocabulary
O	Opening operation

9.4 Technical Requirements

9.4.1 Introduction

Disconnecting switches, also referred to as disconnectors, are primarily intended to provide an isolating function in power systems. The International Electrotechnical Vocabulary (IEV) gives the following definition (ref. 441-14-05) for the disconnecting switch (disconnector):

> A mechanical switching device which provides, in the open position, an isolating distance in accordance with specified requirements.

The requirement for disconnecting switches to provide isolation for safe working conditions was included the first safety code (United States Department of Commerce, Circular of the Bureau of Standards, No. 49 1915). The code required that affected disconnecting switches be opened, blocked to prevent unauthorized closing, and tagged to indicate work in progress, practices still in place today. In later versions of the code, the disconnecting switches are described as providing a "visible break," a term that is embedded in all electrical safety codes in North America (National Electrical Safety Code 1948). In addition to the open visible break disconnecting switch, protective grounds were also required which evolved into earthing switches to be discussed in Sect. 9.4. Note that the provision of a "visible break" is not an IEC standard requirement. Only air-insulated devices are considered in the following.

Standard requirements for disconnecting switches are given in IEC 62271-102 (published in 2001, Amendment 1:2011 and Amendment 2:2013). In the closed position, disconnecting switches are required to withstand rated voltage, temporary overvoltages, and lightning and switching overvoltages, as applicable to earth-to-phase and phase-to-phase, to carry load current without exceeding allowable temperature rises, and to withstand the forces due to fault currents. The latter requirement is discussed in Sect. 9.5. In the open position, disconnecting switches are required to withstand the above-noted voltages to earth and between phases and augmented values across the open gap as verification of isolation capability.

9.4.2 Dielectric Requirements

According to IEC 62271-1, high-voltage switchgear in general is divided into two ranges of rated voltage (IEC 62271-1 n.d.). Range I covers switchgear rated at 245 kV and below and Range II switchgear rated at 300 kV and above up to and including the new UHV levels of 1100 and 1200 kV. In Range I, lightning impulse voltages are dimensioning with respect to clearances, whereas in Range II, switching impulse voltages determine required clearances (IEC 60071-1 n.d.; IEC 60071-2 n.d.). Tables 9.1, 9.2, and 9.3 show the dielectric withstand requirements for disconnecting switches rated at 145 kV, at 550 kV, and at 1100 and 1200 kV, respectively.

Referring to Tables 9.1, 9.2, and 9.3, the following explanations with regard to the required isolation feature can be made:

In Table 9.1, the required withstand capability across the open gap is 15% greater than that to earth. The probability of flashover to earth due to an overvoltage event is thus greater than across the open gap.

In Tables 9.2 and 9.3, both lightning and switching impulses are a consideration, and the open gap withstand capability is demonstrated by the so-called bias tests. In such tests, an AC test voltage is applied to one side of the disconnecting switch and the impulse test voltage to the other side. The polarities of the two test voltages are required to be opposite to one another, i.e., a positive impulse voltage to coincide with a negative AC voltage peak and vice versa. For lightning impulses given their short duration of 1.2/50 μs, coincidence in reality with AC voltage peak regardless of polarity is highly improbable, and an average of 0.7 pu of the peak rated voltage to earth is used (this is a rounded-up value from 0.637 pu average value of a 1 pu sinusoidal half cycle). For a 550 kV-rated disconnecting switch, this corresponds to 450 (kV peak) x 0.7 = 315 kV peak. For switching impulse voltages, the longer duration of 250/2500 μs as compared to a power-frequency half-cycle duration

Table 9.1 Dielectric withstand requirements for a 145 kV disconnecting switch (IEC 62271-1 n.d.)

Rated voltage U_r: kV (rms value)	Rated short-duration power-frequency withstand voltage U_d: kV (rms value)		Rated lightning impulse withstand voltage U_p: kV (peak value)	
	Common value	Across the isolation distance	Common value	Across the isolating distance
145	230	265	550	630
	275	315	650	750

Table 9.2 Dielectric withstand requirements for a 550 kV disconnecting switch (IEC 62271-1 n.d.)

Rated voltage U_r: kV (rms value)	Rated short-duration power-frequency withstand voltage U_d: kV (rms value)		Rated switching impulse withstand voltage U_s: kV (peak value)			Rated lightning impulse withstand voltage U_p: 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
550	620	800	1050	1680	900 (+450)	1425	1425 (+315)
			1175	1760	900(+450)	1550	1550 (+315)

Table 9.3 Dielectric withstand requirements for disconnecting switches rated at 1000 kV and above (IEC 62271-1 n.d.)

Rated voltage U_r: kV (rms value)	Rated short-duration power-frequency withstand voltage U_d: kV (rms value)		Rated switching impulse withstand voltage U_s: kV (peak value)			Rated lightning impulse withstand voltage U_p: 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
1100	1100	1100	1675	2765	1550 + (900)	2250	2250 + (630)
		1100 + (635)	1800	2880		2400	2400 + (630)
1200	1200	1200	1800	2970	1675 + (980)	2400	2400 + (685)
		1200 + (695)	1950	3120		2550	2550 + (685)

means that the coincidence of peak values is a consideration and the full value of the AC-rated voltage peak to earth is used.

For all testing involving impulses, a 15/2 series is used. For each test, 15 impulses are applied, and the test is successful provided that no more than 2 flashovers occur across self-restoring insulation. For air-insulated disconnecting switches, the insulation to earth and across the open gap is self-restoring. However, attention is drawn to the issue of where in the series actual flashovers occur and the need for remedial action (IEC 62271-306 n.d.).

9.4.3 Rated Normal Current and Temperature Rise

The rated normal current for high-voltage switchgear in general is the value of rms current which the switchgear shall be able to carry without exceeding maximum temperature rise and temperature limits for parts and materials in question for an ambient air temperature of 40 °C. Maximum temperature rise and temperature limits are shown in Table 9.4 and are applicable to an altitude of 1000 m above sea level.

For all other contacts, connections, and terminal-related materials, actual properties shall be considered to determine maximum values.

Rated normal current values are selected from the R10 series. This is a geometric series having a constant ratio between successive terms. The nth term and the next $n + 1$ term are given by:

Table 9.4 Rated normal current maximum temperature rises and temperatures for various parts and material in air (IEC 62271-1, published in 2007 and Amendment 1:2011)

		Maximum value	
Part	Material	Temperature °C	Temperature rise at ambient air temperature ≤ 40 °C (K)
Contacts	Bare copper or bare copper alloy Silver coated or nickel coated Tin coated	75 105 90	35 65 50
Connection	Bare copper or bare copper alloy Silver coated or nickel coated Tin coated	90 115 105	50 75 65
Terminals for connection to external conductors by screws or bolts	Bare Silver, nickel, or tin coated	90 105	50 65

$$10^{\frac{n}{10}} \text{ and } 10^{\frac{n+1}{10}}.$$

and the ratio between successive terms is:

$$\frac{10^{\frac{n+1}{10}}}{10^n} = 10^{\frac{1}{10}} = 1.2589.$$

The series after rounding is thus:

$1 - 1.25 - 1.6 - 2 - 2.5 - 3.15 - 4 - 8.$

and rated values are obtained by multiplying by 10^n and hence the well-known rated normal currents such as 3150 A.

For ambient temperatures other than 40 °C, the permissible load currents can be calculated using Table 9.4 and the following equation:

$$I_a = I_r \left(\frac{T_{max} - T_a}{T_r} \right)^{1/1.8} \tag{9.1}$$

where
I_a = permissible load current at an ambient temperature T_a
I_r = rated normal current at ambient temperature 40 °C
T_{max} = maximum temperature from Table 9.4 for the applicable part and material
T_r = allowable temperature rise from Table 9.4 for the applicable part and material

The temperature rise is proportional to the current squared. However, to allow for the effects of radiation and convection, a compromise is to use an exponent of 1.8 as shown in Eq. 9.1.

In general, for ambient temperatures less than 40 °C, Eq. 9.1 is applied using the part and material having the highest T_{max} value, and for ambient temperatures greater than 40 °C, use the part and material having the lowest T_{max} value. This is demonstrated in Fig. 9.2 where the multiplying factors:

$\left(\frac{115-T_a}{75}\right)^{1/1.8}$ and $\left(\frac{90-T_a}{50}\right)^{1/1.8}$.

are plotted. In the range below 40 °C, the former factor gives the permissible load current, and, in range above 40 °C, the current is determined by the latter factor.

For dynamic loading purposes, the calculation procedure is as follows:

1. Calculate the permissible load current at the applicable ambient temperature using Eq. 9.1.
2. Calculate the initial hotspot temperature T_i using Eq. 9.2:

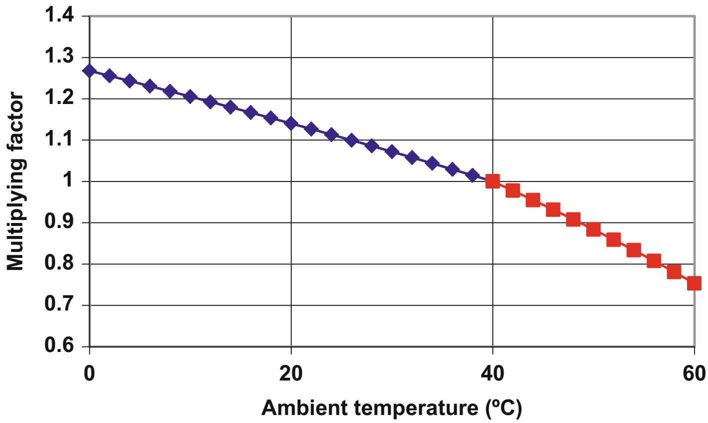


Fig. 9.2 Multiplying factors as a function of ambient temperature

$$T_i = \left(\frac{I_i}{I_r}\right)^{1.8} (T_r) + T_a \tag{9.2}$$

where I_i is the initial load current and the other quantities are as defined earlier.

3. Calculate the hotspot temperature T_s due to the desired short-time overload current I_s using Eq. 9.3:

$$T_s = \left(\frac{I_s}{I_r}\right)^{1.8} (T_r) + T_a \tag{9.3}$$

4. Calculate the temperature rise time t_s from T_i to T_s using Eqs. 9.4 and 9.5:

$$T_{max} = (T_s - T_i)\left(1 - e^{-t_s/\tau}\right) + T_i \tag{9.4}$$

where t_s is the time to reach the part and material T_{max} limit and τ is the thermal time constant.

Rearranging Eq. 9.4, t_s is given by Eq. 9.5:

$$t_s = -\tau ln\left[1 - \frac{T_{max} - T_i}{T_s - T_i}\right] \tag{9.5}$$

By way of example, consider disconnecting switch rated at 3150 A at 40 °C with an initial current 2500 A at 30 °C ambient temperature for several hours. For how long can the disconnecting switch carry a short-time current of 3600 A?

From Eq. 9.1:

$$\begin{aligned} I_a &= 3150\left(\frac{115-30}{75}\right)^{1/1.8} \\ &= 3376\ \text{A}. \end{aligned}$$

From Eq. 9.2:

$$\begin{aligned} T_i &= \left(\frac{2500}{3150}\right)^{1.8}(75)+30 \\ &= 79^{\circ}\text{C}. \end{aligned}$$

From Eq. 9.3:

$$\begin{aligned} T_s &= \left(\frac{3600}{3150}\right)^{1.8}(75)+30 \\ &= 125^{\circ}\text{C}. \end{aligned}$$

This temperature exceeds the 115 °C T_{max} value, and the current must therefore be deceased to 3376 A when T_s reaches 115 °C.

From Eq. 9.5 and taking $\tau = 0.5$ h:

$$\begin{aligned} t_s &= -0.5\ \ln\left[1-\frac{115\text{-}79}{125\text{-}79}\right] \\ &= 0.76\ \text{h} \end{aligned}$$

at which time, the current is reduced to 3376 A.

9.5 Current Interruption Using Air–Break Disconnecting Switches

9.5.1 Overview and Common Practices

Disconnecting switches are not intended or rated to interrupt current, but, by virtue of the fact that they are operated under live conditions, they are expected to be capable of interrupting small currents. A following note is added to the IEC definition of disconnecting switch (see IEV reference 441-14-05):

> A disconnecting switch (disconnector) is capable of opening and closing a circuit where either negligible current is broken or made, or when no change in the voltage across the terminals of each of the poles of the disconnecting switch occurs.

Although not specifically stated, this statement can be interpreted as referring to small capacitive charging currents and to loop switching, also known as parallel switching and, in a specific application, as bus-transfer switching. IEC 62271-102 confirms this and sets an upper limit of 0.5 A with respect to "negligible" capacitive charging current with higher values subject to agreement between the user and the manufacturer (IEC 62271-102 n.d.). Rated bus-transfer currents are also addressed in the standard as follows: 52 kV $< U_r <$ 245 kV, 80% of rated normal current of the disconnecting switch but limited to 1600 A; 245 kV $\leq U_r \leq$ 550 kV, 60% of rated normal current of the disconnecting switch; and $U_r >$ 550 kV, 80% of rated normal current of the disconnecting switch but limited to 4000 A.

In practice, particularly in North America, air-break disconnecting switches are commonly used to switch out unloaded transformers, and this is discussed in Sect. 9.5.2. A further common practice is to extend bus transfer to switching between parallel transmission loops, albeit at lower currents due to the higher loop impedances (refer to Sect. 9.5.4).

Another practice used extensively in North America and to a limited degree elsewhere is to add auxiliary interrupting devices to reduce the severity of the switching event, e.g., minimize the occurrence of restriking, or to achieve higher interrupting capability. These equipment are discussed in Sect. 9.6.7.

9.5.2 Unloaded Transformer Switching

Disconnecting switches are used for the high-side switching of unloaded transformers in the range 72.5–245 kV where the magnetizing current is usually 1 A or less (Peelo 2004). The transformer can be represented as a series RLC circuit as shown in Fig. 9.3, and the associated oscillation is underdamped with an amplitude factor of 1.4 per unit or less (Peelo 2014). A trace from an actual field switching event is shown in Fig. 9.4. The transient recovery voltage (TRV) across the disconnecting switch is thus the difference between the source voltage and the transformer-side oscillation as illustrated

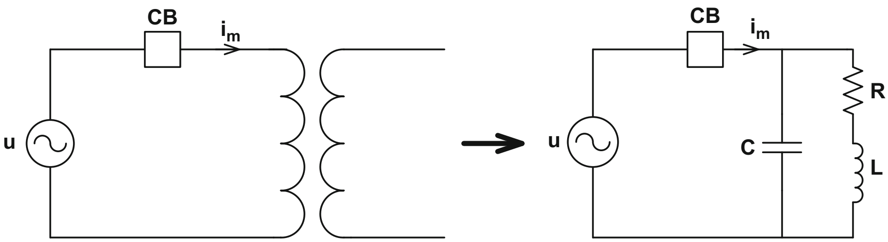


Fig. 9.3 Unloaded transformer switching: transformer equivalent RLC circuit

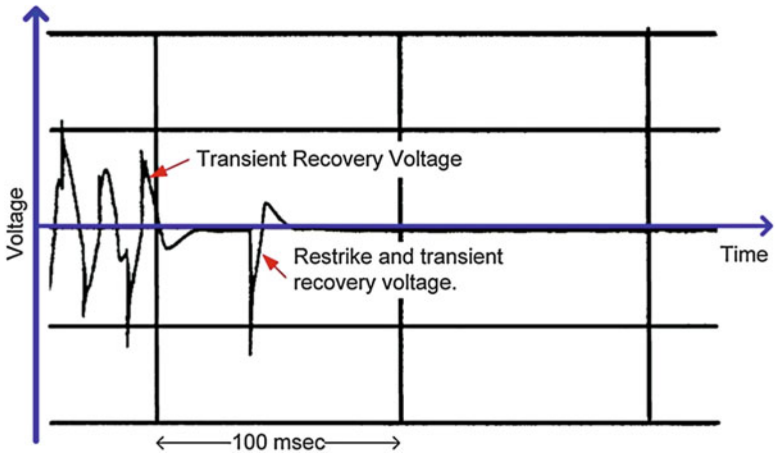


Fig. 9.4 Field trace showing transformer-side oscillation after current interruption. (Courtesy of BC Hydro)

in Fig. 9.5. Current interruption is essentially a dielectric event occurring when the contact gap is sufficient to withstand the TRV.

Breaking the magnetizing current of unloaded transformers is a repetitive break-make event with numerous restrikes. Restriking may result in inrush current which has the effect of prolonging the arcing time by its duration and wear on the arcing horns.

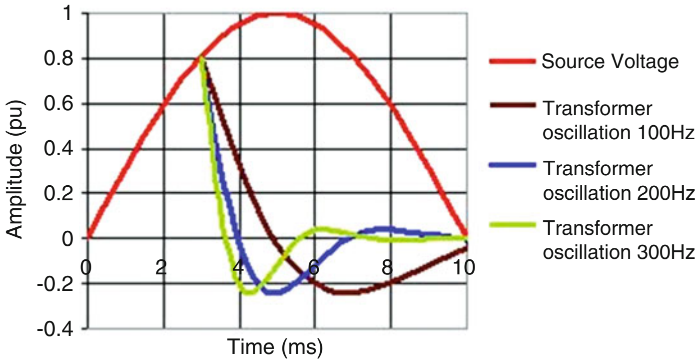
9.5.3 Capacitive Current Interruption

Of necessity capacitive current interruption using disconnecting switches in gas-insulated switchgear (GIS) was standardized early in the evolution of that type of equipment (IEC 62271-102 n.d.). The need to address the same capability with respect to air-break disconnecting switches resulted in considerable research in the past decade (Peelo 2004; Chai 2012; Peelo et al. 2005; Chai et al. 2010). An IEC Technical Report followed which does not prescribe actual ratings but rather how disconnecting switches should be tested for the application current value (IEC 62271-305 TR n.d.).

The equivalent circuit for capacitive current switching is shown in Fig. 9.6. The above-noted research showed that interruption is dependent, not only on the magnitude of the current but also on the ratio of source-side capacitance to the load-side capacitance C_S/C_L.

For currents at 1 A or less, the arc does not exhibit thermal properties and is virtually stationary within the increasing contact gap. Above 1 A, the arc exhibits thermal properties and will rise due to convection. Also, restriking will occur along the previous arc channel, this in contrast to the lower 1 A or less case where restrikes occur over random breakdown paths (Peelo 2004; Chai 2012).

The influence of the ratio C_S/C_L is less obvious and is related to the equalization voltage and the subsequent recovery to the source voltage in the event of restrike. A



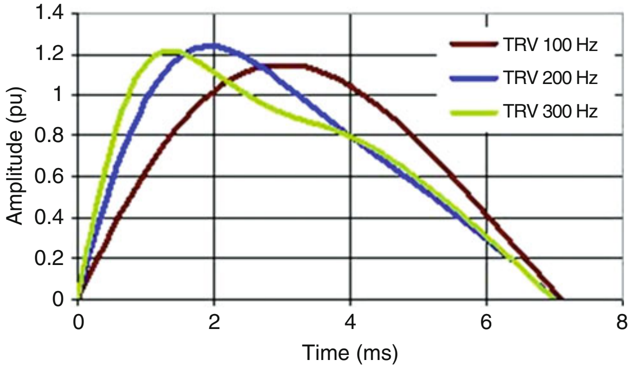


Fig. 9.5 Unloaded transformer switching (Transient recovery voltage is the difference between the source- and load-side voltages)

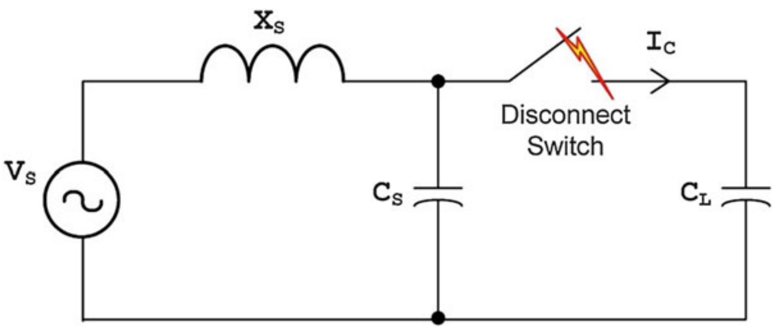


Fig. 9.6 Equivalent circuit for capacitive current switching

restrike actually involves two oscillation events in sequence. With reference to Fig. 9.6, the first event involves the loop C_S – disconnecting switch – C_L, and the restrike causes an equalization of the voltages on C_S and C_L. This is the equalization voltage V_E and is given by the equation (Peelo 2004, 2014):

$$V_E = V_S - \frac{1}{1 + C_S/C_L} V_D \tag{9.6}$$

where V_S is the source-side voltage and V_D is the voltage across the disconnecting switch prior to the restrike. When $C_S > C_L$, the second term in the equation is large, and the value of V_E is close to the source-side voltage V_S. Similarly, when $C_S < C_L$, the second term is small, and the value of V_E will be close to the load-side voltage V_L. In the second event associated with the restrike, the voltage at disconnecting switch recovers from the equalization voltage V_E to the source-side voltage V_S. Clearly, the latter case of $C_S < C_L$ will result in the higher overvoltages and high energy injection into the arc, thus promoting a longer duration.

Traces from a laboratory test on a 300 kV center-break disconnecting switch are shown in Figs. 9.7 and 9.8. In Fig. 9.7, the C_S/C_L ratio is favorable and the overvoltage peak V_{pk} = 300 kV. In Fig. 9.8, the C_S/C_L ratio is unfavorable and the overvoltage peak V_{pk} = 536 kV.

9.5.4 Loop Switching

Loop switching using air-break disconnecting switches is the unforced commutation of the current from the disconnecting switch to a parallel path as shown in Fig. 9.9. The commutation relies on the increasing arc voltage and resistance as it is elongated by the motion of the disconnecting switch moving contact or contacts (Peelo 2004). The corresponding duty for circuit breakers is known as parallel switching and is

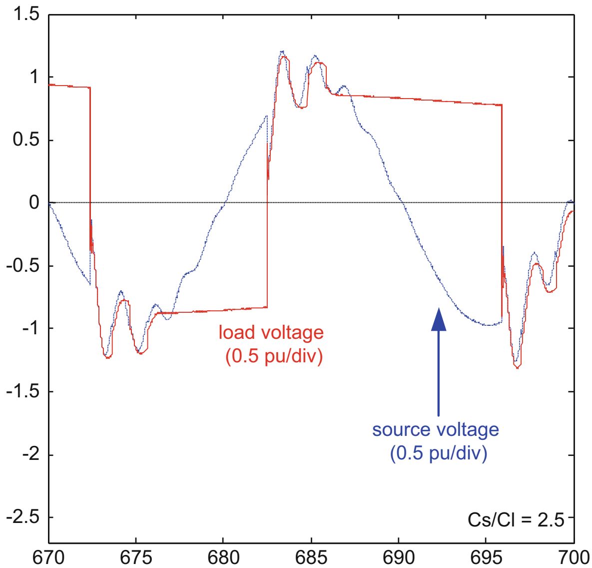


Fig. 9.7 300 kV disconnecting switch breaking 2 A with C_S/C_L = 2.5. (Courtesy of DNV GL/KEMA Laboratories)

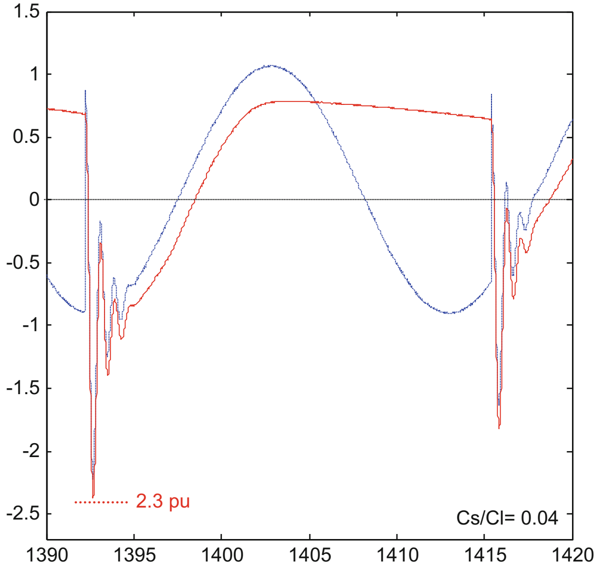


Fig. 9.8 300 kV disconnecting switch breaking 2 A with $C_S/C_L = 0.04$. (Courtesy of DNV GL/KEMA Laboratories)

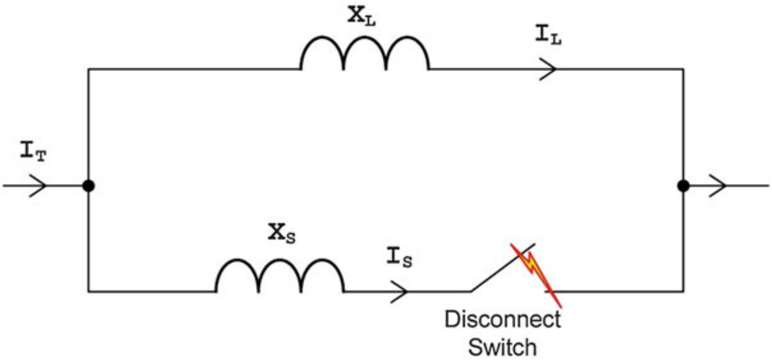


Fig. 9.9 Loop switching circuit

related to the event of two or more circuit breakers clearing a fault in parallel with one another (Smeets et al. 2014).

Loop switching in IEC terminology is referred to as bus transfer given the assumption that it will only occur between buses within a substation (IEC 62271-102 n.d.). The switching is a power-frequency event since the current in the disconnecting switch decays to zero as it is transferred to the path, and the recovery voltage is simply the initial current times the loop impedance. For the original IEC 62271-102 requirement of 1600 A and a recovery voltage of 300 V, the loop impedance is 0.1875 ohms (IEC 62271-102 n.d.). This requirement is now to be revised to 80% of the disconnecting switch rated normal current at varying recovery voltages dependent on the application voltage range.

A loop switching laboratory test trace is shown in Fig. 9.10. The arc will be maintained as long as the rate of change of the power input to the arc is positive and in turn will become unstable and collapse when the rate of change becomes negative (Peelo 2004). This process is evident in Fig. 9.10 as is another phenomenon associated with free-burning arcs in air. Such arcs are very erratic, and two points on the arc may touch, thus short-circuiting the portion of the arc beyond that point. This is known as partial arc collapse. The arc voltage and resistance drop, and the current transfers back from the parallel path prolonging the arcing time. The collapses, however, limit the reach or excursion of the arc and are therefore a positive attribute. A partial arc collapse event, as evidenced by the change in color in the upper part of the arc, is shown in Fig. 9.11.

9.6 Disconnecting Switch Types and Auxiliary Attachments

9.6.1 Introduction

The principal air-break disconnecting switches in use are the vertical break, center side break, double side break, knee, and pantograph types. The type used by individual utilities is generally based on standard substation layout practices.

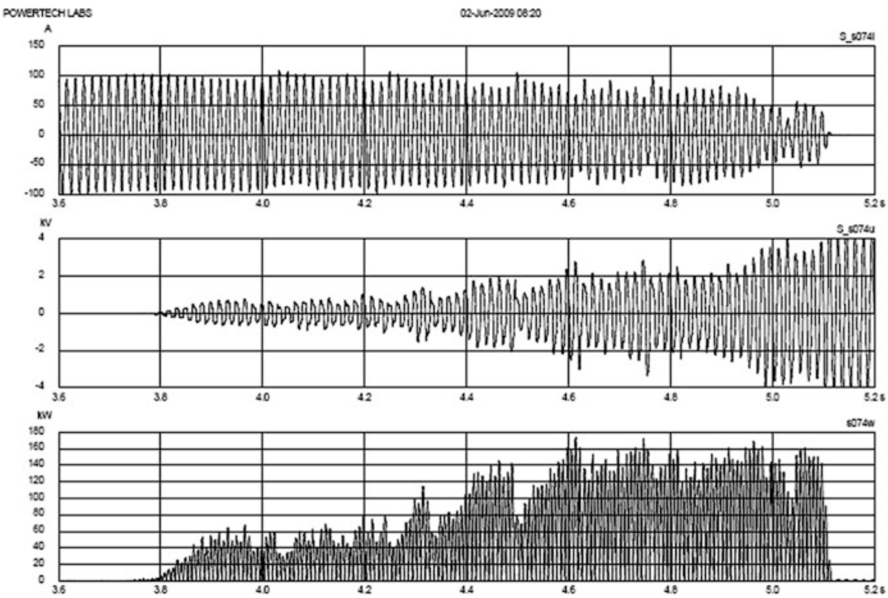


Fig. 9.10 Loop switching trace for initial current 70 A and a loop impedance of 40 ohm. (Courtesy of BC Hydro)

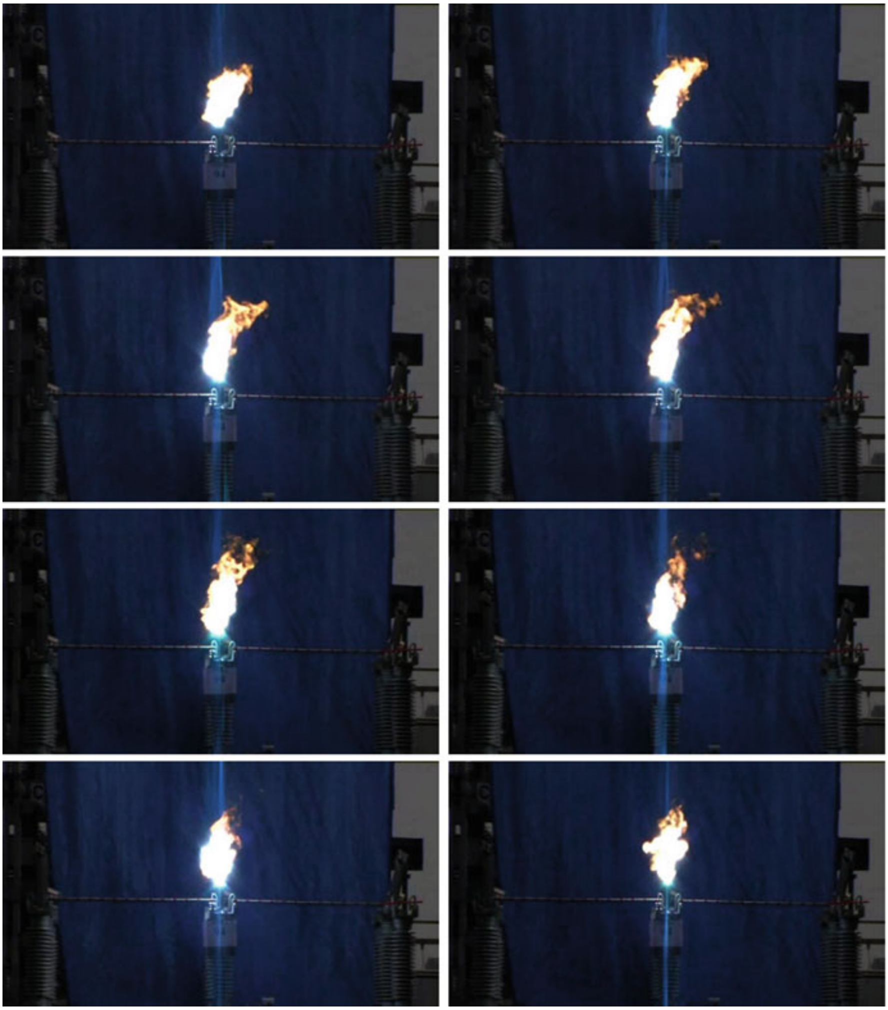


Fig. 9.11 Partial arc collapse. (Courtesy of BC Hydro)

9.6.2 Vertical Break Disconnecting Switches

Vertical break disconnecting switches are usually horizontally mounted as shown in Fig. 9.12 but can also be vertically mounted up to 245 kV and even underhung at system voltages below 52 kV.

Referring to Fig. 9.12, the live parts, hinge-end and jaw assemblies and the blade, are supported by post-type insulators at each end. Operation, manual or motor, is by means of the smaller rotating insulator to the left in the figure.

Current transfer takes place at both ends of the blade. A typical jaw assembly is shown in Fig. 9.13 and comprises the fixed inverse loop main contacts and arcing

Fig. 9.12 Vertical break disconnecting switch. (Courtesy of Hapam B.V.)

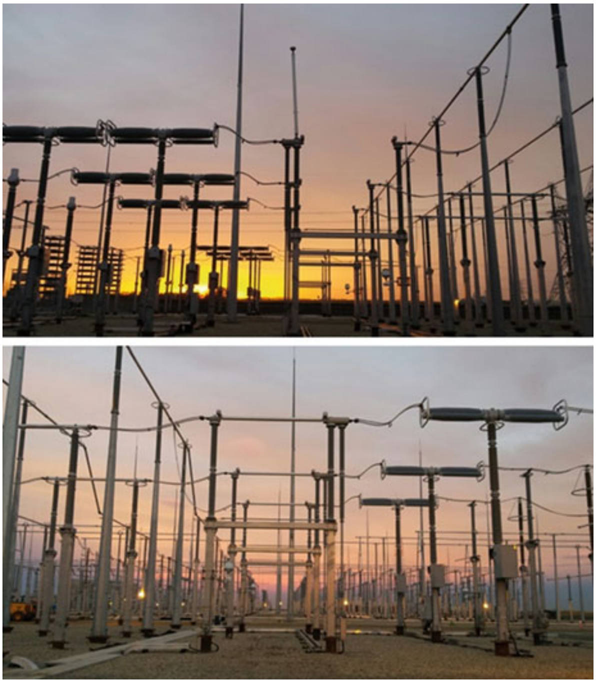


Fig. 9.13 Vertical break disconnecting switch jaw assembly. (Courtesy of Hapam B.V.)

horn. On opening, the first motion is rotation of the blade commutating the current, i.e., the small capacitive current or bus-transfer current, to the arcing horn. The ensuing arc is then drawn between the fixed arcing horn and the corresponding moving arcing horn on the blade end.

9.6.3 Center Side Break Disconnecting Switches

The center side break disconnecting switch, as shown in Fig. 9.14, provides a low profile in both the open and closed position. The side opening feature requires a wider phase spacing as compared to disconnecting switches which open in a longitudinal plane. The insulators serve a dual role providing support and also rotation to open or close the disconnecting switch.

Fig. 9.14 Center side break disconnecting switch. (Courtesy of Hapam B.V.)

9.6.4 Double Side Break Disconnecting Switches

The double side break disconnecting switch is a variation of the center break type with a lesser impact on phase spacing. The disconnecting switch, as shown in Fig. 9.15, opens through an angle of less than 90° as compared to the center type which opens through 90°. The end insulators support the two jaw assemblies, and the center insulator supports the blade and provides rotation to open and close the disconnecting switch.

9.6.5 Knee-Type Disconnecting Switches

The knee-type disconnecting switch, sometimes referred to as a horizontal reach type, is shown in Fig. 9.16. Operation is similar to that for the vertical break disconnecting switch except that the blade motion is in a horizontal direction due to the articulated blade. This disconnecting switch type is favored where clearances above the device are restricted.

9.6.6 Pantograph-Type Disconnecting Switches

Of all disconnecting switch types, the pantograph type requires the least land area for installation. As shown in Fig. 9.17, the equivalent blade is a scissors-type arrangement, and the equivalent jaw is a stirrup-type fixture attached to the overhead. Apart from the layout advantage noted above, the disconnecting switch offers the possibility of providing the transition between low and high bus arrangements. A variation of the "full" pantograph disconnecting switch is the semi-pantograph, also known as a vertical reach type, which incorporates only one-half of scissors arrangement as shown in Fig. 9.18.

Fig. 9.15 Double side break disconnecting switch. (Courtesy of GE Grid Solutions)

Fig. 9.16 Knee-type disconnecting switch. (Courtesy of GE Grid Solutions)

Fig. 9.17 Pantograph-type disconnecting switch. (Courtesy of Hapam B.V.)

Fig. 9.18 Semi-pantograph disconnecting switch. (Courtesy of Coelme-Egic)

9.6.7 Auxiliary Interrupting Devices

The use of auxiliary interrupting devices as attachments on disconnecting switches has been the practice for many decades in North America and is becoming more common elsewhere. The intent of applying the devices is to enable or improve the switching of unloaded transformers, capacitive currents, and loop switching.

To enable unloaded transformer switching and to increase capacitive current interruption, a whip-type device, as shown in Fig. 9.19, is commonly used. As the disconnecting switch opens, the current is first commutated to the arcing horn and then to the whip via its fixed horn. The whip is restrained by the fixed horn and releases at a certain point achieving a fast motion interrupting the current with minimal or no arc development. The device plays no role on closing the disconnecting switch, and any prestriking will occur on the main arcing horns.

Many utilities, again primarily in North America, practice disconnecting switch loop switching between transmission loops. In contrast to bus-transfer loop impedances of less than 0.2 ohm according to IEC 62271-102, transmission loop impedances are in the order of tens of ohms. The addition of a single vacuum interrupter device makes it possible to loop switch hundreds of ampere. An example of such an application is shown in Fig. 9.20. Once such a device is added to a disconnecting switch; the disconnecting switch becomes a dedicated loop current breaking switch.

Line dropping is usually carried out using circuit breakers. However, some utilities prefer a load break device for this purpose, and one approach is to add the device to a line disconnecting switch as shown in Fig. 9.21. As the blade opens, it engages the actuating arm of the load break device causing its contacts to open and interrupt the current. At a certain point, the actuating arm is released from the blade, and the arm drops closing the contacts again. The same sequence applies to vacuum interrupters for the loop switching case.

Fig. 9.19 Vertical break disconnecting switch with whip-type device mounted. (Courtesy of Hapam B.V.)

9.7 Earthing Switches

Earthing switches are typically applied in combination with a disconnecting switch but may also be freestanding. The switches are interlocked with the disconnecting switch, or a circuit breaker in the freestanding case, to prevent closing under voltage. Figure 9.22 shows an earthing switch and vertical break disconnecting switch combination with the transformer in the closed position.

The voltage withstand requirements for earthing switches are the same as those for disconnecting switches to earth. For the combination case, both devices are tested at the same time with the minimum applicable gap for the earthing switch.

Earthing switches are required to have the same through-fault capability as disconnecting switches. In some applications, a fault-making capability is required, and IEC 62271-102 has two electrical endurance levels:

E1: Capability to withstand two fault-making operations
E2: Capability to withstand five fault-making operations

Earthing switches applied on transmission lines are required to have the capability to break the currents induced from adjacent energized lines. This involves electromagnetically induced inductive currents and electrostatically induced

Fig. 9.20 Vertically mounted disconnecting switch with added vacuum interrupter device. (Courtesy of Southern States LLC)

Fig. 9.21 Vertical break disconnecting switch with added SF_6 gas load break device. (Courtesy of Southern States LLC)

capacitive currents, and the switching sequence is shown in Fig. 9.23. Initially earthing switches A and B are closed, and switch A is opened to break the inductive current circulating in the loop formed by the line, the two switches, and the return path through earth. Switch B is then opened to break the remaining capacitive current to earth.

Fig. 9.22 Earthing switch. (Courtesy of Hapam B.V.)

9.8 Type Testing

Disconnecting switches and earthing switches are type tested to verify their rated characteristics taking into account conditions of installation and use with all associated components which may influence performance. The general mandatory type tests for both devices are listed in Table 9.5 (IEC 62271-102 n.d.).

Further type tests are those related to particular applications, ratings, or design and are listed in Table 9.6 (IEC 62271-102 n.d.).

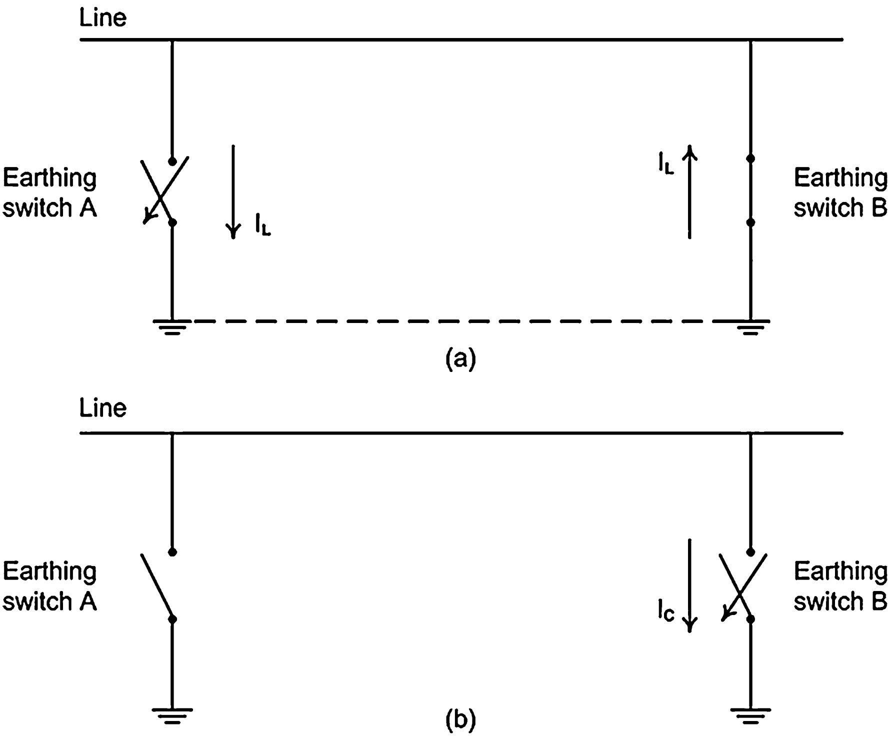


Fig. 9.23 Earthing switch-induced current interruption. (**a**) Inductive current interruption, (**b**) capacitive current interruption

Table 9.5 Mandatory type tests for air-insulated disconnecting switches and earthing switches

Type test	Device	
	Disconnecting switch	Earthing switch
Dielectric tests	R	R
Measurement of resistance of main circuit	R	NR
Temperature rise tests	R	NR
Short-time withstand current and peak withstand current tests	R	R
Additional tests on auxiliary and control circuits	R	R
Mechanical endurance tests	R	R

R required, *NR* not required

The following clarifications to Table 9.6 can be made:

The "Condition" column is to be read as *the test is required if the application, rating, or design condition is met*.

- Classes E1 and E2 relate to the applicable number of fault-making operations that the earthing switch is capable of withstanding as discussed in Sect. 9.4 above.

Table 9.6 Type tests related to application, rating, or design for air-break disconnecting switches and earthing switches

Type test	Condition	Device	
		Disconnecting switch	Earthing switch
Verification of the degree of protection	Assigned IP and/or IK code	R	R
Radio interference voltage (r.i.v.) test	Ur $\geq$ 123 kV	R	R
EMC tests	Presence of electronic components	R	R
X-ray radiation test	Presence of vacuum interrupters	R	R
Test to prove the short-circuit making performance of earthing switches	Class E1 or E2	NA	R
Contact zone test	Divided support	R	NA
Extended mechanical endurance tests	Class M1 or M2	R	NA
Operation under severe ice conditions	10 mm and above	R	R
Low- and high-temperature tests	If maximum ambient temperature $> +45$ °C or minimum ambient temperature < -25 °C	R	R
Tests to verify the proper functioning of the position indicating device	See clarification	R	R
Bus-transfer current switching tests	Bus-transfer current switching capability	R	NA
Induced current switching tests	Class A or B	NA	R
Bus-charging switching tests	User request	R	R

R required, *NA* not applicable

- Mechanical endurance Classes M1 and M2 are extended endurance requirements over and above normal requirements of 1000 close operations. Class M1 requires 2000 close operation and Class M2 10,000 close operation in the type test.
- Verification of the position indicating device is a design consideration to demonstrate that device correctly indicates disconnecting switch and earthing switch moving contact positions.
- Bypass disconnecting switches have bus-transfer requirements that exceed the standard values in IEC 62271-102. These disconnecting switches are required to loop switch line current to a parallel circuit consisting of buswork, a series damping reactor, and the closed bypass circuit breaker. The loop impedance may exceed 0.5 ohm, and the open circuit voltage may approach 1000 V.

- For induced current switching, Class A applies to earthing switches on short sections of line or low coupling to adjacent energized circuits; Class B applies to earthing switches on long line sections or high coupling to adjacent energized circuits.
- Bus-charging current switching, actually small capacitive current interruption, is required only by user request. Testing in this regard is described in Technical Report IEC 62271-306 (IEC 62271-305 TR n.d.).

9.9 Summary

A large number of disconnecting switches and earthing switches are used in the substation to open and close the circuit and earth the equipment in power system.

Different from circuit breakers, disconnecting switches do not have short-circuit current interrupting capability but withstand the voltage stresses in power system. The disconnecting switch cannot be opened when it is conducting a current and when a recovery voltage builds up across the contacts after opening. A disconnecting switch can interrupt a small current when, after opening, a negligible voltage appears over the contacts.

Earthing switch is predominantly used to make parts of the circuit including equipment safe to access by bringing them to earth potential.

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IEC 62271-1.: High-Voltage Switchgear and Controlgear – Part 1: Common Specifications

IEC 62271-102.: High-Voltage Switchgear and Controlgear – Part 102: Alternating Current Disconnecting Switches and Earthing Switches

IEC 62271-305 TR.: High-Voltage Switchgear and Controlgear – Part 305: Capacitive Current Switching Capability of Air-Break Disconnecting Switches

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Dielectric Withstand Performance Tests 10

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Contents

Keywords
Dielectric withstand performance · Power-frequency voltage · Lightning impulse voltage · Switching impulse voltage · Partial discharge

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10.1 Introduction

High-voltage dielectric withstand performance testing with equipment utilizes the phenomena in electrical insulation under the influence of electric fields changing with the power frequency. When electrical insulation is stressed in an electric field, ionization may cause electrical discharges initiating from one electrode of high potential to the one of low potential or vice versa. It may also cause a high current rise and lose the dielectric withstand capability to separate different potentials of the equipment.

External insulation, in most cases, recovers its insulation capability after a breakdown and is, therefore, called self-restoring insulation. Conversely, the internal insulation of equipment such as gas-insulated switchgear (GIS) is more affected by discharges and is often even destroyed when a breakdown is caused by an excessive voltage stress. Figure 10.1 shows a typical example of a dielectric breakdown on the surface of an epoxy cast resin insulator of GIS.

Solid insulators and gas-impregnated laminated insulation elements are non-self-restoring insulations. Some insulation is partly self-restoring, particularly when it consists of gaseous and solid elements. An example of this is GIS which uses SF_6 gas and solid spacers. In case of a breakdown in an SF_6 gas-filled tank (enclosure), the insulation behavior is not completely lost and partly recovers. After a larger number of breakdowns, partly self-restoring elements have a remarkably reduced breakdown voltage, and reliability is lost.

Insulation characteristics have consequences for high-voltage dielectric withstand testing: internal insulation does not require special test conditions where, for example, the environment has to be taken into account. In case of self-restoring insulation, breakdown may occur during HV tests. For partly self-restoring insulation, a breakdown would only be acceptable in the self-restoring part of the insulation like the SF_6.

10.2 Definitions of Terminology

Power-Frequency Voltage Tests
Dielectric withstand performance verification with the power-frequency voltage.

Fig. 10.1 Example of a particle induced breakdown of an epoxy cast resin insulator of GIS. (Courtesy of ESBI, Ireland)

Lightning Impulse Voltage Tests
Lightning impulse withstand performance verification with the standard impulse voltage expected for a lightning stroke.

Switching Impulse Voltage Tests
Switching impulse withstand performance verification with the standard impulse voltage expected for switching operation.

Partial Discharge
Electric discharge that only partially bridges the insulation between conductors, which may occur inside the insulation or adjacent to a conductor.

Medium Voltage (MV)
MV generally refers to the voltage levels up to and including 52 kV corresponding to distribution systems.

High Voltage (HV)
HV generally refers to the voltage levels higher than 52 kV corresponding to transmission systems.

Extra High Voltage (EHV)
EHV generally refers to the voltage levels around 230 kV (the value may differ in country) up to 800 kV. The rated voltages at trunk systems are, for example, 420/380 kV in Europe and in the Middle East and 550/800 kV in the USA, Canada, and Korea.

Ultrahigh Voltage (UHV)
UHV generally refers to the voltage levels exceeding 800 kV operating in China and testing in India and in Japan.

Switching Equipment
Equipment designed to make or break the current in one or more electric circuits.

Switchgear
A general term covering switching equipment and their combination with associated control, measuring, protective, and regulating equipment, also assemblies of such equipment with associated interconnections, accessories, enclosures, and supporting structures, intended in principle for use in connection with generation, transmission, distribution, and conversion of electric energy.

Gas Insulated Metal-enclosed Substation (GIS)
A substation which is made up with only gas-insulated metal-enclosed switchgear.

Mixed Technology Switchgear (MTS)
Compact switchgear assemblies consist of a combination of air-insulated switchgear (AIS) and gas-insulated switchgear (GIS). Typical example is a gas-insulated metal-

enclosed switchgear with bushing terminals. It is also called a hybrid-GIS with both gas and air (hybrid) insulations.

10.3 Abbreviations

AC	Alternating current
DC	Direct current
CB	Circuit breaker
MV	Medium voltage
HV	High voltage
EHV	Extra high voltage
UHV	Ultra high voltage
GIL	Gas-insulated transmission line
GIS	Gas-insulated switchgear
MTS	Mixed Technology Switchgear

10.4 Standardized Withstand Voltage Tests

Several kinds of withstand voltage tests are conducted as type tests for high-voltage equipment to validate the dielectric performance. These tests consider various kinds of voltage stresses imposed on the equipment in operation. Testing voltages are defined in the standards. For example, those of alternating current (AC) circuit breakers are stipulated in IEC 62271-1 and IEC 62271–100 (see Table 10.1) and are based on the potential voltage stresses in transmission networks, which are defined in IEC 60071. These are (1) power-frequency (withstand) voltage tests, (2) lightning impulse (withstand) voltage tests, and (3) switching impulse (withstand) voltage tests and are regarded as major dielectric tests, and their methods are described in detail in IEC 60060-1.

Dielectric withstand performance tests are conducted to verify the withstand capability of equipment against the extreme stresses due to overvoltage events such as lightning strikes and to ensure its long-term reliability under operational conditions. Figure 10.2 shows an example of dielectric withstand performance test with 550 kV mixed technology switchgear (MTS or Hybrid GIS) using hybrid insulations of both SF_6 gas and air.

The short-time power-frequency withstand voltage can be verified by power-frequency voltage tests, and the withstand voltages to lightning surges and switching surges can be verified by lightning impulse voltage tests and switching impulse voltage tests, respectively.

Test conditions, especially test voltages, shall be determined according to the operational voltage of the equipment, taking into account the characteristics of the protection system for the transmission network.

Table 10.1 IEC specifications providing standard test levels

Rated voltage U_r (kV r.m.s. value)	Rated short-duration power-frequency voltage U_d kV (r.m.s. value)		Rated switching impulse withstand voltage U_s kV (peak value)			Rated lightning impulse withstand voltage U_p kV (peak value)	
	Phase- to-earth and between phases (Note 2)	Across open switching Device and/or isolating distance (NOTE 2)	Phase-to- earth and across Open switching device	Between phases (Notes 2 And 3)	Across isolating distance (Notes 1 And 2)	Phase-to- earth and between phases	Across open switching device and/or isolating distance (Notes 1 and 2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
300	395	435	750	1125	700(+245)	950	950 (+170)
			850	1275		1050	1050 (+170)
362	450	520	850	1275	800(+295)	1050	1050 (+205)
			950	1425		1175	1175 (+205)
420	520	610	950	1425	900(+345)	1300	1300 (+240)
			1050	1575		1425	1425 (+240)
550	620	800	1050	1680	900(+450)	1425	1425 (+315)
			1175	1760		1550	1550 (+315)
800	830	1150	1425	2420	1175(+650)	2100	2100 (+455)
			1550	2480			
1100	1100	1100	1550	2635	1550 + (900)	2250	2250 + (630)
		1100 + (635)	1800	2880	1675 + (900)	2400	2400 + (630)
1200	1200	1200	1800	2970	1675 + (980)	2400	2400 + (685)
		1200 + (695)	1950	3120		2550	2550 + (685)

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), (4), (5), (6), (7), 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

Fig. 10.2 Dielectric withstand performance tests with 550 kV H-GIS

Dielectric withstand performance strongly depends on the insulation medium. A condition of SF_6 gas with a pressure of 0.1 MPa-g shows 2.5–3.0 times higher dielectric withstand performance than that of air with atmospheric pressure or the same performance as that of insulation oil.

Since the V-t characteristic in SF_6 gas is comparatively flat, the lightning test with the highest test voltage is most severe in general. On the other hand, switching impulse tests become more severe in proportion with an increase of operational voltage for the verification of air insulation components such as bushings.

HV dielectric withstand performance tests with switching equipment are normally performed using a complete unit of the equipment. Figure 10.3 shows a typical schematic diagram of HV dielectric withstand performance tests.

Several different types of HV generator sources can supply the equipment with the required testing voltages. A power transformer is used as a generator when the AC power-frequency withstand performance is verified with equipment. A resonance reactor is also used as a generator when a capacitive coupling is required to establish an oscillating circuit for HVAC generation.

Since there is some interference between the high-voltage source and the test object (equipment) in HV test circuits, the voltage stress imposed on the equipment under a test will be different from that supplied by the high-voltage generator because of a voltage drop on the HV lead between the high-voltage source and the test object or even a voltage increase because of resonance effects. Therefore, the voltage measurement should be monitored directly at the test object (not at the high-voltage generator terminal).

The impedance of the HV test circuits should be the lowest value it can in order to reduce the interference. For this purpose, all wiring including the HV leads and the

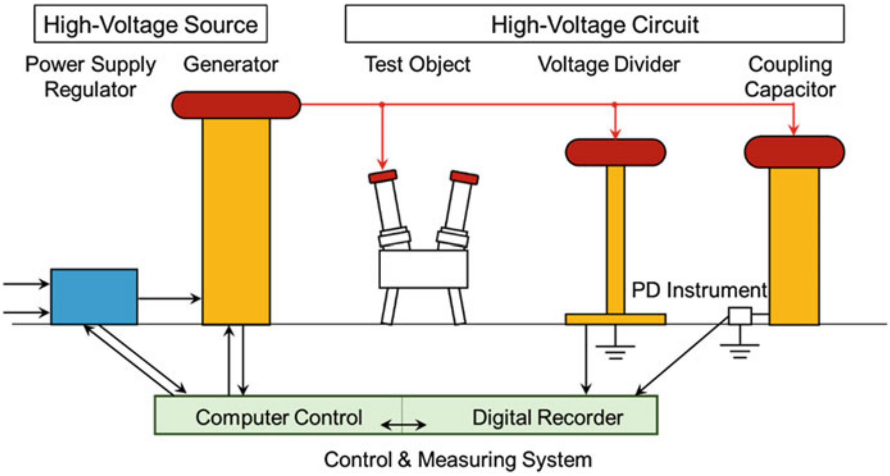

Fig. 10.3 Layout of high-voltage test

earth connections should be connected in minimum length. Nowadays, a compact, portable, and lightweight frequency-tuned resonance test set is available which enables efficient on-site AC tests with GIS.

10.4.1 Atmospheric Correction of Dielectric Withstand Performance Tests for External Insulation

Testing conditions shall be compensated to the standard testing conditions taking into account the actual testing conditions including temperature, atmospheric pressure, and humidity when dielectric withstand performance tests for external insulation are performed.

The standard test voltages shown in Table 10.1 are the values for the following standard conditions. The test voltages for the actual testing conditions shall be corrected according to the equations defined in IEC 60060–1.

- Temperature: $T_0 = 20$ deg. Celsius (293 K)
- Absolute air pressure: $p_0 = 1013$ hPa (1013 mbar)
- Absolute humidity: $h_0 = 11\ \mathrm{g/m^3}$

10.5 Power–Frequency Voltage Tests

Power-frequency voltage tests are conducted to validate the dielectric performance of equipment under the stress imposed by normal or transient voltage with power frequency of 50 Hz or 60 Hz. Figure 10.4 shows a typical test circuit of power-

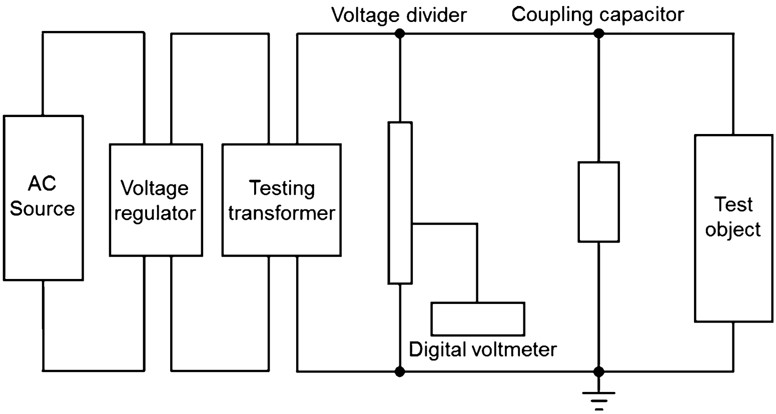

Fig. 10.4 Test circuit of power-frequency voltage tests

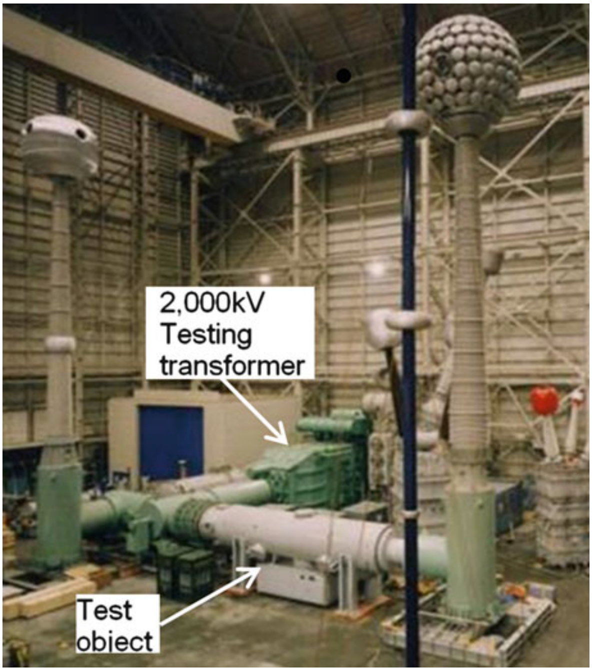

Fig. 10.5 Power-frequency voltage test with 1100 kV GIS

frequency voltage tests, where the test voltage is applied to a test object using an AC power source and is measured by a voltage divider and a digital voltmeter. Figure 10.5 shows a photograph of an 1100 kV GIS under testing with a 2000 kV AC testing power transformer.

10.6 Partial Discharge Measurement

Usually partial discharge (PD) measurements are also performed during a dielectric withstand test to find imperfections in the insulation performance of any parts of the equipment. Therefore, the PD measuring system is an important part of the AC dielectric withstand voltage tests, especially during the development stage, at final check before shipment, or during any trouble shooting. Fig. 10.6 shows a typical PD measurement setup composed of a HV component (e.g., voltage divider, coupling, or standard capacitor), measuring cable for data transfer, and a low-voltage instrument (e.g., laptop with A/D card and PD measuring system), which are shown in IEC 60270. Figure 10.7 shows an example of the PD measurement result of an epoxy insulator with a crack-shaped defect under a dielectric stress of 4 kV/mm. PD signals of around 15 pC, which are much higher than background noise (lower than 1 pC), are observed near the positive and negative peaks of the applied AC voltage.

10.7 Lightning Impulse Voltage Tests and Switching Impulse Voltage Tests

Lightning impulse voltage tests and switching impulse voltage tests are conducted for the evaluation of dielectric stress of transient overvoltages caused by lightning strikes and switching operations, respectively. Steep voltage front waveforms generated by an impulse voltage generator are applied to a test object, and test voltages and their waveforms are measured and analyzed by a measurement system composed of a voltage divider and a digital recorder. Figure 10.8 shows a typical test circuit for lightning impulse withstand voltage and switching impulse voltage tests. Figure 10.9 shows an example of a photo of an impulse voltage generator. The waveform of the test voltage is defined in IEC 60060–1, where the waveform parameters of T_1 and T_2 are 1.2 μs and 50 μs for a lightning impulse and parameters of T_p and T_2 are 250 μs and 2500 μs for a switching impulse as shown in Figs. 10.10 and 10.11.

Figures 10.12 and 10.13 show examples of a lightning impulse withstand voltage test with a 420 kV live tank circuit breaker and a switching impulse withstand voltage test with an 800 kV composite bushing evaluating the critical withstand voltage of equipment imposing excessive voltage conditions higher than the standard values.

10.8 Voltage (Withstand) Test as a Condition Check

In addition to the various specified voltage withstand tests for equipment described above, dielectric performance conditioning checks after performing other tests are required for type tests of switching equipment such as circuit breakers, or disconnectors, and earthing switches in accordance with the standards such as IEC 62271-1, IEC

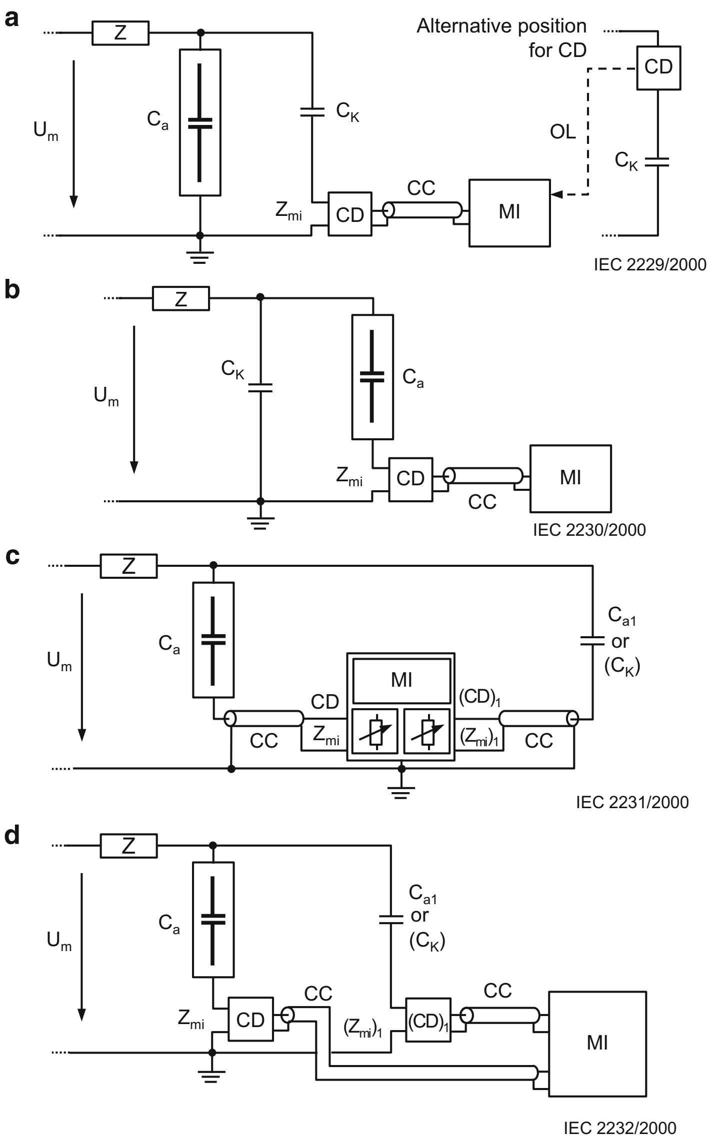

Fig. 10.6 Typical PD measuring circuits according to IEC 60270: 2015. $U_{\sim}$, high-voltage supply; Z_{mi}, input impedance of measuring system; CC, connecting cable; OL, optical link; C_a, test object; C_k, coupling capacitor; CD, coupling device;
MI, measuring instrument; Z, filter

62271-100, and IEC 62271-102. In order to verify the dielectric performance of the tested switching equipment after "mechanical tests," "environmental tests," "making tests," "breaking tests," or "switching tests," a power-frequency voltage test or an impulse voltage withstand test is performed. The conditioning checks after mechanical

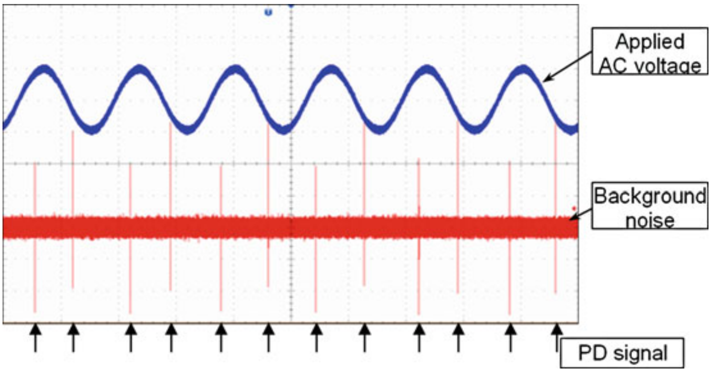

Fig. 10.7 Example of PD measurement of an epoxy insulator with a crack-shaped defect under a dielectric stress of 4 kV/mm, showing PD pulse of around 15 pC

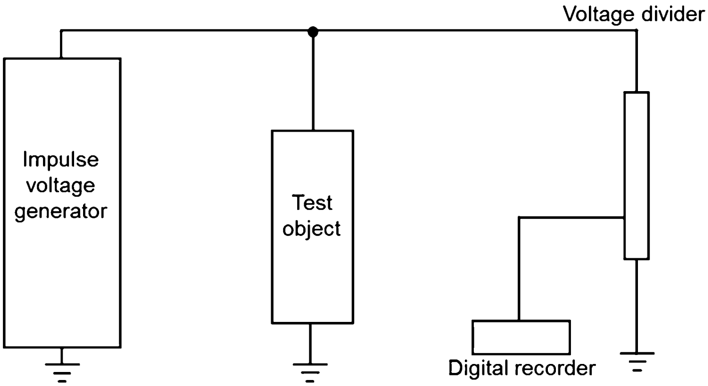

Fig. 10.8 Typical test circuit of lightning impulse and switching impulse withstand voltage tests

or environmental tests are usually performed, only if dielectric performance cannot be verified by visual inspection. However, voltage tests as a condition check after making, breaking, or switching tests are mandatory for a circuit breaker according to IEC 62271-100, where an impulse withstand voltage test is normally carried out. In the impulse withstand voltage test, the waveform of the impulse withstand voltage shall be a standard switching impulse withstand voltage or a waveform according to the TRV specified for terminal fault test duty of T10. The circuit breaker shall withstand five impulses of each polarity without any disruptive discharge.

10.9 Development Tests with Solid Insulation Components

Insulation of live parts to earth under normal and abnormal conditions in service is a fundamental requirement of all substation equipment. Various dielectric performance evaluations, such as power-frequency and impulse withstand tests on

Fig. 10.9 A photo of 6000 kV, 450 kWs impulse voltage generator. (Courtesy of Mitsubishi Electric)

equipment being tested which is newly assembled, cannot ensure the lifetime performance of the equipment. The deterioration of insulation components depending on operational and environmental conditions or switching operations during their lifetime is a major concern of the users.

Modern equipment with compact designs may lead to higher exploitation of the electrical field resulting in higher electrical stresses imposed on the solid insulation components. Therefore fundamental development tests are carried out concerning the long-term behavior of solid insulation components. They show certain aging effects under high electrical stresses. All materials are subject to deterioration and aging processes. The dielectric performance of substation equipment should include an appropriate margin against deterioration during the lifetime considering the service conditions.

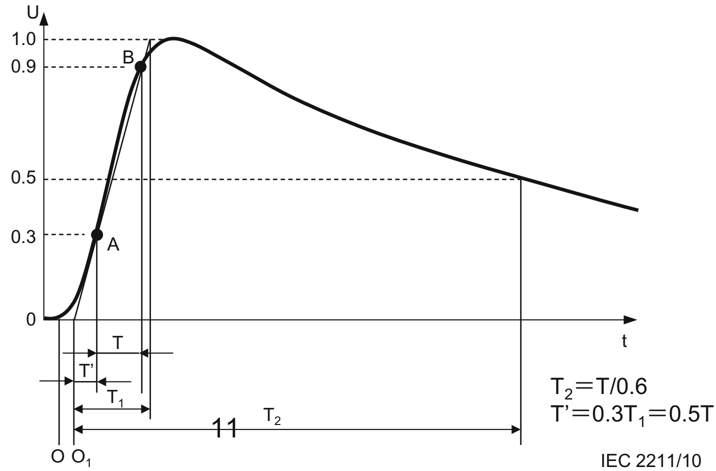

Fig. 10.10 Waveform and time parameters of lightning impulse withstand voltage. T_1, virtual parameter defined as 1/0.6 times the interval T between the instances when the impulses are 30% and 90% of the peak value on the test voltage curve (points A and B); T_2, virtual parameter defined as the time interval between the virtual origin O_1 and the instant when the test voltage curve has decreased the half voltage value

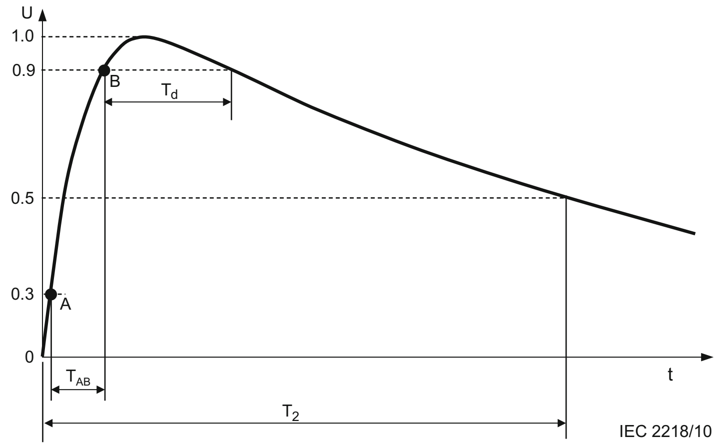

Fig. 10.11 Waveform and time parameters of switching impulse voltage. T_p, time interval from the true origin to the time of maximum value of a switching impulse voltage$T_p = KT_{AB}$, $K = 2.42–3.08 \times 10^{-3}\ T_{AB} + 1.51 \times 10^{-4}\ T_{2;}$ T_2, time interval between the true origin and the instant when the voltage has first decreased to half the maximum value; T_d, time interval during which the switching impulse voltage exceeds 90% of its maximum value

Presently the lifetime dielectric performance of equipment (with different designs) under various operational and environmental conditions with different electrical field strengths, material volume, and different production processes is not completely understood. The users and manufacturers can evaluate its

Fig. 10.12 Lightning impulse voltage test with 420 kV live tank circuit breaker. (Courtesy of Siemens)

Fig. 10.13 Switching impulse voltage test with 800 kV circuit breaker bushing. (Test voltage: Positive 1650 kV)

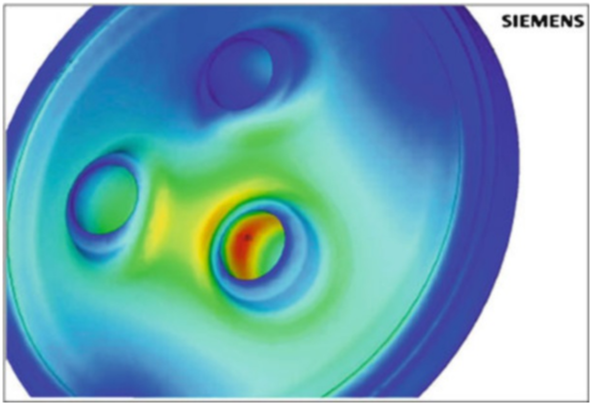

Fig. 10.14 3D model of electrical field of insulating spacer used for three-phase simultaneous operated 145 kV circuit breaker with a common enclosure. (Courtesy of Siemens)

performance in an empirical way. The CIGRE reliability survey on circuit breakers shows that the major failure frequency due to dielectric breakdown has been significantly reduced according to their experience (CIGRE WG A3.06 2012).

Figure 10.14 shows an example of three-dimensional field calculations of a 145 kV insulating spacer. Recently these analytical tools along with some development tests can allow a highly complex and field-optimized design.

10.10 Routine Tests

Production quality is checked and confirmed by a series of routine tests with a complete system, such as a complete bay of GIS at the manufacture's factory. The routine dielectric tests consist of a power-frequency voltage test on the main circuit of the equipment using a PD measurement system according to the IEC standard. IEC standards and the criteria set by most manufacturers require the PD level to be lower than 5 pC. In order to ensure this requirement, the noise level should be lower than 2 pC. Such sensitivity can only be achieved by shielding the measuring system from the main high-voltage test equipment. For solid insulators, a high-voltage routine test with highly sensitive PD measurements enables finding embedded defects in the insulators, such as voids and cracks, before assembly during production of the equipment.

During routine testing, an ultrahigh frequency (UHF) PD detection method can be applied in parallel to the conventional PD measurement. Nowadays quality assurance for the equipment under test is generally performed using such highly sensitive UHF PD detection. Figure 10.15 shows an example of UHF PD couplers which are installed in GIS. The measurements are often used as a reference for the on-site dielectric performance check.

Fig. 10.15 Example of UHF PD sensor (courtesy of Siemens)

10.11 On–Site Tests after Installation

On-site tests are performed to check the dielectric integrity of the completed installation. The purpose of the on-site test is to avoid and eliminate different types of defects which might give rise to an internal fault at the initial stage and/or during service before an expected lifetime at normal conditions. The main causes for these defects are as follows:

- Incorrect assembly
- Inadequate design (often causing infant mortality failures) and immature new design
- Presence of foreign bodies or other contaminants such as free metallic particles and protrusions exceeding design criteria
- Damage during transport, storage, or installation

Different test procedures for on-site testing with GIS are recommended by IEC 62271-203. For GIS with rated voltage levels of $U_m \leq 170$ kV, the application of a power-frequency voltage test is recommended for on-site testing (procedure A). A frequency range of 10–300 Hz should normally be used for the power-frequency voltage test. GIS with rated voltages of $U_m \geq 245$ kV should be tested either with a power-frequency voltage test combined with a PD measurement (procedure B) or as an alternative with a power-frequency voltage test followed by a lightning impulse withstand test (procedure C). However, due to practical and economic reasons, deviations of the recommended test procedures with specific parameters are expressly allowed by IEC. GIS manufacturer and users must agree on an appropriate on-site test procedure. For typical GIS with rated voltage levels up to $U_m = 245$ kV, the HV test procedure A is sufficient to ensure the dielectric integrity.

On-site AC testing of GIS can be combined with sensitive PD measurements in order to detect small defects. The CIGRE proposal for on-site testing of GIS recommends a highest permissible PD level of 5 pC or equivalent. Extensive investigations have confirmed that the detection of PD using the UHF method results in higher or at least the same sensitivity as detection by PD measurement as set out in IEC 60270. UHF PD detection does, however, not provide a direct correlation with the standardized “pC-values” according to IEC 60270. CIGRE has therefore developed a procedure verifying that it is possible to detect “bouncing particles with 5 pC” in complete GIS substations. On-site the voltage signal is fed in at a PD coupler and should be detected at the directly adjacent PD coupler. The signal amplitudes measured are a clear indication of the varying attenuation of the UHF signals between the PD couplers. The sensitivity verification is used to check on-site the correct positioning of the PD couplers in GIS. Recent results of measurements showed that, depending on the GIS type, bay design, and the substation layout, the maximum permissible distance between two PD sensors is in the range 10–30 m.

10.12 Summary

This chapter explains high-voltage testing to evaluate the dielectric performance of AC equipment. Substation equipment is required to withstand both voltages imposed during the normal operation and during transient overvoltages under specific conditions in accordance with international standards. Several dielectric performance tests including power-frequency withstand voltage tests, partial discharge measurements, and lightning impulse withstand voltage and switching impulse withstand voltage tests are used to confirm the dielectric performance in service conditions.

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Short-Circuit Performance Tests

11

René Smeets

Contents

Keywords
High-power test · Interrupting test · Switching test · Synthetic test · Circuit breaker · Breaking current · Transient recovery voltage

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11.1 Introduction

Interruption and switching performance tests with switching equipment are usually performed with one of the following objectives:

(a) **Research and Development**
The interruption and switching tests are normally carried out in a high-power test laboratories of either manufacturers (often they have an accredited laboratory) or in third-party testing facilities depending on users' requests. Apart from custom-designed special equipment, the aim is the development of products that will be ultimately submitted to a type-test report in accordance with international and national standards. Research and development test requirements can vary depending on the stage of development, but the final aim is usually a design capable to withstand the standardized stresses of the standards in order to obtain a type-test report.

(b) **Acceptance**
The acceptance tests are carried out to verify the performance of withstanding non-standardized stresses that may occur under special conditions of power networks or under special environment and operation conditions requested by a user. Regarding short-circuit interruption tests, examples are TRVs beyond the standardized limits (e.g., in the application of series compensated capacitors, series current-limiting reactors, or filter banks in converter stations) or other special conditions (e.g., exceptional short-line fault conditions, missing current zeros, high DC time constants, etc.). Usually, equipment has already been type-tested before being subjected to the additional acceptance tests. The user of switchgear proposes the test requirements based upon his knowledge of abnormal conditions in his power system. Manufacturer's and independent laboratories often perform such tests.

(c) **Type Test Certification**
Type tests are aimed to demonstrate the capability of a single sample of a batch of identical products to conform to a certain standard. Once this has been demonstrated, a type-test certificate is issued by a certification authority. A certificate contains a record of a series of type tests carried out strictly in accordance with a recognized standard. It is a proof that the component tested has fulfilled all the requirements of a recognized standard. If the equipment tested has fulfilled the requirements of this standard, the relevant ratings assigned by the manufacturer are endorsed by the certifying authority. The certificate is applicable only to equipment of a design identical to the tested one. The certifying authority is responsible for the validity and the contents of the certificate.

The responsibility for conformity of any apparatus has the same designation as the one tested rests with the manufacturer. The certificate contains the essential drawings and a description of the equipment tested.

Type tests are carried out in independent, duly accredited test laboratories. Several of these in the world apply the rules of the short-circuit testing liaison

(STL), an organization of test laboratories and authorities looking after a uniform interpretation of standards throughout the world by providing practical guidelines (STL 2011a). STL, a purely technical institute, makes use of the competence and expertise of its members to provide these guidelines. This voluntary society also defines the test report templates to assure that equipment users can easily compare the results of the different member laboratories. The society also defines rules and procedures to assure the quality of the test results and certified products.

Five categories of tests are distinguished by STL to verify (STL 2011b):

- Short-circuit making and breaking performance
- Switching performance, normally the capacitive-current switching performance
- Dielectric performance
- Temperature rise performance and measurement of the main-circuit resistance
- Mechanical performance

STL members issue certificates on these five items related to the specified rated values, except for the mechanical performance, for which there is no rating defined.

By the repetition of the type test duties after a period of time, usually after 5 years, assurance can be obtained that the manufacturing quality of the circuit breaker or switchgear, quality of material, and workmanship is maintained.

In contrast to type tests, carried out on one sample of a batch, *routine tests* are tests to which each individual piece of equipment is subjected. They are for the purpose of revealing faults in material and construction. They do not impair the properties and reliability of the test object.

The following subsections highlight only those test methods intended to verify the *breaking capacity* of circuit breakers, i.e., the capability to interrupt short-circuit currents. A detailed overview with many practical examples of all making, breaking, and switching test methods can be found in reference (Kapetanović 2011; Smeets et al. 2014a).

11.2 Definition of Terminology

Short-Circuit Current
Overcurrent resulting from a short circuit due to a fault or an incorrect connection in an electric circuit.

Overcurrent
Current exceeding the rated current.

Breaking Current
Current in a pole of a switching device at the instant of initiation of the arc during a breaking process.

Recovery Voltage
Voltage which appears across the terminals of a pole of a switching device after the breaking of the current.

Transient Recovery Voltage
Recovery voltage during the time in which it has a significant transient character.

Note 1: The transient recovery voltage may be oscillatory or non-oscillatory or a combination of these depending on the characteristics of the circuit and the switching device. It includes the voltage shift of the neutral of a polyphase circuit.

Note 2: The transient recovery voltages in three-phase circuits are, unless otherwise stated, that across the first pole to clear, because this voltage is generally higher than that which appears across each of the other two poles.

Direct Test
Direct tests are the short-circuit tests with a single power source by either one or more short-circuit generators for the applied current and voltage.

Synthetic Test
Synthetic tests are conducted for the alternative tests which are equivalent to direct tests where current and voltage are obtained by other power source, when direct tests are difficult due to the capabilities of testing facilities.

Major Loop of Current
Asymmetrical current with a certain DC component consists of major and minor loops of current. The time between current zeros in a major loop will be greater than that implied by the power frequency of the system. The major loop may impose greater stress on equipment.

Medium Voltage (MV)
MV generally refers to the voltage levels up to and including 52 kV corresponding to distribution systems.

High Voltage (HV)
HV generally refers to the voltage levels higher than 52 kV corresponding to transmission systems.

Extra High Voltage (EHV)
EHV generally refer to the voltage levels around 230 kV (the value may differ in country) up to and including 800 kV. The rated voltages at trunk systems are, for example, 420/380 kV in Europe and in the Middle East and 550/800 kV in the USA, Canada, and Korea.

Ultrahigh Voltage (UHV)
UHV generally refers to the voltage levels exceeding 800 kV operating in China and as pilots in India and in Japan.

Test Duties of T10, T30, T60, and T100

Short-circuit interrupting and making tests corresponding to a bus terminal fault under the current conditions of 10%, 30%, 60%, and 100% of the rated (maximum) interrupting current of a circuit breaker.

Test Duties of L90 and L75

Short-circuit interrupting test corresponding to a short-line fault interruption, which refers to a fault that occurs on a line a few hundred meters to several kilometers down the line from the circuit-breaker terminal. When a circuit breaker clears, the SLF, TRV with a steep rate of rise, is observed due to high-frequency oscillations generated by the waves that travel on the line and reflection between the circuit-breaker terminal and the fault point. The standards specify the current conditions of 75% and 90% of the rated (maximum) interrupting current of a circuit breaker.

11.3 Abbreviations

HP	High power
HV	High voltage
EHV	Extra high voltage
UHV	Ultra high voltage
MV	Medium voltage
DC	Direct current
AC	Alternating current
PD	Partial discharge
TRV	Transient recovery voltage
RV	Recovery voltage

11.4 High-Power Tests

High-power test technology is an essential facility to evaluate the interruption performance in case of the development of HV circuit breakers. A large number of test circuits and test methods have been developed since 1911 when AEG built the world's first high-power laboratory in Kassel, Germany, with a short-circuit power capacity of 150 MVA.

There are three types of high-power laboratories that can be distinguished how to supply the voltage and current to a test circuit.

- Laboratories are supplied with a voltage and current source directly from the network, as outlined in Fig. 11.1a. The advantage is that a large amount of short-circuit power can be available. In power systems, there are a relatively small number of locations suitable for high-power testing. To avoid instability of the supplying network during the short-circuit test, the available short-circuit power at the location of the test laboratory should be approximately ten times the maximum power used during an actual test. The network must not be disturbed by frequent short circuits and high overvoltages, and often, the test parameters cannot be adjusted as prescribed. Especially, the match of test voltage is not always easy. In addition, the available testing power of even the most powerful network laboratories falls far short of that required for modern HV circuit breakers, the interrupting capability of which corresponds to tens of Giga volt-ampere (GVA) levels.

- Laboratories are supplied with a voltage and current source from their own power source(s), i.e., short-circuit generators or capacitor banks, separate from the network, shown in Fig. 11.1b. Conditions very close to actual electric power systems can be simulated in generator-supplied test laboratories. Testing in these laboratories has numerous advantages in comparison with network-supplied laboratories. The main advantage is flexibility. The main disadvantage is that huge investments are required.
- Laboratories are supplied with a voltage and current source from pre-charged capacitor banks. These facilities are exclusively used for research and development mainly for MV switchgears, since they have limited power even though economical in investments.

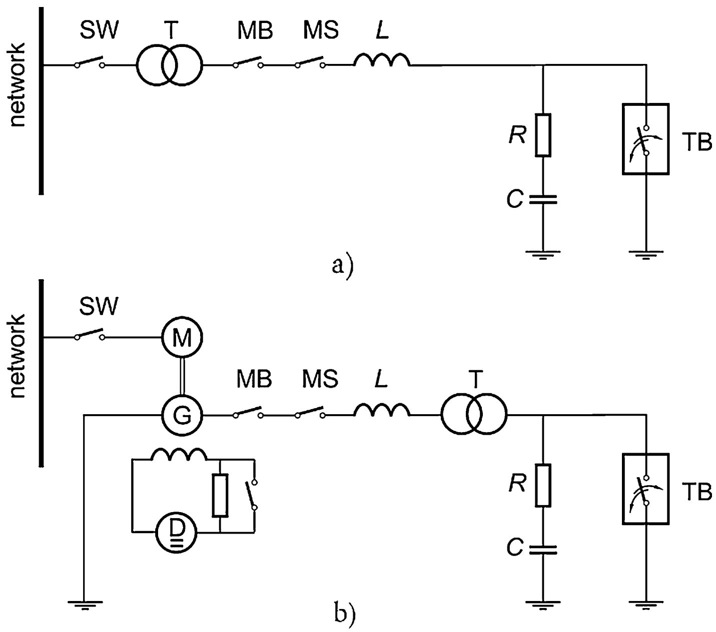

Fig. 11.1 Simplified single-line diagrams of high-power laboratory layout: (**a**) network-supplied; (**b**) generator supplied. SW, source circuit breaker; MB, master breaker; L, current-limiting reactor; M, motor; G, short-circuit generator; T, short-circuit transformer; MS, make switch; ***R***, ***C***, TRV shaping resistor, capacitor; D, excitation circuit; TB, tested circuit breaker

Fig. 11.2 2200 MVA short-circuit generator in order to enable high-power testing with short-circuit current of variable power frequency. (Courtesy of DNV GL, KEMA Laboratories)

The power of even the largest high-power laboratories is not sufficient for testing the majority of HV circuit breakers. Therefore, alternative test methods, such as *synthetic tests, unit testing method, and multipart testing method* (see Sects. 11.5.3, 11.5.4, and 11.6), are in use to impose adequate current and voltage stresses on circuit breakers.

Figure 11.2 shows a short-circuit generator, which is a specially designed three-phase generator that supplies the short-circuit power for various interruption and switching tests in a generator test station. The designs and characteristics of such generators differ markedly from those of their conventional counterparts used to generate electric power commercially.

Figure 11.3 show 50 MVA 13.2 kV vintage short-circuit generator with a motor manufactured in 1951. It had been daily operated to test various circuit breakers with different technologies such as oil, air, vacuum, and gas for 60 years until 2010.

Short-circuit generators are generally designed with very low reactance and high mechanical strength of windings against electrodynamic and centrifugal forces that are suited for frequent impulse excitation. A motor is used to speed up the rotor to its synchronous rated mode of operation before the test. During the short-circuit test, a short-circuit generator (which consists of short-circuiting the stator, the excitation and the kinetic energy of the rotor mass) normally supplies the power. Because it takes approximately 20 min to bring the generator up to speed, the power supplied by the network is considerably lower than the power used for testing.

The largest high-power laboratory using generators and at the same time the largest overall high-power test facility in the world is KEMA Laboratories, owned by DNV GL, Arnhem, the Netherlands, with 12,000 MVA (at 50 Hz) and 14,000 MVA (at 60 Hz) three-phase power available in the test bays (see Fig. 11.4).

Fig. 11.3 50 MVA 13.2 kV vintage short-circuit generator

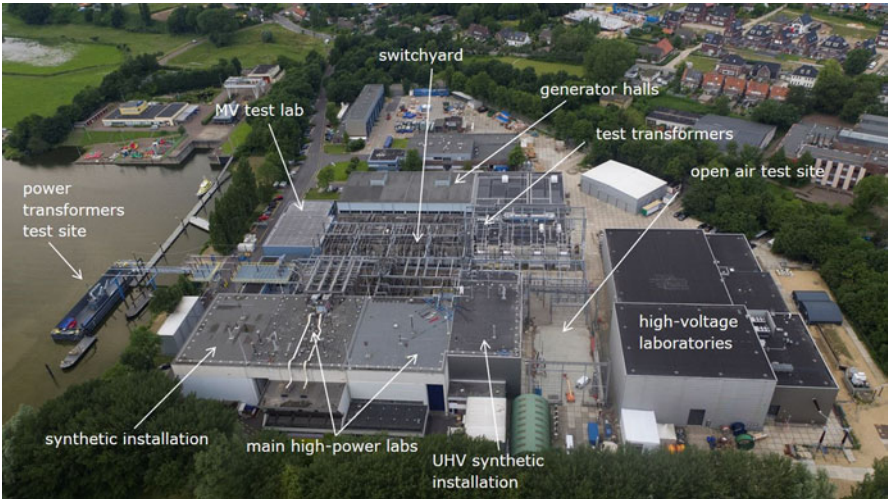

Fig. 11.4 KEMA high-power laboratory in Arnhem, the Netherlands, 2016

This power is sufficient to test a circuit breaker in a three-phase circuit up to 145 kV and a maximum rated short-circuit breaking current of 31.5 kA. Above these levels, HV circuit breakers can be tested in a single-phase circuit; alternatively, single-unit tests, two-part tests, and/or synthetic (indirect) test methods are standardized as described more in details below.

An example of large network-supplied laboratories are located at les Renardières, France, operated by EdF, and Rondissone, Italy, operated by CESI. A large network-supplied national high-power laboratory (NHPL) is put in operation at Bina, India.

Other large, well-known manufacturer-independent high-power laboratories are as follows (Worldwide Directory of HV/HP Laboratories):

CESI located in Milano, Italy
IPH located in Berlin, Germany, operated by CESI
Zkušebnictví located in Běchovice near Prague, Czech Republic, operated by KEMA Laboratories
VEIKI located in Budapest, Hungary; ICMET located in Craiova, Romania
The laboratory of the Federal Grid Company of United Energy System of Russia (FGC of UES), located in Moscow, Russia
XIHARI in Xi'an and EETI in Suzhou, China
CPRI located in Bangalore, India
KERI located in Changwon, South Korea
KEMA Powertest located in Chalfont, Pennsylvania, USA
PowerTech located in Vancouver, Canada
LAPEM located in Irapuato, Mexico and CEPEL located near Rio de Janeiro, Brazil

In addition, most large switchgear manufacturers have their own high-power laboratories: Siemens located in Berlin, Germany; ABB located in Ludvika, Sweden and Baden, Switzerland; Alstom located in Villeurbanne, France; Schneider Electric located in Grenoble, France and Ormazabal Group in Bilbao, Spain; Toshiba Co., Mitsubishi Electric and Hitachi located in Japan.

Methods of testing the breaking capacity of circuit breakers can be divided into direct tests and indirect tests, the latter being known as *synthetic tests* (Slamecka 1966).

(a) **Direct Short-Circuit Tests**

Direct tests refer to an interruption and switching testing method where the applied current and voltage are obtained from a single power source, which can be either one or more short-circuit generators in parallel, the power system, or a combination of these. A direct test is a preferred test method, because it can establish a test circuit to cover the standardized stress easier compared with the indirect tests (see the description in (A) of subclause 11.6.5) or just (see 11.6). The single power source must be capable to deliver the short-circuit current as well as transient and power-frequency recovery voltage. Basically, the direct test allows a test of a three-pole circuit breaker with full current and full voltage, preferably in a three-phase circuit. Direct tests can be performed either in the field or in the testing laboratory.

(b) **Synthetic Short-Circuit Tests**

Synthetic (indirect) tests refer to an interruption and switching testing method that can reproduce the stresses equivalent to the service conditions for verification of the breaking capacity of HV-, EHV-, and UHV circuit breakers by other means than with full short-circuit power available from a single power source. Instead, several sources are employed as described in Sect. 11.6.

Due to limitations of the testing facility, when the short-circuit performance of the circuit breaker cannot be proved in a three-phase circuit, several methods employing either direct or synthetic test methods may be used either singly or in combination:

- *Single-phase tests*: tests on only one pole of a three-pole circuit breaker with appropriate stresses as specified for each of the poles of a three-pole circuit breaker (see Sect. 11.5.2)
- One (or more) *unit(s) tests*: tests on a unit (interrupting chamber) or on a group of units at the current specified for the test on the complete pole of a circuit breaker and at the appropriate fraction of the applied voltage specified for the test on the complete pole of the circuit breaker (see Sect. 11.5.3)
- Two- or multi*part tests*: tests carried out in two or more successive parts when all requirements for a given test duty cannot be met simultaneously (see (D) of subclause 11.5.4)

In order to measure the current and voltage behaviors in a high-power test accurately, appropriate measurement devices should be applied. Since a wide range from DC to several hundred kilohertz must be covered for the voltage measurements in a test, RCR-type voltage dividers are often selected. For current measurements, current transformers are usually applied in a range of power frequencies of 50 or 60 Hz, and Rogowski coils or coaxial shunts are applicable to measure the high frequencies which may be generated by a reignition during a test. In addition, careful consideration must be also given to the signal transmission systems to avoid the influence of electromagnetic induction caused by high testing currents. In most of the modern high-power testing laboratories, electrical to optical or optical to electrical (EO/OE) converters with optical fibers are employed for this purpose.

High-power laboratory should generally record a number of current and voltage waveforms at different time scales. Other time-varying parameters, such as the position (travel) of the tested circuit-breaker contacts or pressure inside the compression volume, can also be recorded. Multichannel digital transient recorders are used for this purpose. The great advantage is that once the data is stored in digital form, it can be analyzed by a computer and stored permanently for future study.

11.5 Direct Tests

11.5.1 Direct Three-Phase Tests

Figure 11.5 shows a typical direct three-phase test circuit, where the master circuit breaker (MB) is placed directly behind the three-phase short-circuit generator (G). This master breaker has the duty to interrupt the short-circuit current, in the case of a failure of the tested circuit breaker (TB) and in the case of a short-circuit occurrence in the test circuit installation. The master breakers and their control shall operate extremely fast (typically within 10 ms) in order to allow study of the root cause of a failure to pass a certain test. Otherwise, the test object will be destroyed during an unsuccessful test, leaving some difficulties for analysis (Fig. 11.6).

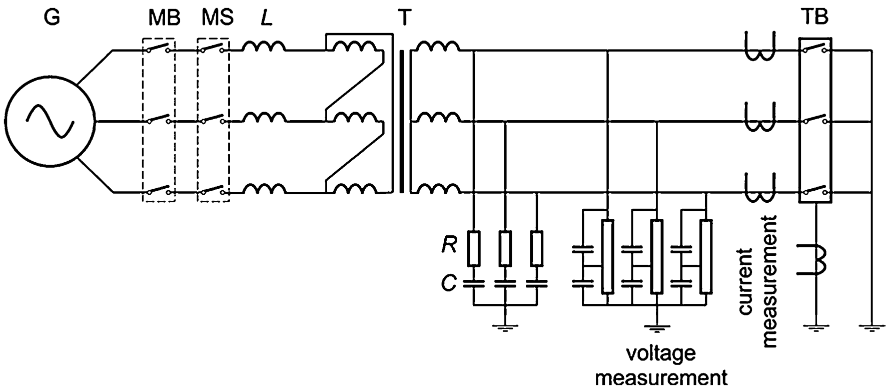

Fig. 11.5 Diagram of a direct three-phase test circuit. G, generator; MB, master breaker; MS, make switch; *L,* current-limiting reactor; T, short-circuit transformer; *R*, *C,* TRV shaping resistor, capacitor; TB, circuit-breaker under test

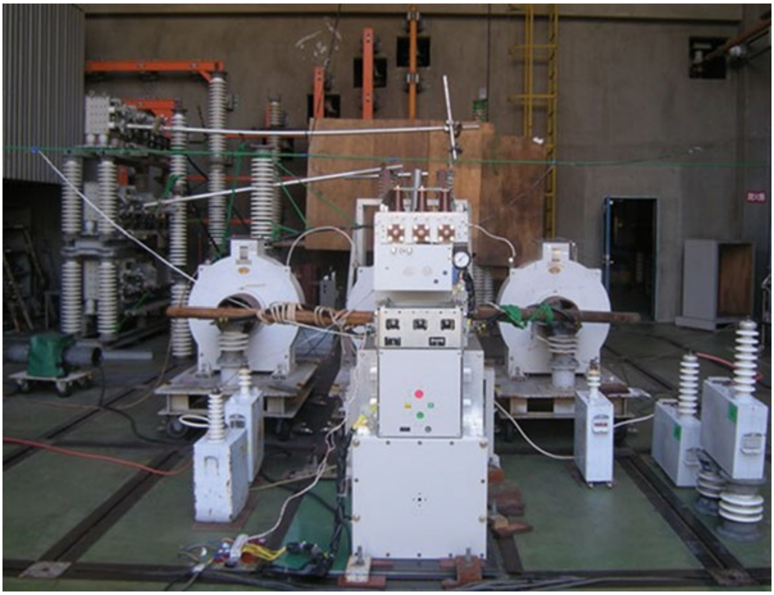

Fig. 11.6 Photo of direct three-phase test with 12 kV 20 kA three-phase simultaneous operating vacuum interrupters

When the tested circuit breaker has to perform a break (interruption) operation, it is initially in a closed position; the master breaker (MB) is also closed, but the make switch (MS) is open. The adjustable reactor (L) is used to add extra reactance in the circuit, to realize the required test current at the chosen test voltage. Because the terminal voltage of the short-circuit generators is relatively low, between 12 and 18 kV, specially designed short-circuit transformers (T) are required to transform the generator voltage to the higher testing voltage. The TRV-adjusting elements such as resistors (R) and capacitors (C) are connected at the HV side of the transformer. After the generator is driven to the nominal power frequency and the rotor is excited, the make switch (MS) is closed which initiates a short-circuit current flowing through the tested circuit breaker (TB). After an opening command, the tested circuit breaker shall interrupt the current. After successful interruption, the tested circuit breaker is stressed by the transient recovery voltage imposed by the TRV-adjusting elements together with the inductance formed by the total circuit reactance consisting of the synchronous reactance of the generator, the reactor, and the leakage reactance of the transformer.

When the tested circuit breaker has to perform a make-break operation, it must make a short circuit. Before a make-break test, the tested circuit breaker is in the open position and it closes, after the make switch has been closed to apply the open-circuit voltage to the tested circuit-breaker terminals.

Figures 11.6 and 11.7 shows an example of direct three-phase testing scene using 12 kV vacuum interrupter and also an example of a test oscillograms using a different testing equipment.

11.5.2 Direct Single-Phase Tests

A direct single-phase test may be performed in substitution of three-phase conditions encountered in service. However, careful consideration must be taken to ensure that relevant stresses are applied since the circuit-breaker poles are generally not equally stressed during interruption.

The first pole-to-clear has to recover against a power-frequency recovery voltage of k_{pp} (p.u.) In a noneffectively earthed system, $k_{pp} = 1.5$ and from the viewpoint of short-circuit power, it can be seen that in this case, the first pole interrupts 50% of the total three-phase short-circuit power P_{sc}:

$$P_1 = 1.5 \frac{U_r}{\sqrt{3}} I_{sc} = 0.5 P_{sc} \tag{11.1}$$

whereas the other two poles face the remaining 50% in series, each pole interrupts approximately 25% of P_{sc}:

$$P_2 \approx P_3 \approx \frac{U_r I_{sc} \sqrt{3}}{4} = 0.25 P_{sc} \tag{11.2}$$

The conditions for the first pole-to-clear represent the most severe stress regarding TRV, but the arcing times of the second and last poles-to-clear become longer. As it is important that both the arcing window and associated TRV are applied during the direct single-phase test, the use of the arcing time of the last pole-to-clear in combination with the TRV of the first pole-to-clear is a possible alternative. Using this alternative makes it possible to carry out only three breaking operations per test

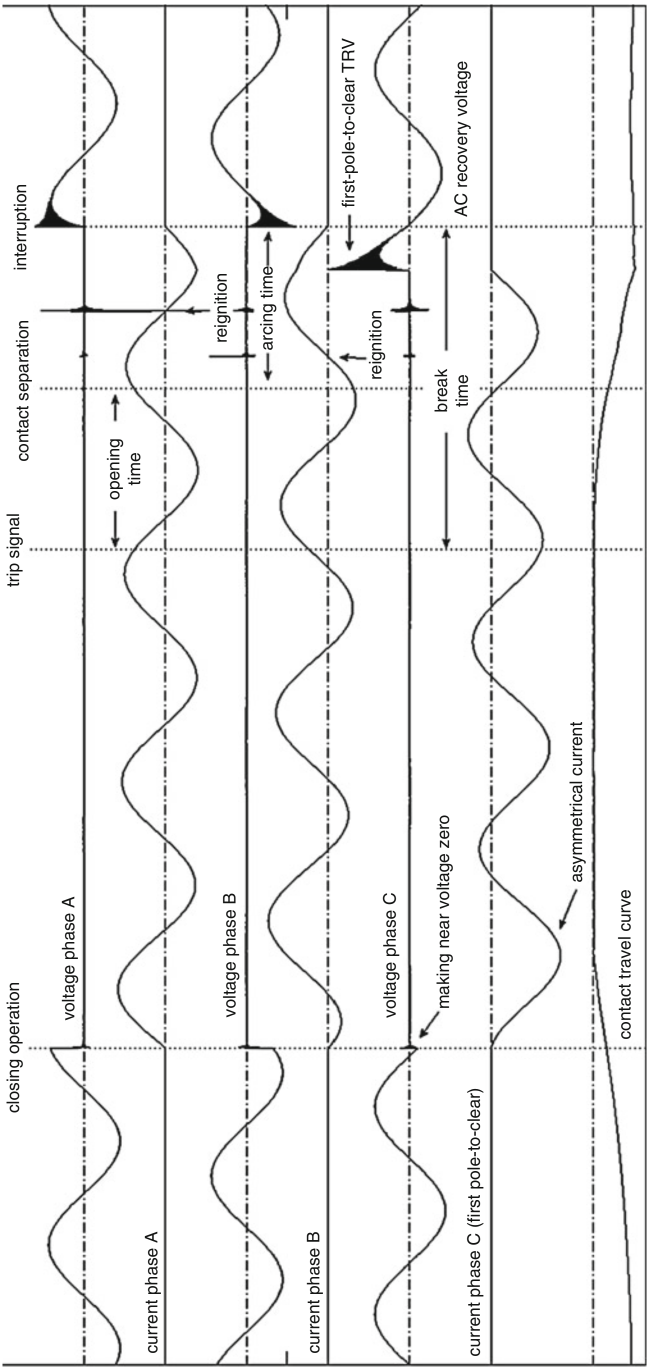

Fig. 11.7 Typical oscillograms of direct three-phase tests

duty, as both IEC and ANSI/IEEE standards are required, but prolongation of arcing times may be necessary. However, it is recognized that such single-phase tests are more severe than three-phase tests (IEC 62271-306 2012) since in the three-phase condition, the highest TRV is applied only on the first pole-to-clear, which has shorter arcing times.

Another alternative test procedure, which reproduces exactly the same stresses of a three-phase interruption, is also possible, but a greater number of interruptions is required to provide a full demonstration. For the first pole-to-clear with $k_{pp} = 1.3$, nine instead of three breaking operations per test duty are required, and for $k_{pp} = 1.5$ six operations are required for complete verification of the performance. This is because three valid operations are required for demonstration of satisfactory performance for each of the separate-phase conditions of arcing time and TRV.

Moreover, during the direct single-phase test, the procedures may give rise to an invalid test that can overstress and damage the circuit breaker. Therefore, particularly for circuit breakers used in non-solidly earthed systems, it is recommended to use synthetic test methods instead of direct single-phase tests (STL 2005).

The description above is relevant for tests with symmetrical short-circuit currents. The test procedure for asymmetrical current is even more complicated, as interruption can occur either after a minor loop or after a major loop of current.

For single-phase testing, it is necessary to determine whether it is justified to subject only one pole to a test. The interrupting process is affected by electrodynamic forces, the gas exhaust from the adjacent poles, the contact speed, the pressure of the extinguishing medium, etc. The energy output of the operating mechanism should be properly considered since the stresses resulting from single-phase operation require only a reduced operating force (see Fig. 11.8).

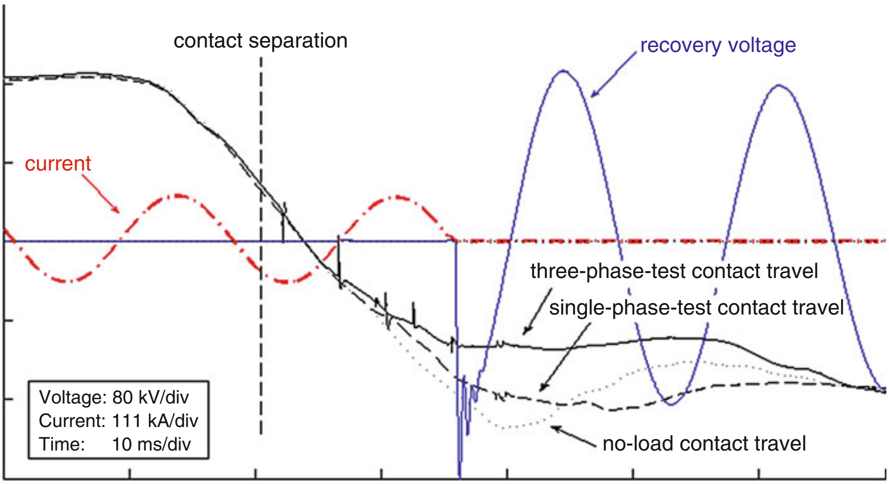

Fig. 11.8 An example of contact travel curves of circuit breakers measured in no-load, single-phase breaking and three-phase breaking tests. (Courtesy of KEMA Laboratories)

In other words, the design of the circuit breaker and the interaction of poles are particularly important when the three poles are driven by a common operating mechanism and are in a common enclosure. In this case, short-circuit performance can only be verified by three-phase testing. This is explained in Fig. 11.8. In this figure, the course of the contact travel is given for a no-load operation, single-phase, and three-phase breaking test on the same circuit breaker. The increasing stress on the operating mechanism, comparing no-load operation (no arcing interrupter) with single-phase breaking (only one arcing pole) and three-phase breaking (three arcing poles), is evident, showing appreciable slowing down of the contact travel in the three-phase arcing condition. These interactions do not apply to circuit breakers having independently operated poles.

11.5.3 Unit Testing Method

When a modular concept is used in the design of HV circuit breakers with two or more identical interrupter units in series (i.e., a circuit breaker composing of multi-break interrupters), performance of a complete pole, and possibly of the whole circuit breaker, can be evaluated from the performance of one or more units. For unit testing to be valid, all (interrupter) units must be identical in construction. They must operate simultaneously and must not influence each other.

The test current must be the same as in service and the test voltage should be the appropriate proportion of the rated voltage *U*r. This proportion depends on the number (*n*) of series units and on the voltage distribution across the units. The test voltage for a unit should correspond to the voltage share that would appear across the highest stressed unit. In order that natural frequencies remain the same as in the full circuit, the circuit inductance (*L*) should be proportionally lower (*L*/*n*), and the capacitance (*C*) should be proportionally increased (*nC*), as it is illustrated in Fig. 11.9 for a circuit breaker with three identical interrupters in series per pole. In order to guarantee the correct voltage across a unit, evaluation has to be carried out on the distribution of voltages across the various units within a frequency range from power frequency to TRV frequency (up to 10 kHz). This involves calculation of the voltage transients, taking into account all capacitors and stray capacitances, such as those to earth.

The tests are then carried out with the voltage of the highest stressed unit, which is normally the unit connected to the source circuit; this voltage is always higher than *U*r/*n*.

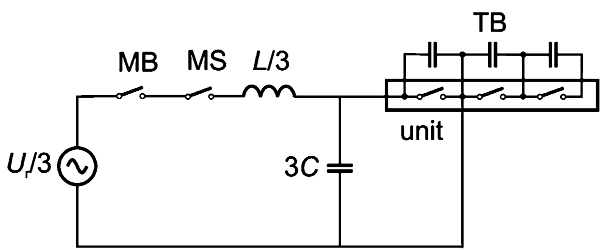

Fig. 11.9 Basic principle of unit tests with three-break circuit breaker

Especially in designs without grading capacitors, where the voltage distribution is determined only by stray elements, a significant influence on the voltage distribution is observed for different locations of the circuit breaker in the test laboratory because of different stray capacitances to the earthed environment in the test circuit.

11.5.4 Two-Part or Multipart Testing Method

If all TRV requirements for a given test duty cannot be met simultaneously, for example, of EHV and UHV class circuit breakers typically with opening or closing resistor, the test may be carried out in two or more successive parts regarding the initial portion of the TRV and the relevant parameters specified for the TRV envelope.

The number of tests for each part is the same as the number required for the test duty. The arcing times in separate tests, forming part of multipart test, are required to be the same with a margin of ± 1 ms.

11.6 Synthetic Tests

Circuit-breaker testing requires high and increasing short-circuit power. The short-circuit ratings of many circuit breakers are so high that verification of their breaking capacity is no longer possible with direct test circuits. Figure 11.10 shows the increase over years of the short-circuit power needed for short-circuit testing per interrupter unit (Fröhlich 2002). The largest breaking capacity of an interruption chamber can interrupt 63 kA at 550 kV at this moment, which would require a single-phase direct power source of 26 GVA.[1] This is more than two times the maximum output power of the largest test laboratory available in the world. Therefore, synthetic (indirect) testing of circuit breakers (Thoren 1950) has been developed as an economical, technically rational, and equivalent alternative to direct testing.

In synthetic tests, all or a major portion of the current is obtained from one source (current circuit), whereas the applied voltage and/or the recovery voltages (transient and power frequency) are delivered wholly or in part by one or more separate sources (voltage circuits).

Synthetic testing methods are based on the fact that during the breaking operation, when high current flows through the circuit breaker, there is only a relatively small arc voltage between the open contacts, and when high (T)RV appears across the contacts, there is basically only voltage across the circuit breaker without current. These two phenomena occur in two consecutive periods.

[1]The power necessary to test a circuit-breaker pole in a single-phase test is given by $k_{pp}(U_r/\sqrt{3})I_{sc}$. The system short-circuit power per phase is given by $(U_r/\sqrt{3})I_{sc}$. The short-circuit power needed to test a three-pole circuit breaker is given by $\sqrt{3}U_rI_{sc}$.

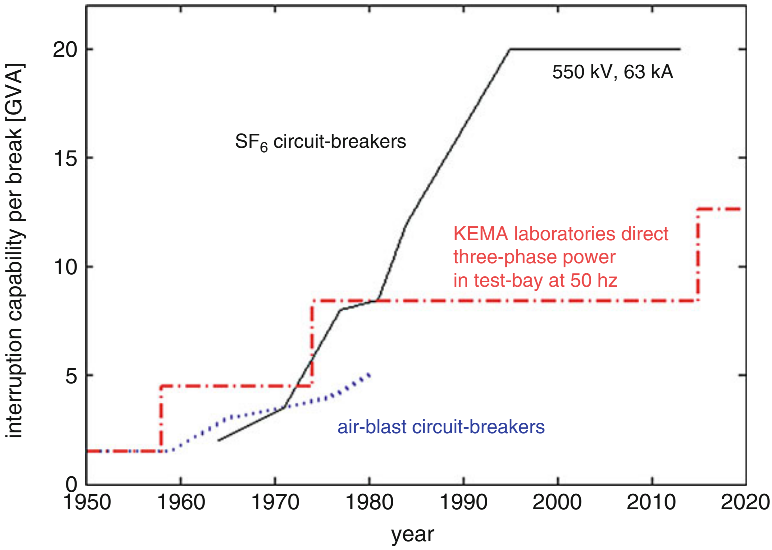

Fig. 11.10 Increase of short-circuit power per interrupter unit and short-circuit test power capacity at DNV GL KEMA Laboratories

Therefore, synthetic testing methods use two energy sources for simulating the electrical stresses on a circuit breaker:

- *High-current source*: a short-circuit generator, which supplies the power-frequency current at reduced voltage of 15–60 kV during the high-current interval
- *High-voltage source*: a capacitor bank with a tuned TRV circuit, which supplies the transient recovery voltage and the recovery voltage at relatively low power during the high-voltage interval

It is essential during synthetic tests that circuit breakers are subjected to conditions as severe as those of full direct-test methods. It has been internationally recognized that synthetic test methods are suitable for type testing of HV circuit breakers because of the proven high degree of equivalence with direct short-circuit tests.

The synthetic methods need not to be seen only as valid substitutes for direct tests. When properly applied, synthetic tests bring significant advantages into testing. One of the advantages is that synthetic tests are nondestructive, because at failure to interrupt, only the capacitor-bank energy is supplied to the failed part instead of the generator energy. This makes synthetic testing an ideal development tool – also because current and voltage stresses can be controlled separately.

However, there are operating conditions, such as capacitor-bank current switching, where synthetic tests show a considerable drawback because in the case of restrikes in a capacitive synthetic circuit, the internal circuit-breaker parts are exposed to much lower stresses than in reality. In service, the full load capacitor discharges across the gap, often already rather wide open. Due to the high energy released, the possible consequence is much higher compared with the restrike in a capacitive synthetic circuit where the discharge energy is quite low. Thus, after a restrike, the probability to pass capacitive tests in a successive test series is larger in a synthetic capacitive circuit than in a direct capacitive circuit.

Because of the importance of synthetic testing, a relevant standard has been published by IEC (IEC 62271-101 2012).

(a) **Important Instants and Intervals During the Interruption Process**

During the interruption process, there are in general three significant instants of short-circuit tests recognized in Fig. 11.11:

t_1: Instant of contact separation
t_2: Start of a significant change in arc voltage
t_3: Cessation of the current flow, including the post-arc current, if any

Considering the current and voltage stresses during interruption process, there are three important intervals after the instant of contact separation:

- *High-current interval* from t_1 to t_2
- *Interaction interval* from t_2 to t_3
- *High-voltage interval* or recovery interval after t_3

The *high-current interval* is the time from the contact separation to the start of the significant change in arc voltage, i.e., the sharp increase to the arc-voltage

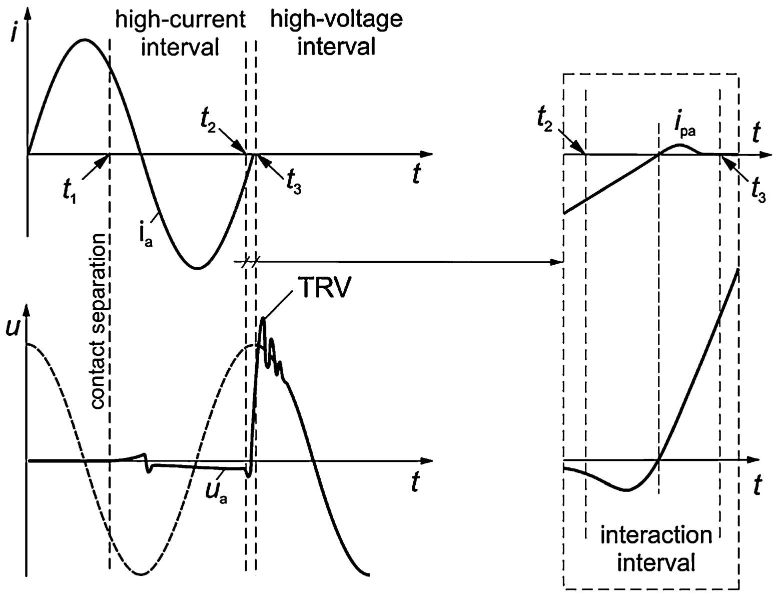

Fig. 11.11 Major instants and intervals during the interruption process. Left, high-current and high-voltage instants; right, interaction instants

extinction peak. During the high-current interval, the tested circuit breaker is stressed by the synthetic test circuit in such a way that the initial conditions for the interaction interval are the same as under service conditions.

The *interaction interval* is the time from the start of the significant change in arc voltage, prior to current zero, to the time when the current, including the post-arc current, if any, ceases to flow. During the interaction interval, the short-circuit current stress changes into dielectric stress, and the circuit breaker behavior can significantly influence the current and voltages in the circuit. As the current decreases to zero, the arc voltage may rise to charge the parallel capacitance and distort the current passing through the arc. After current zero, the post-arc conductivity may result in additional damping of the transient recovery voltage, which may influence the voltage across the circuit breaker and the energy supplied to the residual post-arc plasma in the contact gap.

The interaction between the circuit and arc generated between the contacts of the circuit breaker during the interaction interval is of extreme importance to the interrupting process, and it presents a critical period in terms of possible thermal interruption failure of the circuit breaker. It is therefore important that the interrupter is stressed during this time interval in the same way in the synthetic circuit as under operating conditions in the power system.

The *high-voltage interval* is the time after cessation of the current flow. During the high-voltage interval, the contact gap of the tested circuit breaker is stressed by the recovery voltage. In synthetic testing, the recovery voltage is, in principle, DC voltage, which exponentially decays due to the limited energy storage capability of the voltage circuit. Such a decaying DC recovery voltage imposes an unrealistic stress on the circuit breaker compared with the AC-recovery voltage in the power system. DC recovery voltage must be avoided in synthetic testing as much as possible, since space charges can accumulate and stress the interrupter's internal parts different from the AC voltage case.

A further complication in synthetic testing is the requirement that recovery voltage must not decay too fast and shall not be less than the equivalent instantaneous value of the power-frequency recovery voltage during a period equal to 1/8 of a cycle of the rated power frequency. Whether an exponentially decaying DC, an AC, or a combined DC and AC-recovery voltage is used, it should be kept as close as possible to $U\text{r}\sqrt{2}/\sqrt{3}$. In any case, the recovery voltage must not fall below $0.5U\text{r}\sqrt{2}/\sqrt{3}$ within 100 ms after interruption as stated in the IEC circuit-breaker standard IEC 62271-100 (2012).

Especially in vacuum circuit breakers at higher-voltage ratings having sometimes a tendency to late restrikes, keeping the recovery voltage as close as possible to $U\text{r}\sqrt{2}/\sqrt{3}$ during a period of 300 ms, as required in IEC 62271-100, is important. Hybrid test circuits that combine the synthetic test method (during the TRV period) with a direct test method (during the recovery voltage) have been demonstrated (Smeets et al. 2009, 2014b). Such a solution should be considered for synthetic tests with vacuum circuit breakers or generator circuit breakers.

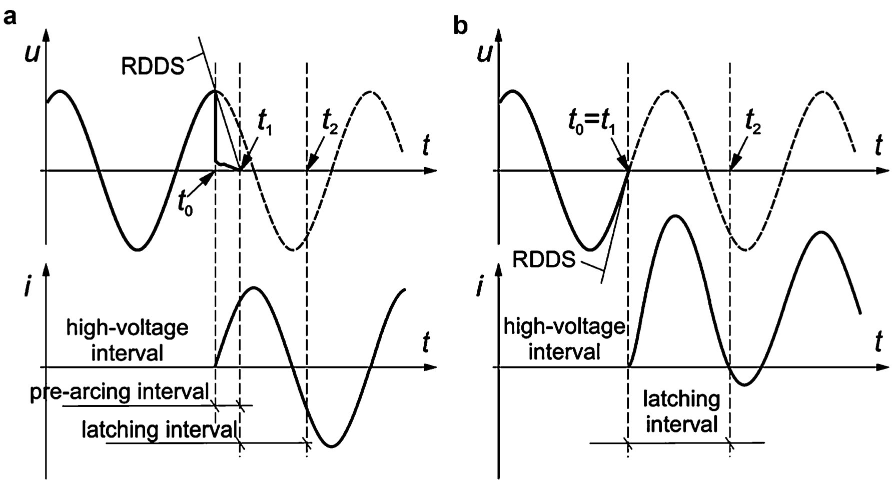

Fig. 11.12 Intervals during the making process. Left, making at voltage peak leading to symmetrical current; right, making at voltage zero followed by asymmetrical current

(b) **Important Instants and Intervals During the Making Process**

A circuit breaker shall also be able to make (close) during short-circuit condition. Prior to making, a circuit breaker shall withstand the voltage applied across its terminals. During the making process, there are in general three significant time instants recognized in Fig. 11.12:

t_0: Instant of prestrike (electrical close)
t_1: Instant of contact touch (mechanical close)
t_2: Instant of reaching fully closed (latched) position

Considering the current and voltage stresses during the making process, there are three intervals after the instant of prestrike between contacts:

- High-voltage interval prior to t_0
- Pre-arcing interval from t_0 to t_1
- Latching interval from t_1 to t_2

The *high-voltage interval* is the time commencing from the application of voltage, with the circuit breaker in the open position, to the moment of breakdown, i.e., *prestrike* of the contact gap. Therefore, during the high-voltage interval, the tested circuit breaker shall be stressed by the voltage circuit in such a way that the initial conditions for the prestrike are the same as under service conditions.

The *pre-arcing interval* is the time, during the closing of the circuit breaker, from the moment of prestrike initiated across the contact gap to the mechanical touching of the contacts. During pre-arcing, the circuit breaker is subjected to electrodynamic forces due to the current and also to deteriorating effects due to the arc energy.

Two typical cases may occur depending on the moment of closing. Figure 11.12a, b shows typical example of current waveforms for different closing instants:

(a) Breakdown occurs near the crest of the applied voltage establishing an almost symmetrical current with maximum pre-arc duration and energy.
(b) Breakdown occurs near the zero crossing of the applied voltage establishing an asymmetrical current with a negligible pre-arc energy but with maximum electromagnetic force.

The *latching interval* is the time, during the closing of the circuit breaker, from the touching of the contacts to the moment when the contacts reach the fully closed (*latched*) position. During this interval, the circuit breaker has to close in presence of the electrodynamic and gas-dynamic forces due to the current as well as the friction forces of moving parts such as contacts.

Taking the fundamental principle of synthetic testing methods into consideration, its initial purpose was to verify interruption capability. Unrealistic conditions arise during making tests if the circuit breaker makes the high-current circuit with full asymmetrical current but at reduced voltage. Considering the severe stresses due to the pre-arc in service, it is also necessary to test the rated short-circuit making capability at full voltage and symmetrical current because only then the proper pre-arcing conditions exist. The symmetrical-current making performance of the circuit breaker is only tested correctly, if the prestrike occurs near the full voltage peak, leading to a symmetrical making current with the longest pre-arcing time.

11.6.1 Types of Synthetic Test Methods

A number of different synthetic test circuits are currently in use; however, all of them are practically based on two basic methods:

(a) **Current-Injection Method**
In synthetic test circuit with current-injection method, a properly tuned capacitor-bank circuit is discharged through the tested circuit breaker before power-frequency current zero, allowing automatically adequate TRV conditions after current zero.

(b) **Voltage-Injection Method**
In synthetic test circuit with voltage-injection method, the voltage circuit is applied to the tested circuit breaker immediately after power-frequency current zero.

Synthetic test circuits are commonly used for single-phase testing, but they are also available for three-phase testing. Three-phase synthetic testing uses a three-phase current source and two or even three voltage sources, one of which provides the transient recovery voltage for the first pole-to-clear and the other supplies the transient recovery voltage for the second and third pole-to-clear, in the case of a non-earthed neutral application.

11.6.2 Current-Injection Methods

The current-injection methods rely upon the superposition of current shortly before current zero of the power-frequency short-circuit current. A current of smaller amplitude but higher frequency, supplied from the voltage circuit, is superimposed to the power-frequency current through the tested circuit breaker. In this way, the current zero in the tested circuit breaker (TB) occurs later than in the auxiliary circuit breaker (AB) placed in series with the tested circuit breaker outside of the injection current loop (see Fig. 11.13). The auxiliary circuit breaker thus separates the high-voltage source, which provides the injection current, from the medium voltage current-source circuit. At the interruption of the current in the tested circuit breaker, it is already connected to the voltage circuit that delivers the TRV. Thus, there will be a natural changeover of stresses from high current to high voltage without delay.

For the current-injection method, there are two principal possibilities: parallel and series current injection. Figure 11.13 shows the simplified circuit diagram of a current-injection circuit with the voltage circuit connected in parallel to the tested circuit breaker (TB). The synthetic test circuit used for the parallel current injection is often referred to as Weil-Dobke circuit (Slamecka 1953). Figure 11.14 illustrates the current through the tested circuit breaker in the parallel-current-injection test circuit.

Before the test, both the auxiliary circuit breaker (AB) and the tested circuit breaker (TB) are in a closed position. Closing of the make switch (MS) initiates the flow of short-circuit current i_G supplied by the current source. Approximately at the same time, the time instant t_0, the auxiliary and tested circuit breakers separate their contacts.

An *arc-prolongation circuit* (APC) (see Sect. 11.6.8), also called the *reignition circuit*, is necessary to produce realistic arc duration in synthetic tests. Without this circuit, the current would be interrupted already at an earlier current zero, because at that current zero, the TRV is far too low, being supplied by the MV high-current circuit only.

At time instant t_1, the spark gap is fired and the main capacitor bank C_0, charged before the test to a certain voltage, discharges through the impedance L_V and injects a high-frequency current i_V, which adds up to the current i_G. The time instant of

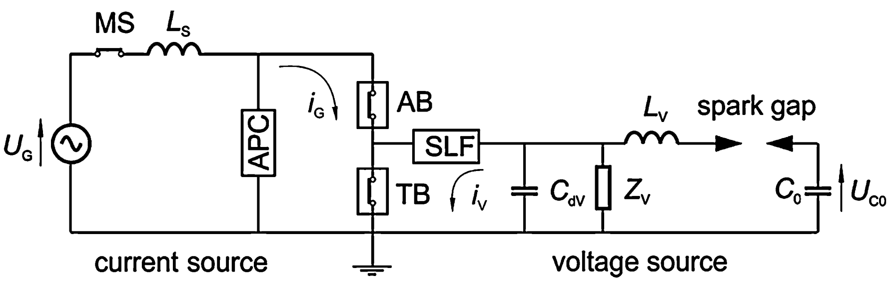

Fig. 11.13 Typical current-injection circuit with voltage circuit in parallel to the circuit breaker under test

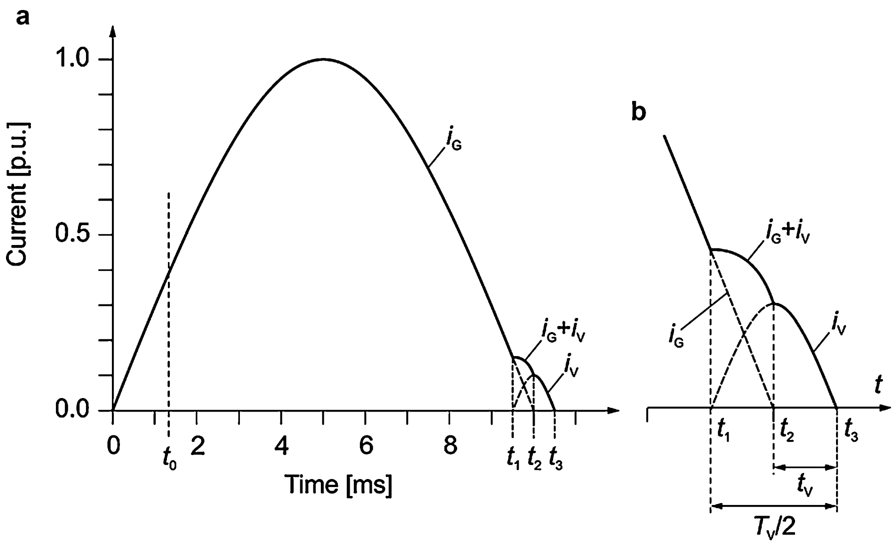

Fig. 11.14 (**a**) Current through the circuit breaker under test in the parallel current-injection circuit; (**b**) current-injection timing

injection is selected by means of a current-dependent control circuit (injection timer). During the time span from t_1 to t_2, the current circuit and the injection circuit are connected in parallel to the tested circuit breaker, and the current through the tested circuit breaker is the sum ($i_V + i_G$).

At time instant t_2, the power-frequency short-circuit current i_G reaches zero. Because the driving voltage of the current source is rather low, it is relatively easy for the auxiliary circuit breaker to interrupt current i_G. Thus, it separates the high-current circuit from the high-voltage circuit. When the tested circuit breaker interrupts the injected current at time instant t_3, it is stressed by the TRV which is provided by the voltage circuit and controlled by the parameters C_{dV}, Z_V, and L_V. The spark gap is still conducting during this period.

Figure 11.15 shows an example of the voltage source of a synthetic test installation which can provide the TRV up to 1000 kV peak.

An artificial line for the testing of HV circuit breakers under short-line-fault conditions (SLF) can be added in the HV TRV circuit. Such a device creates a voltage wave shape very similar to that coming from a faulted short overhead-line section with a limited number of discrete components (van der Linden and van der Sluis 1983).

During the period of current injection, the voltage on the main capacitor bank reverses in polarity. By the time the TRV oscillations have damped out, the remaining recovery voltage has a DC character, and this puts a higher stress on the tested circuit breaker than the power-frequency AC-recovery voltage in the direct test circuit. To overcome this, Z_V should contain a reactor of a high quality-factor, tuned with the main capacitor bank C_0 to the power frequency. Preferably,

Fig. 11.15 Photo of (part of) a synthetic voltage source for producing (T)RV in HV circuit-breaker tests. (Courtesy of DNV GL/KEMA Laboratories)

a power-frequency AC source should be added to provide constant AC-recovery voltage. The latter is called a “Skeats” circuit (Skeats 1936).

Should the tested circuit breaker fail to interrupt at time instant t_3, then the subsequent current flow consists only of the injected current of the voltage source and thereby limiting possible damage to the circuit breaker. This is a significant advantage when performing development tests.

In order to provide maximum equivalence with the conditions in reality, it is essential that the rate-of-change of current is the same as in the service condition:

$$\left.\frac{\mathrm{d}i_{\mathrm{v}}}{\mathrm{d}t}\right|_{i=0} = \left.\frac{\mathrm{d}i_g}{\mathrm{d}t}\right|_{i=0} \tag{11.3}$$

Apart from the correct rate-of-change of the injected current, the frequency of the injected current shall preferably be in the order of 500 Hz, i.e., between 250 and 1000 Hz (Slamecka 1953).

In order to prevent undue influence on the wave shape of the power-frequency current, the lower limit of the frequency of the injected current is 250 Hz.

The maximum allowed frequency of the injected current, 1000 Hz, is determined by the interval of significant change of arc voltage. This interval shall be smaller than the time during which the arc is supplied only by the injected current. To achieve this, the period of the injected frequency should be at least four times the interval of significant change of arc voltage.

The moment of current injection shall be such that the time during which the tested circuit breaker is supplied only by the injected current is no longer than a quarter of the period of the injected-current frequency with a maximum of 500 μs. Attention should be paid to the possibility of overstressing the circuit breaker if the time during which the tested circuit breaker is supplied only by the injected current is shorter than 200 μs, because up to t_2, the di/dt is too high due to the summation of currents delivered by the current and voltage source.

Comparability tests and testing experience over the years have proved that the parallel-current-injection method gives the best equivalence with the in-service situation. It is used by many high-power laboratories in the world and preferred above another method of current injection: *series current injection* (Kapetanović 2011).

11.6.3 Voltage-Injection Methods

Voltage-injection methods also use a current source and a separate voltage source, as parallel current-injection methods. The difference is that the current source in the voltage-injection method delivers not only the short-circuit current but provides also the initial part of the TRV.

The high-voltage part of the TRV is injected from the voltage source after the final current zero, near the peak of the recovery voltage that is produced by the current source. A coupling capacitor C_V, connected across the auxiliary circuit breaker AB, is large enough to effectively apply the transient recovery voltage of the current source to the tested circuit breaker.

Figure 11.16 shows a typical series voltage-injection synthetic test circuit with the voltage circuit connected in parallel to the auxiliary circuit breaker.

Before the test, both the auxiliary circuit breaker (AB) and the tested circuit breaker (TB) are in the closed position. After the make switch MS closing, the current source supplies the short-circuit current and post-arc current for the circuit breaker TB under test. During the whole interaction interval, the arcs in the auxiliary circuit breaker and in the tested circuit breaker are connected in series. Both circuit breakers interrupt the current simultaneously at the instant t_1 in Fig. 11.17. When they have interrupted the short-circuit current, essentially the entire transient

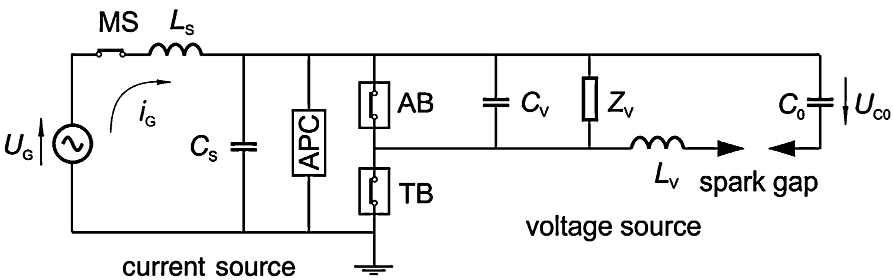

Fig. 11.16 Typical voltage-injection circuit with voltage injection in series with the circuit breaker under test

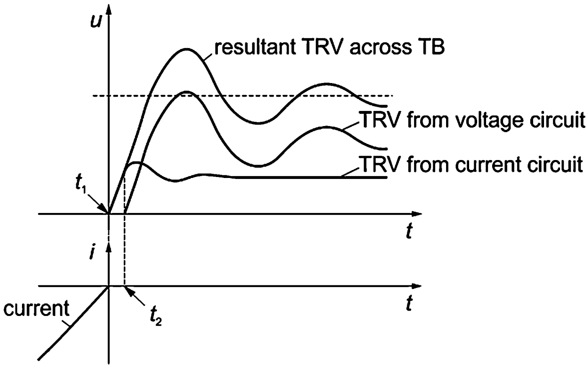

Fig. 11.17 Current and TRV waveforms of the series voltage-injection test circuit

recovery voltage of the current circuit is applied to the tested circuit breaker via the parallel capacitor C_V. In this way, the capacitor transmits the necessary energy for the post-arc current. At instant t_2, just before the peak of this voltage, the spark gap is fired, and the voltage oscillation of the voltage circuit is added to the recovery voltage of the current source across the tested circuit breaker. The resulting TRV across the auxiliary circuit breaker is then practically supplied by the voltage circuit only.

Because the injected current is small, the energy in the voltage circuit is relatively low, and the main-bank capacitance C_0 can be much smaller than that of the current-injection circuit. Voltage-injection methods are therefore more economical. During the interaction interval, however, the circuit parameters of the voltage-injection circuit differ from the circuit parameters of the current-source circuit. This is not the case for the current-injection circuit, and it is for this reason that the voltage-injection methods do not have general applicability. Therefore, according to IEC 62271-101 (Slamecka 1953), voltage-injection methods are only permitted if there are no initial TRV requirements or if these requirements are covered by short-line fault testing without time delay. Voltage injection also requires very accurate timing, which is rather difficult to achieve.

The voltage circuit can be also connected in parallel with the tested circuit breaker instead of the auxiliary circuit breaker. However, this method is not in common use.

11.6.4 Three-Phase Synthetic Test Methods

In principle, the standards allow tests to be performed on a single-phase basis only in the case of circuit breakers consisting of three independent single-pole devices. In any case, the type tests must verify the capability of a circuit breaker to interrupt three-phase faults. Therefore, three-phase tests are desired and preferable whenever possible. This is of particular importance for circuit breakers having their three poles in a common enclosure and also for those with individually enclosed poles but operated by a common operating mechanism. The use of the three-phase test procedure is necessary to reproduce the requested stresses in terms of arcing window, asymmetry, and duration of minor, major, and extended loops on the three poles. Preferably, all the above stresses should be applied in the same test. If this is impossible, a multipart test procedure may be the only available method (Dufournet, 2000).

While single-phase synthetic test methods are well established, three-phase synthetic testing is rather new and technically challenging. The principle that the current is obtained from a current source and the recovery voltage after a chosen current zero from a voltage source, as it is in single-phase synthetic testing, is also applied in three-phase synthetic testing (Dufournet 2000; van der Sluis and van der Linden 1987). These circuits use a three-phase current source and, generally, two voltage sources. One voltage source provides the TRV for the first pole-to-clear and the other gives the recovery voltage for the second and third poles-to-clear, in the case these poles clear simultaneously as in noneffectively earthed systems.

A three-phase synthetic circuit with current injection in all phases, shown in Fig. 11.18, consists of the following components:

G: three-phase current source

Voltage source 1: current-injection parallel circuit connected across the first pole-to-clear

Voltage source 2: current-injection parallel circuit connected across the other two poles in series that interrupt the current at the same moment because of the absence of earthing at the source side

AB: three-pole auxiliary circuit breaker

TB: three-pole tested circuit breaker

APC: arc-prolongation circuits (APC) connected to each phase of the current circuit to prevent an early interruption by the tested circuit breaker and to assure the longest possible arcing time, see Sect. 11.6.8

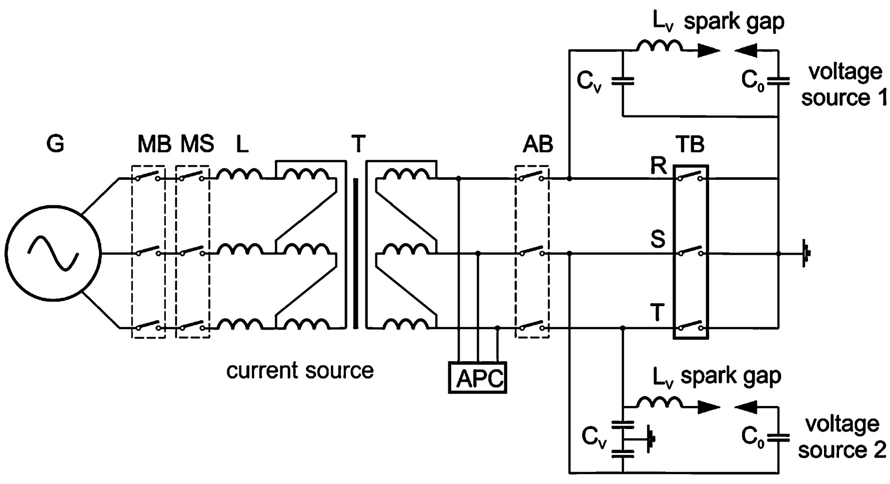

Fig. 11.18 Three-phase synthetic circuit with current injection in all phases for $k_{pp} = 1.5$

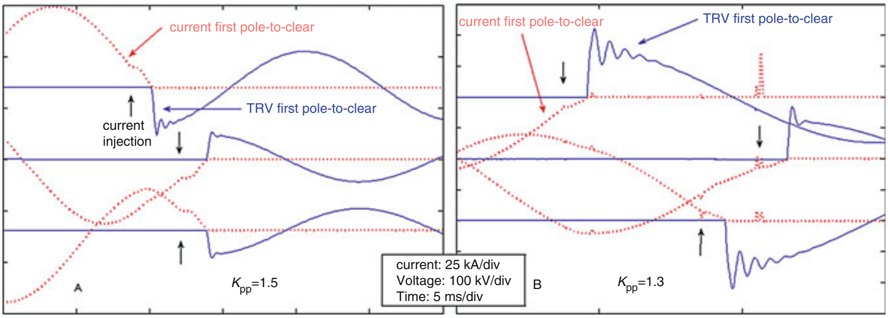

Fig. 11.19 Example of test results of a three-phase test with (**a**) $k_{\mathbf{pp}} = 1.5$ and (**b**) $k_{\mathbf{pp}} = 1.3$. (Courtesy of DNV GL KEMA Laboratories)

The recovery voltage can be adequately distributed between the two last clearing poles with grading capacitors. The operation of the circuit is rather complicated, and therefore, it is only available in a limited number of high-power laboratories (de Lange 2000). An example of such a test result is shown in Fig. 11.19a.

It should be noted that a first pole-to-clear factor lower than 1.5, as is the case of earth faults in effectively-earthed systems, cannot be covered by this circuit since each phase must be provided with its own TRV after each current zero. Synthetic testing of the circuit breakers for such systems requires three separate voltage sources. An example of such a test result is shown in Fig. 11.19b.

11.6.5 Synthetic Testing of Metal-Enclosed Circuit Breakers

In case circuit breakers consist of more than one interruption chamber, a part of the tests that has to verify the fault-current interruption capability may be performed on only half (or a quarter) of the circuit-breaker pole. For live-tank circuit breakers equipped with grading capacitors, this is generally a valid approach.

However, in order to meet the requirements for metal-enclosed switchgear according to IEC 62271-203 (2011), the correct dielectric stresses between live parts and enclosure must be guaranteed also during the interruption process. Consequently, any test other than on the complete circuit breaker is considered technically incorrect.

In unit testing of metal-enclosed EHV and UHV circuit breakers (or half-pole testing in case of two units), it is very difficult to correctly represent all the mechanical, gas dynamic, electrodynamic, and dielectric stresses with reference to the full-pole service conditions. The stresses to be considered when single-phase testing replaces three-phase testing are:

- Dielectric stresses during current interruption
- Gas dynamic stresses
- Electrodynamic stresses

These stresses are described in more detail below.

(a) **Dielectric Stresses During Current Interruption**
Half-pole tests on metal-enclosed circuit breakers do not represent the correct (full) dielectric stresses between live parts and enclosure, at least not in the short-circuit current tests (Fig. 11.16), since there is only half the test voltage between live internal parts and the enclosure.
In testing of metal-enclosed circuit breakers with grading capacitors (including live-tank type), unit tests may not represent the transient stresses that occur in service due to unequal dielectric behavior of the arcing chambers. In unit tests, stresses on grading capacitors, such as occur in prestrikes, and on the breaker chambers are not represented correctly. This is essential since work of CIGRE identified grading capacitors as a major contributor to circuit-breaker failures (CIGRE Working Group A3.18 2007).
A dielectric-stress safety margin of some percents is usually applied in unit testing. This is to allow for an unequal voltage distribution due to stray capacitance across the circuit-breaker units. Because grading capacitors are normally much larger than the stray capacitances, the unequal voltage distribution is covered by a safety margin of a few percents above 50% (for a two-chamber circuit breaker). In case of designs without grading capacitors, this small safety margin is not adequate.
It is obvious that tests performed on a half-pole of a circuit breaker do not imply all the fore-mentioned stresses, and consequently, they cannot provide adequate evidence for a satisfactory performance of the test object in service. Such evidence can be provided only by tests on a full-pole assembly.

(b) **Gas-Dynamic Stresses**
Depending on the design, which may or may not use a combined gas compartment for the arc extinction medium, the dynamic gas pressure and gas flow of the interruption chambers may mutually affect the gas-dynamic phenomena that interfere with the extinction process.
The hot exhaust gases may also deteriorate the dielectric withstand capability of the space surrounding the interruption chambers, i.e., the space between poles, across the chambers and to the enclosure, as illustrated in Fig. 11.20. With GIS and dead-tank circuit breakers, the gas-dynamic phenomena and the influence of hot, ionized, contaminated exhaust gas have to be taken into account for a decision to perform tests on a unit- or full-pole assembly and to which side of the circuit breaker the largest dielectric stress has to be applied.

(c) **Electrodynamic Stresses**
Tests performed on a half-pole assembly, without using the other unit as an auxiliary circuit breaker, require an equivalent conducting path for the short-circuit current, simulating correctly its influence on the arc in the unit under test. For the same reason, three-phase tests are necessary on three-phase metal-enclosed circuit breakers due to the compact design. Also, the high-current connections in the direct vicinity of the test object have to be designed with

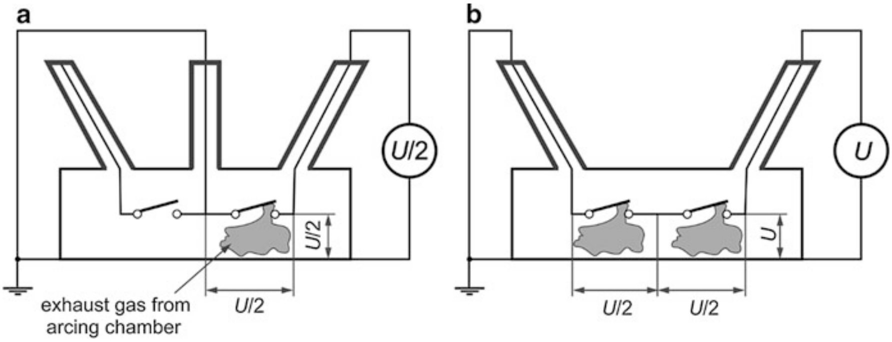

Fig. 11.20 (**a**) Half-pole test of metal-enclosed circuit breaker: voltage across interrupter is OK, voltage between live parts and enclosure is not OK; (**b**) full-pole test of metal-enclosed circuit breaker: voltage across interrupters is OK, voltage between live parts and enclosure is OK

great care, taking into consideration realistic electrodynamic stresses on the arc and the circuit-breaker structure.

Vacuum circuit-breaker arcs, which need the complete contact surfaces, may be sensitive to phase-to-phase forces that constrain their activity to certain contact areas only. Therefore, testing of such devices in a three-phase arrangement, especially in compact arrangements such as in dead-tank designs, is highly recommended.

11.6.6 Synthetic Testing with UHV Circuit Breakers

Circuit breakers for UHV (Ultrahigh voltage, rated voltage >800 kV) are required especially for various large-scale transmission projects. The testing of these apparatus is a challenge in itself and several solutions have been proposed (Sheng and van der Sluis 1996).

The considerations in Sect. 11.6.5 resulted in new synthetic UHV test circuits specially designed to test dead-tank and GIS circuit breakers under full-pole conditions with the metal enclosure at earth potential (Smeets et al. 2016).

In order to realize this, a two-stage synthetic solution was adopted (see Fig. 11.21). One synthetic installation provides the first stage of the TRV, and the second installation delivers the top part superimposed on the voltage waveform from the first stage. This method makes UHV short-circuit testing possible even for circuit breakers at rated voltage of 1200 kV.

An alternative solution to perform UHV short-circuit testing is to apply suitable voltages to both sides of the circuit breaker that has to be placed on an insulating platform. This method, however, has disadvantages, such as the need to bring all control and power signals to high potential, mechanical instability, and long assembly time.

In Fig. 11.22, an oscillogram is shown of IEC test duty T10 with 2060 kV peak voltage for the first pole-to-clear factor $k_{pp} = 1.5$. In the absence of standardized

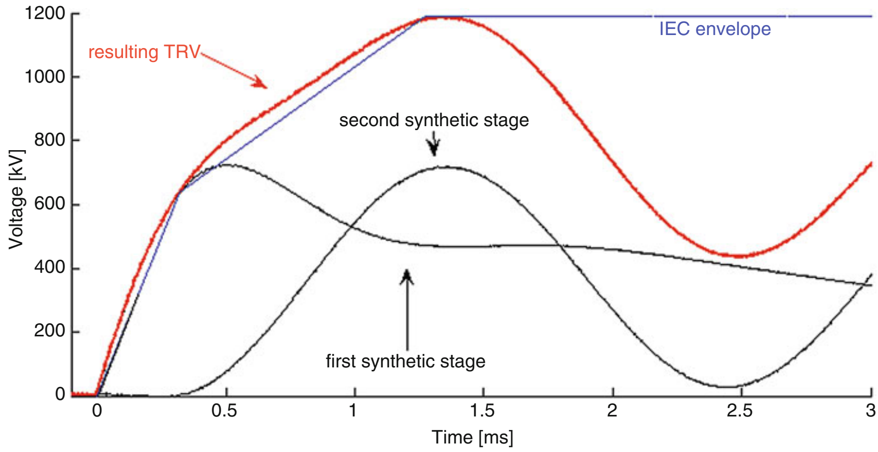

Fig. 11.21 TRV waveforms of two-stage synthetic four-parameter TRV for 800 kV circuit breakers and IEC TRV envelope. (Courtesy of DNV GL KEMA Laboratories)

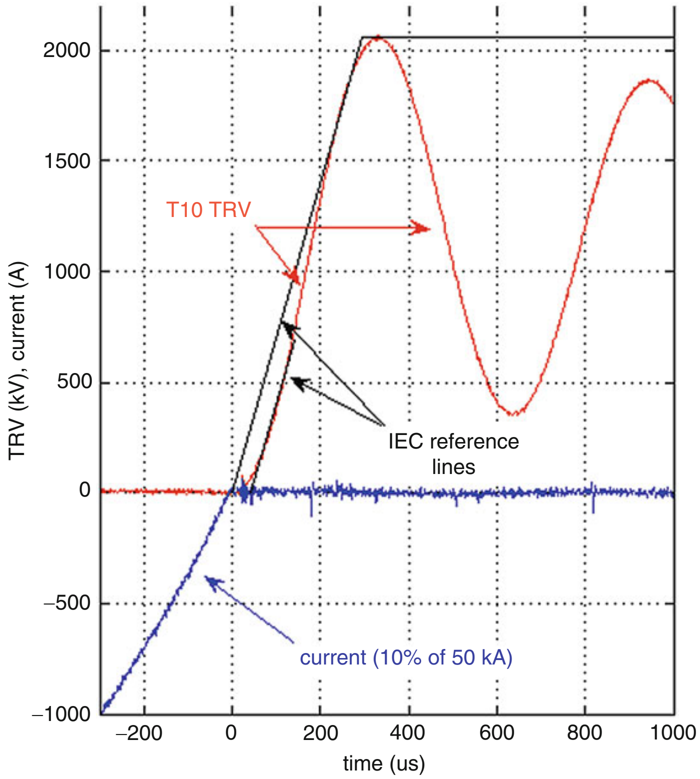

Fig. 11.22 Realized TRV of T10 test duty ($k_{\mathbf{pp}} = 1.5$) for 1100 kV circuit breaker and IEC TRV envelopes based on 2 × 550 kV. (Courtesy of DNV GL KEMA Laboratories)

Fig. 11.23 Setup at KEMA Laboratories for full-pole short-circuit tests of a 1100/1200 kV circuit breaker. (Courtesy of DNV GL KEMA Laboratories)

values at the time of testing, the TRV parameters were based on linear extrapolation from the IEC 62271-100 requirements for 550 kV rated voltage. The circuit breaker under test was a dead-tank four chamber circuit breaker. A visual impression of this test setup given in Fig. 11.23.

TRV parameter values for rated voltages >800 kV have been proposed by CIGRE (2008) and adopted by IEC in the circuit-breaker standard (IEC 62271-100 2012).

Unusual large number of arcs placed in series, such as eight gaps in series, results in at least a total (14–18) kV of arcing voltage, and this may unacceptably distort the current in the test circuit. In order to avoid such distortion, such tests should be performed with a generator voltage of high supply voltage, like 60 kV; see also subclause 11.6.9.

11.6.7 Synthetic Testing for Making Test

For the higher ratings of circuit breakers, it may be difficult to conduct the direct making tests similarly to direct breaking tests due to the limitation of testing facility. In such a case, a synthetic three-phase making test circuit is used with the test circuits shown in the standard IEC 62271-101 along with testing procedures suggested in the STL guide (see Fig. 11.24).

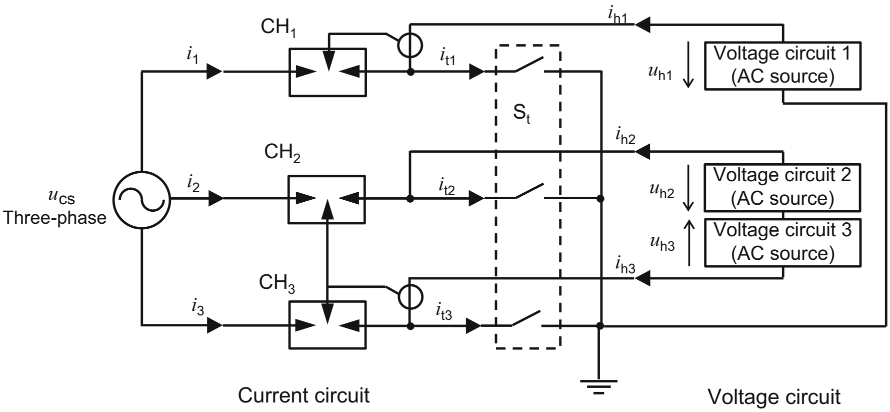

Fig. 11.24 Typical synthetic three-phase making test circuit

Before the making of tested circuit breaker, full stresses of a rated voltage are supplied from the voltage circuit. Just after prestrikes start in the tested circuit breaker, making devices, spark-gaps of CH1, CH2, and CH3, are triggered, and short-circuit currents are supplied through the devices.

Figure 11.25 shows an example of currents and voltages waveforms in case of three-phase making test with the synthetic test method. In order to verify the making performance of the circuit breaker with a sufficient energy of pre-arcing, short-circuit current shall be supplied immediately after the instance of prestrike. The standard specifies that the time delay of making device (t_m) is as short as possible but in any case not longer than 300 μs.

11.6.8 Arc Prolongation

The *arc-prolongation circuit* (APC) most commonly applied provides a rapidly rising pulse of current approximately 10 μs before current zero. The polarity of this pulse is the same as the power-frequency current; however, its di/dt is much higher. Consequently, the tested circuit breaker cannot interrupt the summation of pulse plus power-frequency current, which is thus forced to continue after zero. The injected current is obtained by a properly triggered discharge of a capacitor through the auxiliary circuit breaker and the tested circuit breaker. A series resistor damps the circuit over-critically and controls both the peak value of the injected current and time constant of this reignition circuit. Sometimes an inductance is built in the reignition loop to limit the di/dt of the current through the triggered spark gap. A basic requirement is the accurate timing of the firing of the spark gap just before power-frequency current zero. For synthetic testing of vacuum circuit breakers, di/dt > 3 kA/μs is required because vacuum interrupters have the capability to interrupt di/dt values below this value (Smeets et al. 2010).

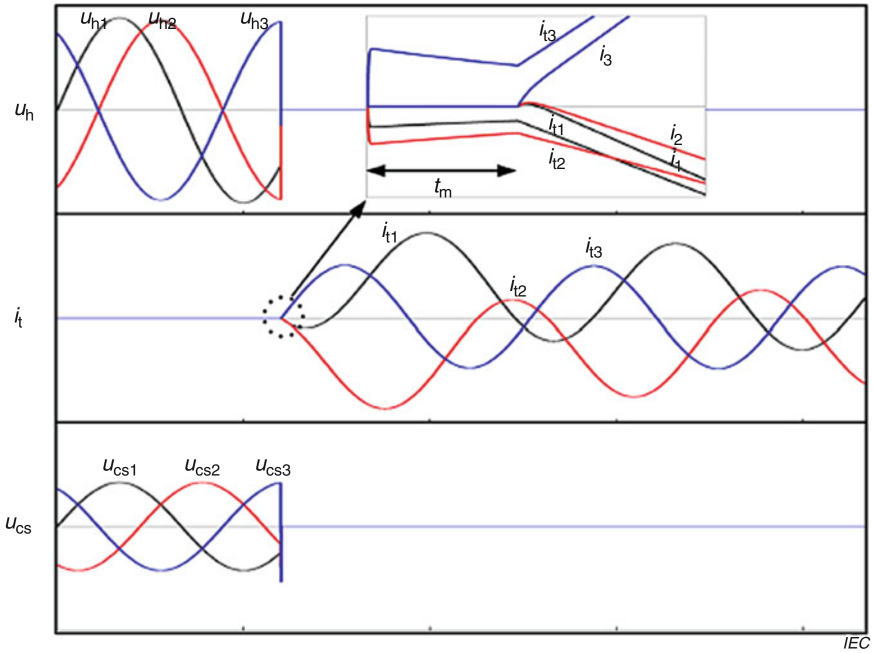

Fig. 11.25 Currents and voltages of three-phase making test by synthetic test (IEC 62271-101 Ed. 2.1). u_{cs1}, u_{cs2}, u_{cs3}: voltage of current circuit; u_{h1}, u_{h2}, u_{h3}: applied voltage; i_1, i_2, i_3: current supplied by the current circuit; CH_1, CH_2, CH_3: making device; i_{t1}, i_{t2}, i_{t3}: current through the test object; St: test circuit breaker; i_{h1}, i_{h2}, i_{h3}: initial transient making current (ITMC); t_m: time delay of making device

Several such circuits may be used for prolonging the arcing time through several loops of current. In principle, the same reignition circuit can be applied to reignite both the tested and the auxiliary circuit breaker.

11.6.9 Voltage of the Current-Source Circuit

A critical aspect of synthetic testing is the voltage level at which the short-circuit current is supplied. In testing of SF_6 circuit breakers, there are at least two breakers in series, test and auxiliary circuit breaker, each with a number of arcs in series, one arc for each extinction chamber.

This implies that the total arc voltage of all these series arcs reduces the available voltage that drives the test current (van der Sluis and Sheng 1995). Thus, especially for tests at EHV/UHV levels, where up to four arcs in series are active in each circuit breaker, i.e., at least eight in total, the test current is reduced after contact separation of the circuit breakers. In order to keep the reduction of the test current by the arc voltage within an acceptable limit, the voltage of the current supply source must be chosen as high as possible, for EHV/UHV testing in the order of (40–60) kV.

For testing circuit breakers with very low arc voltage, such as vacuum breakers, this argument does not hold, and rather low-voltage sources, e.g., 1 kV, can be satisfactory.

11.7 Summary

This chapter explains high-power test to evaluate the interruption and switching performance of AC circuit breakers. The circuit breakers are required to make and interrupt the rated short-circuit breaking currents under specific conditions in accordance with the international standards. Several short-circuit tests including direct tests and synthetic tests are used to reproduce an equivalent voltage and current stresses to those in service conditions.

Acknowledgment The chapter on interruption and switching performance tests was based on the contents of the technical book titled *Switching in Electrical Transmission and Distribution Systems* written by R.P.P. Smeets, L. van der Sluis, M. Kapetanovic, D. F. Peelo, and A. Janssen, published by Wiley in 2015 modified by the editor. Wiley kindly granted CIGRE the right to partially use the content on the Chap. 14 on testing for the Chap. 11 of the CIGRE Green book on switching equipment published in 2018. CIGRE appreciates Wiley's kind cooperation in the Green book project.

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Simulations as Verification Tool for Design and Performance Evaluation of Switchgears 12

Martin Kriegel and Nenad Uzelac

Contents

Keywords
Circuit breaker · Simulation · Interpolation · Extrapolation · Verification

12.1 Introduction

Historically, modeling of arc behavior advanced the development of large capacity circuit breakers. A great step forward in understanding arc-circuit interaction was made in 1939 when A. M. Cassie (Cassie 1939; Cassie and Mason 1956) published

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H. Ito (ed.), *Switching Equipment*, CIGRE Green Books,
https://doi.org/10.1007/978-3-319-72538-3_12

the paper with his well-known equation for the dynamics of the arc (arc model) and then, in 1943, O. Mayr (1943) followed with the supplement that takes care of the time interval around current zero. Much work was done afterward to refine the mathematics of these arc models and to confirm their physical validity through practical measurements (CIGRE Working Group 13.01 1988, 1993).

Later gas dynamic simulations made it clear that current interruption with a gas circuit breaker by an electrical arc is a complex physical process when we realize that the interruption process takes place in microseconds, the plasma temperature in the high-current region is more than 10,000 K, and the temperature decay around current zero is about 2000 K per microsecond while the gas movements are supersonic. Gas simulation is still one of the important tools to design compact switching equipment.

Not only circuit breakers but also various substation equipments such as disconnecting and earthing switches, instrument transformers, and surge arresters have been thoroughly tested for conformance to standard requirements for their electrical, mechanical, thermal, and environmental operations, as well as their endurance. Over the years, the standards covering those devices have evolved, and new testing requirements to cover more and more different and complex cases have been developed. On the other hand, the material, components, and technologies employed in the design of the mentioned equipment have also evolved significantly. Today, focusing on high-voltage switching equipment applied in power systems, switching equipment primarily with SF_6 and vacuum media is commonly used rather than oil or air-blast types, and such insulating and arc-extinguishing media, combined with new solid insulating materials, such as epoxies and silicones, result in smaller and more compact designs. Overall, the switchgear design has become more and more complex.

Due to these evolving trends, it is more difficult and expensive to be able to predict and test a device for all possible cases and for increasing number of applications.

Another important aspect is the economics of typical testing, such as certification of equipment to standards. Such testing procedures are performed and paid for by manufacturers. This cost, depending on the number of units involved, results in higher cost for R&D and, consequently, of final products. On the other hand, testing permits an increase in the reliability of the equipment.

CIGRE A3 committee has been examining what can be done in order to supplement and even reduce the number of tests with the aid of modern simulation and calculation techniques. Many software tools exist to simulate electrical, thermal, mechanical, and other stresses. These tools are used extensively today within the manufacturer's internal R&D. A natural step is to extend the acceptance of those tools beyond the R&D environment. Precedence exists, for example, in power transformer standards.

The different levels of prediction power of simulations and calculations as verification tools are:

1. **Interpolation**, i.e., data from the actual tests could be interpolated to a new condition not covered by the tests but between the boundaries of the previously tested cases.

2. **Extrapolation**, i.e., data from the actual tests could be extrapolated to a new condition not covered by the tests but outside the boundaries of the previously tested cases.
3. **Verification**, i.e., since the laboratory testing is also only an approximation of the actual conditions, computer simulation can provide an independent confirmation of the validity of the test conditions.
4. **Test replacement**, based on feasibility, availability, and cost of testing.

12.2 Definitions of Terminology

Arc Fault
Single-phase arc fault is an arc occurring between one conductor and ground. Three-phase arc fault is an arc occurring between three conductors or between three conductors and ground.

Gas Circuit Breaker
The gas circuit breaker is an electrical switch using sulfur hexafluoride as insulating and interrupting media. SF_6 gas breakers consist of moving and fixed contacts in an enclosure filled with gas, the gas inside the puffer cylinder is pressurized during the opening operation and blasts high pressure gas through a nozzle into the arc generated between the contacts to extinguish the arc by cooling.

Computational Fluid Dynamics (CFD)
Numerical analysis is to solve a problem that involves fluid flow. Computers are used to perform the calculations required to simulate the interaction of liquids and gases with surfaces defined by boundary conditions. Recent research can provide software that improves the accuracy and speed of complex simulation scenarios such as transonic or turbulent flows for many different applications (e.g., aircraft, automobile, train).

Finite Element Analysis (FEA)
Finite element analysis (FEA) is a computerized method for predicting how a product reacts to real-world forces, vibration, heat, fluid flow, mass transport, and electromagnetic potential. Finite element analysis shows whether a product will break, wear out, or work the way it was designed. The analytical solution of the problem generally requires the solution to boundary value problems for partial differential equations.

Kp Factor
The Kp factor is the ratio of that part of the arc power (or energy) responsible for the heating of gases inside the arc compartment to the total arc power (or energy). Total arc power is the power of an arc given by the product of momentary current and arc voltage measured between the electrodes of an arc. The higher Kp factor is, the larger the pressure rise is with all other variables being equal.

12.3 Abbreviations

CB	Circuit breaker
SF_6	Sulfur hexafluoride
AC	Alternating current
DC	Direct current
HV	High voltage
MV	Medium voltage
CFD	Computational fluid dynamics
CAD	Computer-aided design
FEA	Finite element analysis
FEM	Finite element method
FVM	Finite volume method

12.4 Simulations and Modeling

Recognizing an increasing role of commercial modeling software in the power industry recently, Study Committee A3 evaluated existing simulation technologies to determine the extent to which they can be used as verification tools to enhance understanding and verification of equipment performance, to extrapolate test results, to provide an alternative to testing, or to replace some of the tests.

The purpose of the assessment is to analyze the accuracy of modeling the behavior of a device under certain physical constraints as reproduced during the tests. This process is performed in two steps:

1. Stress calculation: the ability of the model to compute certain physical parameters such as temperature, electric and magnetic field, pressure, etc.
2. Performance forecast: prediction of capability to withstand the stresses. It has been found to be a much more difficult task, because models of physical failure processes like breakdown, burst, reignition, melting, rupture, or explosion are generally not yet available, let alone software that would implement them. Instead, "design rules" based on practical experience and observations from tests are applied.

There are a number of applications for modeling and calculations. Several examples of this assessment are presented in this chapter:

- **Modeling of the switchgear parameters to better predict its behavior**:
  One example would be simulation of switchgear dielectric performance.
  A benchmark of dielectric simulation tools has been conducted. An experimental SF_6 circuit breaker has been manufactured and subjected to high-voltage tests specifically for this purpose. Based on the digital CAD files, the electric field was calculated by six major manufacturers. The analysis showed that different

software tools predicted almost identical dielectric stresses. However, the comparison between predicted and measured withstand voltages (performance forecast) showed, with one exception, that the predicted values from the manufacturers were up to 40% below the measured value.

Another example would be thermal modeling to simulate the behavior of single components or complete assemblies during a heat run test:

Temperature (and temperature rise) is directly specified by the standards and relatively straightforward to simulate by software. From a theoretical aspect, electromagnetic and thermal models are extremely reliable for both solid and fluid parts. Consequently, simulation tools can help to predict the thermal behavior of equipment. An example showing the accurate calculation of temperature rise in a 4000 A GIS is presented.

- **Substitution of type tests which are impractical or difficult to implement** such as the internal arc withstand test of GIS enclosures:
  Due to the complexity of handling the contaminated SF_6 after tests and the risk of release of SF_6 to the environment, very little testing is carried out on the equipment, and manufacturers usually rely on calculation.
- **Experience using simulations to determine design parameters for new equipment that is not covered by the standards**:
  When the rating of the equipment exceeds the laboratory's capacity, the verification of performance relies on simulation results. This is the case for new 1100 kV switchgear designs. Particular examples are seismic analysis and the use of EMTP simulations to establish the TRV peak, RRRV value, and DC time constant of the 1100 kV circuit breaker.

12.5 Overview of Simulation Tools and Tests

In addition to custom homemade software for simulations – typically developed by R&D groups – there are a number of commercially available software packages that are used in the power industry. Table 12.1 provides a not complete list. In recent years, multi-physics tools have been developed, capable of solving multiple physical phenomena at the same time, e.g., thermal and electrical stress.

Table 12.2 summarizes the tests requested by electrical equipment standards. Stresses involved in the test, expected results, and the corresponding numerical methods are listed. The prediction power for each application is estimated through different criteria which reflect the industry practice as known to the WG members. In most applications, interpolations from existing type tests can be achieved. Sometimes extrapolations (outside the already tested range) can be made as long as the phenomena are well known, e.g., for mechanical and dielectric stresses. Only in a few cases can type tests be replaced since many physical phenomena cannot yet be modeled accurately enough by such available software. Nevertheless the standards accept even today pressure and seismic calculations as verification. Factors such as wear, manufacturing tolerances, gas and arc physics, contact resistance, magnetic saturation, and material inhomogeneity remain very difficult to model. Models of

Table 12.1 Commercially available software packages

Application	Name of software	Numerical method
Electric field analysis	MAXWELL	FEM
	ANSYS	FEM
	FLUX	FEM
	COULUMB	BEM
Magnetic field analysis	MAXWELL	FEM
	ANSYS	FEM
	FLUX	FEM
	ELEKTRA	BEM
Thermal analysis	ANSYS	FEM
	STAR-CD	FVM
	FLUENT	FVM
Fluid analysis	CFX	FVM
	MC3	FVM
	FLUENT	FVM
	PHOENICS	FVM
Structural analysis	Pro/MECHANICA	FEM
	ANSYS	FEM
	ABAQUS	FEM
Kinematic analysis	ADAMS	Multibody analysis
Electrical transient analysis	EMTP/ATP	FDM
	Saber	FDM
Interrupting performance	Home-made	–

physical failure processes like breakdown, burst, reignition, melting, rupture, and explosion are not yet available for industrial use, due to their even higher degrees of difficulty to represent accurately such phenomena.

12.6 Examples of Modeling of Switchgear

12.6.1 Electric Field Analysis

Although one of the main tasks of a high-voltage circuit breaker is to ensure a reliable power supply, the capability to withstand the supply voltage or any transient voltages might be even more demanding. The circuit breaker has to withstand the supply voltage against ground in the closed position, the voltage across the switching contacts in the open position, and any transient voltage during operation. One of the most important tasks for the design engineer is to optimize the breaker to withstand any kind of voltage stress. The starting point is the simulation of the electric field.

Table 12.2 Assessment of switchgear tests with respect to modeling

Application		Stresses	Expected results from simulation	Method			No test possible	Prediction power				Comments
				Numerical methods	Analytic	Home made		Understanding	Interpolating	Extrapolating	Replace type test	
Short time current		Thermal mechanical		X	X	X		X		X		
Continuous current		Thermal	Temperature field, time constant for temperature rise	X	X			X	X	X		
AC, BIL, SIL, ChW	Air insulation	Electrical	Electrical field distribution	X		X		X	X			Prediction power is reduced to corona free situations under dry condition
	SF6/gas mixtures			X				X	X	X		Extrapolation possible within certain limits
	Vacuum					X		X				Transfer of theory into simulations is still ongoing
	Liquid insulation (oil)			X		X		X	X			Flashover behavior is strongly influenced by impurities and vapor phase in oil which make simulation difficult
	Solid insulation			X		X		X	X			Simulation is possible for pure and clean malarial
PD, RIV												No possibility to predict exact PD or RIV values

(*continued*)

Table 12.2 (continued)

Application	Stresses	Expected results from simulation	Method: Numerical methods	Method: Analytic	Method: Home made	No test possible	Prediction power: Understanding	Prediction power: Interpolating	Prediction power: Extrapolating	Prediction power: Replace type test	Comments
Mechanics	Mechanical	Dynamic behavior	X				X	X			Possible to calculate breaker travel curves accurately for no load situations as long as no current interruption is involved Not possible to replace endurance test
		Stresses and deformations caused by pressure	X	X			X	X	X	(X)	Simulations can be used to know the maximum allowed working pressure. Note 1) CENELEC standard EN 50052/64/68 mentions calculations replace type tests: tests are done in case or doubt. Note 2) CENELEC standard EN 50069/90 specify that test is required for composite welded wrought.

			Stresses and deformations caused by static loads like: cantilever load, terminal load, wind load, bushing weight load and quasi-static seismic load	X				X	X	X	(X)	Simulation can replace tests only for simple static loads like wind load and quasi-static situations
			Stresses and deformations caused by seismic stresses	X				X	X	X	(X)	
Switching	Terminal fault opening, out of phase opening	Electrical, mechanical, thermal, chemical	Gas behavior (pressure built up, gas temperature and density, electromagnetic fields, etc.) network response	X		X		X	X			The prediction power for TF is higher than for SL. The prediction power is limited to interpolations linked to specific test results and limited parameters Two output categories: keeping the breaker unchanged and modify network conditions or inverse

(*continued*)

Table 12.2 (continued)

Application		Stresses	Expected results from simulation	Method			No test possible	Prediction power				Comments
				Numerical methods	Analytic	Home made		Understanding	Interpolating	Extrapolating	Replace type test	
	Terminal fault closing, out of phase dosing	Electromagnetic, mechanical	Dynamic behavior	X		X		X	X	X		Limitation for simulation is the typical mechanical contact behavior
	Short line fault	Electrical, mechanical, thermal, chemical	Gas behavior (pressure built up, gas temperature and density, electromagnetic fields, etc.) network response	X		X		X	X			The prediction power is limned to interpolations linked to specific test results and limited parameters. Prediction or electrical results in case of network changes is valuable and higher than for breaker charges Two output categories: keeping the breaker unchanged and modify network conditions or inverse

	Capacitive currents	Dielectric	Electrical field, gas density, pressure built up	X		X		X	X		(X)	Test replacing possible based on cold characteristic tests
	Switching or inductive currents	Dielectric	Network overvoltage	X	X	X	(X)	X	X			Three phases can be calculated: current chopping, network response, dielectric stress
	Electrical endurance	Electrical, mechanical, thermal, chemical	Interrupting capability based on assessment or end of life stresses	X				X				Very difficult to simulate the end of life Simulation can just estimate nozzle erosion, gas contamination, and contact wear
	Closing/ opening resistor	Electrical, thermal	Dielectric behavior, network overvoltage	X	X			X	X			Thermal stress or resistor is predictable as well as the network response Insertion time depends on useful input of mechanical boundaries
	Internal arc	Mechanical, thermal	Gas behavior (pressure built up, gas temperature and density, electromagnetic fields, etc.)	X	X	X	(X)	X	X			Impossible to calculate the arc behavior (location, movement, etc.) the pressure built up and consequently burn through tanks (cf IEC62271-203 6.105)

The capability for gas-insulated equipment to withstand the applied voltage mainly depends on the electric field and the gas density (Sedlacek et al. 2003; Dhotre et al. 2011). To calculate the electric field, simulations are used. They are based on solving the linear Laplace equation. The equations can be solved by either finite element or finite volume method (ABB review 2013; Dhotre et al. 2014). While the density is uniformly distributed for most of the equipment, gas density field distributions need to be considered for breakers during operation.

Time-consuming simulations are done in particular to simulate a breaker during operation as the electric field needs to be calculated for all contact distances. In the case of capacitive switching, the maximum voltage stress occurs a half cycle after current interruption. The calculations have to cover all contact distances up to this moment to ensure that the interrupter will operate without restrikes and reignitions. The dielectric recovery characteristic can be evaluated up to this point. Based on this, the breakdown voltage is estimated. The performance can be improved by reducing the electric field or raising the gas density with the help of simulations (Dhotre et al. 2014). In case of making (closing), the electric field is simulated for all contact distances between the fully open position and the position of pre-arcing.

Figure 12.1 shows a simplified geometry of an SF_6 circuit breaker. The major elements of the breaker are the nozzle, the main contacts, and the arcing contacts. The design has been developed by CIGRE WG A3.20 (Kriegel et al. 2008) as a dielectric benchmark case. However, it can be used to illustrate the main tasks that are needed to design the dielectric layout of a circuit breaker.

Finite element calculation of the electrical stress as shown in Fig. 12.1 is typically done to review the switching operation. During the open operation, the electric field on the main contacts and arcing contacts varies with contact distance. The maximum electric stress is evaluated on the arcing contacts as well as on the main contacts. In case of capacitive switching, the design engineer verifies that the predicted breakdown voltage is always below the transient recovery voltage which is supplied by the network. In case of short circuit current interruption and for arcing times shorter than the minimum arcing time or in case of making, the reignition or pre-arcing should always occur between the arcing contacts. The design engineer, therefore, reviews the dielectric stress on the main and arcing contacts to check for lower breakdown voltages on the arcing contacts.

12.6.2 Thermal Analysis

Most of the simulations are done to calculate a physical stress that is needed to be known as the base for further performance prediction. For example, the electric field is calculated to predict the breakdown voltage and, thus, the performance of the breaker to withstand the applied voltage. Contrary to those simulations, temperature analysis focuses on the calculation of the stress only, which is the temperature rise of the components in HV and MV equipment.

Temperature rise in the switchgear is determined by the balance between power losses due to resistive and inductive effects and energy dissipation, which is given by

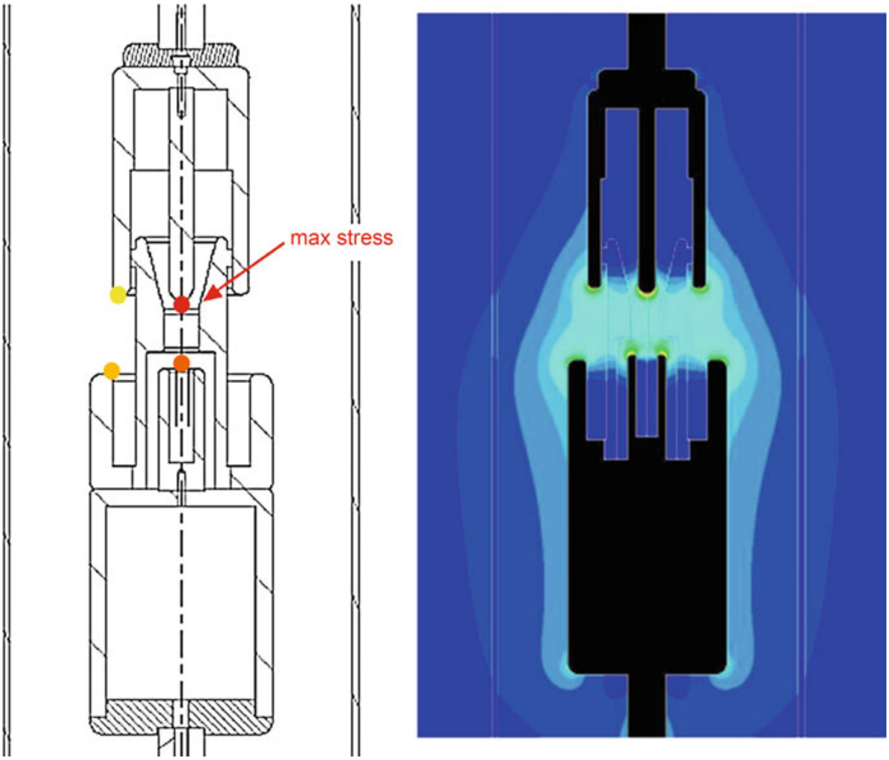

Fig. 12.1 A simplified breaker design and a finite element analysis calculating the electrical field stress

convection, conduction, and radiation. Multi-physics simulations are typically used to link all physical effects. Electromagnetic codes solve the Maxwell equations to determine the current distribution and the resulting power losses. The thermal process can be analyzed using computational fluid dynamic (CFD) (Bedkowski et al. 2016).

Figure 12.2 shows a simplified design of a HV breaker with the main components involved in carrying the nominal current. This design has been developed by WG A3.36 to study a benchmark of multi-physics simulations to predict temperature rise tests. It can be used to highlight the tasks for a design engineer using multi-physics for temperature rise simulation.

The first step is to prepare the computer-aided design (CAD) model for finite element method (FEM)/finite volume method (FVM) simulation (Zienkiewicz 1971). Typically, inconsiderable parts such as bolts and nuts are removed. The model is checked for consistency. The second step is to define the material properties of the components and to create the mesh for simulation (Bamji et al. 1993).

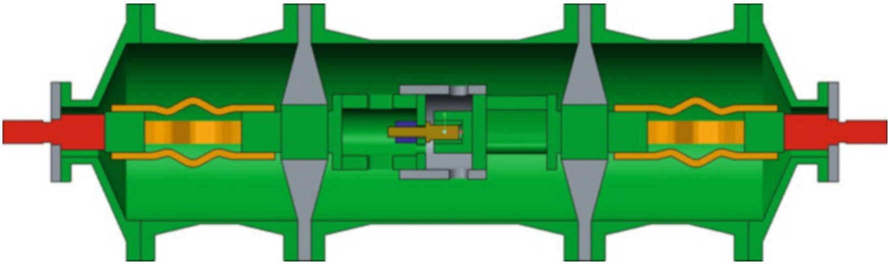

Fig. 12.2 Simplified geometry of the benchmark device

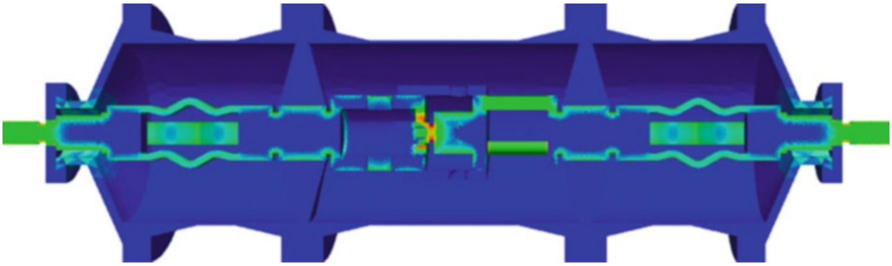

Fig. 12.3 Loss calculation

While the material properties are typically well known, the contacts between the connecting parts are difficult to be calculated. Normally the contact resistance is determined by measurement. The Joule losses for DC can be calculated based on the resistivity of material and contacts. However, for AC the distribution of the currents within the conductors as a result of proximity and skin effects need to be considered. Figure 12.3 shows an example of a power loss calculation for the benchmark device.

The electromagnetic solver will be coupled with the thermal solver to calculate the power losses. An example of the temperature distribution as result of the simulation is given in Fig. 12.4.

The last step in the design phase is to compare the temperature rise of the components against the maximum permissible value that is given by the standards. If the temperature rise is above certain levels, some parts and even the complete switching device may be degraded with expected lifetime loss.

12.6.3 Internal Arc

Another example for using calculations in electrical switchgear would be to calculate the effect of the internal arc fault (CIGRE WG A3.24 2014; Smeets et al. 2008). An internal arc fault is an unintentional discharge of electrical energy inside the switchgear. In the case of an internal arc, the arc energy rapidly heats the surrounding

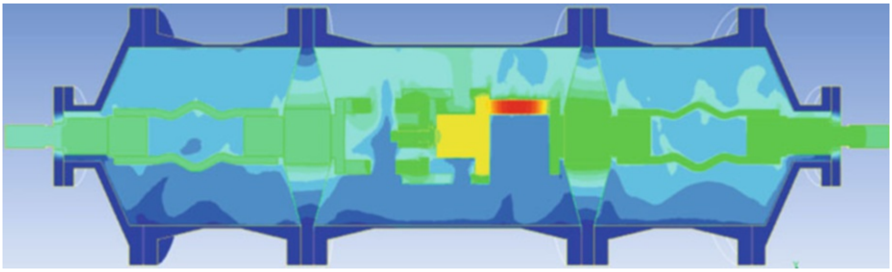

Fig. 12.4 Temperature distribution

gas resulting in a pressure rise and mechanical stress on the enclosure. In addition, the internal fault can result in enclosure burn through if it is arcing to the switchgear tank. Performing internal arc tests is time-consuming and expensive. Therefore, it is beneficial to perform simulations prior to going for the test.

(a) **Pressure rise**

An internal arc causes a pressure rise and mechanical stress on the switchgear. If the switchgear enclosure is not strong enough, it can rupture. Before going to test to check the design integrity, it is important to calculate the pressure rise inside the switchgear compartments. The pressure rise can be calculated in a number of ways with different complexity. In CIGRE "Tools for the simulation of the effects of the internal arc in T&D Switchgear" brochure, three different methods are identified: basic, enhanced, and computational fluid dynamics (CFD). While first two methods are analytical, CFD method is computational and requires powerful computers to solve 3D fluid dynamic equations (Table 12.3).

Using calculations, the pressure rise inside compartments during an internal arc can be reasonably predicted if the arc energy is known. This means that the arc energy and K_p factor (the ratio between the input electric energy and the energy that is used to heat up the gas) should be taken from previous internal arc tests on similar switchgear designs. It is not realistic to accurately calculate the arc voltage in the complex switchgear design due to the stochastic nature of the arc.

In CFD models, pressure, temperature, and flow velocity are available at each point of the flow domain over time. The solver calculates the average gas pressure on surfaces or in the volume automatically. The postprocessing tools allow animations (video) of the gas flow, providing a good visual to understand the phenomena.

Figure 12.5 shows the pressure inside air-insulated switchgear compartment, 55 ms after initiation of internal arc.

(b) **Mechanical stress on the switchgear enclosure**

Understanding the performance of the switchgear enclosure during the event of the internal arc is an important safety aspect. If the structure is not strong enough, it may fail releasing high velocity debris and hot gases to the surroundings, which is a major safety issue.

Table 12.3 Simulation tools for internal arc simulation

	Model	When to use?	Limitations
1	**Basic** (low complexity)	To quickly calculate uniform pressure rise inside arc compartment and exhaust volume in MV switchgear and HV GIS applications	Does not consider spatial nonuniformity of gas parameters (pressure, temperature, density) in each volume part Not applicable if the relief opening area is too large in relation to the compartment volume Calculations are not reliable, when gas temperature exceeds approx. 2000 K for SF6 and 6000 K for air Doesn't consider gas mixtures in the exhaust compartment
2	**Enhanced** (medium complexity)	To calculate uniform pressure rise with the basic model by adding further approaches to match test results and calculations	Doesn't consider spatial nonuniformity of gas parameters (pressure, temperature, density) in each volume part Limitations and applications depend on the implemented approximations
3	**CFD** (high complexity)	For calculating spatial pressure, gas flow and temperature distributions (in angled and large rooms)	High effort for modeling and meshing of the fluid domain Requires large computing power and time and detailed knowledge

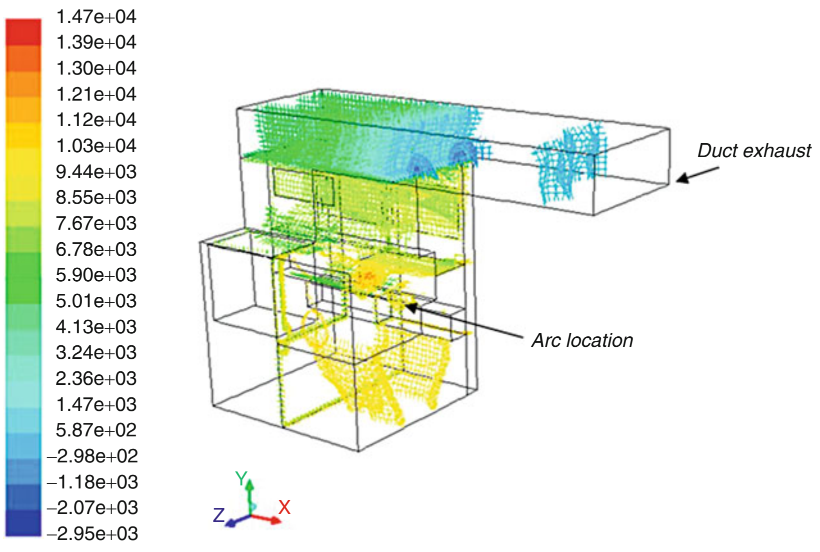

Fig. 12.5 Simulation of internal pressure inside switchgear cabinets during the internal arc fault, using computational fluid dynamics software

The good news is that once the pressure rise inside the switchgear is known, the mechanical stress (of Von Mises stresses) on the switchgear enclosure can be fairly accurately calculated using commercial finite element analysis (FEA) software. Since the internal arc overpressure is a very short event (lasting from few cycles to a few hundred milliseconds), the inertial effect has to be considered when calculating deformation and stresses. The structure behaves differently if the force is applied slowly and when is applied instantly.

Figure 12.6 shows an example of deformation of a MV SF_6 insulated switch after an internal arc. The switch has been subjected to a 25 kA internal fault for 250 ms. As a result, the test tank deformation was 81 mm in the center of the side plate. Using FEA software and calculating the Von Misses stresses, the deformation was well predicted, missing the mark by only 1 mm.

(c) **Burn through**

Arc roots on the surface of metallic enclosures cause burn through. The time to burn through depends on the current density, thickness of the enclosure wall, type of material, and duration of the fault. In the brochure test, results and calculations using known empirical formulae are

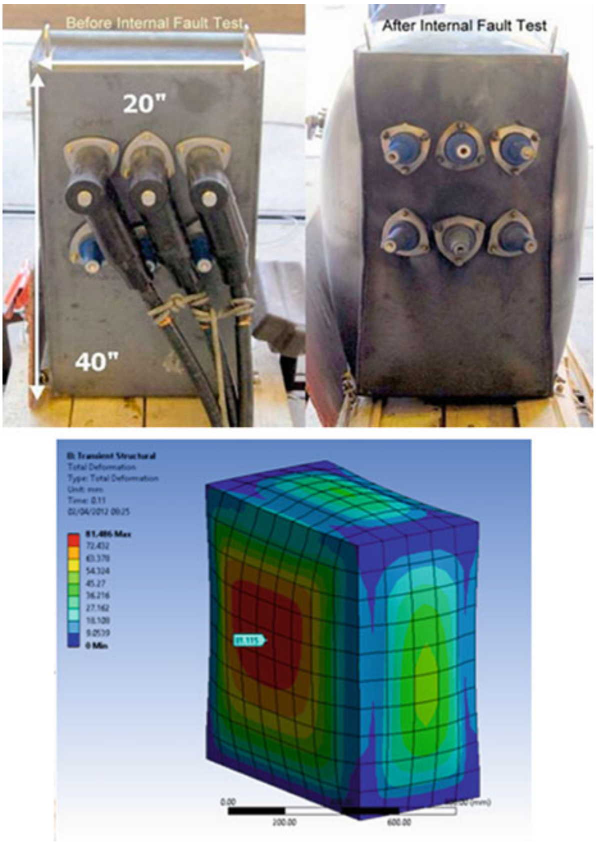

Fig. 12.6 Deformation of the MV SF_6 switchgear after 25 kA, 250 ms internal fault. The FEA results (on the right) accurately calculated the deformation for the given pressure rise

Fig. 12.7 Examples of burn through of a HV GIS enclosure

summarized. The focus is on burn through in single-phase enclosed high-voltage switchgear (Fig. 12.7).

No reference has been found for the comparison of burn-through time in SF_6 and air. Nevertheless, some differences in the fundamental characteristics of arcs in SF_6 and air could be extracted with the conclusion that the burn-through time in SF_6 is likely to be somewhat shorter than in air.

12.7 Summary

It is concluded that simulation is an excellent, helpful, and instructive tool in the development process of power system equipment, including switchgear and that good prediction of performance can often be possible in cases where performance is proven by tests on similar designs (interpolation). At the same time, extrapolation of test results and performance prediction of “new” equipment designs seem to be possible only in a limited number of cases.

Pressure rise inside compartments during an internal arc fault test can be reasonably predicted as long as the input arc energy is known. This means that arc voltage and in particular kp should be taken (not calculated) from previous internal arc tests on similar switchgear designs. Due to the stochastic nature of the arc, accurate calculation of the arc voltage in complex switchgear designs is not realistic; hence recorded values should be used for more accurate predictions of pressure rise.

Mechanical stress of the switchgear enclosure can be fairly accurately calculated with off-the-shelf FEA software once the pressure rise is known.

Burn-through time can be evaluated using different empirical formulas, which were compared in the technical brochure with available test results.

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Fault Current Limiting (FCL) Devices and Techniques

13

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Contents

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13.1 Introduction

Fault current limiters (FCLs) are special power system devices used to mitigate and lower high short-circuit currents to much more manageable levels for existing protection equipment like circuit breakers (CBs). FCLs are generally installed with the goal to lower the available fault current to a level the CB is capable of interrupting safely prior to the CB beginning its opening operation. The FCL limits the fault current to a preset level based on the particular system configuration and system conditions. In the past, engineers were forced to either upgrade existing equipment to protect the system from the increased short-circuit capacity (if replacements can safely interrupt the new short-circuit level), or they must find a way to lower the short-circuit rating such as bus splitting, increase impedance of transformer, etc. The FCL allows the engineer to apply the chosen technology to avoid a full system upgrade of protection equipment like circuit breakers, which can be rather costly.

CIGRE conducted several surveys on FCL technologies in power systems. For example, CIGRE WG A3.10, "Fault current limiters in electrical medium and high voltage systems," investigated functional specifications and testing requirements (CIGRE WG A3.10 2003). WG A3.16 "Guideline on the Impact of FCL devices on protection system" studied the interaction between FCL technologies and different protection systems in power systems (CIGRE WG A3.16 2008). CIGRE WG A3.23, "Applications and Feasibility of Fault Current Limiters in Power Systems," summarized the field experience of FCL and showed possibility to reduce the amplitude of fault currents with increasing short-circuit levels and strengthened power systems (CIGRE WG A3.23 2012).

It is not uncommon for short-circuit ratings to exceed a circuit breaker's maximum interrupting capabilities (kA rms, sym) in medium-voltage and high-voltage installations. At the higher levels of short-circuit current (63 kA or more), there are very few options to reduce the high fault current. In this context, it is of major importance to look for solutions that are (a) effective in terms of limiting or mitigating short-circuit current levels, (b) reliable, and (c) of low cost, in a broad sense. Methods used to mitigate the high fault currents are listed in this chapter and are not only limited to fault currents above 63 kA rms, sym. These methods are commonly used to protect system from any level of fault current even if the short-circuit current does not exceed the circuit breaker ratings of that system. Some of the mitigation techniques can lower the energy let-thru during a fault and protect workers and equipment. The reduction in fault energy can also extend the life of existing equipment.

The connection of new power producers to the network is likely to cause an increase of short-circuit levels not considered in previous long-term planning forecasts and may change power flow or initiate voltage stability problems. This context will require more and more knowledge of techniques for short-circuit limitation at both high-voltage and medium-voltage/low-voltage levels of the existing network. The most common solutions to successfully protect the power system from increased fault current levels are increased rating of switchgear and other equipment, splitting the grid and introducing higher voltage connections (AC or DC), introducing higher impedance transformers and series reactors, and using complex strategies like sequential network tripping. Nevertheless, these alternatives may create other problems such as a reduction of power system security and reliability, increased costs, and increased power losses. They may also not be practical due to imposed regulations and the physical space available. For DC applications, a DC reactor can reduce the rate of current rise during a short-circuit event and can effectively mitigate the circuit breaker requirements.

At several locations in a power system, employing some kind of fault current limiting measure is necessary to avoid costly system upgrades. The power system experiences additional benefits if fault current levels can be reduced. The conventional methods that are currently in practice are effective to an extent but have their limitations, and there is still a need for improved performance.

Fault current limiters (FCLs) that are based on novel technologies such as solid-state and superconducting materials can be highly effective and efficient in theory. However, these FCLs are still in various stages of development with most of these technologies not mature enough and not grid ready (although rapidly approaching). Once ready for use, the next-generation FCLs are expected to find widespread applications in transmission and distribution systems all over the world. In fact, there are many pilot installations already installed and going through the trial phase and proof of concept phase. A FCL operation with both current limitation and current interruption is shown in Fig. 13.1.

The basic physical effect of FCL applications is the increase of impedance in series with the line. Therefore, grid impacts and interactions have to be considered when applying FCLs. Generally, the FCL impacts can be divided into two groups as shown in Fig. 13.2.

It is common knowledge in the power engineering community that the choice of a particular voltage level for new or expanded transmission and/or distribution systems is governed primarily by the desired power ratings required to supply the load. The objective is to keep rated current levels and short-circuit levels within the standard ratings of commercially available equipment, especially circuit breakers. These ratings typically provide enough margin with respect to short-circuit power at any given voltage level. Nevertheless, depending on the constraint of the applications (e.g., grid density, nearby generation), the short-circuit current may exceed the ratings of the available equipment. This may require choosing a higher-voltage level based on the short-circuit capability of the equipment or may involve choosing a short-circuit limitation method listed below. All of these factors must be considered when designing new systems.

For an existing system, increasing the voltage level is more likely a viable option for medium-voltage levels where the increase in system voltage can be accommodated more easily within the same or similar space constraints by simply installing more modern and physically more compact equipment. However, a FCL is still a viable solution to solving the excessive short-circuit rating in medium-voltage systems. In high-voltage systems, increasing the voltage level often is associated with major investments and thus not a

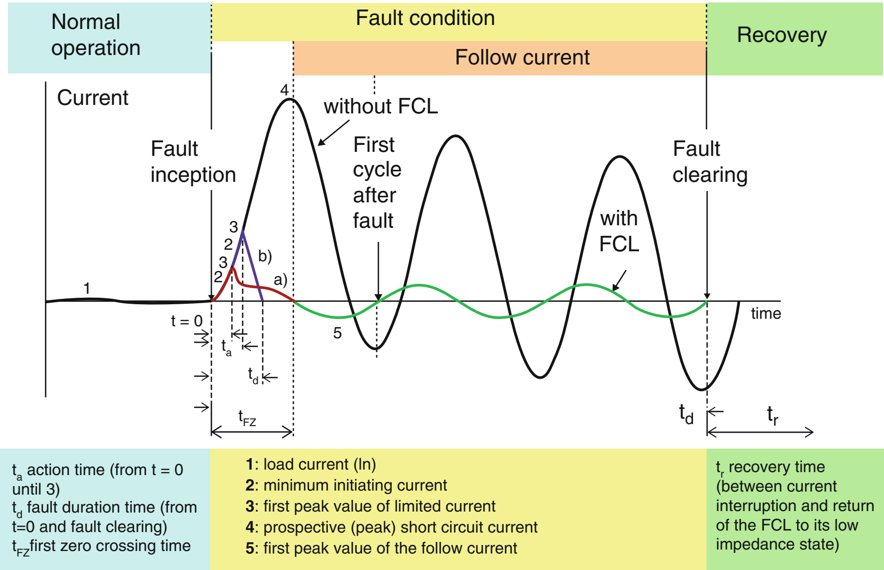


Fig. 13.1 Generalized fault current limitation and fault current interruption trace (ABB Calor Emag 2016)

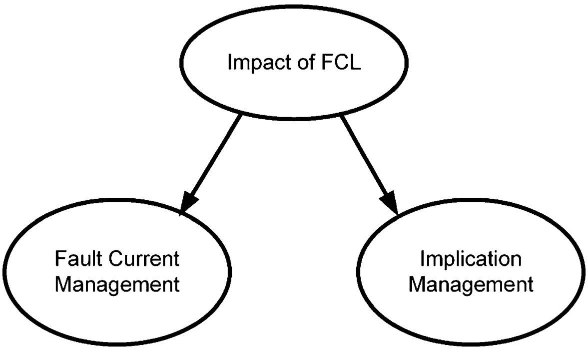


Fig. 13.2 Impacts of FCLs on the system

preferred option in many cases. Therefore, FCLs can be a tool used by engineers to solve exceedingly high short-circuit current issues and to protect and limit damage to existing equipment while still permitting the capacity expansion

13.2 Definitions of Terminology

This set of terms is not intended to be comprehensive but rather help the reader to understand and recognize the terms used and their meaning with respect to this subject (FCL devices).

Active Power
The term active power, also called real power, signifies the net power transferred within one cycle of the ac waveform. It is often used to qualify the general term power in order to differentiate from reactive power.

Alternating Current
An electrical current, which reverses direction periodically due to a change in voltage which occurs at the same frequency, often abbreviated AC or ac.

Capacitor
A device that stores electrical charge, usually by means of conducting plates or foil separated by a thin insulating layer of dielectric material. The effectiveness of the device, or its capacitance, is measured in Farads (F).

CCL – Abbreviation for commutating current limiter or pyrotechnic fault current limiter.

Circuit Breaker
A device designed to open and close a circuit (make or break a current) either by manual action or by automatic action. As opposed to a regular switch, a circuit breaker is designed to interrupt fault currents. A circuit breaker can provide over-current protection when combined with a protection relay or trigger unit that commands the breaker to open when current exceeds a preset value.

Commutating Current Limiter
See triggered current limiter.

Conductor
Usually a metallic substance capable of carrying electric current with little resistance. The best conductor at room temperature is gold, followed by silver, and the most common conductor which is copper. Some other recently discovered substances called superconductors actually have zero resistance at extremely low temperatures (typically below 77 K, the liquefaction temperature of Nitrogen).

Continuous Load
A sustained electrical load current for 3 h or more.

Cryogenic
The scientific study of very low temperatures.

Current Limiting Reactor
A reactor connected in series with the phase conductors for limiting the current that can flow in a circuit under short-circuit conditions.

Current Transformer
A device that measures the time-varying electrical current from via electromagnetic induction.

Fault
Unintentional reduction of the phase-to-phase, phase-neutral, or phase-to-ground impedance, typically resulting in the subsequent flow of a large current.

Fault Current Limiter
A fault current limiter is a device, which offers condition-based increase in resistive and/or reactive impedance between normal conducting mode and current limiting mode to limit the prospective peak and/or RMS fault current in an alternating current power system to or below a desired value. The change in the resistive and/or reactive impedance is due to the change in electrical conductivity or the magnetic permeability of the device or a combination of both.

Feeder
Circuit conductors between the service equipment and the last downstream branch circuit overcurrent protective device.

Frequency
The number of complete alternations or cycles per second of an alternating current measured in hertz. The standard values of the rated frequency in Europe and Asia are typically 50 Hz, while the USA and many other countries maintain 60 Hz.

Grid
In the electrical area, a term used to refer to the electrical utility transmission and distribution network.

Harmonic
A sinusoidal oscillation at an integral multiple of a base frequency. For example, the third harmonic on a 60 Hz system oscillates at a frequency of 180 Hz. Certain types of electrical equipment generate harmonics which interfere with the proper functioning of other devices connected to the same system.

Impedance
The total effect of an electrical circuit as it opposes the flow of current. In ac systems, the impedance consists of resistance (dissipating real power) and reactance (due to inductance and capacitance). Impedance is quantified in the units of ohms (Ω).

Inductance
The proportionality between the rate of change of magnetic flux and induced voltage in an electric circuit. Typically, the change of magnetic flux is caused by the variation of the current in the circuit itself (self-inductance) or in a nearby circuit (mutual inductance). The inductance is measured in the units of henries (H).

Load
A device which consumes electrical power and is connected to a source of electricity.

Neutral
A conductor of an electrical system, which usually operates with minimal voltage to ground. In three-phase systems, it carries the unbalance of the phase currents. Systems that have one conductor grounded use the neutral for this purpose.

Overcurrent
Any current beyond the continuous rated current of the conductor or equipment. This may be a value slightly above the rating as in the case of an overload or may be far above the rating as in the case of a short circuit.

Overload
Operation of electrical equipment above its normal full load rating or of a conductor above its rated capacity. An overload condition will eventually cause dangerous overheating and damage.

Power
The rate at which work is performed or that energy is transferred. Electric power is measured in watts (W). A power of 746 W is equivalent to one horsepower.

Pyrotechnic Current Limiter
See triggered current limiter.

Rated Current
Current (rms), which a FCL should be able to carry permanently.

Resistance
The characteristic of materials to oppose the flow of electricity in an electric circuit by dissipating real power. Resistance is quantified in the units of ohms (Ω).

rms or RMS
Abbreviation for "root-mean-square," a method of computing the effective value of a time-varying electrical signal. The basis is that the rms value of an AC quantity, applied in a dc circuit, dissipates the same amount of real power. For example, an AC current of one ampere rms produces the same amount of heat over one cycle in a given resistance as a dc current of one ampere in the same resistance.

Short-Circuit
A low-resistance connection made between normally isolated points of an electrical circuit, which may result in a large current flow, far above normal levels.

Single Phase
An AC electric system or load consisting of one pair of conductors energized by a single alternating voltage. This type of system is simpler than three phase but has substantial disadvantages when large amounts of power have to be delivered.

Three Phase
An AC electric system or load consisting of three conductors energized by alternating voltages that are out of phase by one third of a cycle. This type of system has advantages over single phase including the ability to deliver greater power using the same ampacity conductors and the fact that it provides a constant power throughout each cycle rather than a pulsating power, as in single phase. Large power installations are three phase.

Thyristor
A solid-state semiconductor device with four layers of alternating N- and P-doped semiconductor material. A thyristor acts as a unidirectional switch, conducting when its gate receives a current pulse and continuing to conduct as long as it is forward biased.

Triggered Current Limiter
A FCL that has a main conducting path that is physically severed pyrotechnically upon experiencing an overcurrent that exceeds the control system's preset threshold and diverts the overcurrent to a parallel fuse.

Voltage Drop
A voltage reduction due to impedances between the power source and the load. These impedances are due to wiring and transformers and are normally minimized to the extent possible.

13.3 Abbreviations

AC	Alternating current
CB	Circuit breaker
CCL	Commutating current limiter
CLR	Current limiting reactor
CT	Current transformer
DC	Direct current
ETO	Emitter turn-off thyristor
FCL	Fault current limiter
FMEA	Failure mode and effect analysis
GTO	Gate turn-off thyristor
HTS	High temperature superconductor
HV	High voltage
Hz	Hertz
IEC	International electrotechnical commission
IEEE	Institute of Electrical and Electronics Engineers
IGBT	Insulated gate bipolar transistor
IGCT	Integrated gate-commutated thyristor
kA	Kilo-amperes
kV	Kilo-volts

MOV	Metal oxide varistor
MV	Medium voltage
P	Real power
PWM	Pulse width modulation
Q	Reactive power
R	Resistance
RMS	Root-mean-square
SiC	Silicon-carbide
SIL	Safety integrity level
SFCL	Superconducting FCL
SCFCL	Saturable-core FCL
SSCB	Solid-state circuit breaker
SSFCL	Solid-state FCL
Sym	Symmetrical
TCL	Triggered current limiter
TRV	Transient recovery voltage
UPS	Uninterruptible power supply
X	Reactance
YBCO	Yttrium barium cobalt

13.4 Methods for Reducing the Short-Circuit Levels in Power Systems

A fault condition creates a surge of current through the electric power system that can cause serious damage to grid equipment. Switchgear, such as circuit breakers, is deployed within substations to protect equipment. Increasing fault levels, especially in the high-voltage systems, correspond to an increase of rating limits of switchgear and equipment like circuit breakers and disconnect switches and the incident energy levels, which can increase the risk and severity of electrical hazards.

Utilities all over the world are experiencing the ever-increasing need for fault current limitation in MV and HV systems. An overview of fault current limiting measures is given in the figure below.

"Passive" measures make use of higher impedance under all the conditions, whereas "Active" measures introduce higher impedance only under fault conditions. The measures may also be classified as "Topological" and "Apparatus" measures. Some measures could be identified as "Novel" as well, depending on the technology used (Fig. 13.3).

13.4.1 Bus Splitting

Bus splitting entails separation of sources that could possibly feed a fault by the opening of normally closed bus ties or the splitting of existing buses. This effectively reduces the number of sources that can feed a fault but also reduces the number of

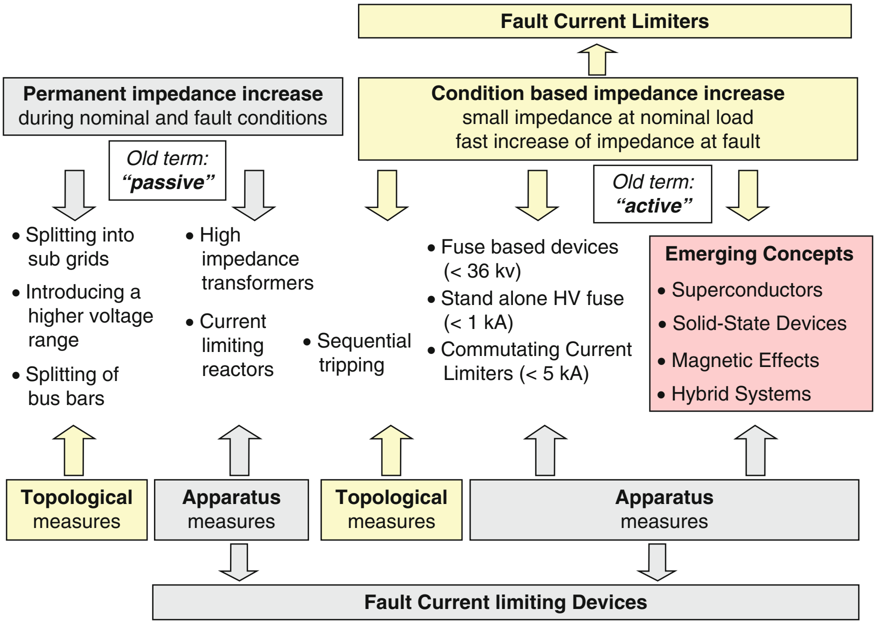


Fig. 13.3 FCL systematic definitions (AMSC 2016)

sources that supply load current during normal or contingency operating conditions. This affects reliability and security of the power system and may require additional changes in the operational philosophy and control methodology, especially the protection settings and coordination.

13.4.2 Splitting into Sub-grids

This term refers to a measure applied to a grid (with one common voltage level) resulting in the original system being divided into smaller portions, which are then fed separately from the next higher-voltage level. The splitting reduces the fault current level in each of the sub-grids to the allowable level. Splitting the system into sub-grids will affect reliability and security of the power system and may require additional changes in the operational philosophy and control methodology. Splitting the system into sub-grids is similar to the bus splitting technique.

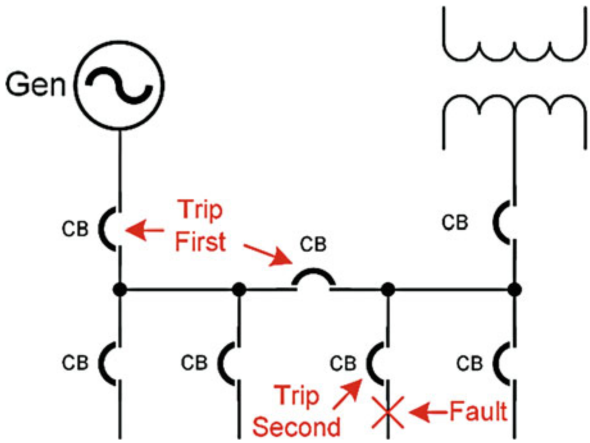
13.4.3 Sequential Breaker Tripping

Sequential tripping of circuit breakers is a special measure occasionally used in substations to manage high fault currents without replacing some or all circuit breakers. A sequential tripping scheme prevents circuit breakers from interrupting excessive fault currents. If a fault is detected, a breaker upstream to the source of fault current is tripped first. This reduces the fault current seen by the breaker within the zone of protection at the location of the fault. Operating the protection system in this manner is contrary to most designs where the breaker closest to the fault operates first. The overdutied breaker can then open safely. A disadvantage of the sequential tripping scheme is that it adds a delay of one breaker operation before final fault clearing. If the overdutied breaker cannot withstand the I^2t it is subjected to while it waits for the upstream breaker to open, the overdutied breaker may fail catastrophically or may have its separating contacts welded shut. Also, opening the breaker upstream to the fault affects protection zones that were not originally affected by the fault. An example of sequential breaker tripping is shown in Fig. 13.4.

13.4.4 Current Limiting Reactors (CLRs) and High Impedance Transformers

A current limiting reactor (CLR) is essentially an inductor installed in a power system to reduce the short-circuit current by adding a reactive-based impedance thus increasing the voltage drop across their terminals during the fault. However, current limiting reactors also have a voltage drop under normal operating conditions and present a constant source of losses due to the copper windings of the coil. A CLR may or may not have a magnetic core. Assessment in applying a CLR for short-circuit limitation at the primary transmission network should include aspects like the transmission system performance under steady-state and transient conditions; the definition of the physical dimensions for the equipment; the specifications of the electrical characteristics and the special cares with respect to the possible damage caused by the magnetic flux generated by the CLR to human life, directly or through contact with metallic structures in the vicinities; and the economic profits of this limitation in short-circuit level compared to the costs of the substitution of

Fig. 13.4 Sequential tripping example



overstressed equipment and facilities and erection at site. A CLR is a passive FCL device that requires only a fixed and easy setting to determine redefinition of protection after being installed in the network.

13.4.4.1 Position at the Substation Busbar

The typical application of a CLR in HV power systems is both in series with the incoming/outgoing feeder circuits or in bus tie/coupling. On the other hand, despite these disadvantages their benefits could be economically attractive when avoiding equipment substitution or replacement. The position of the CLR at the substation busbar used to meet the technical needs and to maximize the cost/benefit equation should be analyzed for each specific case. The possible positions of the CLR at the substation busbar are shown in Fig. 13.5.

Air-core reactors at the substation busbar yields better voltage regulation and minimum losses, regarding other possible positions for the FCL reactor (incoming or outgoing feeders of the substation). Considering the adopted solution for installing the CLR splitting the substation busbar, lines and transformers circuits should be properly redistributed among the two sections of the substation busbar, for a better load sharing in normal operating conditions. By evenly distributing the loads on both sides of the CLR in a bus tie configuration, the current flow through the CLR can be minimized which minimizes the nominal losses of the CLR and makes the CLR a more economically attractive solution.

The presence of a lumped inductance in an electrical circuit can lead to an increase in the severity of the transient recovery voltage (TRV) across the circuit breaker (CB) contacts. An increase of the TRV can affect the interruption capability of the CBs, increasing the possibility of an interruption failure, and possibly catastrophic device jeopardy. When an air-core dry type series reactor (CLR) is inserted into the circuit, for instance, to limit the short-circuit current symmetric RMS value, the rate of rise of the transient recovery voltage tends to drastically increase because of its very large surge impedance (at least few thousands of Ohms). Fortunately, installing a suitable capacitor across the reactor may easily solve this problem. In some cases, it might be necessary to also install capacitors on each side of the CLR to ground. Normally, an in depth computer engineering analysis is performed to determine if the circuit breaker characteristics are not exceeded in the presence of adding a CLR.

Reactors at the substation busbar yield better voltage regulation and minimization of losses due to minimal current flow between buses, if evenly balanced, as compared to the other possible installations for the FCL reactor. When installing a CLR solution for splitting the substation busbars, transformer circuits, generator circuits, and load circuits should be properly redistributed among the two sections of the substation busbar, for a better load sharing in normal operating conditions. Examples of CLR installations are shown in Figs. 13.6 and 13.7.

The CLR can interact with other system components and cause instability, as well as an increase in transient recovery voltage (TRV), since the presence of a lumped inductance in an electric circuit from the CLR could lead to an increase in the severity of the transient recovery voltage (TRV) across the circuit breaker contacts

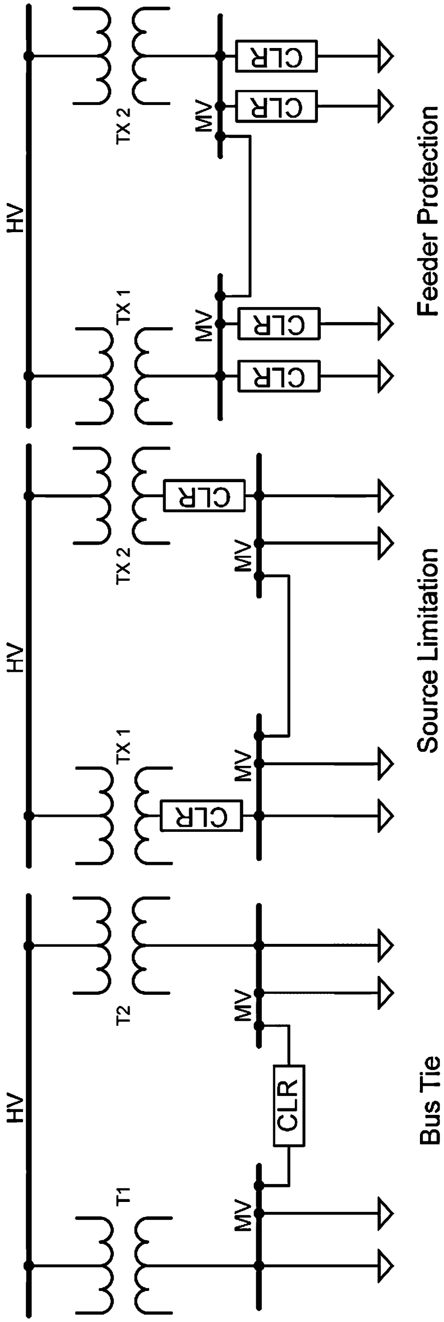


Fig. 13.5 Possible install locations of the CLR

Fig. 13.6 Example of a CLR installation

associated with the interruption of the circuit current, as already mentioned. This may lead to increased requirements of the CBs for TRV issues. When conditions are right, air-core CLRs can be an economical solution to high fault currents.

As an example, a real case of CLR installation splitting busbars at a 345 kV level substation of the transmission system of the Itaipu power plant in Brazil is presented. Due to the next foreseen networks expansions, the short-circuit currents will approach or even exceed the Tijuco Preto's 345 kV equipment rating of 50 kA. The solution chosen for this example is the installation of two sets of bus tie air-core 345 kV/15 ohm reactors at the 345 kV busbar of the Tijuco Preto substation, in order to reduce the short-circuit level from 54 kA to 45 kA. Thus, this solution will avoid the replacement of 37 circuit breakers (at 345 kV operational voltage level) and associated equipment with new equipment with higher short-circuit ratings. It is worth mentioning that the cost of the proposed CLR solution is equivalent to the cost of a single circuit breaker at this 345 kV voltage level.

Experience in the usage of such devices has proven that the chosen position for the air-core reactors at the substation busbar yields better voltage regulation and minimum losses, regarding other possible positions for the FCL reactor (incoming or outgoing feeders of the substation). Lines and transformer circuits should be properly redistributed among the two sections of the 345 kV substation busbar for a better load sharing in normal operating conditions.

Due to the installation of the proposed two sets of the FCL reactor shown in the left figure of Fig. 13.8, several evaluation studies have to be done in order to

Fig. 13.7 Example of an air-core reactor (CLR) installation

determine the new TRV requirements imposed to the circuit breakers of Tijuco Preto substation in the presence of the bus tie FCL reactor. It is worthwhile to mention here that just one of the two FCL reactors will be in operation all the time. The other one is just a spare device, to substitute for the one in operation whenever necessary (i.e., for maintenance purposes).

As one can see in the right figure of Fig. 13.8, the new TRV requirements will increase in terms of peak values for the mentioned circuit breakers when the bus tie FCL reactor is in operation. These new TRV requirements occur by means of the different propagations and reflections of the traveling waves caused by the FCL reactor during the application of the short circuits, compared to the previous situation (without any fault limiting device in the Tijuco Preto substation). The results of such electromagnetic transient studies showed that the conventional ratings, regarding circuit breaker TRV requirements, given by IEC Standards, are still suitable for this new configuration.

Thus, the proposed solution for short-circuit current limitation will be possible to be installed, without any need of new special requirements for the circuit breakers of the Tijuco Preto substation. After the complete analysis, this was shown to be a very interesting solution for this fault current limiting problem, from the economic and

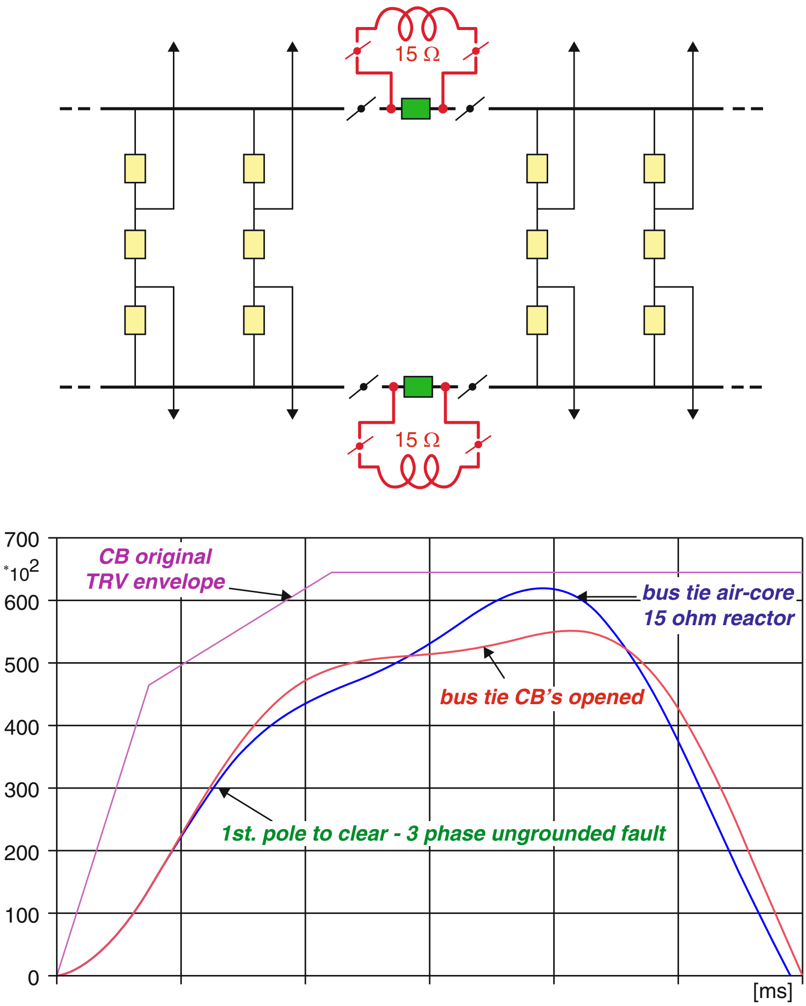


Fig. 13.8 CLR example installation with associated TRV

technical points of view, avoiding the replacement of several units of switchgear in that substation that would be overstressed if this solution was not implemented.

13.4.5 Impedance Grounding

When the high fault currents are ground fault currents, solidly grounded systems can be converted to impedance grounded systems, such as low or high resistance grounding and inductance grounding. The introduction of an impedance grounded system reduces the available ground fault currents.

13.4.6 Pyrotechnic FCL

13.4.6.1 Technology Overview

Pyrotechnic fault current limiters, also known as triggered current limiters (TCL) or commutating current limiters (CCL), consist of a main conduction busbar path and a parallel mounted current limiting fuse. These devices are electronically controlled and sensed and upon a measured current value reaching and exceeding its triggering criteria, a pyrotechnic charge is initiated which severs the main conduction path and shunts in the parallel mounted current limiting fuse. The fuse then melts and interrupts the current in a current limiting fashion (before the first peak occurs). Time to clear and interrupt the fault current flowing through the device down to zero current ranges between 1/4 and 1/2 of a cycle based on the level of short-circuit asymmetry. Electrically, these devices consist of a high speed switch that can only open once with a parallel mounted current limiting fuse. Under normal operating conditions, the current flows through the main busbar path, but upon a short circuit, the current limiting fuse is inserted interrupting the short-circuit current and protecting the power system or equipment. Some common electrical schematic symbols used in drawings are shown in Fig. 13.9.

The pyrotechnic fault current limiter's triggering logic senses the instantaneous current magnitude or a combination of rate of current rise (di/dt) and instantaneous current magnitude. Once one or both conditions exceed preset values that are based on that specific installation's protection needs, the logic system sends the trip signal to initiate the pyrotechnic charge located in the main conduction path and begins the process of inserting the current limiting fuse for circuit interruption. Upon activation, the main conduction path and the current limiting fuse must be repaired or replaced. The end user typically has a set of spares located nearby to quickly facilitate replacement and re-energization of the system. After an operation, the logic system and all support structures do not require replacement. These devices actually interrupt the short-circuit current that flows through it instead of "limiting" the prospective short-circuit current to a specific percentage and then relying on a circuit breaker to interrupt the circuit. While other FCL technologies may only achieve a 50% reduction in short-circuit current which may render their application inadequate, the pyrotechnic FCL may still be a possible solution as it reduces the short-circuit current flowing through it to zero (100% reduction) after an operation. The system must still be able to interrupt the residual short-circuit current safely after the pyrotechnic FCL has operated. Examples of commercial pyrotechnic FCLs are shown in Fig. 13.10.

Ratings for these type of FCLs range from low voltage (750 Vac) to medium voltage (40.5 kVac) with continuous currents up to 5000 A and interrupt ratings up to 210 kA rms, sym. Although no official rating exists, these FCLs have cleared above 300 kA rms, sym at 15.7 kV before. These devices are rated for indoor or direct outdoor use without an enclosure and are rated up to 20 years in service without requiring replacements. Variations of their design include multiple parallel main conduction paths for increased continuous current ratings and multiple parallel barrels of current limiting fuses for increased interrupt ratings and trip settings.

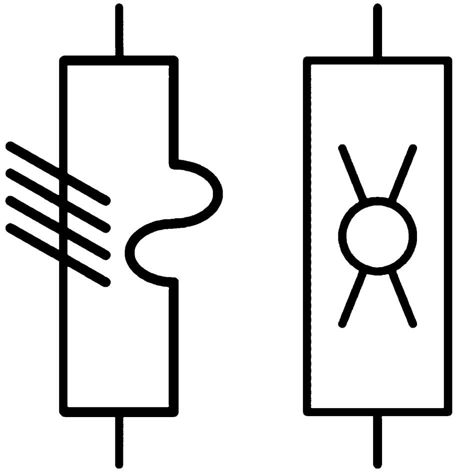


Fig. 13.9 Electrical schematic symbol for pyrotechnic FCL

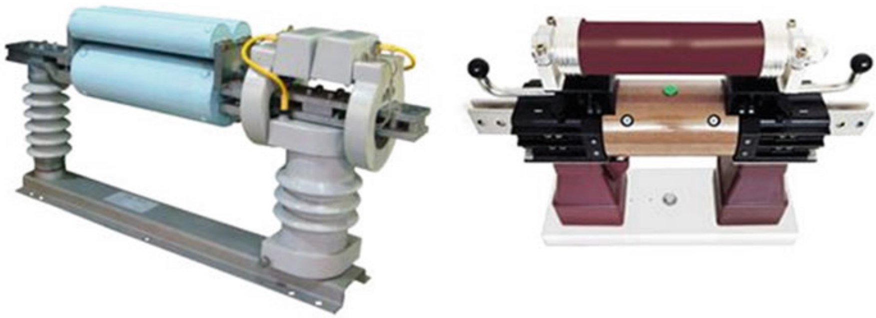


Fig. 13.10 Examples of pyrotechnic FCLs (ABB Calor Emag 2016; G&W Electric Company 2016)

Their parallel current limiting fuses have a low continuous current rating compared to the main busbar path, which allows it to operate in its current limiting range regardless of trip setting. While no official DC ratings exist at the time of transcribing this section, these FCLs can potentially interrupt DC current if they can produce enough arc voltage during interruption.

In addition, the triggering logic for the pyrotechnic current limiter may also be disabled (turned off) when the power system is operating within its limits to prevent unnecessary operations, or they may be enabled (turned on) at all times to help minimize damage. Typically, when the system reaches 90–95% of the existing breaker rating and beyond, the pyrotechnic fault current limiter is activated and enabled. This is however a guideline and the actual settings are dependent on the application needs. These FCLs may or may not trip all three phases for a single- or two-phase short circuit but would trip all three phases for a three-phase short circuit. They are also capable of providing a remote operational signal within a few sinusoidal cycles which alerts a series breaker to initiate a three-phase clearing to prevent single-phasing and ferroresonance conditions if only one or two phases trip. Common applications for pyrotechnic FCLs include bus ties, damage limitation, source limitation, reactor bypass, distributed generation, and arc flash mitigation.

13.4.6.2 Bus Tie Applications

For bus tie applications, the pyrotechnic FCL is installed in the bus tie with a tie breaker on one side in series and a disconnect switch or 2nd tie breaker on the other side in series to allow for physical isolation after an operation when changing the spares. The FCL must be able to operate and protect the system with varying loads on either side, and the trip setting must take into account a percentage of uneven loading on each bus. An industry common uneven loading may be a 25% split on one bus with 75% of the loads on the other bus; however, this percentage may vary between fully balanced (50% on each bus) between buses to fully loaded on one bus. A balanced loading on both buses usually permits the highest possible trip setting. The bus tie application is pictured in the figure below. The pyrotechnic FCL limits the current flowing from one bus to the other bus. These devices are bi-directional but can be configured to only operate in one direction of current flow (i.e., downstream only vs. upstream) while being prevented to operate in the other direction of current flow. In many cases, one pyrotechnic FCL can protect multiple breakers or an entire substation without the need of upgrading each overdutied piece of equipment. An example of a bus tie application is shown in Fig. 13.11.

13.4.6.3 Damage Limitation Applications

The damage limitation application is common among utilities and industrial facilities with expensive equipment. Utilizing a pyrotechnic FCL to protect desired feeders in a system can not only allow lower-rated equipment but can also reduce the energy (damage) subjected to the piece of equipment, potentially extending the life expectancy. In utility applications, the pyrotechnic FCLs can help mitigate network transformer failures and can prevent manhole covers from being expunged into the sky. For industrial systems, it may reduce the damage enough to allow an expensive piece of equipment to be repaired and operational the same day instead of needing replacement. An example of a typical damage limitation application and its damage reduction to equipment is shown in Figs. 13.12 and 13.13.

Source limitation and distributed generation applications are very similar to each other as the pyrotechnic FCL interrupts the contribution from a specific transformer or generator. When adding an additional source to an existing system which overduties all existing equipment, installing a pyrotechnic FCL in series with the transformer/generator can keep the short-circuit currents within existing system ratings without the need to replace equipment. It essentially cuts off the contribution and keeps the residual short-circuit current within existing ratings. An example installation is shown in Fig. 13.14.

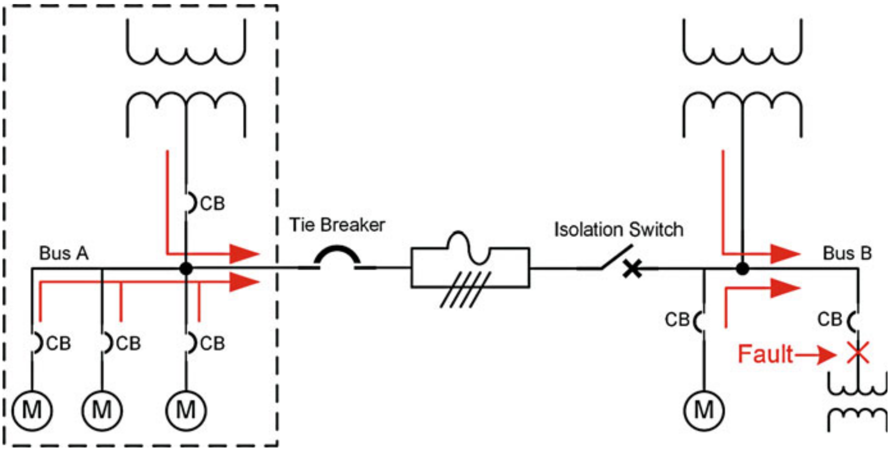


Fig. 13.11 Example of a bus tie application with the pyrotechnic FCL interrupting the short-circuit current flowing from bus A to bus B

13.4.6.4 Reactor Bypass Application

Reactor bypass applications are installed in parallel with a current limiting reactor to "bypass" the reactor's voltage drop and I2R losses which can be significant based on reactor impedance and the system's continuous current rating. Pyrotechnic FCLs are typically installed in parallel with the reactor for a critical process that cannot be shut down, or, if it is shut down, it is a substantial cost not only in wasted material but also downtime. The reactor bypass application allows the system to "ride through the fault" as the pyrotechnic FCL does not interrupt the short circuit; it only transfers the current to the reactor where the reactor performs the limiting. Some systems have boosted their output by up to 25% and have saved a substantial amount of money after installing a reactor bypass application. The pyrotechnic FCL requires two switches in series with the pyrotechnic FCL but in parallel with the reactor to provide physical isolation for changing of spares after an operation. One of the switches should be at least a motor-actuated switch that can break load current. It is recommended to install a breaker as the motor-actuated switch. An example installation is shown in Fig. 13.15.

13.4.6.5 Arc Flash and Arc Blast Application

A growing application for pyrotechnic FCLs is the application of arc flash and arc blast mitigation. Due to the high speed of this particular FCL (1/4 to 1/2 of a cycle), the pyrotechnic FCL is very effective at lowering incident energy for certain applications which may also lower the arc flash hazard level and required PPE of personnel. Typically, for low-voltage installations, many applications will be reduced below 4 cal/cm^2 which equates to a category 1 or 0. For medium-voltage installations, it is common (but not guaranteed) to achieve a hazard category reduction of 2 categories (i.e., category 4 now becomes a level 2). An example of the TCL installation in the system on a single-line diagram is shown in Fig. 13.16.

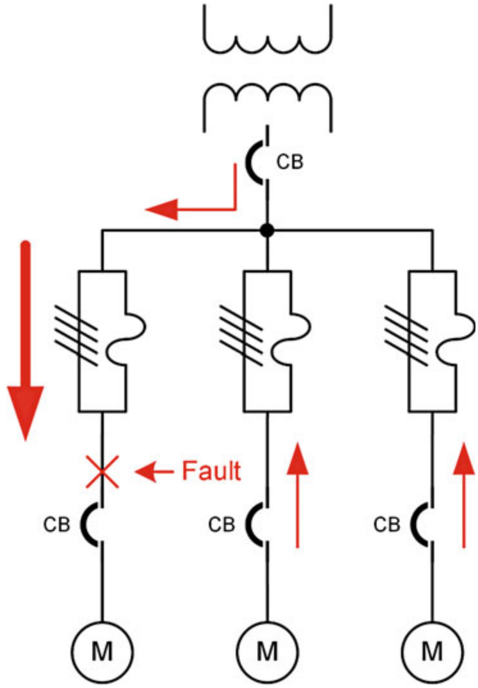


Fig. 13.12 Example of a damage limitation installation

Fig. 13.13 Damage limited from a 25 kA rms, sym fault with a pyrotechnic FCL installed (Deal 2009)

13.4.7 Solid-State FCLs

Utilities and industrial entities are considering fault current mitigation methods and are considering emerging new technologies (solid-state, superconducting, etc.) as vital alternatives to existing methods, provided these technologies prove to be the most cost effective means of fault current management, or they allow improved operational flexibility to justify the extra cost. Recently, there has been a large increase in R&D activities toward the development of technically feasible and economically viable technologies to design a range of medium-voltage and high-

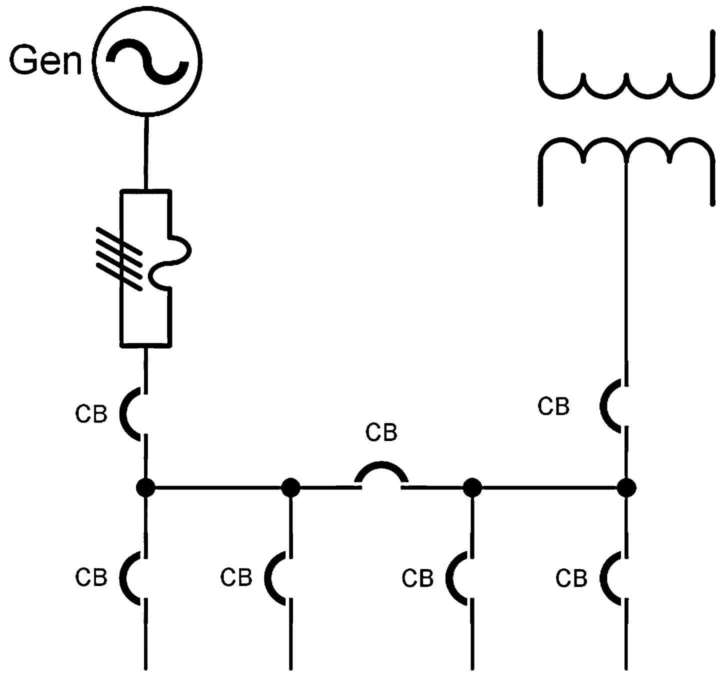


Fig. 13.14 Example of the source limitation application

voltage devices for fault current limiting applications in distribution and transmission (Prigmore 2013).

The solid-state FCL (SSFCL) can provide the advantage of repeated switching patterns and introduces the operational philosophy of "controlling" the fault current instead of just "limiting" it by a certain percentage (Prigmore 2013). The SSFCL uses semiconductor switches such as the Insulated gate bipolar transistor (IGBT), emitter turn-off thyristor (ETO), gate turn-off thyristor (GTO), integrated gate-commutated thyristor (IGCT), and other various devices. A SSFCL conducts current through the semiconductor switches in normal operation, and upon a short circuit, the semiconductors are gated "OFF" and force the fault current into a parallel branch impedance. The parallel impedance limits the fault current to a level the system can handle, and a breaker clears the fault some time later. A common design requirement for FCL is to be able to limit the fault current for 60 s before a breaker operates. An example of an SSFCL is shown in Fig. 13.17.

The SSFCL can allow the user to set a desired fault current level or a window of levels in an effort to minimize existing protection settings. For example, the SSFCL may use the concept of pulse width modulation (PWM) to vary the duty ratio of the semiconductor switches for the system to experience a fault current level set by the user. A maximum fault current level and a minimum fault current level may be set. An example of an SSFCL is shown in Fig. 13.18.

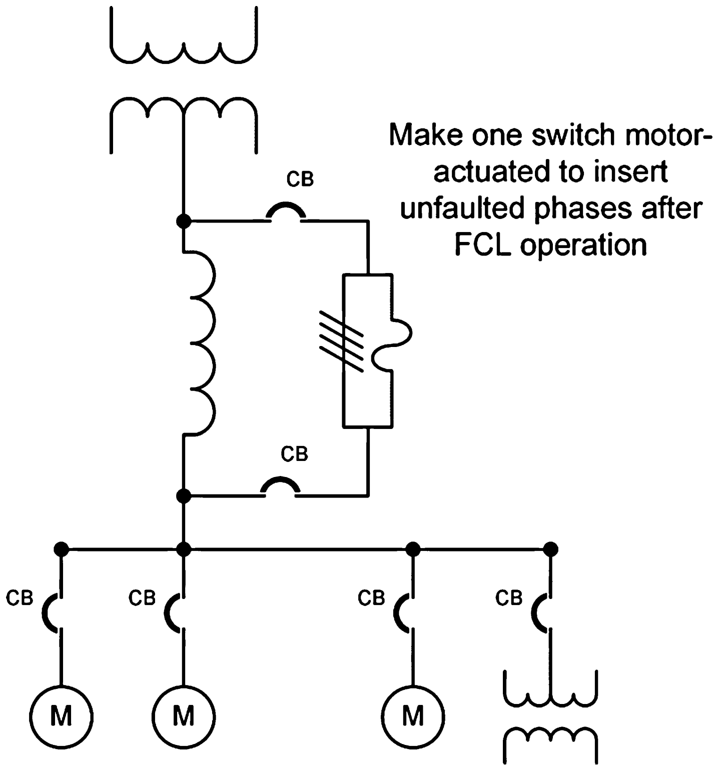


Fig. 13.15 Example of a reactor bypass application

Applications for an SSFCL are similar to the other devices presented in this chapter. If the semiconductor devices are rated high enough, the SSFCL may be permitted to operate as a solid-state circuit breaker (SSCB) and interrupt the current instead of just limiting the current (Prigmore 2013).

Design concerns for the SSFCL include overvoltages, exceeding the rate of rise ratings in both voltage and current (dv/dv and di/dt) for the semiconductor switches, conduction losses, high-side gate driver, absorbing the energy in the system due to the inductances in the system during the turn-off period, temperature rises, and withstanding the full system voltage after turn-off. Generally, a metal oxide varistor (MOV), also known as a surge arrestor, is used to protect the switches against overvoltages (Vodyakho et al. 2011). Although there are many design considerations for each application, the benefits of a SSFCL may justify its use, and SSFCL is one of the most promising technologies for the future grid. With the introduction of silicon-carbide (SiC) as the material of choice for semiconductor switches, power ratings should only increase making the SSFCL more attractive as this technology matures.

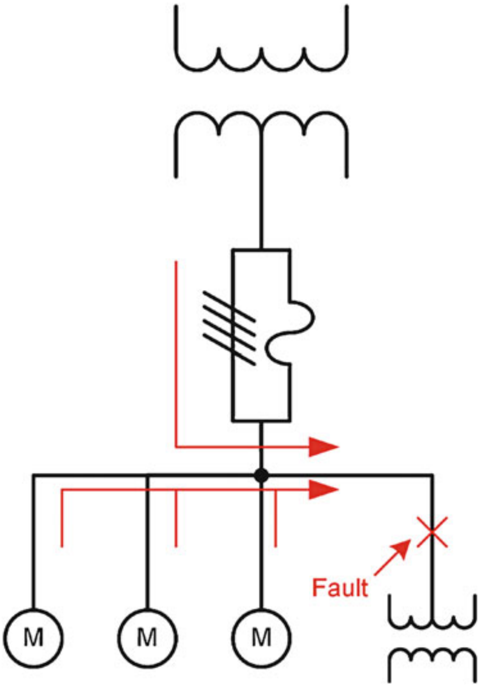


Fig. 13.16 Example of an arc flash mitigation installation

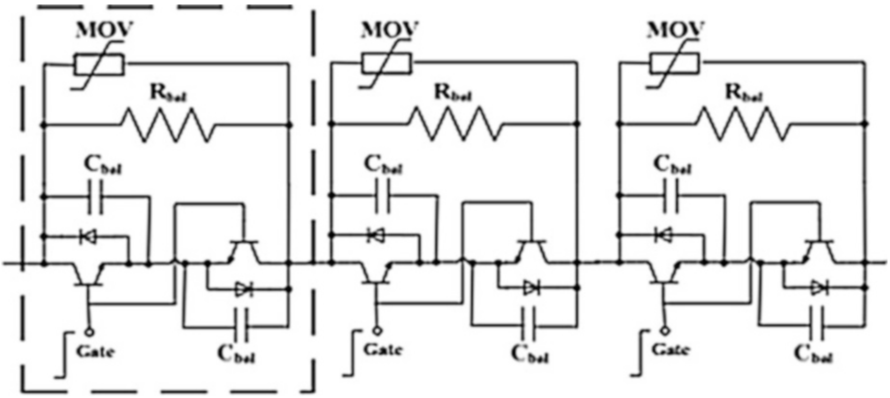


Fig. 13.17 Typical semiconductor switch design used in FCL applications (Vodyakho et al. 2011)

13.4.8 Superconducting FCLs

13.4.8.1 Technology Overview

Superconducting fault current limiters (SFCL) exploit the intrinsic property of super conducting material. The superconductivity property provides low losses ($<1\%$) in normal operation as the superconductive material is cooled to a temperature just

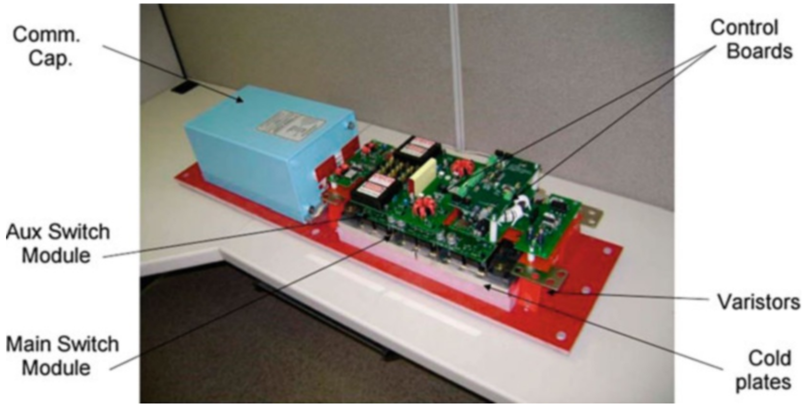


Fig. 13.18 Solid-state fault current limiter modular design (Sundaram and Gandhi 2008)

below its Curie temperature. The Curie temperature is the critical temperature where the superconducting material becomes superconductive if cooled below this temperature. If the superconducting material's temperature is above the Curie temperature for that material, it is no longer behaving as a superconducting material. The SFCL takes advantage of this property by cooling the superconducting material (YBCO is the most common at the time of this book) just below its Curie temperature through cycling liquid nitrogen. In normal operation, the SFCL's temperature will be below the Curie temperature. Upon a short-circuit event, the superconducting material experiences a rise in temperature due to the extra current flowing through the device. The increased temperature will exceed the material's Curie temperature and cause a 2nd order phase transition from a superconducting state to a nonsuperconducting state. While in a nonsuperconducting state, the SFCL has a large impedance which may be resistive or an inductive impedance. Resistive SFCLs are the most common. After a short circuit has subsided, the SFCL is cooled below its Curie temperature and reenters a superconducting state appearing "invisible" to the system. One area of concern is the time it takes to reenter the superconducting state after an operation occurs. This time may vary from a few seconds up to 10 or 15 min. While not in a superconducting state, the system experiences increased losses.

Recent developments in high temperature superconductors (HTS) that use liquid nitrogen have sparked a renewed interest in superconducting FCLs. It is much cheaper and simpler to build and operate cryogenic equipment involving liquid nitrogen systems as compared to the previously used liquid helium systems. Superconducting FCLs may be broadly classified into quench and non-quench types. A quench-type FCL offers effectively zero impedance due to a superconducting state under normal conditions. A fault would trigger the superconductor to quench, and increased impedance would provide the desired limiting of the fault current. In a non-quench-type FCL, such as a saturable-core-type FCL, the superconductor is always in the superconducting state, and the fault current limiting takes place as a result of a change in magnetic saturation caused by AC fault current.

13.4.8.2 Applications

An FCL of this type can be applied to reduce the available fault current to a lower, safer level where the existing switchgear can still protect the grid. FCLs employing high temperature superconductors (HTS) provide the necessary current limiting impedance during a fault condition but have essentially zero impedance during normal grid operation. Therefore, HTS FCLs typically have negligible impact on overall system performance, in contrast to other conventional current limiting devices, such as a CLR that produces a constant voltage drop and energy loss.

The degree of necessary short-circuit current limitation (dynamic current limitation as a function of time) will be derived from the grid analysis taking into account the relevant behavior of the FCL under consideration. Based on the results of these calculations, the manufacturer will derive the necessary design criteria for the FCL, e.g., maximum limited current with FCL and minimum initiating current (i_{min}) at which the trigger/tripping of the FCL starts. An example of an SFCL is shown in Fig. 13.19.

13.4.8.3 Power Transfer Application

Another application for superconductors is the application of power transfer. A superconductor is capable of carrying a greater amount of current than its non-superconductor counterpart for the same cross-sectional area of the conductor. Therefore, superconductors are capable of carrying large amount of power for their physical size. While this is not a fault current limiting application, it is a viable and promising application for this technology. Power transfer applications can yield power transfers up to ten times or more when using a superconducting cable versus a nonsuperconducting one (AMSC 2016). There have been a couple of installations worldwide as this application is still in the proof of concept phase and is not wide spread at the moment. An example installation is show in Fig. 13.20.

13.4.9 Saturable-Core FCL

A saturable-core FCL (SCFCL) consists of two magnetic cores wound in magnetically opposite directions (see figure below) with a DC bias system wound around the common (middle leg) to keep the magnetic cores in a saturated state during normal operation. While the cores are saturated, they exhibit low losses (<1–2%) (Vodyakho et al. 2011). One of the two magnetic cores is in a saturated state for the positive half of the AC sinusoidal wave, while the second core is in a saturated state for the negative portion of the AC sinusoidal wave. Upon a short-circuit current, for each half cycle, the cores enter and exit saturation depending on if the current is in the positive or negative half cycle of the AC sinusoidal waveform. A simplified overview of the internal configuration of an SCFCL is shown in Fig. 13.21.

Hysteresis and saturation are common phenomena with magnetic cores and must be taken into account when designing an SCFCL (Moriconi et al. 2010). The fault current subjected to the SCFCL cannot transition the magnetic cores into saturation

Fig. 13.19 A 12 kV, 800 A SFCL

Fig. 13.20 HTS superconducting cable installation in Germany for power transfer

during the half cycle that the cores are designed to limit the fault. Otherwise, little impedance will be provided, and the SCFCL would act as if it was invisible in the system providing no limitation. Different magnetic materials have different hysteresis curves and saturation points. An example of a hysteresis curve is shown in Fig. 13.22.

Many of the SCFCL have trial installations in both medium- and high-voltage installations across the world, and their use is starting to increase, especially in high-voltage installations where they now become more economically viable as compared to medium voltage. Some of the alternative technologies listed in this chapter are economically more advantageous than the SCFCL.

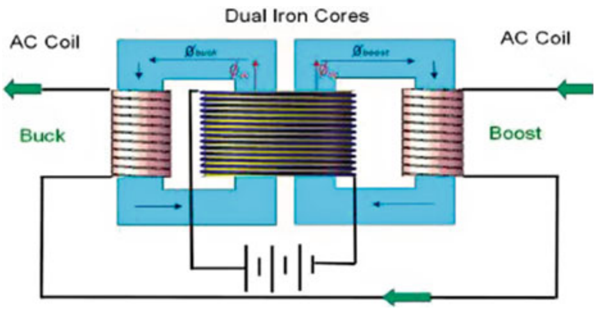


Fig. 13.21 A saturable-core FCL magnetic design (Noe et al. 2008)

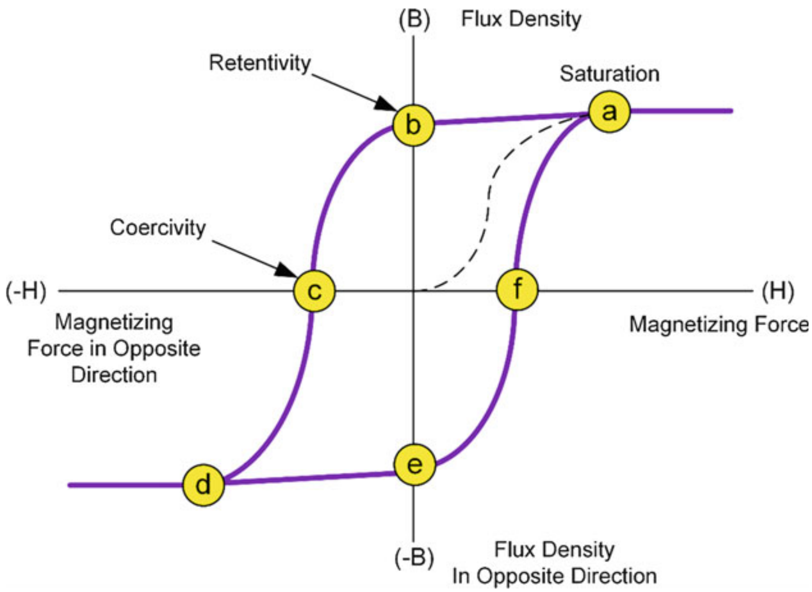


Fig. 13.22 Hysteresis curve with critical points for a magnetic core

13.5 Fault Current Management

Fault current management represents the primarily intended impact of an FCL application. Implication management comprises physical impacts or site effects of FCL applications. These "by-products" are either partly intended or not intended. On the other hand, they are partly advantageous and disadvantageous under operational aspects of the grid. Hence a detailed investigation of these "by-products" is advisable. The main subjects of impacts and interactions can be structured as follows:

- Transient stability (rotor angle stability)
- Protection system impacts

- Transient response (TRV) for both the system and the FCL
- Power quality (voltage drop, fault recovery, harmonics, ferroresonances)
- Thermal losses
- Number of operations
- Maintenance

13.6 FCL and Protection Systems

System protection is a critical part of a power system. Possible interactions between FCLs and protection systems have to be investigated and understood. Different types of FCLs, protection functions, and network configurations lead to a rather complicated investigation due to the multiple possibilities for interactions. Manufacturers of the FCL equipment may be able to assist in determining some of the impacts the FCL may have on the system if installed. It must be mentioned that installing an FCL typically outweighs any potential negative impacts on the power system.

13.7 FCL and Power Quality

The following three aspects of power quality are of importance in conjunction with the use of fault current limiters

- Voltage drop (voltage regulation)
- Harmonics
- Ferroresonance

A distinction also has to be made between the power quality during the normal operation of a fault current limiter (i.e., without limiting action) and during the current limiting process. Each type of FCL may have different characteristics and effects on power quality than others. An investigation may be necessary to determine if any detrimental effects occur if installing a particular FCL. Some types of FCL may have more of an effect than others.

13.8 FCL Reliability and Availability

From a reliability and availability standpoint, FCLs can be broadly classified into two groups; those that require a control signal to operate and those that don't. For example, a solid-state FCL typically requires a current sensor and processing circuitry to determine when phase current exceeds a threshold (becomes a fault) such that the power semiconductor switches should be turned off to limit the fault current. By contrast, a superconducting FCL needs no control signal as triggering, and current limiting is inherent in the technology.

"Active" versus "passive" is another way to classify FCLs. Active FCLs, those that require a control signal to perform their function, should be thoroughly investigated to determine if the likelihood of a single point failure within the control signal path is sufficient to require redundancy. For example, if the current sensor and associated control circuitry is integrated within the FCL and its functionality is validated at the factory before installation, redundancy may not be required. Even so, system-level testing should be performed to make sure other factors do not interfere with the proper operation of the controls. For example, if a voltage sag resulting from a fault causes the power supply feeding the controls to collapse such that the controls do not respond to the fault, then a redundant (backup) source of control power is required. If an external power supply for an FCL's control system is used to power the control system, it should come from a reliable source like a UPS or DC station batteries. The power source used to trip the system breakers is generally the best source to power the FCL's control system.

Going back to the original example, if the active FCL requires an external current transformer (CT) located elsewhere in the substation to serve as the control current sensor, now the likelihood of a single point failure is greatly increased as more cable runs, connection points, test switches, etc. will be present in the control signal flow path. A second CT placed at a second location and wired with a second cable that follows a second spatially separated path back to the FCL control circuits may be required to reduce the likelihood of a failure to an acceptable level. For active FCLs, a failure mode and effects analysis (FMEA) is the recommended method to identify the sources and assess the likelihood of single point failures in the control path. The safety integrity level (SIL) may also be used to determine the overall reliability of the FCL's control system.

13.9 Maintenance

As has been mentioned, high FCL system availability can be achieved through redundancy provided the failure is automatically detected and communicated such that corrective action can be taken. Tools such as FMEA can be used in the design phase to determine what equipment needs to be redundant and data acquisition and remote monitoring can be used to predict when to schedule preventative maintenance. Routine maintenance is typically specified by the manufacturer and may even be performed by the manufacturer or a contractor.

13.10 Environmental Benefits

The environmental impact of fault current limiters has to be investigated on a case-by-case basis as there are many different locations and applications for fault current limiters in power systems. In general, the following benefits can be achieved by using fault current limiters:

- Reduction of losses
- Small footprint

- Preserves resources
- Use of liquid nitrogen

13.11 Needs, Requirements, Specification, and Selection Criteria

In the following, a set of detailed questions is listed which should be answered thoroughly by system planners/operators in order to deliver the necessary information about the FCL application. This information will be the basis for potential manufacturers enabling an adequate design of a fault current limiter. If users do not want to expose their system characteristics and future planning strategy, as that could affect competitiveness, the delivery of this information may be restricted through a confidentiality agreement between the user and the manufacturer.

13.11.1 Basic Characteristics of the System

- Rated frequency: frated
- Nominal voltage of the system (rms): Vnominal
- Rated continuous current (A): Inominal
- Rated circuit breaker making/breaking capacity:
- Peak/momentary rating of the circuit breakers:
- Short-circuit current flowing through in both directions:

13.11.2 Basic Data for the Insulation Coordination of the System

- Please specify the basics for insulation coordination according to IEC 60071 or IEEE 1313.1:
- Highest voltage of the system (rms): Vs
- Highest voltage for equipment (rms): Vm
- BIL (basic insulation level): lightning impulse withstand voltage
- Power frequency withstand voltage
- Maximum switching overvoltages (transient overvoltages)

13.11.3 Neutral Grounding in the System

The knowledge of the grounding system is necessary in order to have indications on the kind of faults which may occur in the system and to select the right level for the line-to-earth (ground) insulation.

The relevant neutral grounding for the grid where a FCL is intended to be installed can be:

- Isolated neutral (ungrounded)
- Solid grounding

- Impedance grounding (specify grounding impedance, R and X)
- Resonant grounding

13.11.4 Structure of the System

A detailed model of the system is necessary in order to run system studies (e.g., load flow and short-circuit current calculations) showing the necessity and the effects of fault current reduction measures. For this purpose, a single-line diagram of the system should be delivered, showing at least the relevant parts of the system in which the fault currents need to be reduced and which may be affected by the limiting effect of fault current limiting measures. A single-line diagram showing the current directions for faults at all locations should be supplied. The single-line diagram should include sub-transient, transient, and steady-state short-circuit current values. The current values should typically be represented as rms, sym, and peak values but may include rms, asym values. The manufacturer would need to know what current values are provided to them in the single-line diagram.

Different diagrams will be needed if the system topology is subject to changes according to operational conditions.

The single-line diagram should provide the following information:

- Specify power frequency impedances of all passive system elements shown in the single-line diagram, e.g., transformers (including zero sequence impedance), cables, overhead lines, limiting reactors, etc.
- Specify the points of neutral grounding (does this change according to operation conditions?).
- Specify the equivalent network impedance (power frequency impedance) of the supplying system (slack node).
- Indicate the loads (P and Q) at the nodes:
- Deliver actual values and indicate prospective changes for the future.
- Are there any loads showing transient or pulsating load behavior, e.g., motor startup, arc furnace, welding machine? If yes, give some indications on their location as well as overload factor and duration.
- What are the expected changes in your system, which lead to increasing of, short-circuit currents?
- Connection of new lines, connection of additional generating units, bus tie coupling.
- Which components require fault current limiting?
- Busbars, breakers, isolating switches, transformers, lines, grounding system, etc. Indicate their permissible short-circuit currents: (Ip, Ibreak).
- What is the reason for the desired fault current limiting?
- Dynamic mechanical strength, thermal withstand, breaking capacity.
- Indicate the concerned subsystem, substation, or equipment on the single-line diagram.

- Do you have an idea at which location in the grid a fault current limiter should be installed? If yes, please indicate location in the single-line diagram. Give a short justification for your choice.
- Indicate the short-circuit currents (Ip, Ibreak) in the branches without any limiting function.
- Prospective short-circuit currents, FCL bypassed.
- Indicate min and max values for different operating conditions in the system if relevant.
- What are the minimum required fault current at different locations and their relevant duration to retain existing protection coordination (including backup protection)?
- Deliver actual protection scheme, if possible.
- Do you have auto reclosing? If yes, provide details such as number of trials for reclosing and the relevant dead times.

13.12 Summary

As short-circuit currents continue to rise in power systems, FCLs can be viable options to power engineers to reduce the available fault current to within the existing system ratings so that the existing protection system (i.e., circuit breakers) can operate as intended (i.e., within its ratings). As different technologies mature and enter the market, there are multiple options and suppliers to choose from to provide the FCL products. Each FCL installation should be carefully engineered with technical support provided from the manufacturer. This chapter highlighted many types of FCL technologies that range in not only technical but also in market maturity.

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Controlled Switching

14

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Contents

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14.1 Introduction

Controlled switching systems (CSSs) have become an economical solution and are commonly used to reduce switching surges for various switching applications (CIGRE TF 13.01 1995, 1996). Recent developments of transformer switching taking account of the residual flux can effectively mitigate severe inrush currents and temporary overvoltages that may lead to false operation of protective relays and degradation in power quality. CSS combined with metal oxide surge arresters can reduce undesirable overvoltages caused by energization of a long transmission line and contributes to the optimization of insulation coordination. The limited number of applications for line switching in service up to 2005 may arise from initial difficulties due to insufficient technical considerations; however, the applications recently increase with a controller with highly processing capability. IEC62271–302 Technical Report titled “High voltage alternating current circuit breakers with intentionally non-simultaneous pole operation” was published to standardize the testing procedures required for CSS based on the recommended evaluation tests by CIGRE WG A3.07 (CIGRE WG13.07 1999, 2001). The CIGRE guide emphasizes the importance of compensation for the variations of the operating time because a CSS requires accurate operation consistency during the lifetime of circuit breaker. Variations of the operating times due to external variables such as ambient temperature, control voltage, and mechanical energy of the drives can be compensated by the controller using dependencies evaluated according to the testing requirements.

The number of installations has increased rapidly due to satisfactory service performance since the late 1990s. It is often specified for shunt capacitor and shunt reactor banks because it can provide several economic benefits such as elimination of closing resistors and extension of the maintenance interval of nozzle and contact. According to the CIGRE survey shown in Fig. 14.1, approximately 2800 controlled switching systems (CSSs) had been supplied and were installed around the world in 2001, and more than 16,000 units are now estimated to be in service in 2015. Before 1995, the number of the installations was limited because of technological immaturity, but the number has increased rapidly since the late 1990s when effective compensation algorithms became available using advanced sensors and reliable digital relay technologies. Nowadays 55–70% of the installations worldwide are applied to capacitor banks; however no CSSs are used for shunt capacitors in some countries, as the amplitude of the inrush currents is suppressed by fixed inductors, originally intended to reduce the 5th harmonics of the power frequency.

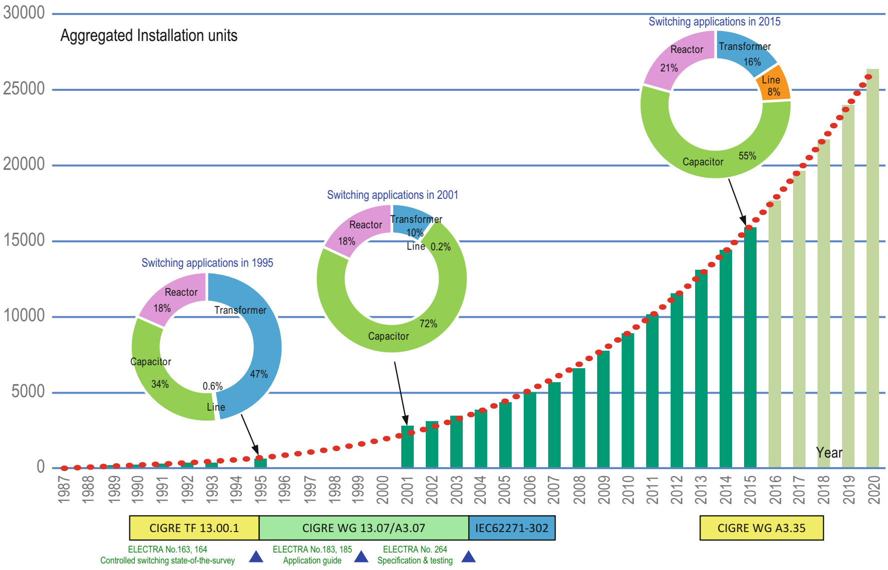


Fig. 14.1 CIGRE survey on worldwide installations of CSS in service

14.2 Definitions of Terminology

Controlled Switching

Circuit breaker applied with an electronic control equipment to facilitate operation of the contacts at a predetermined point in relation to an electrical reference signal for the purpose of reducing switching surges.

Note: The terms point-on-wave switching and point-on-cycle switching are also in widespread use to describe controlled switching; however it is preferable not to use synchronous switching in order to avoid confusion with different technology of synchronous switch.

Idle Time

The time between consecutive operations (either close or open operations) of a circuit breaker during which the circuit breaker remains static.

Compensation

Predictive correction for changes in operating time taking account of ambient, drive (operating mechanism), and supply conditions.

Adaptive Compensation

Correction for changes in operating time based on past operating pattern, for example, the change due to contact wear of circuit breaker or lubricant degradation of moving parts.

Controlled Switching System (CSS)
Circuit breaker, controller, and necessary sensors and auxiliary equipment required to achieve controlled switching.

Intentional Nonsimultaneous Pole Operation
Operation of a circuit breaker with a specific, predetermined time delay between the operations of the individual poles.

Mechanically Staggered Circuit Breaker
Circuit breaker with fixed, mechanically implemented, nonsimultaneous pole operation.

Independent Pole Operation
Circuit breaker with an independent operating mechanism for each pole, which can operate each pole at different instants.

Opening Time
Opening time of a circuit breaker defined according to the tripping method as stated below and with any time delay device forming an integral part of the circuit breaker adjusted to its minimum setting:

For a circuit breaker tripped by any form of auxiliary power, the opening time is the interval of time between the instant of energizing the opening release, the circuit breaker being in the closed position, and the instant when the arcing contacts have separated in all poles.

For a self-tripping circuit breaker, the opening time is the interval of time between the instant at which, the circuit breaker being in the closed position, the current in the main circuit reaches the operating value of the overcurrent release and the instant when the arcing contacts have separated in all poles.

Note 1: The opening time may vary with the breaking current.

Note 2: For circuit breakers with more than one interrupting unit per pole, the instant when the arcing contacts have separated in all poles is determined as the instant of contact separation in the first unit of the last pole.

Note 3: The opening time includes the operating time of any auxiliary equipment necessary to open the circuit breaker and forming an integral part of the circuit breaker. Delays introduced by controlled switching equipment are excluded from the opening time.

Note 4: For circuit breakers with mechanically staggered poles, separate opening times may be quoted for each pole.

Closing Time
Interval of time between energizing the closing circuit, the circuit breaker being in the open position, and the instant when the contacts touch in all poles.

Note 1: The closing time includes the operating time of any auxiliary equipment necessary to close the circuit breaker and forming an integral part of the circuit breaker. Delays introduced by controlled switching equipment are excluded from the closing time.

Note 2: For circuit breakers with mechanically staggered poles, separate closing times may be quoted for each pole.

Make Time
Interval of time between energizing the closing circuit (due to pre-arcing), the circuit breaker being in the open position, and the instant when the current begins to flow in the first pole.

Note 1: The make time includes the operating time of any auxiliary equipment necessary to close the circuit breaker and forming an integral part of the circuit breaker. Delays introduced by controlled switching equipment are excluded from the make time.

Note 2: The make time may vary, e.g., due to the variation of the pre-arcing time.

Mechanical Scatter
Random statistical variation of the mechanical operating time of a circuit breaker excluding the influence of external variables and the effect of long-term wear and/or drift.

NOTE: For the purposes of this definition, the term “external variables” includes all variables which might have a systematic effect on the operating time, e.g., ambient temperature, operating pressure, and control voltage.

Rate of Decrease of Dielectric Strength (RDDS)
Voltage withstand reduction as a function of time or contact gap during closing operation of a circuit breaker.

Rate of Rise of Dielectric Strength (RRDS)
Voltage withstand increase as a function of time or contact gap during opening operation of a circuit breaker.

Target Point for Closing
Prospective instant of contact touch during a controlled closing operation.

Target Point for Making
Prospective instant of current initiation during a controlled closing operation.

Target Point for Opening
Prospective instant of contact separation during a controlled opening operation.

Making Window
Total tolerance around the target point for making.

Note: Making within a correctly chosen making window will lead to a pre-determined making voltage. For practical values of RDDS, the center of the making time window may not correspond to the target point for making.

Closing Window
Time interval around the target point for closing.

Making Voltage
Voltage at which current is initiated in a closing circuit breaker.

14.3 Abbreviations

CB	Circuit breaker
CSS	Controlled switching system
MOSA	Metal oxide surge arrester
RDDS	Rate of decrease of dielectric strength
RRDS	Rate of rise of dielectric strength
TOV	Temporary overvoltage
TRV	Transient recovery voltage

14.4 Principles of Controlled Switching

Controlled switching is the term which is commonly used to describe the application of electronic control equipment (a controller) to facilitate operation of the contacts of a switching device at a predetermined point in relation to an electrical reference signal for the purpose of reducing switching surges.

CIGRE TF 13.01 collected examples of controlled switching systems (CSSs) (CIGRE TF 13.01 1995, 1996) based on international surveys of field experience. Since CSS requires accurate operation consistency, the guide emphasizes the importance of compensation for variations of the operating times. The following WG 13.07 published an application guide based on an international survey of the field experience in 1999 (CIGRE WG13.07 1999, 2001) and proposed testing requirements and procedures for the components and integrated system of CSS as summarized in Table 14.1 (CIGRE WG A3.07 2004a, b, c, d, e, f).

The components used for CSS are normally tested in the factory as a part of the routine and type tests. Factory testing items for circuit breakers include electrical performance tests such as dielectric characteristics, rate of decrease of dielectric strength, and rate of rise of dielectric strength, minimum arcing time for reignition-free window, as well as mechanical performance tests such as variations of the operating time due to operating conditions and delay of the operating time after an idle time. The controller and the related sensors are tested to verify its functions and electromagnetic, seismic, and environmental compatibilities. Finally, the controlled switching performance with the integrated system is demonstrated (CIGRE WG A3.07 2004f).

The term controlled opening (de-energization) refers to the technique of controlling the contact separation of each pole of a circuit breaker with respect to the phase angle of the current and thereby controlling arcing times in order to minimize stresses on the components of the power system.

Figure 14.2 provides typical timing sequence for controlled opening or de-energization.

To achieve controlled opening, the current through the circuit breaker or a reference voltage is monitored, for example, the controller often detects periodical current zeros for the reference signal. The arcing time for each pole is controlled by setting the instant of contact separation with respect to the current waveform.

Table 14.1 Testing requirements for the components and integrated system of CSS

Components and system	Test items	Characteristics/remarks
Type test for circuit breakers	Electrical performance	Rate of rise of dielectric strength (RRDS) Rate of decrease of dielectric strength (RDDS) Maximum making voltage for voltage zero target Minimum arcing time for restrike-free or reignition-free
	Mechanical performance	Scatter of operating times Variations of operating times on operating conditions Change of operating time after an idle time
Type tests for controllers and sensors	Functional test	Timing scatters of open/close commands All compensation functions Self-check function, etc.
	Electromagnetic, mechanical environmental	Dielectric withstand, EMI Vibration, shock, seismic Cold, dry heat, temperature/humidity, etc.
Commissioning tests for integrated system	Controlled switching test	Distribution of switching instants Distribution of making voltage Verification of restrike-free or reignition-free interruptions

The initial opening command is issued randomly with respect to the reference signal. This command is delayed in order to separate the contact of each phase independently (in case of independent-pole operation) when the circuit breaker can secure an optimum arcing time. It can substantially reduce the probability of restrike during consecutive capacitor de-energization or avoid reignition in case of reactor de-energization.

Similarly, the term controlled closing (energization) refers to the technique of controlling the instant of making (current initiation) with respect to the system voltage waveform (phase angle). Typical timing sequence for controlled closing (energization) targeted for voltage zero is given in Fig. 14.3.

For controlled closing, a source voltage is monitored by the controller. Again the closing command is issued randomly with respect to the reference signal. This command is delayed in order to make an optimum phase angle at closing of each voltage. The example relates to a capacitive load, where the optimum making instant is the voltage zero, which can be attained with an ideal circuit breaker which has infinite rate of decrease of dielectric strength (RDDS) with no mechanical scatter. Pre-arcing before contact touch is not considered. A practical case targeted for voltage zero is described in next sections.

In case of an inductive load, the optimum making instant is the voltage peak as shown in Fig. 14.4, where the pre-arcing time between the instant of prestrike and

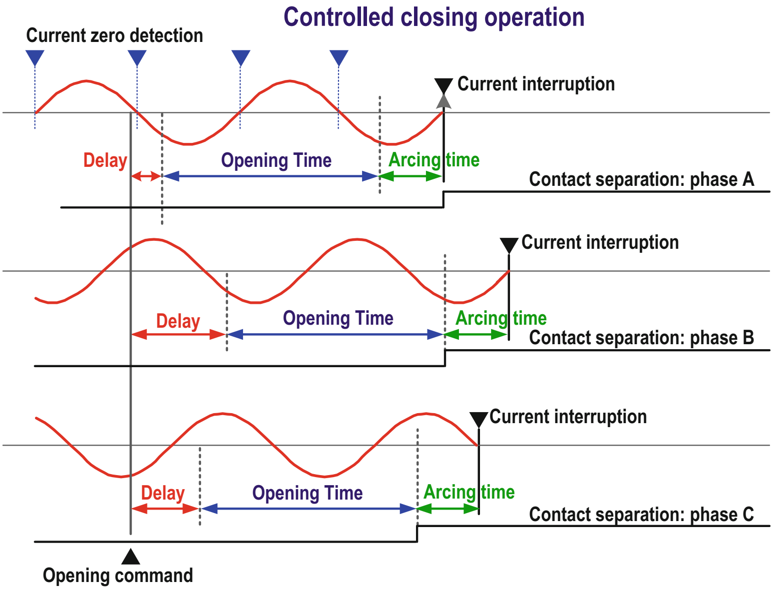


Fig. 14.2 Controlled opening

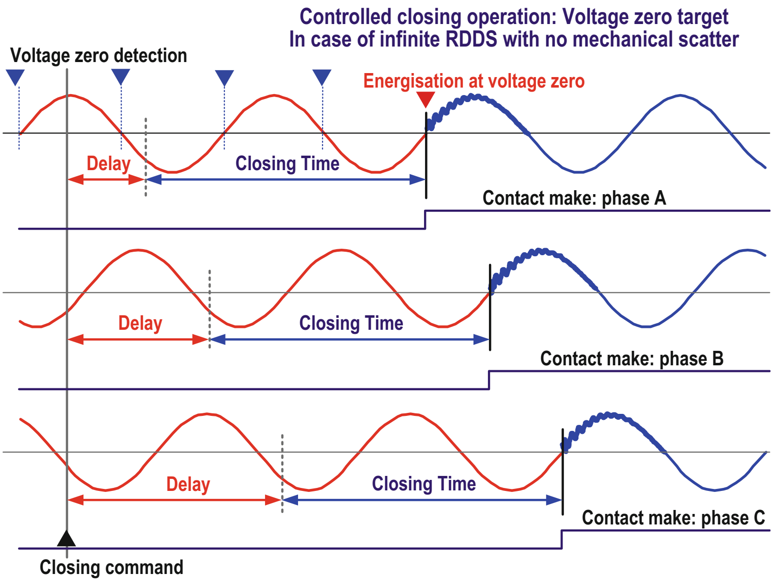


Fig. 14.3 Controlled closing at voltage zero

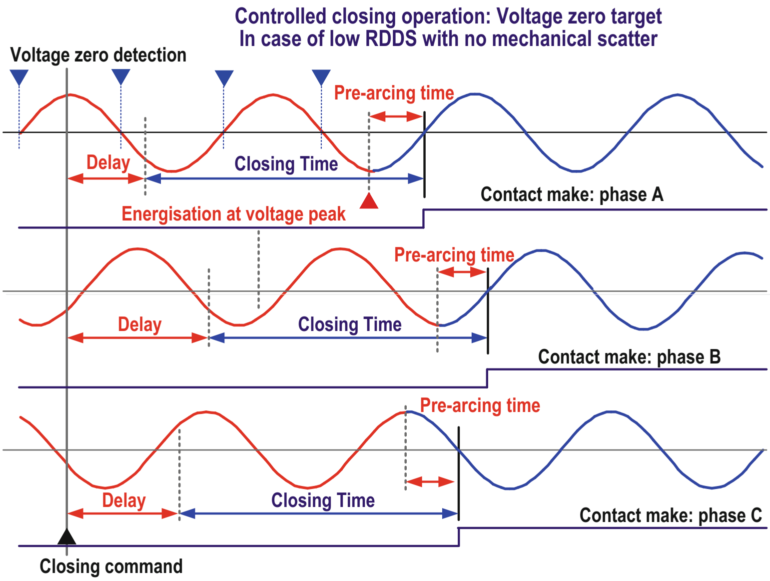


Fig. 14.4 Controlled closing at voltage peak

contact touch is assumed to be a quarter of a cycle. The closing time dependence on the operating conditions as well as the prestrike behavior is particular to each type of circuit breaker.

The optimum targets for different applications are summarized in Table 14.2.

The optimum making instant for a practical transformer is when the prospective normal core flux at energization is identical to the residual flux (CIGRE WG A3.07 2004a; Mercier et al. n.d.-a; Ito et al. n.d.). The strategy of voltage peak energization can be suited for a transformer with a large parallel capacitance that will result in a significant reduction of the residual flux after de-energization.

Modern SF_6 circuit breakers generally offer a very low probability of restrike for capacitive current interruption such that restrike-induced problems are rare. Nevertheless the probability of restrike can be further reduced by mean of controlled switching which is employed to ensure long arcing times and hence larger contact gaps at current interruption.

When controlled switching is applied to reactor de-energization, the optimum opening instant is often targeted for the long arcing time sufficient to eliminate the occurrence of reignitions, even though the use of controlled switching may increase the chopping overvoltages with an increase of pre-arcing time. This approach is adopted since reignition overvoltages are normally more severe than chopping overvoltages (especially for modern SF_6 circuit breakers).

In case of reactor switching, circuit breakers exhibit a high probability of reignition for arcing times less than a minimum arcing time, which may damage

Table 14.2 Optimum instants of controlled switching (CIGRE TF 13.01 1995, 1996)

Switching applications	Optimum instants of controlled switching	Benefits
No load transformer energization	Voltage peak with no residual flux or prospective core flux identical to the residual flux	Reduction of inrush current and associated overvoltage
No load line energization	Voltage zero across the circuit breaker	Reduction of overvoltage, elimination of closing resistor
Shunt capacitor energization	Voltage zero across the circuit breaker	Ditto
Shunt capacitor de-energization	Maximum arcing time	Minimization of restrike probability
Shunt reactor de-energization	Maximum arcing time (to avoid reignition)	Reduction of overvoltage, elimination of reignition probability

the nozzle and contacts of the circuit breaker. Conversely, chopping overvoltages may be prominent depending on the number of series-connected breaking units (to achieve its interrupting performance) and the capacitance across the circuit breaker, especially in case of an air blast circuit breaker. However, users must decide upon the relative importance of reignition versus current chopping.

14.5 Circuit Breaker Characteristics

14.5.1 Mechanical Operation Characteristics of Circuit Breakers

All practical circuit breakers exhibit some variations of operating times, and the absolute value of the variations of closing time is usually larger than that for the opening time, since the opening times are often less than half of the closing times. Since these variations may be relevant for the operating conditions, different approaches for corrections are used since they differ considerably for different types of circuit breakers.

First it is important to distinguish between predictable and purely statistical changes in operating times since any changes in operating times that can be predicted with sufficient accuracy by the controller do not reduce the effectiveness of controlled switching. The operating time ($T_{operating}$) of a circuit breaker can be expressed as:

$$T_{operating} = T_{nominal} + \Delta T_{predict} + \Delta T_{statistic}$$

$$\Delta T_{predict} = \Delta T_{comp} + \Delta T_{drift}$$

$T_{operating}$: Mean operating time under nominal operating conditions which is readily measured and programmed into the controller.

$\Delta T_{predict}$: Predictable variation of the operating time that can be corrected by the controller.

$\Delta T_{statistic}$: Purely statistical variation of the operating time that cannot be corrected by the controller.

ΔT_{comp}: The variations of the operating time with predetermined features, those depends on the operating conditions.

ΔT_{drift}: The variations of the operating time with adaptive features, such as long-term drift and wear-related changes.

The predictable variations of the operating times ($\Delta T_{predict}$) can be further split into those variations for which predetermined compensation can be applied (ΔT_{comp}) and those can be dealt with adaptive features (ΔT_{drift}).

The variations related to predetermined compensation (ΔT_{comp}) are readily measured by appropriate sensors, and transducers in the field and result in defined changes of the operating times can be compensated for. The typical parameters such as the control voltage ($V_{control}$), stored energy of the drive (e.g., hydraulic pressure, E_{drive}), and ambient temperature (T_{temp}) are often compensated by the controller.

The operating time used by the controller on any given occasion is adjusted, on the basis of sensor inputs, according to a known set of operating characteristics, which has been determined under well-defined operating conditions during the testing for each circuit breaker type:

$$\Delta T_{comp} = f\left(V_{control}, E_{drive}, T_{temp}\right)$$

Figure 14.5 shows the difference from the standard operating time with a spring operating mechanism plotted in the form of the mesh map showing the operating time dependence on the ambient temperature and the control voltage. The mesh map can be installed into the controller as the common characteristics for the same type of the breaker having a slightly different average operating time due to design tolerance.

Adaptive control refers to the use of previously measured operating times to detect changes in operating characteristics and to predict the operating times for the next operation. Adaptive control can effectively compensate for any drift in operating times which persists over a number of consecutive operations such as that associated with long-term aging and wear.

Various algorithms may be used and a simple example for purely adaptive control is given here:

$$\begin{aligned} T_{\text{next }(n+1)\text{ operation}} = {} & T_{\text{last }(n)\text{ operation}} + \sum W_n \\ & \times \left(T_{\text{nominal of } n \text{ operation}} - T_{\text{nominal of } n-1 \text{ operation}}\right) \end{aligned}$$

The weighting factor W_n determines to what extent the measured changes of operating times are taken into account. To ensure that statistical and periodic changes are not amplified, W_n is limited to be less than 1.

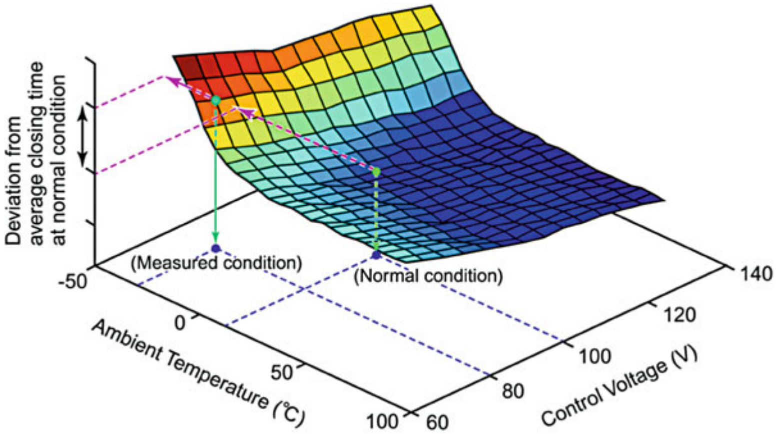


Fig. 14.5 Deviation from the mean operating time polled as functions of the ambient temperature and the control voltage

Gas circuit breakers are commonly designed using several sliding parts such as contacts and sliding seal rubbing between metal surfaces during close and open operations. As a result, operating characteristics are affected by the change of friction or sticking force on the surfaces of these parts due to long-term aging and wear. As the change will progress considerably slowly, the adaptive control can effectively compensate for the drifts of operating time caused by the consecutive operations. The effect of adaptive control varies with the number of previously measured operating times and their weighting factors. These parameters are decided by detailed investigations of a series of mechanical endurance tests.

Figure 14.6 shows the typical drifts of the closing time measured with and without adaptive control over 1500 operations of 145 kV circuit breaker with spring operating mechanism. The variation of the closing time is given by the difference between the predicted closing time and the result. Although the closing time becomes longer with the increase in the number of operations, the closing time could be effectively compensated with good accuracy by the adaptive control. When the controller is able to detect the making instant directly by measuring the main circuit current, the rate of decrease of dielectric strength (RDDS) characteristics can also be compensated to the actual value with this adaptive control. The width of deviation was decreased from +4.1/−1.2 ms to +1.2/−1.2 ms with the adaptive control.

Some inherent statistical scatter of the operating times will occur even at identical operating parameters and ambient conditions. The degree of scatter may depend on the operating/ambient conditions (e.g., ambient temperature and idle time). Statistical scatter of the operating time has an important impact on the effectiveness of controlled switching and may present an inherent limitation to the applications.

The scatter is best described by a standard deviation (σ_{mech}) and can be assessed by performing operations under operating conditions identical to those experienced in the field. The maximum scatter may be approximated by $\Delta T_{statistic} = 3\sigma_{mech}$.

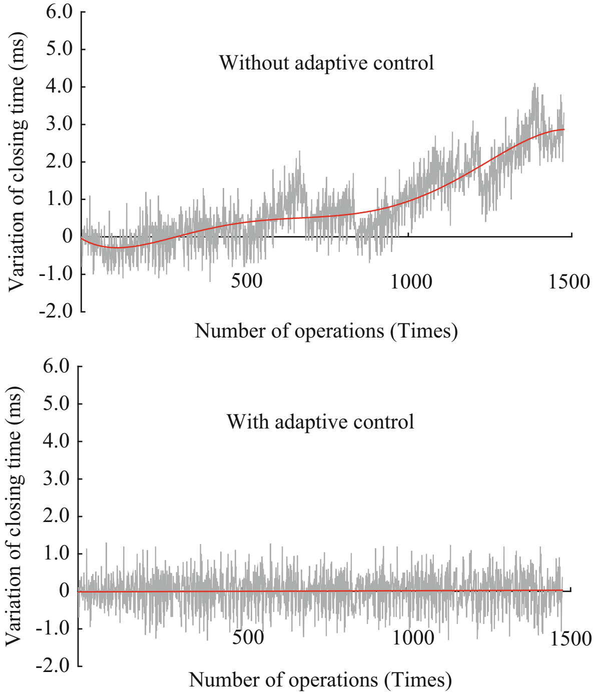


Fig. 14.6 Typical drift of the closing time measured with and without adaptive control

The inherent statistical scatters of the closing and opening times were investigated for the different control voltages and the different ambient temperatures using a 145 kV independent-pole spring-operated gas circuit breaker. The voltage and temperature dependence of the closing and opening times for 40 operations are evaluated, and the scatters from the average closing and opening times are shown in Fig. 14.7. They show that the appropriate compensation for the breaker can decrease its maximum scatter within ± 1.0 ms around the closing target.

The idle time dependence of the drive is potentially one of the major limitations of controlled switching in case of the controller without the idle time compensation function when the drive shows a certain delay on this characteristic.

Figure 14.8 shows the idle time dependence of spring-operated mechanisms for 145 kV–362 kV ratings and of a conventional hydraulic-operated mechanism for 300 kV. These characteristics were evaluated for operating cycles of C-O-C-O after idle times of 2, 4, 8, 16, 64, 128, 256, and 720 h repeatedly. The spring operating mechanisms have lubricating coating on its main sliding parts and show small idle time dependence up to 1000 h. However, the test results with a conventional hydraulic drive reveal that the increase of closing time is observed from several hours of idle time and stabilizes at the maximum delay of about 2.0 ms if the idle time exceeds 72 h. The requirement of the idle time compensation can be judged from a measurement up to 100 h.

The friction force between these moving parts of a circuit breaker varies with the change of the properties of the lubricant due to long-term aging and evaporation. This is

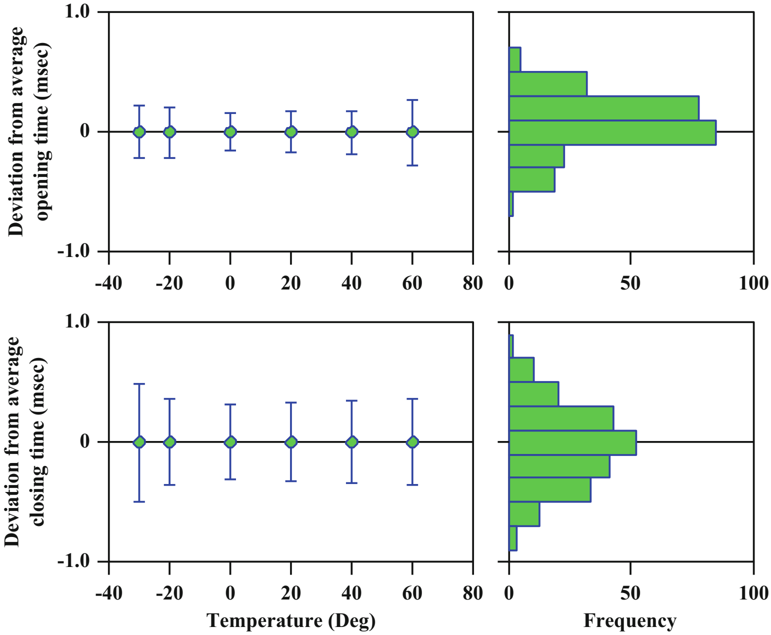


Fig. 14.7 Variation from average opening and closing time for different ambient temperatures

one reason for the change of the operating time after a certain idle time. Another reason for the delay in hydraulic drives is ascribed to the dissolved air in the hydraulic fluid that can appear as bubbles when a pressure is released during operation. The bubbles in hydraulic fluid may delay the response of hydraulic piston movement at the next operation. Figure 14.9 shows an example of the closing time delay of a 204 kV hydraulic-operated gas circuit breaker. The operating mechanisms, of which operating times have time dependence, show the increase of the closing time after a few hours, and the value is saturated around 1.4 ms after 100 h.

14.5.2 Electrical Characteristics of Circuit Breakers

For a given contact gap, there is a certain voltage level at which the contact gap will break down and current will be initiated. Without considering arcing, a first approximation of the dielectric strength may be a linear increase with gap spacing after the contact separation. Knowing the travel characteristics of the circuit breaker contacts, the rate of rise of dielectric strength (RRDS) may be time-dependent characteristic.

When interrupting capacitive currents, there is a certain probability of reignition for particular circuit breakers, depending upon the contact gap at current zero and the RRDS. The application of controlled capacitor de-energization facilitates current interruption with a relatively large contact gap, since dielectric strength can be considered to increase with contact gap. The application of CSS for small capacitive

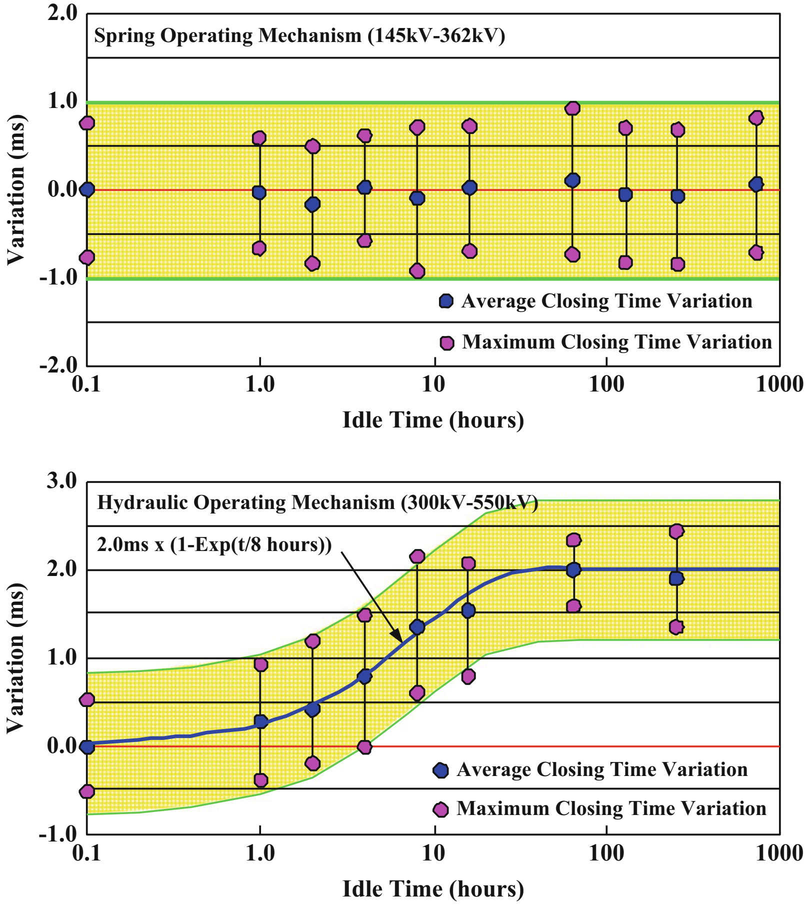


Fig. 14.8 Idle time dependence of the circuit breakers with the spring operating mechanisms and a conventional hydraulic operating mechanism

current interruption can avoid small arcing times, and therefore the dielectric stresses and reignition probabilities can be markedly reduced.

When interrupting small inductive currents, there is again a certain probability of reignitions since the contact gap at current zero may not be sufficient to withstand the recovery voltages, which is determined by the chopping current levels and load characteristics. The arcing time and therefore the contact gap at current zero should be large enough to ensure interruption without reignitions. The application of CSS is the appropriate method of achieving reignition-free interruption.

On the other hand, the mean value of the decrease of the withstand voltage can be approximated by a linear function of time when the contacts are close to touching during the closing stroke. The slope (rate of decrease of dielectric strength (RDDS)) is proportional to the mean value of the closing velocity and the gas pressure for

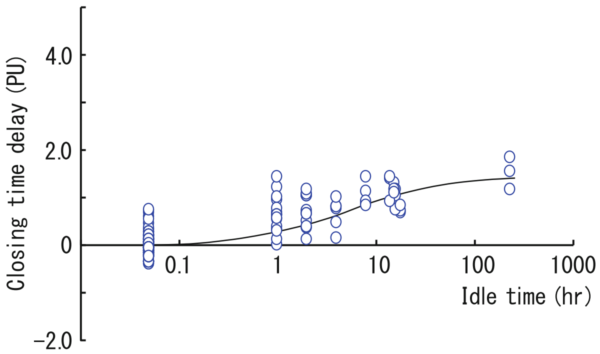


Fig. 14.9 Closing time dependence on idle time with 204 kV hydraulic-operated gas circuit breaker

gas-blast circuit breakers. The making (prestrike) instant is when the voltage across the circuit breaker exceeds the dielectric withstand strength of the contact gap.

For an ideal circuit breaker, the RDDS is infinite, while typical practical RDDS values are in the range of 35 kV/ms up to 100 kV/ms per break. It is important to note that values of the normalized RDDS (which is normalized by the rate of rise of the system voltage at voltage zero crossing) smaller than unity do not necessarily limit the use of a particular circuit breaker for CSS.

The statistical nature of dielectric breakdown has a significant influence of the RDDS. The actual withstand of the contact gap is a statistical property and exhibits some scatter, which may be given by the standard deviation of the withstand voltage distributions ($3\sigma_{\text{electrical}}$).

For example, Fig. 14.10 shows a typical measurement of prestrike characteristic plotted with a cycle of power frequency. Each gradient calculated by an inverse-tangent value of a prestrike voltage divided by a pre-arcing time (from the instant of prestrike to contact touching) gives the RDDS value of the circuit breaker. Figure 14.10 also shows the results of the RDDS, which is normalized by a gradient of the system voltage at the zero crossing point. The normalized RDDS shows the average value of 1.37 for positive polarity and 1.34 for negative polarity. The RDDS shows little dependence on the polarity of voltage.

Figure 14.11 illustrates the making instant for a voltage zero target which results from a mechanical variation of the closing time and an electrical variation of the prestrike behavior. The broken lines are due to RDDS variations (Δk), and the solid lines are due to mechanical variations (ΔT_{making}). Any value of the making voltage which lies within the range bounded by the outer lines can occur at the actual making voltage. The corresponding making time window is defined by $\pm\, \Delta T_{\text{making}}$ around voltage zero.

Taking this into account, the target point must be set such that symmetry of the making voltages on both the falling and rising slope is achieved. From this graph it is clear that a slight shift of the target contact touch to the left results in a doubling of the maximum making voltage, while a small shift to the right will change the maximum making voltage only slightly.

Figure 14.12 shows the making voltages for the target points covering a complete half cycle at 50 Hz in the case of the nominal RDDS = 1.0 with the electrical

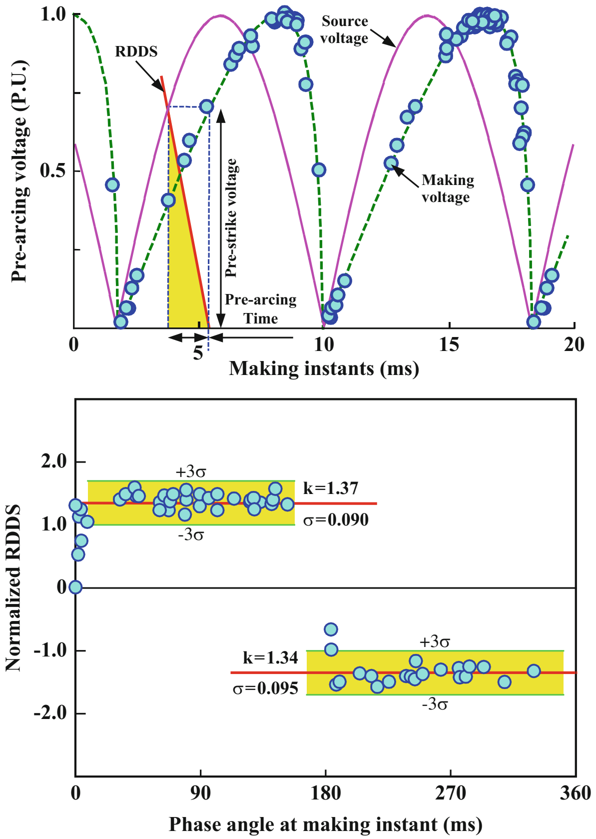


Fig. 14.10 RDDS measurement obtained by prestrike test

variation of ±20% and no mechanical scatter. If a mechanical scatter of $\Delta T_{making} = \pm 1$ ms is taken into account, the making voltage will be approximately 0.8 pu at maximum when the target point is set to 1.2 ms. However, the choice of 1.3 ms will limit the making voltage to only 0.3 pu.

The making instant for voltage peak target is optimized when the symmetrical making voltages on the both the falling and rising slope around the voltage peak are achieved. Figure 14.13 illustrates the making instant for voltage peak target considering a mechanical variation of the closing time and an electrical variation similarly shown in Fig. 14.11. The corresponding making time window is defined by $\pm \Delta T_{making}$ around voltage peak. It is notable that an unrealistically low value of the RDDS ensures making in the vicinity of voltage peak no matter how large the mechanical scatter might be.

Figure 14.14 shows the field performance of closing instants with 204 kV gas circuit breaker for GIS that show a normal distribution around the target closing instant of 79 electrical degrees (voltage peak target) with a standard deviation of less than 0.5 ms. The minimum making voltage is 0.8 pu.

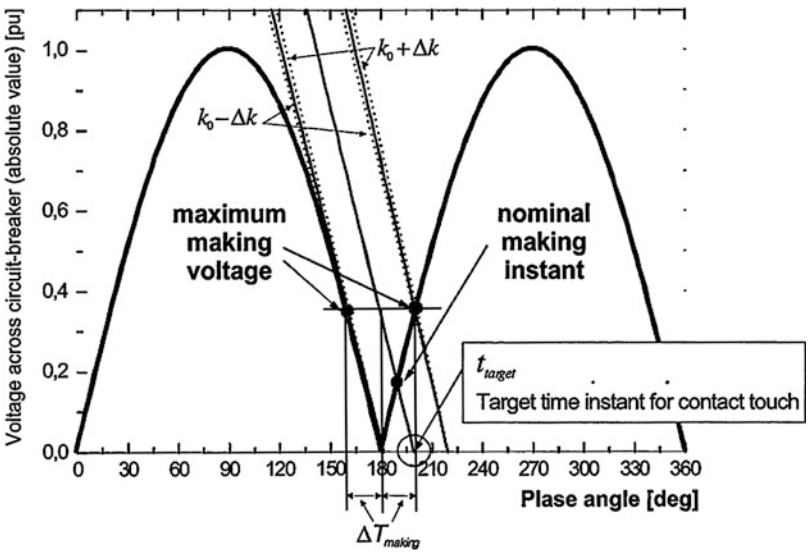
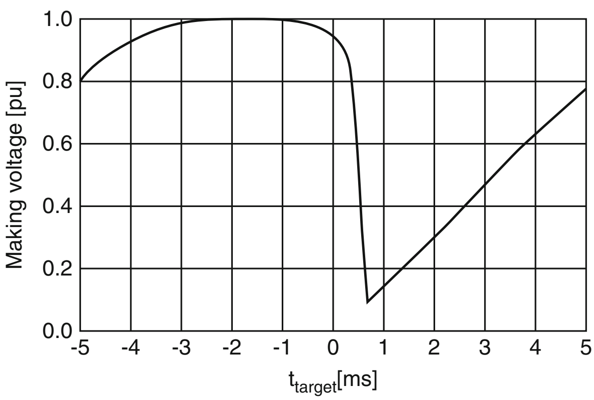


Fig. 14.11 Prestrike characteristic and influence of mechanical and electrical variation for voltage zero target

Fig. 14.12 Making voltages for the target points covering a complete half cycle (RDDS = 1.0 ± 20%) with no mechanical scatter at 50 Hz (for 60 Hz, times are to be multiplied by 5/6)



An overall probability distribution of making voltage may be evaluated to yield the 2% value of the making voltage for specific RDDS with electrical and mechanical variations. An example of this approach is shown in Fig. 14.15 in the case that RDDS = 1.2 and $\Delta T_{mech} = \pm 2$ ms. The minimum is the optimum nominal target point for making at voltage zero. To add an additional safety margin, it is recommended that in practice the actual target point is shifted further to the right when making at voltage zero is considered.

Figure 14.16 summarizes the dependence of the minimum making voltage on the RDDS and the mechanical variations bands. The correlation can be applied to circuit

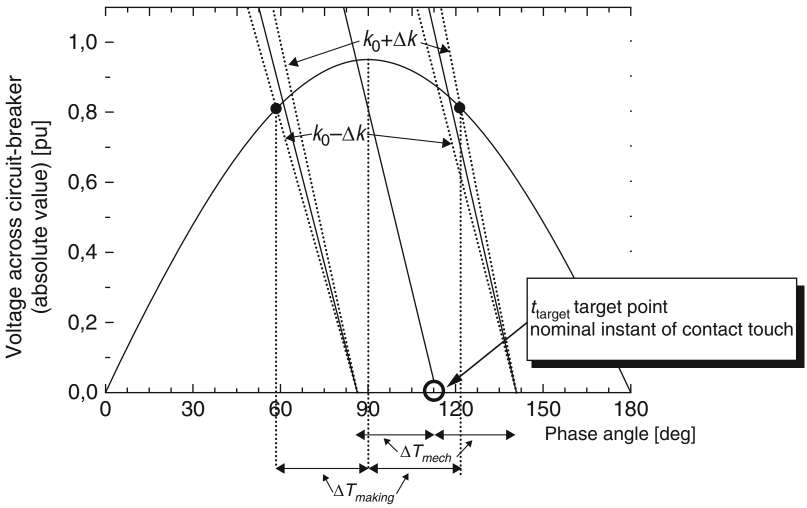


Fig. 14.13 Prestrike characteristic and influence of mechanical and electrical variation for voltage peak target

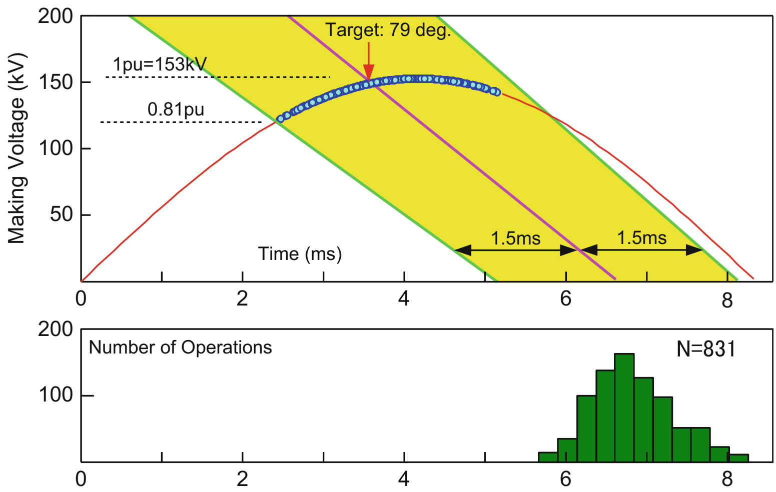


Fig. 14.14 Distribution of making voltages and closing instant during controlled reactor switching

breakers of all the ratings. In case of RDDS = 1, the minimum making voltage becomes around 0.4 pu using a circuit breaker with the mechanical variations bands of +/−1.0 ms. The optimal targets for voltage minimum are also shown as functions of the RDDS and the mechanical variations bands.

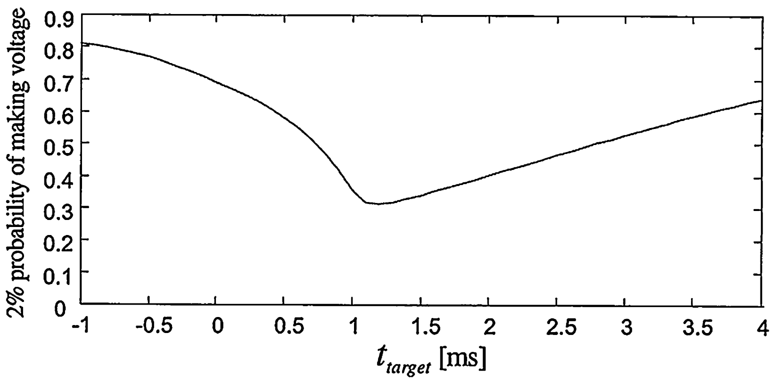


Fig. 14.15 2% probability value of making voltage as function of target point (system voltage zero at 0 ms)

14.6 Basic Controlled Switching Strategies

14.6.1 Capacitive Switching Applications

Controlled switching of shunt capacitor banks is used to minimize stresses on the power system and its components. Controlled closing reduces the magnitude of inrush currents and the associated overvoltages. It provides an alternative to the use of fixed inductors. Controlled opening allows for a reduction in the probability of restrikes of the circuit breaker. Switching of single capacitor banks leads to higher local and remote overvoltages, while the back-to-back switching condition generates inrush currents of larger magnitudes.

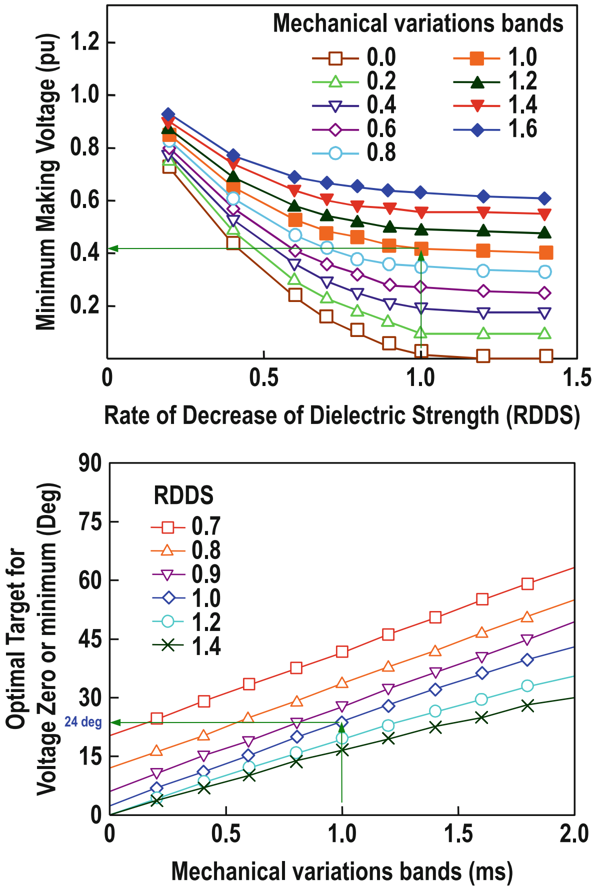
The energization of shunt capacitor banks causes local effects in the substation and remote effects at the receiving end of transmission lines connected to the substation. Local effects include inrush currents and overvoltages, mechanical and dielectric stresses in the capacitor bank and other equipment in the substation, erosion of the circuit breaker contacts, transient potential rise of the substation earthing mesh, and transient surges coupling to control and protection wiring. Remote effects include overvoltages at the far end of radial connected transmission lines as well as overvoltages generated in MV and LV networks connected to the secondary of transformers at the end of these lines.

The optimum making instant for wye-connected, earthed-neutral, shunt capacitor banks should be energized at the instant of voltage zero across the circuit breaker in each phase.

Figure 14.17 shows an example of inrush current evaluation when energizing 145 kV capacitor banks. The maximum inrush current attains 4.9 pu of the nominal current, which can be suppressed less than 2.4 pu with CSS.

After calibration, controlled switching tests were performed at the system voltage of 121 kV using the target for closing operation of 8 electrical degrees determined by

Fig. 14.16 Minimum making voltage and optimal target for voltage zero or voltage minimum as functions of the RDDS and mechanical variations bands of gas circuit breaker



the characteristics of RDDS and mechanical scatter plus a slight safety factor. The target for the opening operation is set as a maximum arcing time before the current zero.

Figure 14.18 shows the voltage and current waveforms of the second, third, and sixth results of ten controlled energization tests conducted during the commissioning tests. For the first making test, the making instant of the third phase shows a slight delay even though the inrush current of 1290 A is within the permissible tolerance. This delay is probably caused by a difference of the actual RDDS due to design tolerances of the interrupter dimension or a closing velocity scatter. The controller applied to this circuit breaker can compensate for such difference by adaptive control.

The circuit breaker with the normalized RDDS of less than 1 can be applied to capacitor switching because the inrush current can be sufficiently suppressed if the making voltage is less than half of the maximum prestrike voltage. The idle time compensation is recommended for the drives of which operating times have the idle time dependence. The adaptive control is also required to compensate for any drift in operating times that persist over a number of consecutive operations.

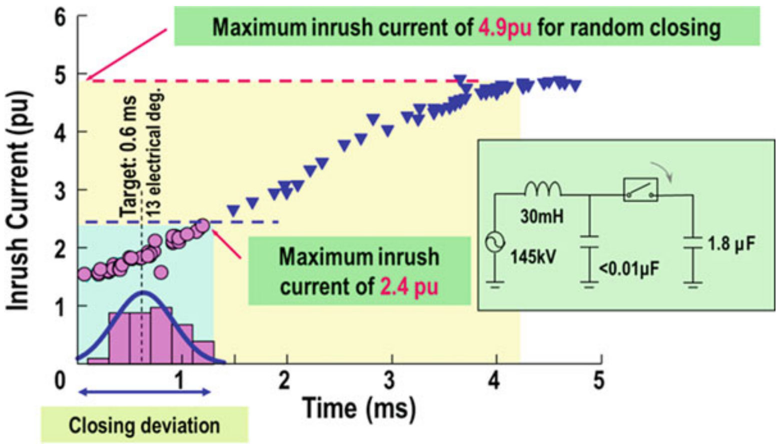


Fig. 14.17 Example of analytical inrush currents when energizing 145 kV capacitor banks

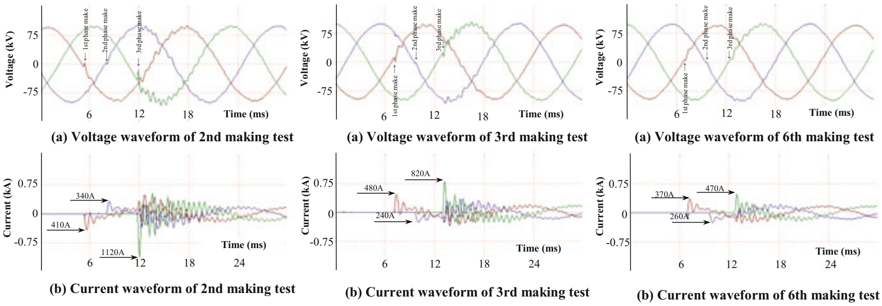


Fig. 14.18 Waveforms of 2nd, 3rd, and 6th controlled energization test using 121 kV CSS in the field

The controlled switching tests were performed at the system voltage of 145 kV using the target closing instant of 16 electrical degree determined by the measured RDDS and mechanical scatters. The circuit breaker has continued to operate daily in the field after the commissioning tests. Figure 14.19 shows the distribution of the closing instants measured by the controller with the distribution of making voltages calculated from the data. The results of closing instants showed a normal distribution around the closing target of 16 electrical degree with a small standard deviation less than 0.3 ms, which corresponds to the maximum making voltage of 0.35 pu.

14.6.2 Reactor Switching Applications

Shunt reactor switching has been recognized as a source of current and voltage transients. Overvoltages due to current chopping and reignition can prove dangerous

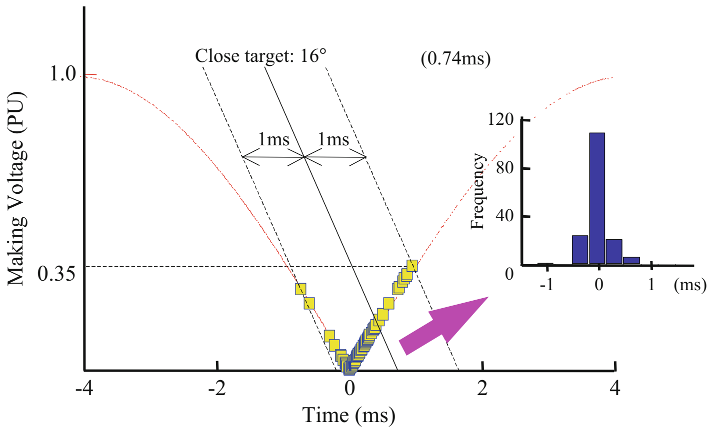


Fig. 14.19 Distributions of making voltages and closing instants

for all equipment. High asymmetrical inrush currents may be generated due to shunt reactor energization at an unfavorable instant. These inrush currents can provoke electromechanical stress or extended duration of high magnitude zero sequence current. Controlled switching may be applied to both cases in order to reduce the expected transients.

During the de-energization of shunt reactors, overvoltages may be generated by two different causes: current chopping and reignitions.

Chopping overvoltages are the consequence of the forced interruption of the inductive current before its natural zero. They mainly depend on the number of series-connected breaking units, the chopping number of the circuit breaker, the capacity (in MVA) of the reactor, the capacitance in parallel to the circuit breaker, and in certain cases, the arcing time. For modern SF_6 circuit breakers, chopping overvoltages (typically up to 1.5 pu level) are not too high, but they increase with arcing times.

Reignition overvoltages are generated by reignitions following initial interruption. Reignitions are provoked when the voltage between contacts exceeds the dielectric withstand of the contact gap. The rate of rise of voltage during a reignition is a range between lightning and fast-front transients depending on the length of the bus bar between circuit breaker and reactor, while chopping overvoltages are similar to slow-front transients (switching surge). Reignition may affect circuit breaker elements such as nozzle and contacts and reactor insulation. For example, perforation of insulating nozzle, signs of arcs external to the arcing contacts, and the metal particles in the interrupter have been reported. The CIGRE international reliability survey in the years of 2004–2007 shows the major failure frequencies for circuit breakers operating on shunt reactors are around one order of magnitude higher than for line and transformer breakers. Even though all types of circuit breakers are not damaged in the same way, it is desirable to eliminate reignitions.

All circuit breakers exhibit a high probability of reignition for arcing times less than a minimum arcing time (T_{amin}). Figure 14.20 shows a schematic drawing of the

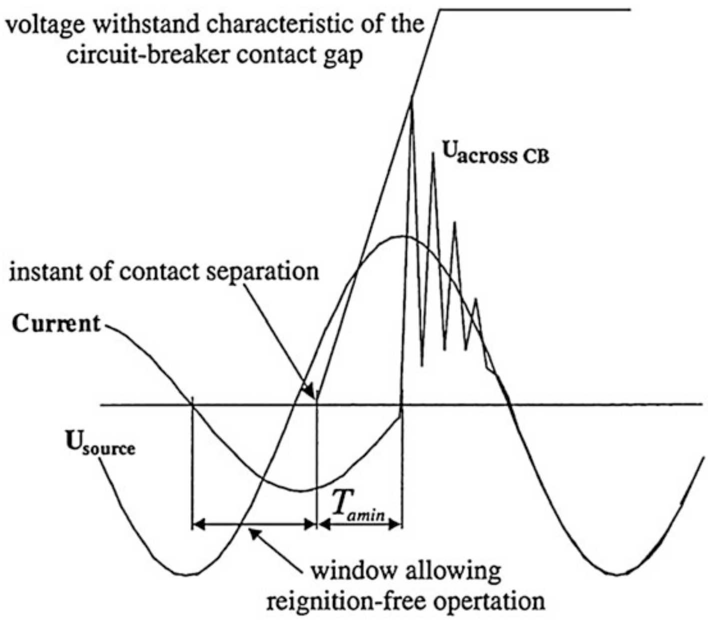


Fig. 14.20 Definition of minimum arcing time for reactor de-energization

voltage withstand characteristic of the circuit breaker along with the transient recovery voltage across the circuit breaker in case of reactor de-energization. Since the avoidance of the reignition window is the main criterion for elimination of reignitions, the optimum instant for contact separation is when the expected arcing time exceeds T_{amin}. When promoting increased arcing times in this way, it may be necessary to take into account that chopping overvoltages may increase with arcing time.

Since reignition overvoltages are normally more severe than chopping overvoltage, the use of controlled switching to increase arcing time is common. However, users must decide upon the relative importance of reignitions versus current chopping depending on the circuit breaker design.

The preceding demonstrates the benefits which are achieved by the application of controlled opening. However, there are certain cases where controlled opening provides little or no advantage. For example, tests of controlled reactor opening applied to a minimum oil circuit breaker were not successful due to presence of reignitions for all possible arcing times. In this case, controlled switching cannot avoid reignitions.

Figure 14.21 shows the distribution of the opening instants. The deviations of the opening instants are 0.21 ms, and all the de-energization are carried out within the reignition-free windows.

Figure 14.22 shows successful results of the voltage and current oscillograms for a 245 kV controlled shunt reactor de-energization and energization in the field. The maximum inrush current of 1270 A observed by random closing can be suppressed to below 50 A.

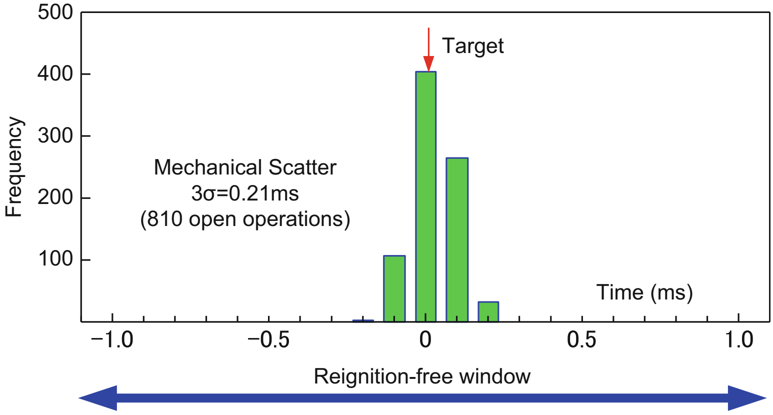


Fig. 14.21 Distribution of opening instant during controlled reactor opening

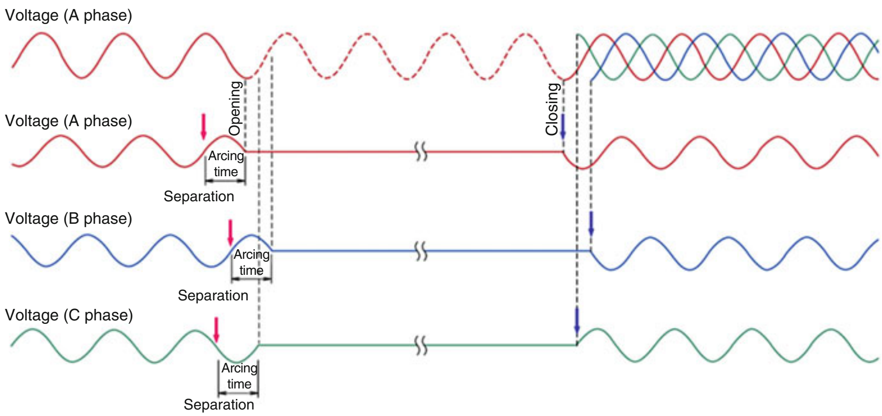


Fig. 14.22 Voltage and current behavior of controlled shunt reactor switching

14.6.3 Unloaded Transformer Energization

Energization of unloaded transformer can generate high-amplitude inrush currents, which stress the windings and can cause mal-operation of protection relays and prolonged temporary harmonic voltages, which in turn lead to degradation in the quality of electricity supply. High inrush currents also impose severe mechanical stresses on the transformer windings and may reduce the life expectancy of a transformer exposed to frequent energization, for example, step-up transformer in hydroelectric power plants is frequently switched to adapt with the daily load variation. These risks can be mitigated by using a closing resistor (or by controlling the making instant of the three-phase simultaneous operated circuit breakers).

The interruption of no-load transformer currents is of similar nature as for shunt reactors. However, the natural frequencies are much lower and damping very high, meaning that the overvoltages generated at de-energization are extremely low in amplitude. The control of the breaking instants are the same as the one used for shunt reactors in the case that the residual flux in transformer cores can be negligible.

The magnetic circuits of transformers have magnetization curves with a pronounced bend from the non-saturation region to the saturation region. For the reasons for economy, power transformers are designed with an operational peak flux value as close as possible to the saturation value. The flux in a transformer energized by a steady-state alternating voltage varies from a peak negative value to an equivalent positive value during one half cycle of the voltage waveform. The change in flux of twice the maximum flux value is proportional to the time integral of the voltage waveform between two successive zero points. If the circuit breaker is closed at the voltage zero, the full flux change is required during the first half cycle. When the flux is initially at zero, the maximum developed flux will be twice the normal operational peak value. Since the operational peak flux is already close to the saturation value, an increase of flux to double this value corresponds to extreme core saturation. Consequently, the inductance drops and the current rises rapidly to very high values.

At the instant of making, a residual flux resulting from the previous opening can remain in the transformer. If this residual flux is of the same polarity as the flux change, then the inrush current can reach still higher values. The change of the flux can in fact combine with the residual flux and provoke still greater saturation of the magnetization circuit.

A description of the processes occurring when a three-phase transformer is energized is less simple because the three phases are connected both magnetically and galvanically. The structure of winding connection and the treatment of the neutral point are factors which all influence the value of the inrush current.

It is possible to describe a general controlled closing principle to reduce inrush currents by adopting the hypothesis that there is no residual flux and that the flux in all the cores is nil prior to closing. The first closing must be performed either on only one phase if the neutral of the primary winding is earthed or on two phases if the primary winding is isolated. The making target is the maximum line-to-earth voltage (earthed neutral) or the maximum phase-to-phase voltage (isolated neutral) such that fluxes are generated without transients. The making instant of the remaining phase (s) must be chosen such that the flux circulating in the corresponding cores since the initial closing is the same as the flux that will circulate in these cores under steady-state conditions. This avoids creation of flux transients in the cores (CIGRE WG13.07 1999).

Figure 14.23 shows the energization strategy of a three-core transformer with wye (star) connection and isolated neutral. The energizing of a single phase has no effect, since there is no flow path of magnetizing current due to isolated neutral point. The phase-to-phase voltage U_{13} is switched on at its maximum value at time t_1. The corresponding stationary core fluxes ϕ_1 and ϕ_3 have instantaneous values of zero at

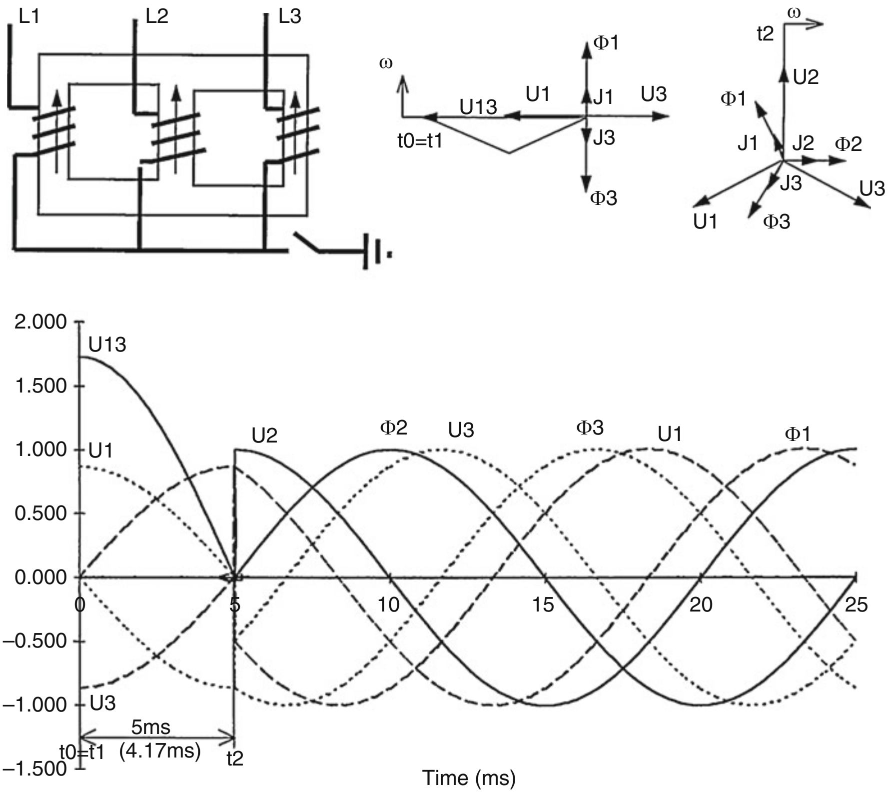


Fig. 14.23 Close strategy for isolated neutral transformer

this moment t_1. They attain their maximum values 90 electrical degrees later at time t_2; those are identical to the steady-state core flux values. This means that voltage U_2 can be switched in without any transient reaction at time t_2.

On the other hand, Fig. 14.24 shows the energization strategy of a three-core transformer with wye (star) connection and solidly earthed neutral. Phase L2 is energized when phase voltage U_2 is at its peak at time t_1. The magnetizing current J_2 is able to flow through the earthed-neutral point. The magnetizing field ϕ_2 begins without any transient. The associated magnetizing current J_2 must also provide for excitation of the other two phases, each of which has half the flux during this stage. Consequently, this current has a value 1.5 times that of its three-phase steady-state value.

By the time t_2, the fluxes ϕ_1 and ϕ_3 have reached levels corresponding to their three-phase steady-state value. Phases L1 and L3 may therefore be energized without transients at time t_2.

The choice of the making instant for the different phases to obtain a minimum inrush current can be summarized by Table 14.3, in the hypotheses that there is no residual flux. The Phase L2 is wound around the middle core in the case of 3 or 5 leg (core) power transformers. The voltage of the different phases can be written as follows:

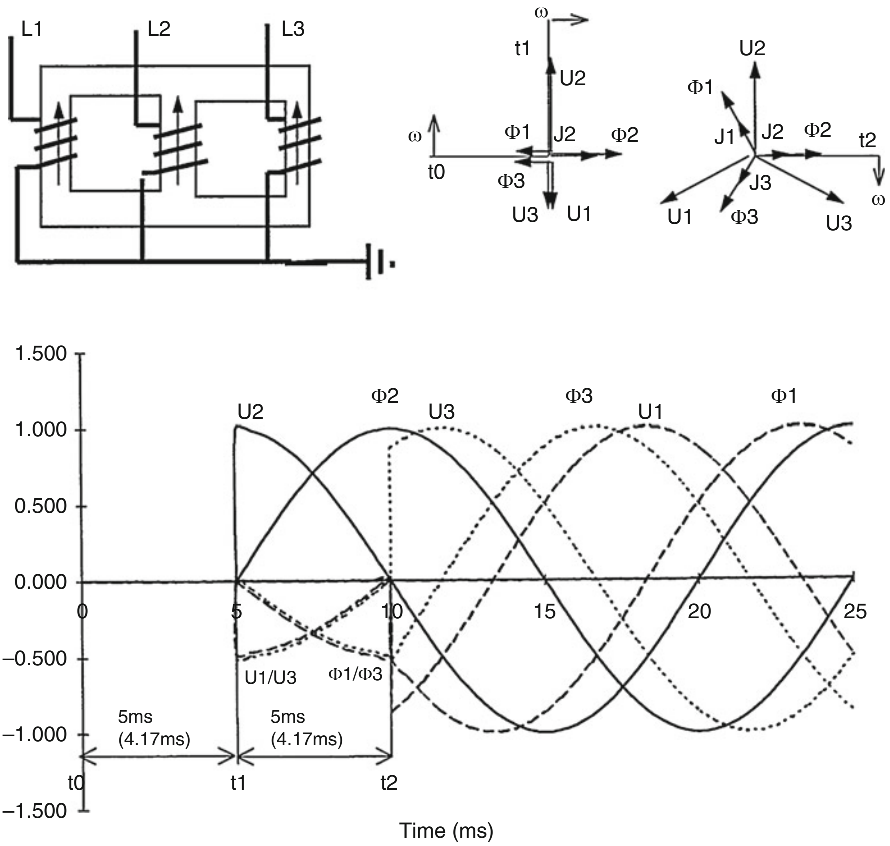


Fig. 14.24 Close strategy for solid earthed transformer

$$U_1 = U \times \sin(\omega t + 2\pi/3),$$

$$U_2 = U \times \sin(\omega t),$$

$$U_3 = U \times \sin(\omega t - 2\pi/3)$$

The making instant is given in relation to the zero voltage instant of U_2 (see Figs. 14.23 and 14.24).

For a practical application of CSS to transformer energization, the residual fluxes in the transformer cores should be considered to determine the optimum energization instants, especially in the case of smaller capacitance between the windings to the ground. Therefore, the inrush currents will depend on the following characteristics: (a) on the magnetic characteristics of the transformer cores, (b) on the making instants of the circuit breaker, (c) on the power transformer electrical connections,

Table 14.3 Ideal making instants for different power transformers without the residual fluxes in the cores

Primary winding connection	Secondary of tertiary coupling	Magnetic circuit	Making instant voltage value Phase 2	Making instant voltage value Phase 1	Making instant voltage value Phase 3
Wye (star) Connection with isolated neutral Y	Wye (star) Or delta	* 3- or 5-core transformers * transformer banks	5 ms (50 Hz) 4.17 ms (60 Hz) (90°) 1.5 U	0 ms (50 Hz) 0 ms (60 Hz) (240°) $U\sqrt{3/2}$	0 ms (50 Hz) 0 ms (60 Hz) (120°) $U\sqrt{3/2}$
Wye (star) Connection with earthed-neutral Y_n	Wye (star) Or delta	3- or 5-core transformers	5 ms (50 Hz) 4.17 ms (60 Hz) (90°) 1.5 U	10 ms (50 Hz) 8.33 ms (60 Hz) (60°) $U\sqrt{3/2}$	10 ms (50 Hz) 8.33 ms (60 Hz) (300°) $U\sqrt{3/2}$
Wye (star) Connection with earthed-neutral Y_n	Delta Δ	Transformer banks	5 ms (50 Hz) 4.17 ms (60 Hz) (90°) 1.5 U	10 ms (50 Hz) 8.33 ms (60 Hz) (60°) $U\sqrt{3/2}$	10 ms (50 Hz) 8.33 ms (60 Hz) (300°) $U\sqrt{3/2}$
Wye (star) Connection with earthed-neutral Y_n	Wye (star) Y or Y_n	Transformer banks	5 ms (50 Hz) 4.17 ms (60 Hz) (90°) 1.5 U	1.67 ms (50 Hz) 1.39 ms (60 Hz) (270°) $U\sqrt{3/2}$	10 ms (50 Hz) 8.33 ms (60 Hz) (270°) $U\sqrt{3/2}$
Delta Δ	Wye (star) Or delta	* 3- or 5-core transformers * transformer banks	5 ms (50 Hz) 4.17 ms (60 Hz) (90°) 1.5 U	0 ms (50 Hz) 0 ms (60 Hz) (240°) $U\sqrt{3/2}$	0 ms (50 Hz) 0 ms (60 Hz) (120°) $U\sqrt{3/2}$

(d) on the residual flux, (e) and on the electrical characteristics of the “source” system (CIGRE WG A3.07 2004e; Mercier et al. n.d.-a; Ito et al. n.d.; Hayward 1941; Bronzeado and Yacamini 1995; Fernandez et al. n.d.).

Figure 14.25 shows the dynamic magnetic flux and the current behavior when a transformer is energized. Energization of a transformer with no residual flux in a core at peak voltage will cause no transients. However, the flux change after energization depending on the residual flux and the energization instant will generate greater saturation of the magnetizing currents. Therefore, the optimum targets should be adjusted taking into account the residual flux. The inrush current can be only minimized by energization when the prospective normal core flux is identical to the residual flux.

An innovative residual flux measurement was developed and its accuracy proven in the field by integrating the voltage waveform after de-energization of the transformer as

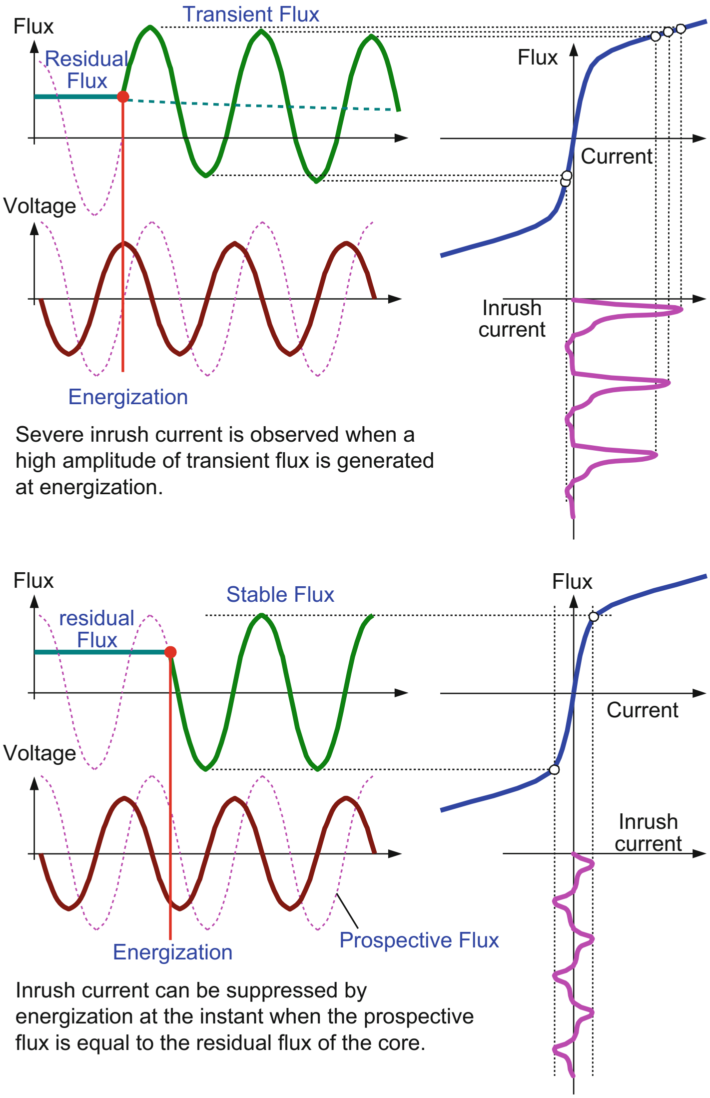


Fig. 14.25 Magnetizing flux in a core of a transformer and corresponding magnetizing current. (Ito et al. n.d.)

well as any CB operations in case of fault clearing connected to the system. In 2001, Canada installed two prototype systems to control the ideal instant for energizing high-voltage step-up transformers. Each system consists of a CSS with the new residual magnetic flux measurement system (Mercier et al. n.d.-a). The system uses the relation between the magnetic flux "Φ" of an "N" turns coil and the applied voltage "E," expressed in this equation, $\Phi = \int E/N + \Phi r$, where Φr is the residual magnetic flux.

The algorithm of the residual flux evaluation generally consists of four steps shown in Fig. 14.26.

First step: A precise calibration for the zero level of the dynamic flux is required. The zero level of integration of the voltage signal is determined by monitoring several cycles of voltage waves before current interruption.

Second step: The time duration for voltage integration is defined as the time before the voltage amplitude becomes smaller than a specified value, where the flux draws a micro-hysteresis loop.

Third step: The voltage integration is performed over the time determined in the second step above.

Final step: The difference between the values obtained at the third step and the zero level evaluated at the first step gives a residual flux.

A novel transformer built-in voltage sensor was developed to measure each phase voltage of the transformer shown in Fig. 14.27 (Mercier et al. n.d.-a).

Figure 14.28 shows a typical record of measured residual fluxes for three phases at transformer de-energization, which is used to determine the optimal energization instant for each phase.

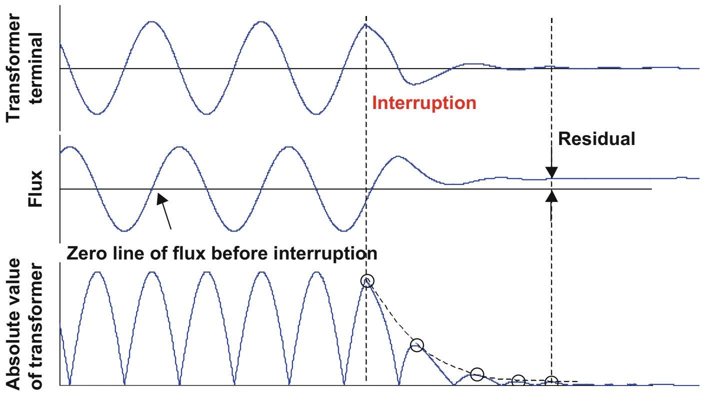
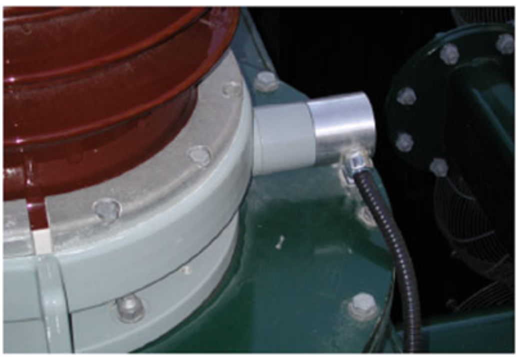


Fig. 14.26 Residual flux evaluation with integration of voltage measurement

Fig. 14.27 Transformer bushing voltage sensor for CSS application. (Courtesy of Hydro-Quebec)



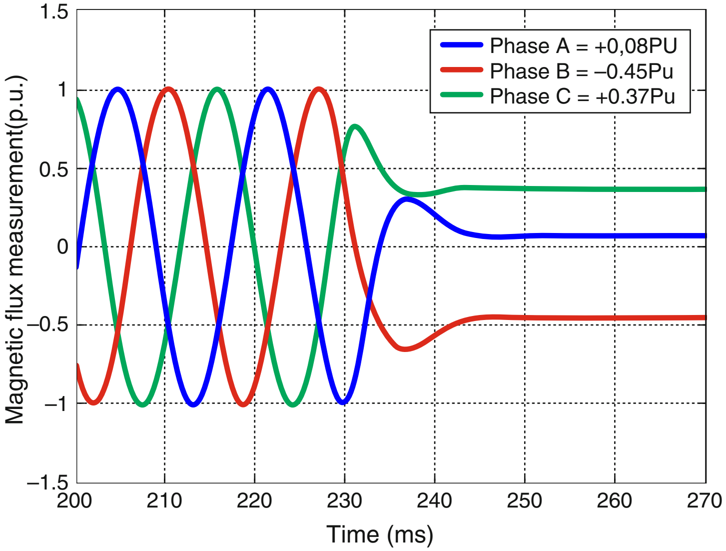


Fig. 14.28 Typical record of measured residual flux of three-phase transformer

Fig. 14.29 Example of residual flux pattern dependence on de-energization phase angle

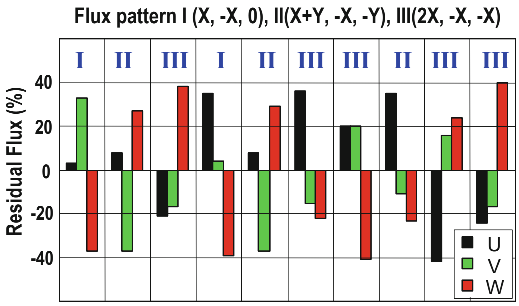


Figure 14.29 shows an example of the residual flux pattern dependence on the opening phase angle at the random de-energization in the field. Three patterns were observed in the field measurement. Note that a summation of the residual fluxes of three phases becomes zero.

Pattern I (X, −X, 0): Two phases have a larger flux with the same amplitude and different polarity. The remaining phase has a minimum flux.

Pattern II (X + Y, −X, −Y): One phase has a larger flux and the remaining phase shares the value with different polarity.

Pattern III (2X, −X, −X): One phase has a larger flux and the remaining phase shares a half value with different polarity.

The pattern III clearly provides a benefit for the control strategy, because the residual fluxes in the second and the third phases are close to the flux after the first phase energization. The pattern will give flux conditions in the second and the third phase cores close to the ideal ones with a limited closing delay.

This suggests further improvement of controlled transformer switching by application of controlled de-energization. In the case of the transformer, residual fluxes can be controlled to the pattern with a specified phase as the maximum, when the circuit breaker de-energizes the current at specific phase angle.

Figure 14.30a shows a typical example of voltage, current, and flux in the cores calculated in case of three-phase simultaneous random energization. High inrush currents ranging from 1245 to 2678 A are obtained due to magnetic saturations in the cores that cause the voltage drop up to 11.2% in the primary bus terminal. On the other hand, Fig. 14.30b shows a typical example of controlled transformer energization using an independent-pole-operated circuit breaker with the delay controlled strategy taking into account the residual flux. The controller chooses a phase with the maximum residual flux (Phase V) as the first phase to close. The first phase is closed at the instant when a prospective normal core flux is identical to the residual flux. The second and the third phase (U and W phases) are closed 1.5 cycles later around a voltage peak of the first phase. The inrush currents are reduced below 100 A, and the voltage disturbance is suppressed effectively by choosing the phase having the maximum residual flux value to be first energized; both mechanical and electrical stresses can be greatly reduced on the transformer (Ito et al. n.d.).

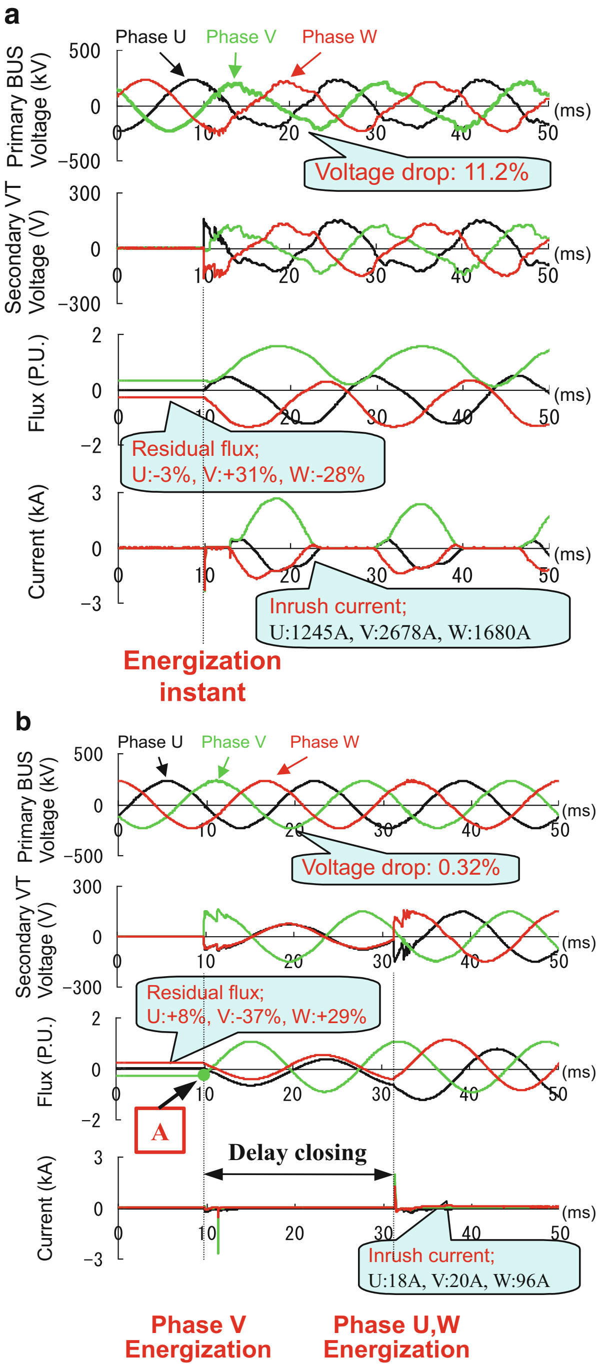
14.6.4 Uncompensated and Compensated Line Switching

Energization and auto-reclosing of long transmission lines can cause undesirable overvoltages in the transmission network, so special overvoltage mitigation measures are employed to meet the insulation coordination. The most common practice has been metal oxide surge arresters (MOSAs) that are often combined with a closing resistor to improve reliability, but this approach is relatively expensive. There is also a growing need of shunt reactors in order to mitigate the phase-to-ground transient overvoltages due to line switching especially high-speed auto-reclosing. The highest phase-to-ground transient overvoltage may appear in the middle of the line, because they are limited at the ends of the lines due to the application of shunt reactors, MOSA and CSS. These overvoltages can be reduced by using MOSA at the middle of the line.

The CSS can potentially reduce the reclosing transients and improve the reliability of restrike-free performance. It can also provide economic benefits such as elimination of closing resistors and reduction of the insulation level for surge arresters and transmission towers. For line applications, a circuit breaker with a higher RDDS is generally preferable although operating scenario and targeting strategies should be studied thoroughly. Idle time compensation is essential for drives whose operating times have this dependence (Fröhlich 1997; Avent et al. n.d.).

The physical phenomena governing line switching overvoltages is the propagation of electromagnetic waves along the line, generally called traveling wave phenomena. The wave propagation is initiated by the circuit breaker making operation, and the initial voltage amplitude is the circuit breaker pre-arc voltage, i.e., the instantaneous value of the voltage across the circuit breaker pole at line charging

Fig. 14.30 (**a**) 3-phase simultaneous random energization, (**b**) controlled energization taking account of residual flux



current making instant. As a consequence of the traveling wave propagation phenomenon, the optimum making instant for controlled switching of unload transmission lines is at a voltage minimum across the circuit breaker pole. The strategies for different line configurations are described as follows:

(a) In the case of an uncompensated line with an inductive potential transformer, the controller can suppress the surge effectively (less than 1 pu) by controlled closing at voltage zero on the source-side because the trapped DC charge is rapidly discharged, typically less than 100 ms. See Fig. 14.31.
(b) In the case of uncompensated line with a capacitive potential transformer, no leakage path exists for the trapped charge. The optimum target is voltage peak on the source-side of the same polarity as the trapped charge. See Fig. 14.32.
(c) In the case of a compensated line, the degree of compensation has a significant effect on the line-side voltage. The voltage across the breaker shows a prominent beat especially for a high degree of compensation because the line oscillation frequency typically falls in the range 30–50 Hz. The optimum instant is voltage minimum across the CB, preferably during a period of the minimum voltage beat (Avent et al. n.d.) as shown in Fig. 14.33.

Figure 14.34 shows an example of series capacitor-compensated 550 kV transmission lines with a length of 300 km in Canada. The system is equipped with

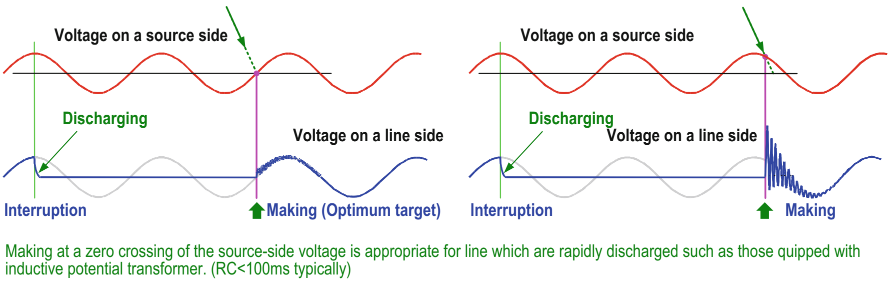


Fig. 14.31 Optimum target for uncompensated line equipped with inductive potential transformer

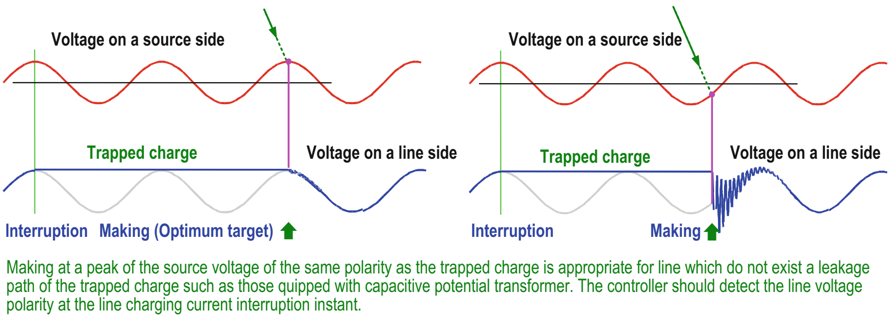


Fig. 14.32 Optimum target for uncompensated line equipped with capacitive potential transformer

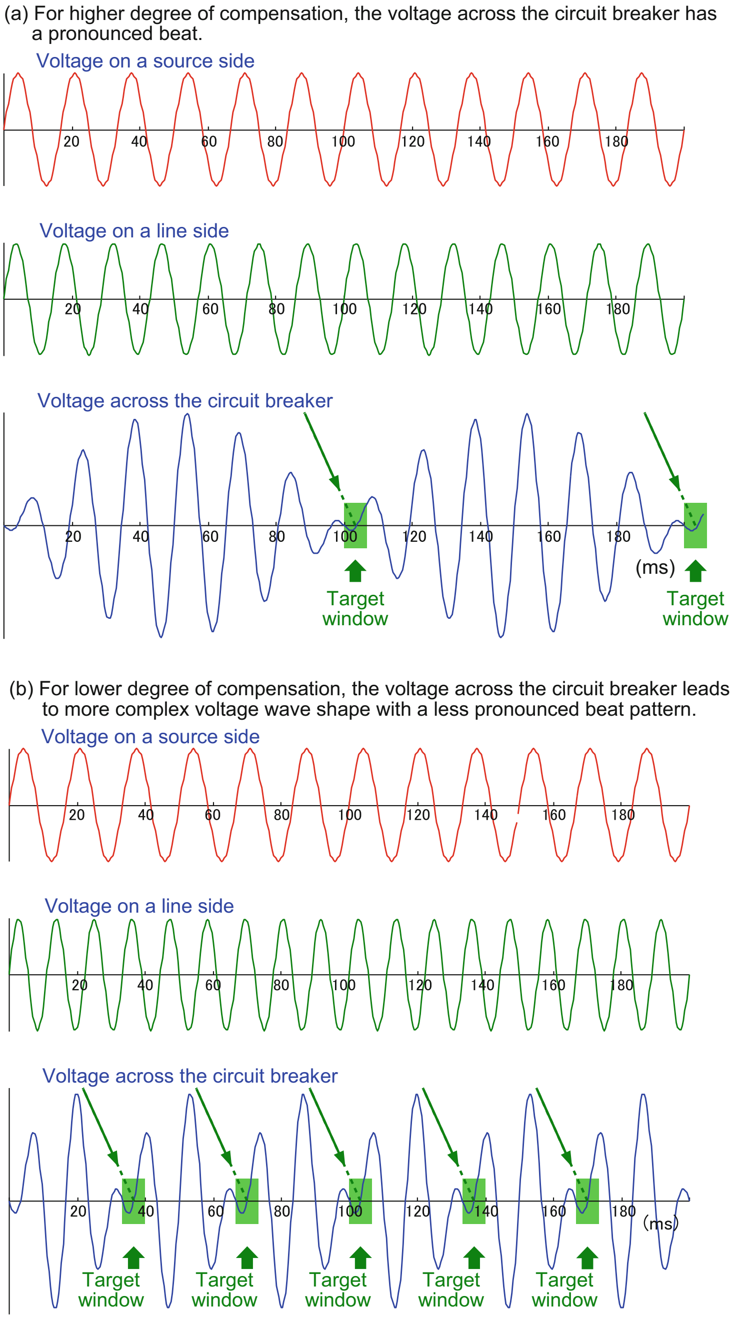


Fig. 14.33 Optimum making targets for compensated line switching

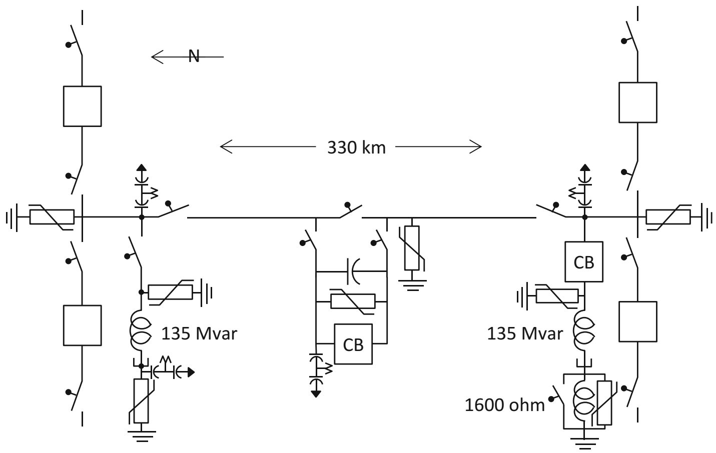


Fig. 14.34 Series capacitor-compensated 550 kV transmission line arrangement

midline series capacitors providing 50% compensation. Economics resulted in the bypass protection for this bank being a MOSA rated 2.2 pu, 89 MJ with no self-triggered or triggered gap. The line is equipped with 135 MVA/525 kV, three-phase shunt reactors at each end of the line with the reactor at the receiving end switchable.

The line will be operated with single-pole reclosing, and consequently the southern end shunt reactor is equipped with a neutral reactor rated 1600 ohms for secondary arc damping. The reactor at the northern end is grounded through a surge arrester to achieve a high grounding impedance to optimize the secondary arc control (Avent et al. n.d.).

Figure 14.35 compares the voltage profile along the line with conventional closing resistors to use of two and three MOSAs with staggered closing. The effectiveness of overvoltage control due to the closing resistor decreases when the line length becomes longer than 150 km. It is evident that with three MOSAs, only a small portion of the line experiences voltages over the design target, even with the non-optimum times inherent in the staggered closing.

Figure 14.36 indicates the improvement that can be obtained by use of line-connected MOSA. Two alternatives were considered, a MOSA at each terminal of the line and three MOSAs with the third connected at midline. Note that the objective that reduces the overvoltage less than 1.7 pu can be achieved only with the use of three MOSAs plus controlled closing.

From the results, the CSS has a general performance similar to the closing resistor, either controlling phase-to-ground and phase-to-phase switching transient overvoltages, in both receiving end and middle of the line. By comparing the cases with/without CSS, it can mitigate the switching overvoltages under a considerable level in the middle of the line. Of course, it can be noticed that the potentiality of phase-to-phase TOV mitigation exists.

The use of a more compact UHV OH line design yields expressive savings in capital-costs of the line itself, due to shortening of mechanical structure dimensions and weight. MOSA and CSS altogether can potentially allow transmitting large

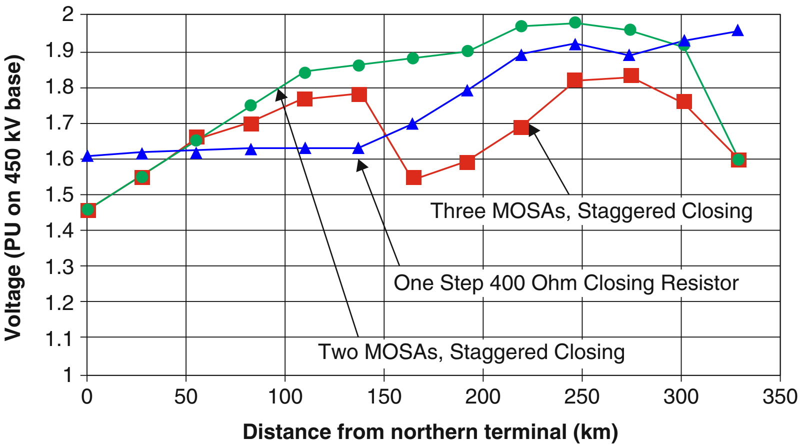


Fig. 14.35 Voltage profiles with a closing resistor or two and three MOSAs

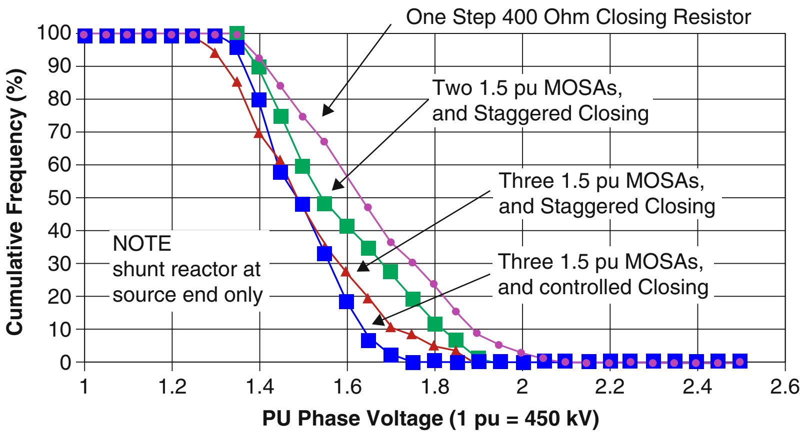


Fig. 14.36 Three-phase reclosing overvoltage comparison for various mitigation methods

amounts of power perspective considering recent increasing economic and environmental constraints.

14.7 Field Experience of Controlled Switching

14.7.1 Field Experience on Controlled Capacitor Switching

Controlled capacitor switching tests were conducted to check the performance of the complete CSS applied to a 121 kV capacitor bank in the field. Figure 14.37 shows the CSS applied to 121 kV capacitor bank. Each pole has an independently operated

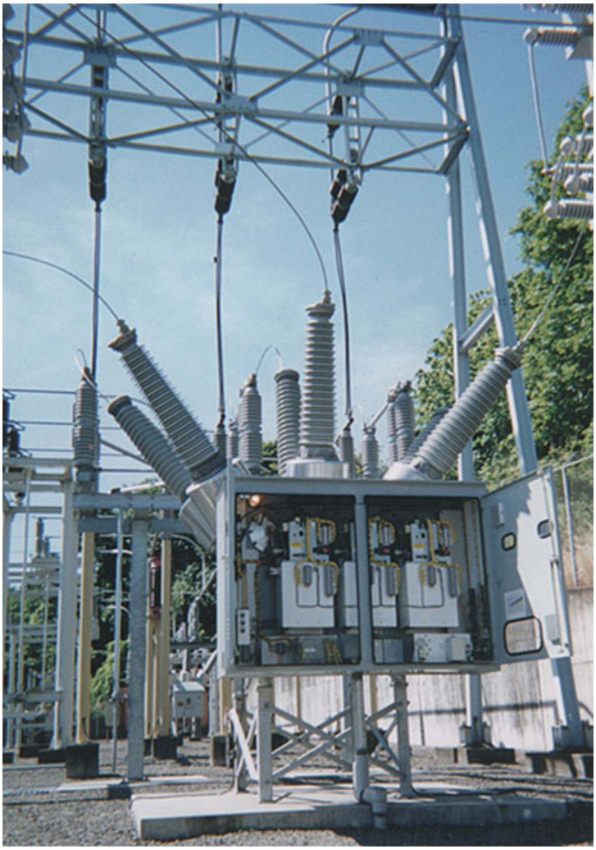


Fig. 14.37 CSS applied to 121 kV capacitor bank

spring mechanism. A total of ten controlled energizations and ten controlled de-energizations (even though the gas circuit breaker was verified under the extremely low probability of reignition during the capacitor switching tests) of the CSS were carried out by means of the controller during the commissioning tests. Field performance shows satisfactory controlled capacitor energization and de-energization.

In addition to the type and routine tests at the factory, commissioning tests at the site were performed to calibrate several parameters such as the average operating time, the travel, and the control voltages, which accounts for the difference of the operating conditions between the factory and the field.

After calibration, controlled switching tests were performed at the system voltage of 121 kV using the target for closing operation of 8 electrical degrees determined by the characteristics of RDDS and mechanical scatter plus a slight safety factor. The target for the opening operation is set as a maximum arcing time before the current zero.

With an increase of the number of operations, the CSS shows more successful results of controlled closing to the voltage zero targets since the adaptive control can reduce the prediction error of the operation time because it learns its actual performance from the previous nine operations. The current waveforms of the sixth making tests show a very low inrush level for all three phases. The CSS has continued, after the commissioning tests, to operate point-on-wave daily within a deviation of ± 1.5 ms in the field. More than 1000 operations have been successfully conducted in the field and no restrikes have been observed.

The CSS has continued, after the commissioning tests, to operate daily in the field. The controller measures and stores the operating conditions and the results of each operation. These data are also useful for circuit breaker maintenance because they provide detailed operating characteristics of the circuit breaker.

Figure 14.38 shows the results of the ambient temperature, the closing time, and their scatters from the targets where the CSS has been typically closed in the early morning and opened in the late night for several months. The ambient temperature at capacitor energization ranged from 7 to 20 degree Celsius. The operating times differ among the poles. The difference of the average closing times between the phase A and phase B was about 1 ms. The controller successfully compensated this difference caused by design tolerances.

Figure 14.39 summarizes the field performance of closing instants that show a normal distribution around the target instant of 8 electrical degrees with a standard deviation of less than 0.3 ms. The maximum making voltage was 0.25 pu.

Figure 14.40 shows the idle time characteristic of the 121 kV spring-operated gas circuit breaker in the field. The idle time of the closing time is normally 24-h intervals or up to 3 days. The result shows the spring drive does not require idle time compensation because the deviation of the closing times is observed within ± 1.0 ms even for the maximum idle time of 72 h.

14.7.2 Field Experience on Controlled Reactor Switching

Figure 14.41 shows the CSS system applied to controlled reactor switching. Controlled reactor switching can reduce the inrush current or the transient stresses. The making target that minimizes reactor inrush current is the voltage peak. The associated switching overvoltage in this case is generally low, but a steep voltage wave front may stress the reactor insulation. Since it is impossible to achieve reduction of both inrush current and transient stresses on the reactor energization with the same target, a compromise solution must be reached.

Figure 14.42 shows voltage and current oscillograms for a 204 kV controlled shunt reactor de-energization and energization in the field. The maximum inrush current of 1270 A observed by random closing can be suppressed to below 50 A.

Figure 14.43 shows the results of the ambient temperature, the mechanical pressure of the hydraulic mechanism, the closing and opening time, and their scatters from the targets where the CSS had been opened in the early morning and closed in the late night over a 1-year period. The ambient temperature at reactor de-energization and reactor energization ranged from 5 to 30 degree Celsius. The scatter is found to be within ± 1.2 ms for the closing operation and $\pm$ 0.2 ms for the opening operation, respectively. The closing time in the winter increased by 5% over

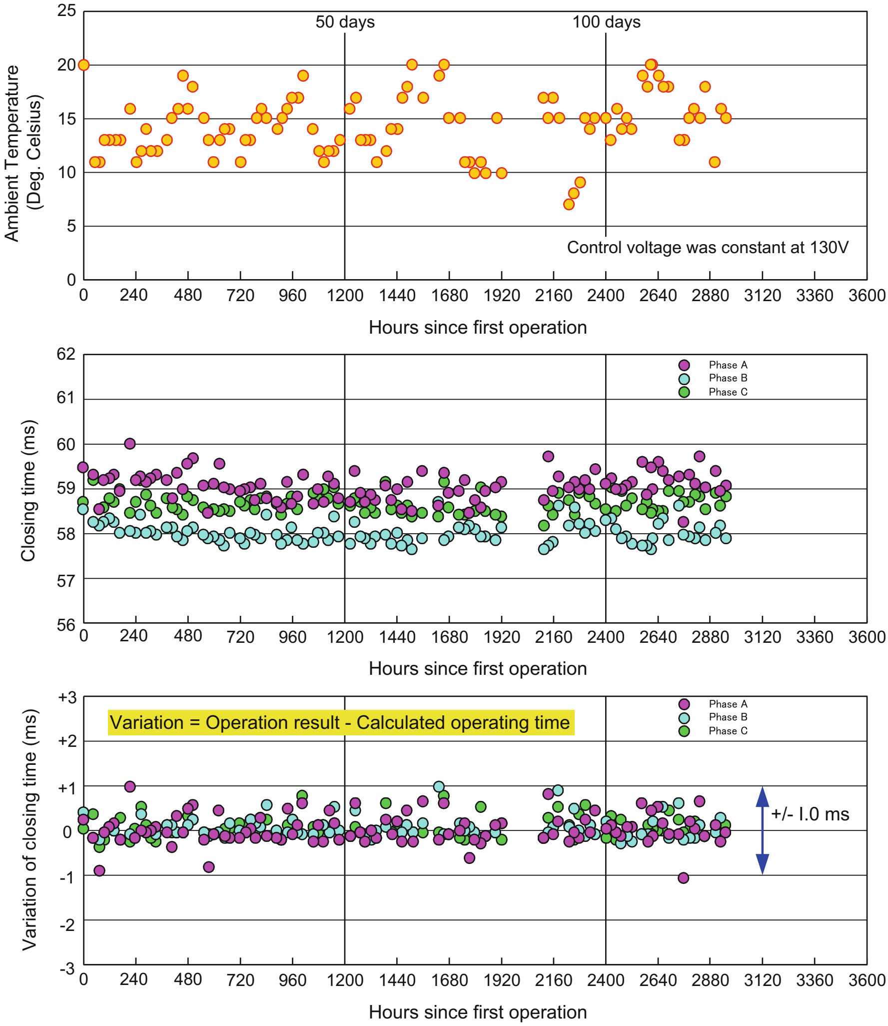


Fig. 14.38 Closing times and their deviations of each controlled capacitor energization in the field

the average closing time while that in the summer decreased by 5%. The CSS demonstrated an accurate operating consistency for all four seasons.

Figure 14.44 summarizes the field performance of closing instants that show a normal distribution around the target closing instant of 79 electrical degrees with a standard deviation of less than 0.5 ms. The minimum making voltage is 0.8 pu. On the other hand, Fig. 14.45 shows the distribution of the opening instants. The deviations of the opening instants are 0.21 ms, and all the de-energization are carried out within the reignition-free windows.

Figure 14.46 shows the idle time characteristic of the 204 kV CSS. The idle time of the closing time is normally 16 h from the opening operation in the early morning to

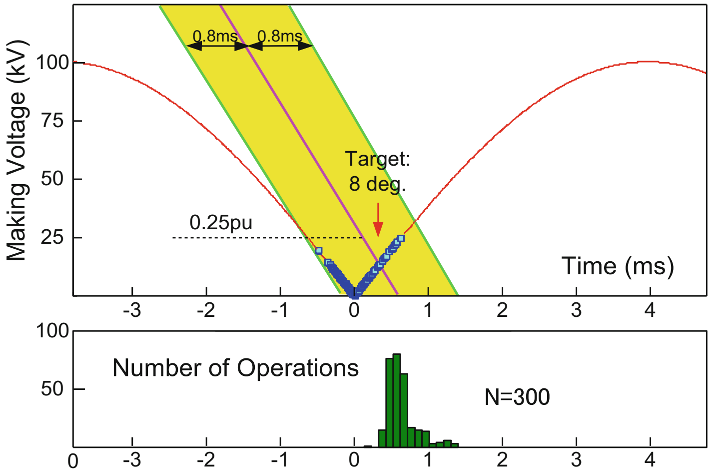


Fig. 14.39 Distribution of making voltages instants during capacitor switching and closing

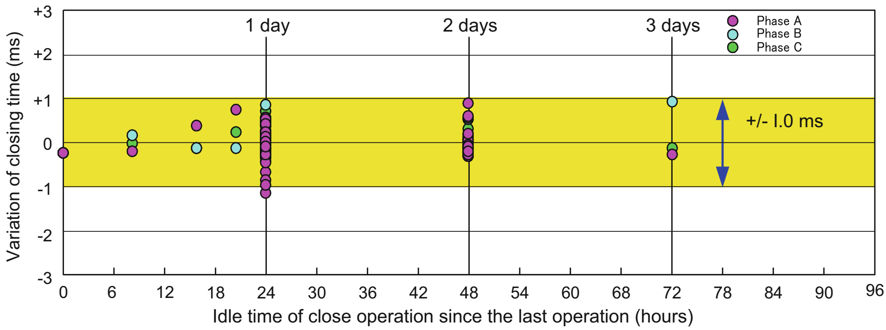


Fig. 14.40 Idle time dependence of the closing time delay with 145/121 kV gas circuit breaker

Fig. 14.41 CSS applied to 204 kV reactor bank

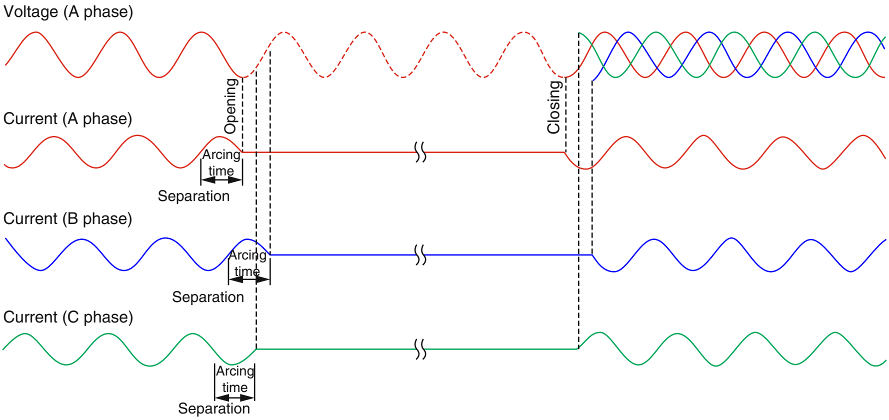


Fig. 14.42 Voltage and current behavior of controlled shunt reactor switching

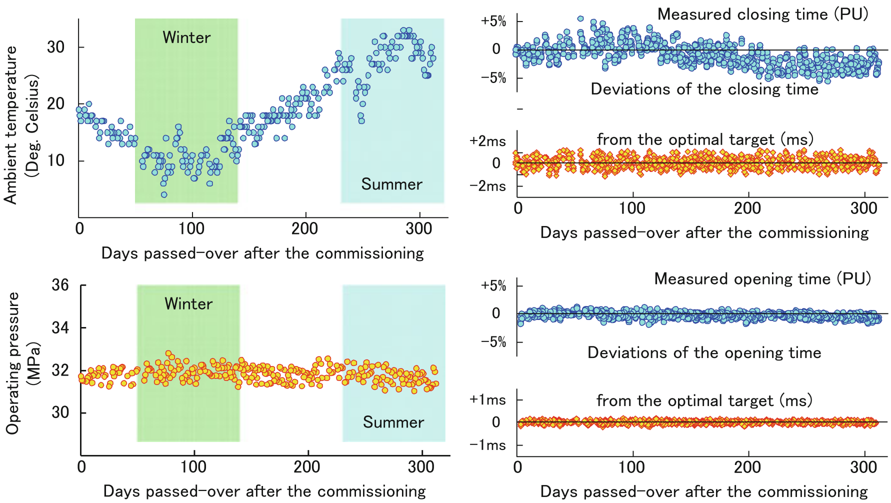


Fig. 14.43 Operational conditions and closing and opening time and their scatters from the targets for operations during controlled reactor switching with 204 kV CSS

the closing operation in the late night on the same day or up to 4 days later. The stable high-pressure hydraulic drive shows that the increase of closing time is observed from a few hours of idle time and saturates at a maximum delay of 1.2 ms if the idle time exceeds 16 h. Since the idle time characteristic is consistent among the same mechanisms, it is convenient to compensate the operating time of gas circuit breaker with an idle time characteristic showing a saturated value in a short period. Innovative stable high-pressure hydraulic drives (Ito et al. n.d.) can minimize the delay of operations, and their effectiveness was verified to solve this problem.

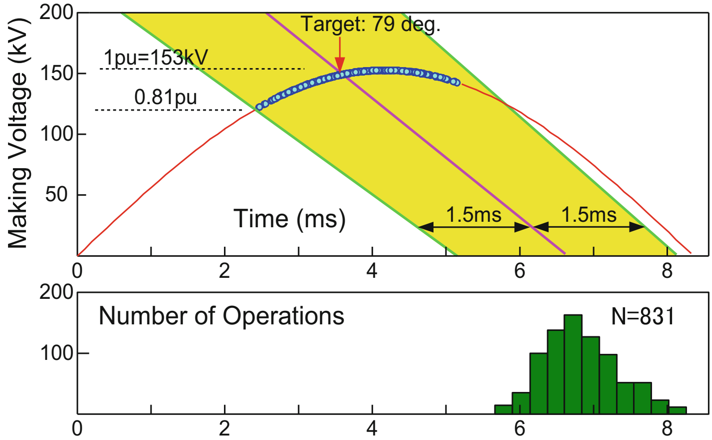


Fig. 14.44 Distribution of making voltages and closing instant during controlled reactor switching

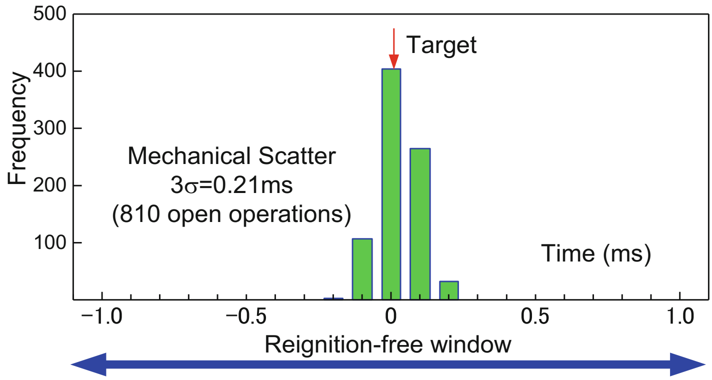


Fig. 14.45 Distribution of opening instant during controlled reactor switching

14.7.3 Field Experience on Transformer Switching

Controlled transformer switching can minimize inrush currents by energization when the prospective normal core flux is identical to the residual flux in a transformer core. Therefore a controlled switching application requires additional function to measure the residual flux at every de-energization. It is widely recognized that the residual flux is sustained and does not change over time unless there are external voltage disturbance.

A series of controlled transformer switching tests were performed in 315 kV substation in Canada with 315 kV GIS-type circuit breakers and 465 MVA transformers. First the inrush currents up to 1600 A were measured at random transformer energization shown in Fig. 14.47. It took more than a few seconds to decay the inrush currents and reach the steady states. Figure 14.47 also shows the inrush

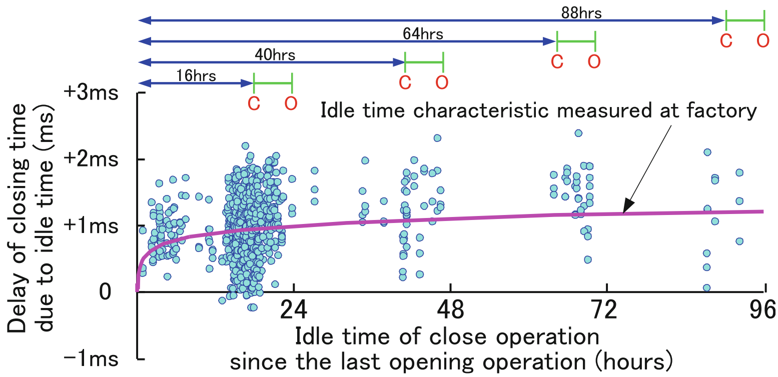


Fig. 14.46 Idle time performance of 204 kV GIS with the advance hydraulic drives in the field

currents when a controlled transformer energization is applied. The result shows almost no significant inrush currents nor associated TOV at any phase.

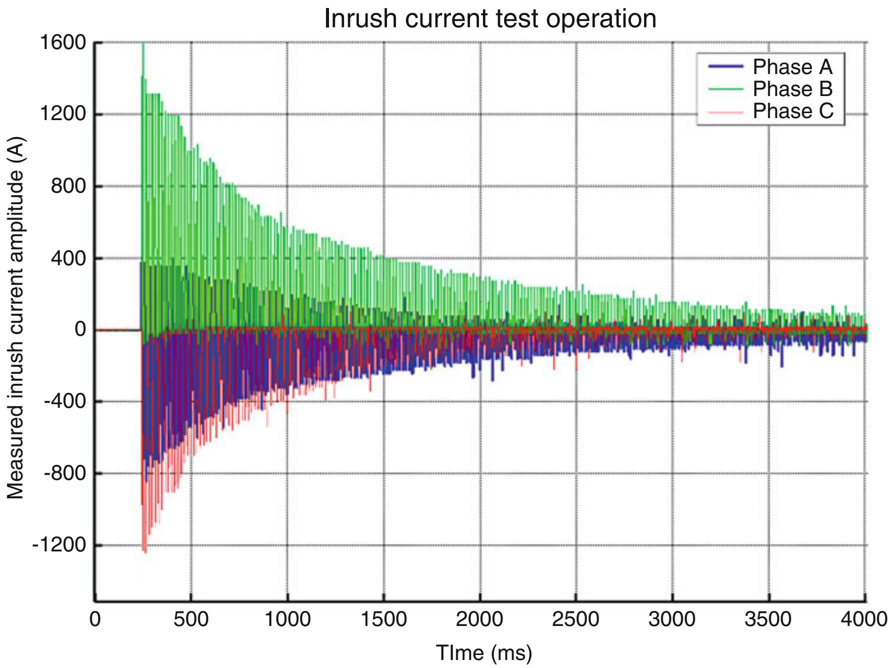
Field experience of a controlled transformer switching with independent-pole-operated 300 kV circuit breaker was performed to confirm a long-term reliability for a half year after commissioning tests. Voltage and current behavior during each switching operation along with the circuit breaker operating conditions and residual flux were recorded in the switching controller.

Figure 14.48 shows the associated voltage disturbance due to inrush currents as a function of an idle time measured for a half year. The controller can also compensate an operating time dependence on the idle time beside the operating conditions. The circuit breaker was operated with an idle time of up to 278 h, and inrush current were controlled within the operation target of 2% for the voltage drop, where the maximum 11% voltage drop and 2680 A inrush current are expected at random switching.

In the substations with the voltages of 170 kV and below, a simultaneous (gang) operated circuit breaker is commonly used. For capacitor switching or reactor switching applications, it is difficult to minimize the switching surges with a simultaneous (gang) operated circuit breaker except special geometric modification in mechanism or chambers. However, in the case of transformer energization, inrush current can be reduced to satisfactory level even with a simultaneous (gang) operated circuit breaker (Mercier et al. n.d.-b).

Figure 14.49 explains the strategy of controlled transformer energization using a simultaneous (gang) operated circuit breaker, which shows the voltages at each transformer terminal, dynamic fluxes in the core of transformer as a result of the voltage integration, and the differences between the dynamic flux and the residual flux for each phase. The figure 14.49 indicates that there exists a range of the phase angle where the differences of the dynamic flux and the residual flux for three phases become the minimum.

Therefore, the optimal target to minimize the inrush currents of three phases is the instant when the summation of the differences of three phases becomes the minimum value. The optimal closing instant exists during one cycle of power frequency for the residual flux patterns I, II, and III (Kohyama et al. n.d.).



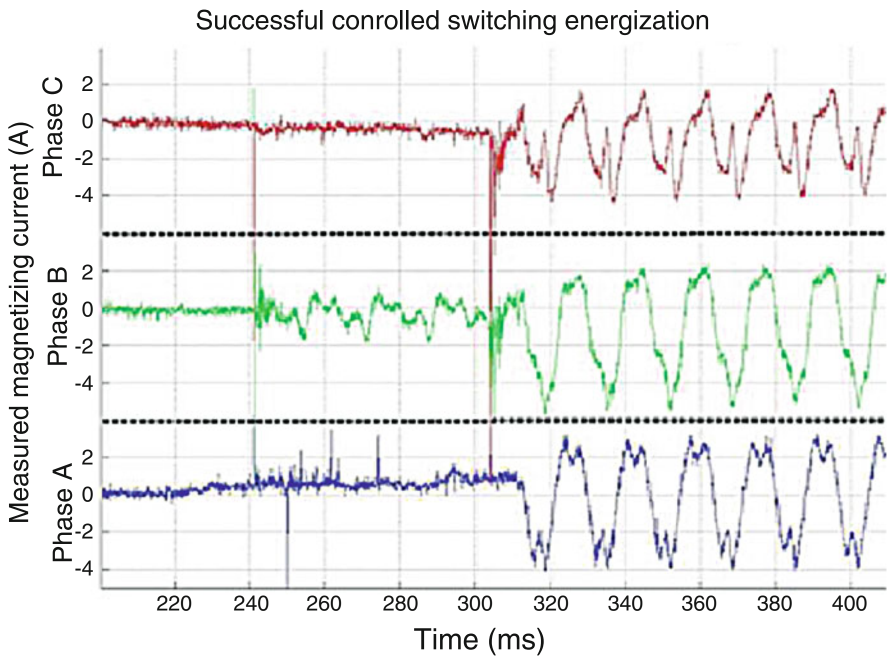


Fig. 14.47 Inrush currents measured at random energization and controlled energization

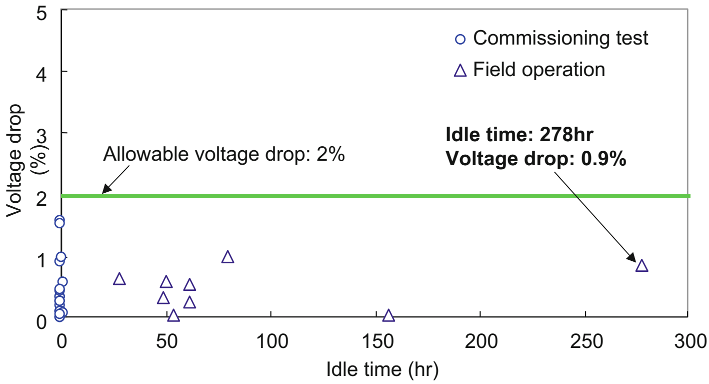


Fig. 14.48 Associated voltage disturbance due to inrush current measured after commissioning tests in case of controlled transformer energization with 300 kV gas circuit breaker

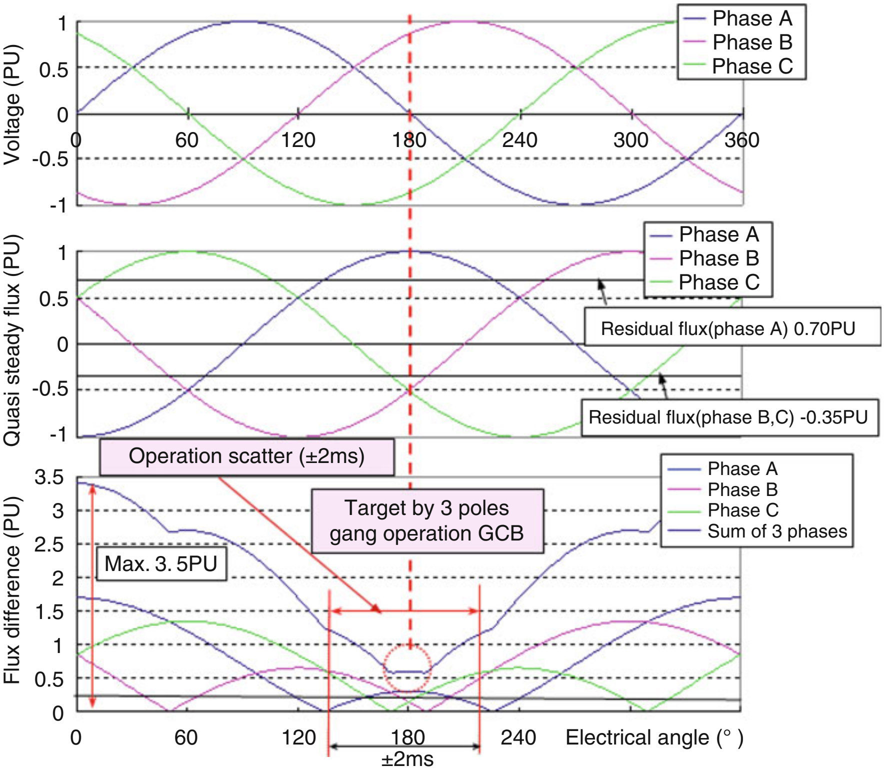


Fig. 14.49 Transformer switching strategy using gang-operated circuit breaker

Even in the case of first energization after installation, where three-phase fluxes are supposed to be zero (which is different case from three residual flux patterns), there is an optimal instant to reduce the inrush current as shown in Fig. 14.50. However, the inrush current may not be reduced to acceptable level. In such a case, another mitigation technique should be required. For example, a special energization network can be used to increase impedance between power sources to the transformer.

In practical application, mechanical scatter of closing time and RDDS for each pole affects the effectiveness of controlled switching, since actual flux difference in each phase at even simultaneous energization can vary depending on each phase variation of the characteristics as shown in Fig. 14.51.

14.8 Summary

The rapid increase of CSS applications is ascribed to several factors such as successful field experiences of the system with an effective compensation algorithm, the CIGRE proposal for type testing recommendations, and versatile operations and controls of transmission systems due to global changes in the electrical industry. Since CSSs can provide significant technical and economic benefits including enhancement of power quality and operation flexibility, it could be incorporated into circuit breaker control systems as a standard specification in the near future.

CSSs will provide many economic benefits when they are applied to shunt reactor banks and transformer energization in the power system. In the case of making at the voltage minimum, the RDDS of at least 186 kV/ms at 60 Hz (155 kV/ms at 50 Hz) is required for 550 kV single-break and 1100 kV two-break gas circuit breakers which corresponds to RDDS = 1.

A step-up power transformer in hydroelectric power plants is being frequently switched to cope with the daily load variations. Controlled transformer switching

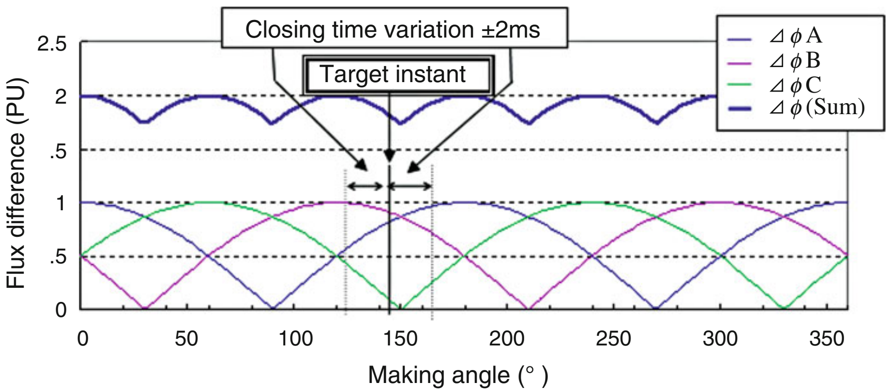


Fig. 14.50 Summation of flux difference in case of no residual flux

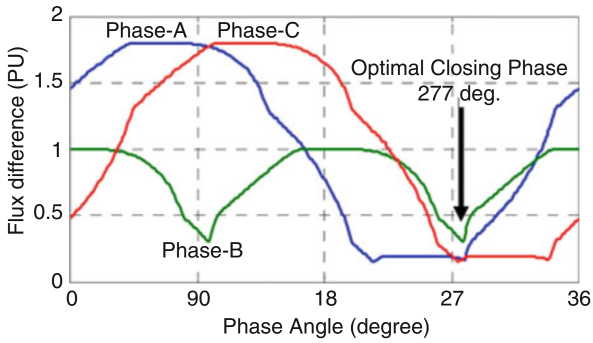


Fig. 14.51 Example of flux difference behaviors at simultaneous operations

taking account of the residual flux can be one of the schemes to reduce the overvoltage effectively due to transformer energization. Inrush current can also be reduced to satisfactory level by CSS using a simultaneous (gang) operated circuit breaker.

Since the effectiveness of a closing resistor to reduce the overvoltage may be reduced in the case of very long lines typically longer than 200 km, CSS combined with MOSA could be one of the solutions for a UHV/EHV long transmission lines.

The possibilities of more compactness related to the design of transmission towers and lines, given by the application of CSS in OH line circuit breaker, associated with shunt reactors and MOSA applications for TOV mitigation, should be deeply investigated during the planning or engineering design step of power systems.

As information technologies progress, it may become possible to use CSS for fault current interruption, uprating of modern and aged circuit breakers, and compensated line auto-reclose with a minimum surge arresters in the future. Furthermore, various monitoring results of circuit breakers recorded in the controller can be used for remote diagnostics and condition-based maintenance in order to improve further equipment reliability and optimize maintenance practice.

Commissioning tests as well as field verifications for the components and the integrated system were conducted using different types of circuit breakers following the CIGRE recommendations. The measurement of RDDS can be obtained by random closing. Little difference of RDDS value was shown for the polarity of the voltage. Effective compensation for deviations of operating time based on past operations has been demonstrated. The idle time dependence of the close operation with spring drives and a conventional hydraulic drive was compared. It can be seen that the requirement of idle time compensation can be judged from the measurement up to 100 h. Innovative spring operating mechanisms do not show any delay of the operating times for idle time up to 1000 h.

Controlled shunt capacitor switching in the field showed more successful results of controlled closing to the voltage zero targets because the adaptive control reduces the prediction error caused by the design tolerance after learning from the previous operation results. The CSS also demonstrates successful reactor opening without any reignition. Therefore, CIGRE WG13.07 recommendation successfully covers all the testing requirements and their procedures.

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Surge Arresters

15

Robert Le Roux and Kevin Kleinhans

Contents

Keywords
Metal oxide surge arresters · Lightning impulse protection · Switching impulse protection

15.1 Introduction

Surge arresters are installed in substations and in transmission lines with the purpose of limiting both lightning- and switching-induced overvoltages to a specified protection level, which is, in principle, below the withstand voltage of the equipment in order to protect it from excessive overvoltages. The ideal surge arrester would have a nonlinear voltage and current characteristic that starts to conduct at a specified voltage

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H. Ito (ed.), *Switching Equipment*, CIGRE Green Books,
https://doi.org/10.1007/978-3-319-72538-3_15

level (switch-on), keeping a certain margin above its rated voltage, holds the specified voltage level without variation for the duration of the overvoltage for expected lifetime, and then ceases to conduct as soon as the voltage across the surge arrester returns to a value below the specified voltage level (switch-off). Therefore, surge arresters are fundamentally required to absorb the energy that is associated with the overvoltages.

Figure 15.1 shows an example of voltage and current (V-I) characteristic of a typical metal oxide surge arrester (MOSA) applied in a 420 kV power system. The characteristic shows three distinctive regions: (I) MOSA can leak a small capacitive current at continuous operating voltage levels up to the rated voltage; (II) MOSA starts to conduct and the current increases rapidly with a slight voltage increase showing a flat V-I characteristic in the breakdown region; (III) then the MOSA increases voltage for large currents.

Overvoltages in power systems can be classified into two categories: External overvoltages generated by lightning strikes and internal overvoltages generated by changes in operating conditions of the power system such as switching operations and a ground fault occurrence.

The design and operation of surge arresters have advanced from valve- or spark gap-type silicon carbide (SiC) surge arresters to gapless metal oxide (MO) or zinc oxide (ZnO) surge arresters. A metal oxide surge arrester is composed of many microscopic junctions of metal oxide grains that turn on and off in microseconds to create a current path from the top terminal to the earth terminal of the arrester. It can be regarded as a very fast-acting electronic switch, which is opened at operating voltages and closed at switching and lightning overvoltages. An important parameter of surge arresters is the switching impulse protection level (SIPL), defined as the maximum permissible peak voltage on the terminals of a surge arrester subjected to switching impulses under specific conditions.

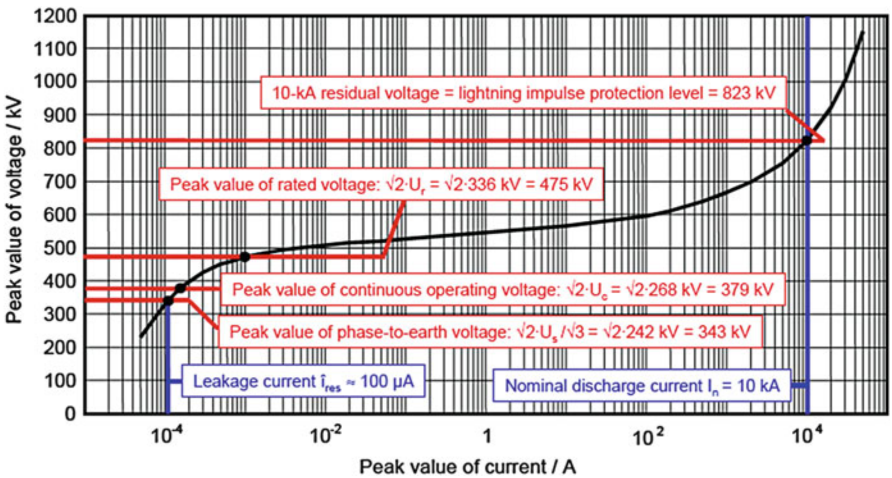


Fig. 15.1 V-I characteristic of a typical metal oxide (MO) surge arrester in a solidly earthed neutral 420 kV system. (Courtesy of Siemens)

In order to reduce the power consumed by a metal oxide arrester during nominal operation at system voltage, the continuous operating voltage of the arrester has to be chosen such that the peak value of the resistive-current component is well below 1 mA and the capacitive-current component is dominant. This means that the voltage distribution at operating voltage is capacitive and is thus influenced by stray capacitance. The voltage-current characteristic of the metal oxide material offers the nonlinearity necessary to fulfill the mutually contradicting requirements of an adequate protection level at overvoltages and low current, i.e., low energy dissipation, at the system operating voltage. Metal oxide surge arresters are suitable for protection against switching overvoltages at all operating voltages.

Traditionally, porcelain-housed metal oxide surge arresters were used. For satisfactory performance, it is important that the units are hermetically sealed for the lifetime of the arrester disks. The sealing arrangement at each end of the arrester consists of a stainless steel plate with a rubber gasket. This plate exerts continuous pressure on the gasket, against the surface of the insulator. It also serves to fix the column of the metal oxide disks in place by springs. The sealing plate is designed to act as an overpressure relief system. Should the arrester be stressed in excess of its design capability, an internal arc is established. The ionized gases cause a rapid increase of the internal pressure, which in turn causes the sealing plate to open and the gases to flow out through venting ducts. Since the ducts are directed toward each other, it results in an external arc, thus relieving the internal pressure and preventing a violent shattering of the insulator.

However, porcelain-housed distribution arresters tended to fail due to problems with sealing. The benefits of a leak tight design, using polymers, have been generally accepted, leading to the changeover to polymers. Polymer-housed arresters have a very reliable bond of the silicone rubber to the active parts. Thus, gaskets or sealing rings are not required. Should the arrester be electrically stressed in excess of its design capability, an internal arc is established, leading to rupture of the enclosure, instead of explosion. The arc will easily burn through the soft silicone material, permitting the resultant gases to escape quickly and directly. Thus, special pressure relief vents, with the aim of avoiding explosion of the housing, are not required for this design. Moreover, polymer-housed distribution arresters are less expensive than porcelain-enclosed ones.

Figure 15.2 shows different designs of MOSA. The left drawing shows the MOSA with a porcelain housing, the middle drawing shows a tube-type MOSA with a composite hollow core insulator, and the right drawing shows a cage-type MOSA completely molded in silicone rubber.

15.2 Definitions of Terminology

Surge Arrester

A surge protective device designed to limit the duration and frequently the amplitude of the voltage.

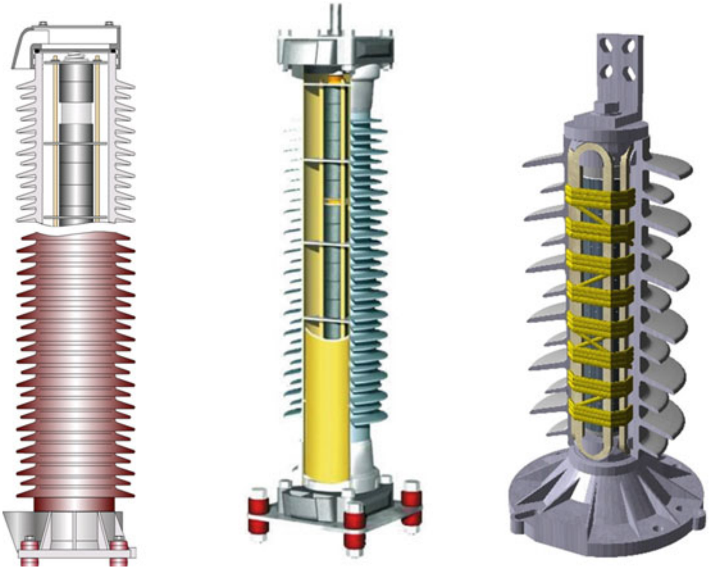


Fig. 15.2 Different designs of MOSAs for high voltage systems (CIGRE TB544, 2013)

Lightning Impulse Withstand Voltage
Peak value of the standard impulse voltage wave which the insulation of the MOSA withstands under specified conditions.

Switching Impulse Withstand Voltage
Depending on the wave shape of the impulse withstand voltage, the term may be qualified as switching impulse withstand voltage.

Lightning Impulse Protection Level
The operating voltage level of the MOSA must be lower than the voltage of the equipment being protected, thus the level at which the MOSA will provide protection.

Switching Impulse Protection Level
The level at which switching impulse voltages will occur for equipment to be protected must be higher than that of the MOSA.

15.3 Abbreviations

CB	Circuit breaker
EGLA	Externally gapped line arrester
LIPL	Lightning impulse protective level

LIWV	Lightning impulse withstand voltage
LSA	Line surge arrester
MO	Metal oxide
MOSA	Metal oxide surge arrester
SIPL	Switching impulse protection level
SIWV	Switching impulse withstand voltage

15.4 History of Surge Arresters

Lightning protection began with the invention of the lightning rod in the 1750s. The first telegraph systems started in 1837, and the first lightning protection devices were installed on telegraph lines. The gapped devices were named “arresters.” Surge arresters applied to power systems were first developed in the 1880s (Fig. 15.3). In the 1970s the first gapless metal oxide surge arresters (MO surge arresters) appeared in the market, and, in the 1980s, the first completely molded polymer-housed arrester was applied in medium voltage power systems.

The application of surge arresters improved the reliability of power systems and facilitated their rapid growth. Aluminum cell-type surge arresters and oxide film-type surge arresters were replaced by valve-type arresters using silicon carbide (SiC). Efforts were focused on improving the performance with lower protection levels as well as with better current cutoff. Finally, Matsushita Electric Industrial Co., Ltd., developed ZnO varistors for application in television in 1968.

The world’s first metal oxide surge arrester (MOSA) was developed by Meidensha and installed in a 66 kV system in Japan in 1975 as shown in Fig. 15.4. MOSA provided several advantages with respect to protection level, electrical durability, antipollution performance, and simple construction and compactness. The first 500 kV MOSA applied to GIS was installed in 1978, and the first porcelain-type 500 kV MOSA was installed in 1979 in Japan. MOSA was also applied to 6.6 kV pole-mounted transformers in 1985.

In the 1980s, the performance of MO resistors such as protection performance during the lifetime and energy absorption capability was significantly improved. They could reduce the lightning impulse withstand voltages (LIWV) requirements for switchgear and power transformers and also contributed their compact and economical designs (Fig. 15.5).

Following the invention of the ZnO-based MO resistors and the first gapless MO surge arresters put in service in Japan, development, based on the Matsushita patent, also started in Europe. In 1972 BBC (now ABB) started the development of MO resistors based on their own recipe. In 1976 the first HV MO resistors were available, and in 1980 the first gapless MO surge arresters were available. In the same year, ASEA (now also ABB) entered the market with a complete HV surge arrester portfolio. In the USA, GE started at the LV level and announced the first LV MO resistor elements based on the Matsushita license in 1972 from where they moved on toward MO elements for HV applications.

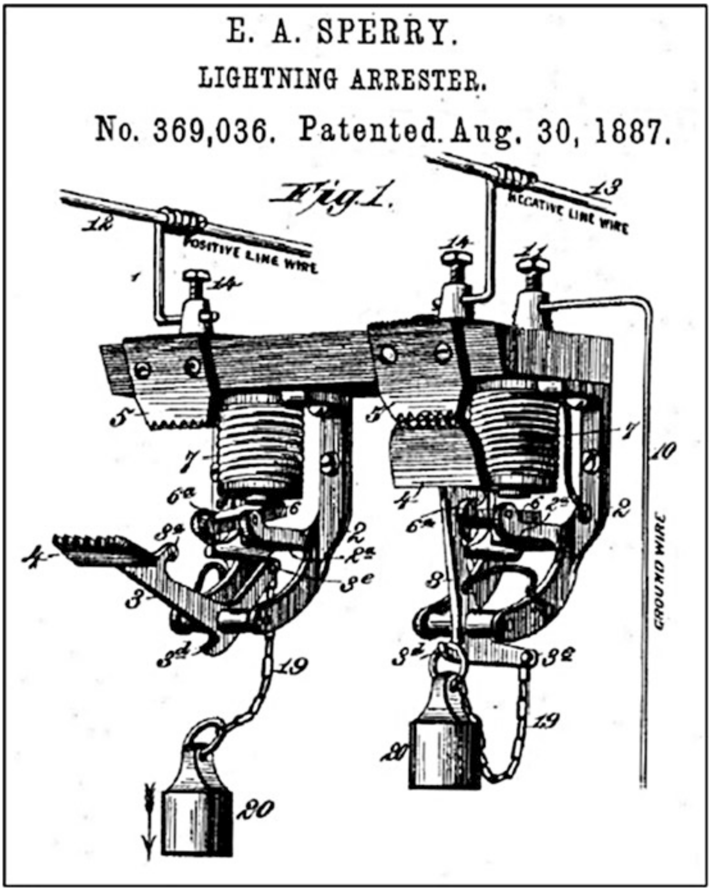


Fig. 15.3 Arrester patent in 1887

In 1982 Siemens supplied their first MO surge arrester, an SF_6 gas-insulated (GIS) arrester. There is no other type of MO arrester where its introduction leads to such a simplification of the design as for the metal-clad SF_6 insulated arresters. The elimination of the N_2 space, sealed tube, and additional capacitive grading resulted in a reduction of both the arrester diameter and length and, finally, the arrester costs. In the same year, ASEA developed a gapless GIS MO surge arrester for a 400 kV system. In 1994 a worldwide first, a 1050 kV GIS arrester, was delivered by ABB for the 1050 kV GIS pilot plant from ENEL in Italy.

Nowadays, gapless MO surge arresters in porcelain housings, polymer housings, or metallic housings of various designs are used at all system voltages, in traction systems, wind farms, and various other specific applications. Figure 15.6 shows an example of a polymer-housed MOSA with a pressure relief system, which can relieve excessive hot gases generated during the energy dissipation by MOSA.

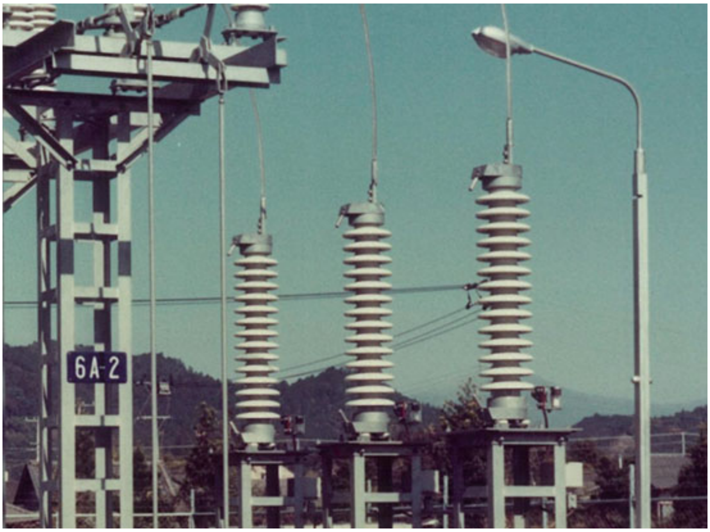


Fig. 15.4 World's first MOSA application in 66 kV power system in 1975. (Courtesy of Kyushu Electric Power, MOSA was produced by Meidensha)

15.5 Construction of MOSA

Figure 15.7 shows the cross section of the design of a porcelain-housed unit of a MOSA. The MO resister column and its supporting construction form the active part of the arrester. The column consists of individually stacked MO resistors, almost always cylindrical in shape as shown in Fig. 15.8. The resistor diameter determines the energy absorption and current carrying capability. Diameters vary from approximately 30 mm for distribution up to 100 mm and more for higher voltages.

When a MOSA has a length from 1.5 m to 2 m and higher, a grading ring is required. This is essential in controlling the voltage distribution from the top to the bottom. This is unfavorably influenced by the earth capacitances that affect the arrester. If the grading ring is not in place, the top, or high-voltage end, would be stressed considerably more than the earthed end of the arrester. (See Fig. 15.9.)

In EHV and UHV applications, as well as in specialized applications like series compensation capacitor protection, multicolumn units are utilized. DC circuit breakers applied to the future multiterminal HVDC grids, which are required to dissipate a large amount of energy of up to several tens MJ, also are equipped with multicolumn MOSA connected in parallel. See Fig. 15.10.

15.6 Insulation Coordination by MOSA Arrangement

Insulation coordination in power systems was introduced to ensure that the electrical insulation levels for substation equipment in power systems are below their LIWV and SIWV specifications. Surge arresters play a primary protection role against

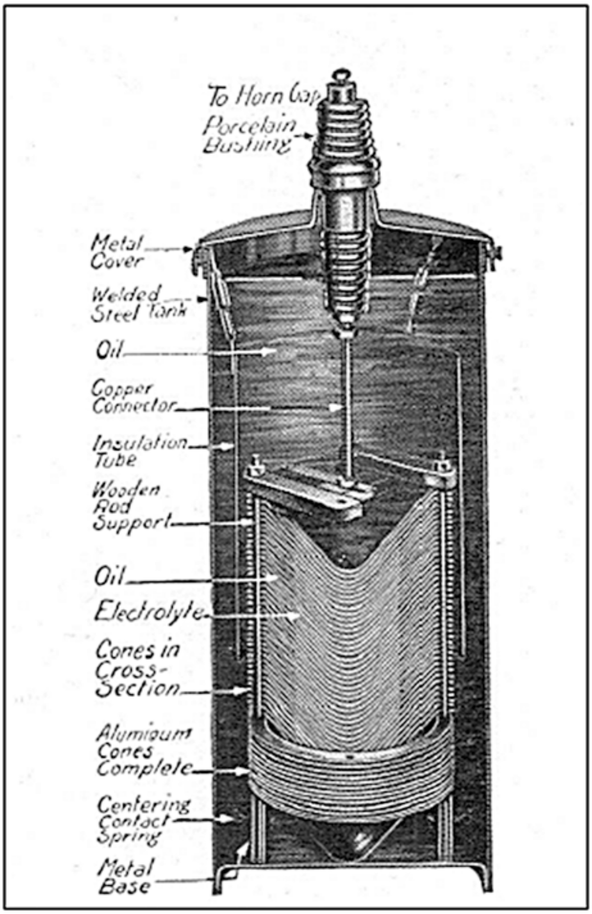


Fig. 15.5 Electrolyte arrester in 1907, well known as aluminum cell arrester

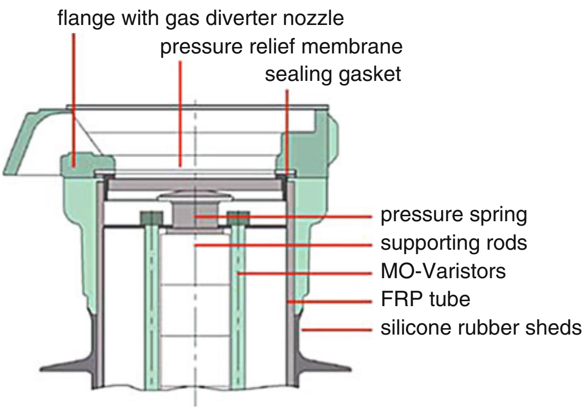


Fig. 15.6 Pressure relief system of a polymer-housed MOSA. (Courtesy of Siemens)

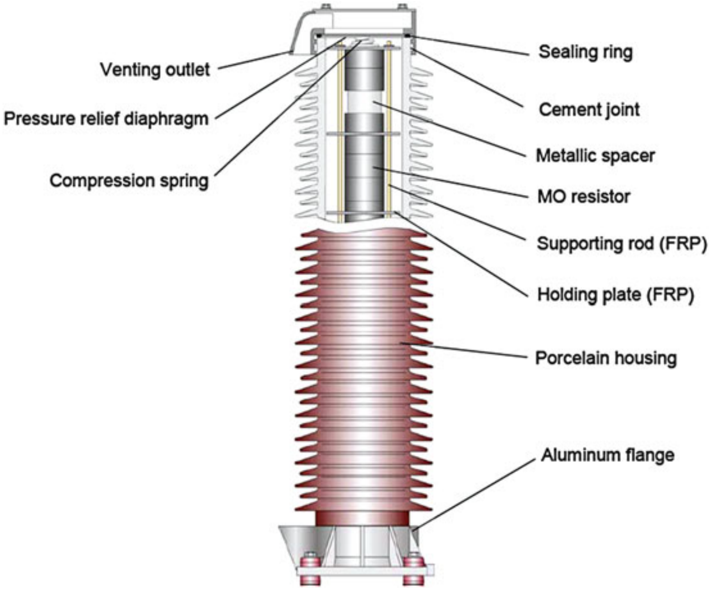


Fig. 15.7 Example of cross-sectional drawing of MOSA

Fig. 15.8 Various metal oxide resistor disks. (Courtesy Siemens)

overvoltages caused by external factors (e.g., lightning) and system disturbances (e.g., switching). Selection and arrangement of MOSA in the substation determine the insulation levels required for substation equipment in case of lightning strikes, grounding faults, and switching operations.

System analysis can evaluate lightning overvoltage levels by providing the lightning impulse waveform at any point in the power system (typically the first transmission tower located adjacent to the substation) and also switching overvoltage levels caused by operating any switching equipment under normal and abnormal conditions (e.g., clear a fault by a circuit breaker or switching a circuit such as an

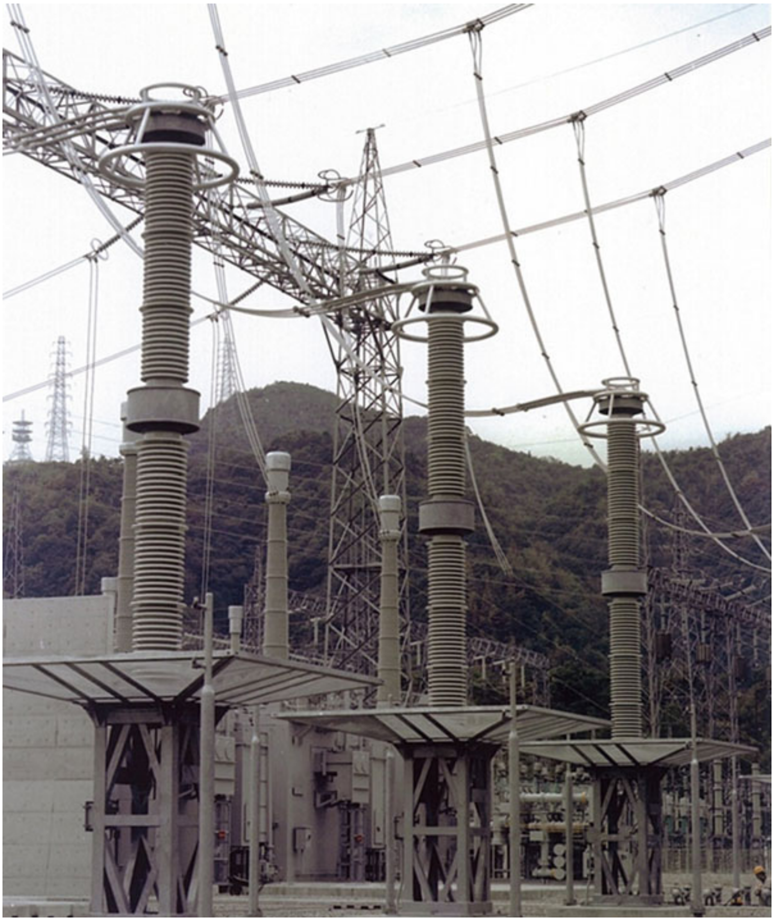


Fig. 15.9 Example of MOSA with a grading ring in 550 kV substation. (Courtesy of Kansai Electric Power)

unloaded transmission line, capacitor, and reactor bank). MOSAs are often arranged at the terminals of power transformers, at both ends of the bus terminals, and at both ends of transmission lines to mitigate the overvoltage levels imposed on equipment.

Technical and economic consequences of insulation levels become increasingly important, especially in UHV systems where MOSAs are a key technology to realize rational insulation coordination. Table 15.1 illustrates examples of several MOSA arrangements with the corresponding costs and lightning impulse withstand voltages (LIWV) on UHV substation equipment. The arrangement that is composed of two surge arresters per circuit at the line entrance, two per quarter bus, and one per transformer bank is provided as one of the most favorable applications for UHV transmission in Japan.

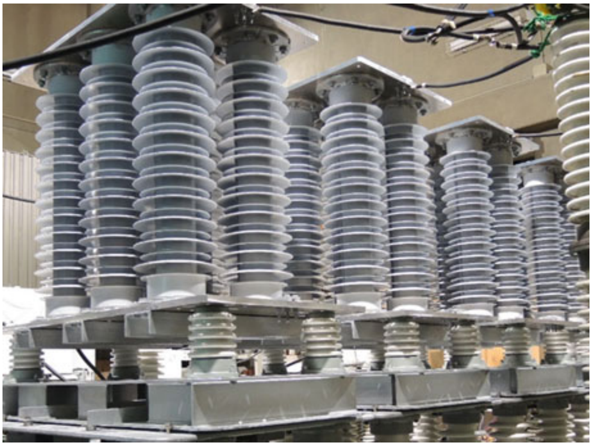


Fig. 15.10 Example of multicolumn MOSA units for prototype HVDC circuit breaker. (Energy dissipating capacity: 4 MJ)

It is important for EHV and UHV systems and equipment to suppress lightning overvoltages effectively by arranging higher-performance MOSAs at appropriate locations such as at line entrances, bus bars, and transformers. With respect to very fast transient overvoltage (VFTO), these levels are reduced to 1.3 p.u or below with application of the resistor-fitted disconnecting switch with a 500 Ω resistor.

The requirements for surge arresters emerged from two basic requirements: It should provide adequate protection with sufficient safety margin, which means that overvoltages at the device to be protected must always remain below its withstand voltage. Furthermore, the surge arrester should be dimensioned for stable continuous operation, which means that the arrester must remain electrically and thermally stable under all conditions while handling all long-term, temporary, and transient stresses resulting from network operations. These two requirements cannot be fulfilled independently.

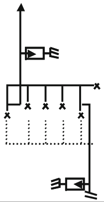
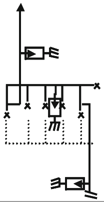
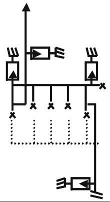
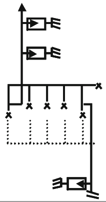
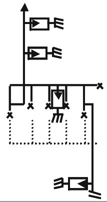
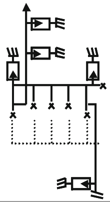
A reduction of the protective level automatically means a higher degree of specific electrical stress during continuous operation, and conversely, the continuous operating voltage (COV) of an arrester cannot be increased arbitrarily without raising its protective level as well. Both operating points for a given type of MOV are strictly associated with each other through the voltage-current (V-I) characteristic curve.

15.7 Introduction of CIGRE Investigations on MOSA

CIGRE has investigated technical requirements based on MOSA field experience in different power systems and provided IEC TC37 the background information on MOSA standards.

CIGRE WG A33.06 “Metal oxide surge arresters in AC systems” published CIGRE Technical Brochure 060 (CIGRE WG A33.06 1991) in 1991. The WG reported the excellent performance of gapless metal oxide surge arresters composed

Table 15.1 Relationship between LIWV and MOSA layouts (CIGRE WG A3.22 2011; Zaima et al. 2007)

						(:kV)
Layout of surge arrester						
Transformer overvoltage	1950	1943	1895	1943	1938	1896
LIWV	1950	1950	1950	1950	1950	1950
GIS overvoltage	2898	2854	2730	2628	2506	2208
LIWV	2900	2900	2900	2700	2550	2250
Cost	102%	105%	109%	103%	103%	100%

of zinc oxide varistors to effectively protect various overvoltages in HV power systems as compared with systems with conventional surge arresters made of silicon carbide.

The microstructure of the metal oxide material consists of a mixture of ZnO grains with granular layers of additives, the combination which is pressed into a disk shape which has low resistivity, thus making it more conductive. The voltage-current characteristic of the resistive component of the microstructure is purely dependent on the electric field distribution across the disk. The voltage drop across the resistive component of the ZnO grains in the structure is much higher under high electric field scenarios than in the low electric field scenarios. Figure 15.11 shows an example of microstructure of MOSA disk element.

The choice of material by the arrester manufacturer is very important as it has a direct impact on the energy dissipation in the MOSA. This peak value of the resistive component of the current is usually low due to high resistance and that the small capacitive component is predominant. Figure 15.12 shows an equivalent circuit of the MOSA disk.

The voltage-current characteristics of the MOSA offer a degree of nonlinearity, which results in low protection level (due to the dispersion of the resistive voltage-current characteristics at higher current values) and low power dissipation at the system operating voltage.

MOSA can be connected to the system without series spark gaps disconnecting the varistors from the operating voltage. This is only possible if its voltage-current characteristics remain stable with time and are selected adequately with respect to the voltage stresses in service. The design of the surge arrester also has to be thermally stable. The current through the metal oxide varistor block at the operating voltage has to stay well within the voltage-current characteristics.

When the current through the metal oxide varistor remains capacitive, the voltage across the varistor elements is determined by their capacitance and thus influenced by stray capacitances. Stray capacitances to earth cause a deviation from the linear axial voltage distribution with higher voltage stress of the upper elements in the arresters. This deviation is influenced by the physical parameter of the arrester such as height, number, and length of arrester units and grading rings.

With increasing varistor temperature, the ohmic current component of the varistor contributes to a more linear voltage distribution in the arrester. Insertion of grading rings as a passive measure to improve the voltage distribution is the most effective.

The MOSA requirements for temporary overvoltages that depend on system conditions were also studied. A temporary overvoltage (TOV) is an oscillatory phase-to-ground or phase-to-phase condition that is of relatively long duration and is less damped. TOV are one of the most crucial stresses to MOSA and are detrimental for its layout. In most cases TOV do not cause conventional arresters to sparkover, whereas they may result in MOSA conducting sufficient current to cause considerable heating of the ZnO resistor elements.

The performance of MOSA under different electrical stresses in AC power systems is discussed, which includes protection performance in case of both switching (slow-transients) overvoltages and lightning (fast-transients) overvoltages.

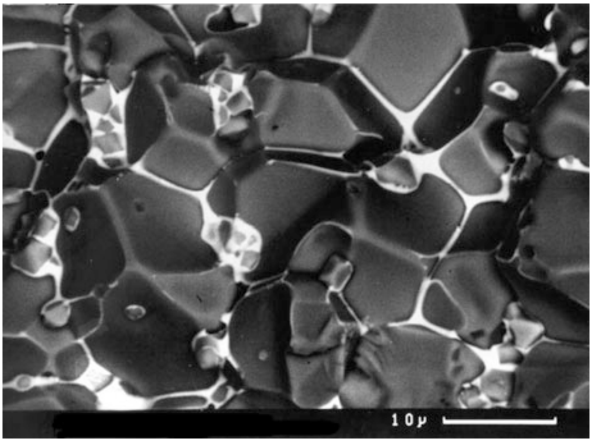


Fig. 15.11 Microstructure of a MOSA element (dark, doped ZnO grains; white, Bi_2O_3 phase at triple points; gray, spinel secondary phase)

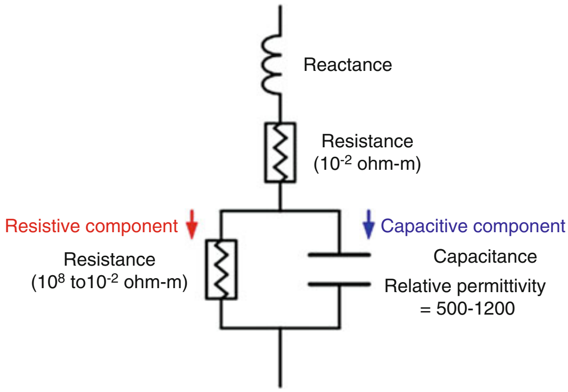


Fig. 15.12 Equivalent circuit of a MOSA disk element

The performance of the MOSA can be described by its voltage-current characteristics. Adequate increase in the residual voltages or additional turn-on resistance can improve the time delay in the current conduction mechanism of the varistor for fast-front overvoltages. MOSA can also significantly reduce the slow-front overvoltages.

A surge arrester for a specific application can be chosen by developing some specification of critical parameters such as prospective levels, TOV capability, and energy capability. An arrester with a higher energy capability reduces the risk of failure but usually means increased cost. It is essential to evaluate and know the actual arrester stresses. An optimum selection also requires a detailed knowledge of arrester capabilities regarding TOV and energy, as well as how the standards and manufacturer's data shall be interpreted and correlated to service stresses. The procedure for the selection of the correct arrester rating was recommended, focusing on the continuous operating voltage, the rated voltage, and energy capability of the arrester.

After CIGRE reorganization in 2002, CIGRE SC A3 established WG A3.17 "Metal Oxide (MO) Surge Arresters, Stresses and Test procedures." The WG especially investigated the MOSA energy handling capability and proposed testing procedures and published CIGRE Technical Brochure 544 (CIGRE WG A3.17 2013) in 2013.

With the advance of technologies, MOSA has been more commonly applied to power systems at higher stress levels to protect power system and equipment against severe overvoltages in power systems. The stresses imposed on MOSA include winter lightning strokes, seismic stresses, and severe pollution (especially for polymeric housings) discussed below.

Temporary Overvoltages

A temporary overvoltage (TOV) is an oscillatory phase-to-ground or phase-to-phase condition for relatively long duration with less damping. TOV appears in following situations:

- TOV due to grounding fault. TOV amplitude depends on the effectiveness of earthing.
- Disconnection of a load, which raises the voltage at the source side. TOV amplitude depends on the load change and the short-circuit capacity of the feeding substation.
- Voltage rise along a long unloaded transmission line due to Ferranti effect.
- Harmonic overvoltages originating from DC system or saturated transformer.
- Resonances, in particular, Ferro resonances.
- Overvoltages due to flashover between two systems with different voltages installed on the same tower.

Slow-Front Overvoltages

Slow-front overvoltages are associated with load switching or fault clearing due to switching operations. Different switching cases have to be considered, such as line de-energization, switching of capacitive loads, and inductive loads.

Fast-Front Overvoltages

Fast-front overvoltages are generally caused by lightning stroke on a transmission tower. The heaviest thunderstorms will normally be experienced in the equator region. Other causes include current chopping of breakers or back flashovers.

Distribution lines are generally of lower height and less exposed to direct lightning strokes as compared with transmission lines, where direct lightning strokes, back flashovers, and induced overvoltages will statistically result in higher stresses for the installed MOSA. EHV and UHV transmission lines have steel towers with shield wires. Most of the lightning strokes will hit the towers or the shield wires, and only shielding failures and back flashovers will cause a critical surge.

Some positive lightning flashes caused by winter thunderstorms transfer higher charge than those negative lightning flashes, which are typical for summer thunderstorms. In 90% of all cases, lightning flashes are negative flashes from cloud to earth.

HVDC Networks

Since the late 1970s, overvoltages in HVDC converter stations have been protected exclusively by MOSA due to their superior protection characteristics and reliable performance. The continuous operating voltage stress for HVDC MOSA differs from those of a normal HVAC MOSA in that it consists of not only the fundamental frequency voltage but also of components of direct voltage, fundamental frequency and harmonic voltages, and high-frequency transients.

These waveforms require other dimensioning rules for the continuous operating voltage and some specific tests of the MOSA, e.g., the accelerated aging procedure, as described in the future IEC 60099-9.

Stresses from Ambient Conditions

Ambient stresses can be very different in the different regions of the world. Very cold climates with ice and snow loads have to be considered as well as climates of high temperature and high humidity. Mechanical stresses like seismic loads strongly affect the structure and materials used for the design of the MO arresters. Vibrations as well as static and other dynamic loads have to be considered, and appropriate test procedures have been developed accordingly.

Energy Handling Capability of MOSA

The energy handling capabilities of MOSA should pay attention to different requirements: "thermal" energy handling capability and "impulse" energy handling capability.

The requirement for impulse energy handling capability should cover withstand performance for single impulse stress, multiple impulse stress (without sufficient cooling between the impulses), and repeated impulse stress (with sufficient cooling between the stresses).

On the other hand, the requirement for thermal energy handling capability can be verified with a complete MOSA unit, as it is mainly affected by the heat dissipation capability of the overall MOSA design, besides the electrical MOSA block properties.

The WG A3.17 evaluated the energy handling capability under different impulse stresses such as rectangular impulse currents, sine half waves, AC currents, and exponential high-current impulses. More than 3000 pieces of commercially available MOSA provided by American, European, and Japanese manufacturers were evaluated. Two basically different sizes of MOSA were tested, one test piece used in high-voltage systems (size 1: 40–45 mm in height, 60 mm in diameter) and the other used in medium voltage systems (size 2: 30–40 mm in height, 40 mm in diameter).

For the impulse stress tests, an extended failure criterion, beyond simple visible damage, was used to differentiate the various failure modes and to quantify changes in the electric characteristics. The AC stress tests were performed up to mechanical failure.

Figure 15.13 shows the results of the mean failure energy versus the amplitude of current density found for the tested MOSA of size 1. The results are compared with findings published by Ringler et al. (1997).

Figure 15.14 shows the change of a characteristic of MOSA of size 2 tested with AC voltage U_{ch} (approximately corresponding to the arrester's reference voltage) specified in the low current region is shown versus the energy injection by a 4/10 μs impulse current.

For the statistical evaluation of failures, it has turned out that the AC test (as compared to impulse stress tests) gives more reliable information on very low failure probabilities, which are difficult to assess with limited testing efforts. Figure 15.15 shows an example of a statistical evaluation for AC stress tests.

The conclusions obtained through the energy handling capability under different impulse stresses are summarized below:

– Energy handling capability increases with current density.
– AC stress tests lead to more reliable predictions than for impulse stress tests.
– Energy handling capability may be affected by the coating of the MOSA.

CIGRE WG A3.25 "MO surge arresters, Metal oxide resistors and surge arresters for emerging system conditions" published CIGRE Technical Brochure 696 (WG A3.25 2017) in 2017. MOSA energy handling capability was studied and the impact of multiple and repeated current impulses was reported. The long-term performance of MOSA was investigated. MOSA applications in UHV substations and UHV transmission lines were also addressed.

The focus on energy handling capability leads to a broad investigation of the long-term performance of MOSA under different types of voltage stresses. An analysis of aging curves (due to electrical aging) of today's MOSA of different makes from different manufactures indicated that three different types of aging performance exist. However, the majority of MOSA from worldwide established manufacturers show very good long-term stability (electrical aging). The energy injection with high-current impulses of the wave shape 4/10 μs and high-current densities leads to dramatic change of the characteristic voltage. This change does not have a measureable effect on the energy handling capability of the MOSA. It, however, has to be considered when determining the thermal stability of surge arresters.

The advantages and disadvantages of increasing field strength are dependent on the type of surge arrester and the manufacturer's design philosophy. Technical solutions include increasing the resistor diameter, using heat sinks, or making use of the enhanced cooling of the resistors in insulating gases like SF_6 in GIS MOSA for UHV systems. The development and application of "high field" MOSA, having two or three times higher field strength than those conventional air-insulated MOSA, can realize compact designs.

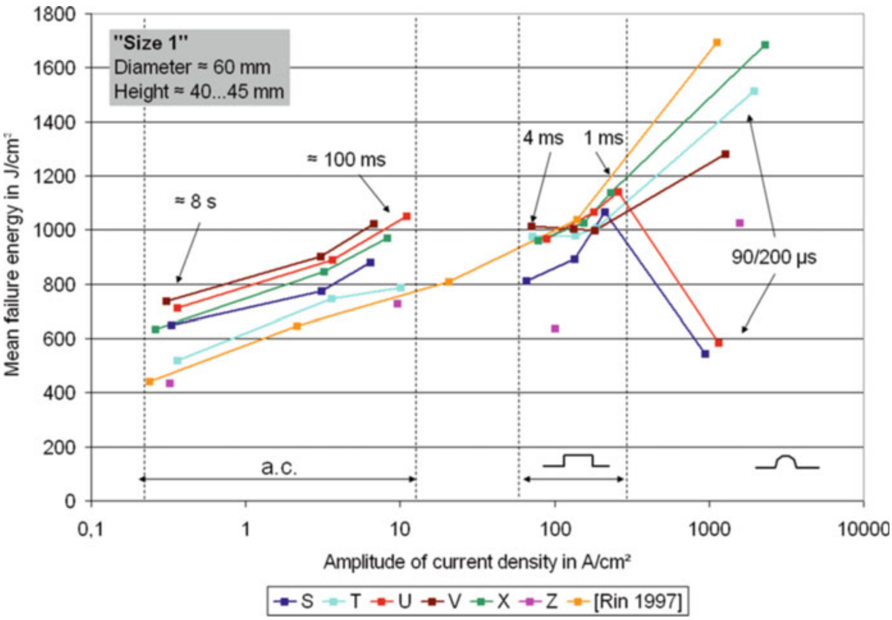


Fig. 15.13 Mean failure energy versus amplitude of current density for MOSA for high-voltage applications. Letters S to Z indicate the different makes compared to results investigated by Ringler et al. (1997)

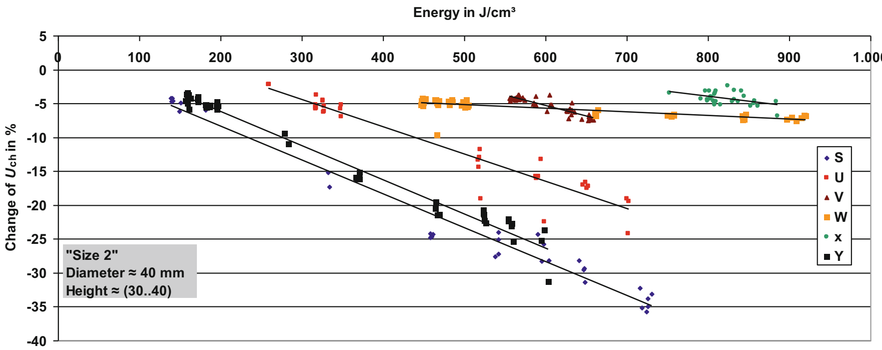


Fig. 15.14 Change of the characteristic voltage versus energy injection by 4/10 μs impulse currents for blocks of size 2. The letters S to Y indicate the different makes

The principle of operation for UHV arresters is not in any way different from standard high-voltage arresters. They are, however, more prone to TOV stresses due to their excessive lengths of more than 10 m and from their very low switching impulse protection levels. Since the sum of arrester height, height of the pedestal (i.e., length of ground lead), and length of connection lead can easily reach values of

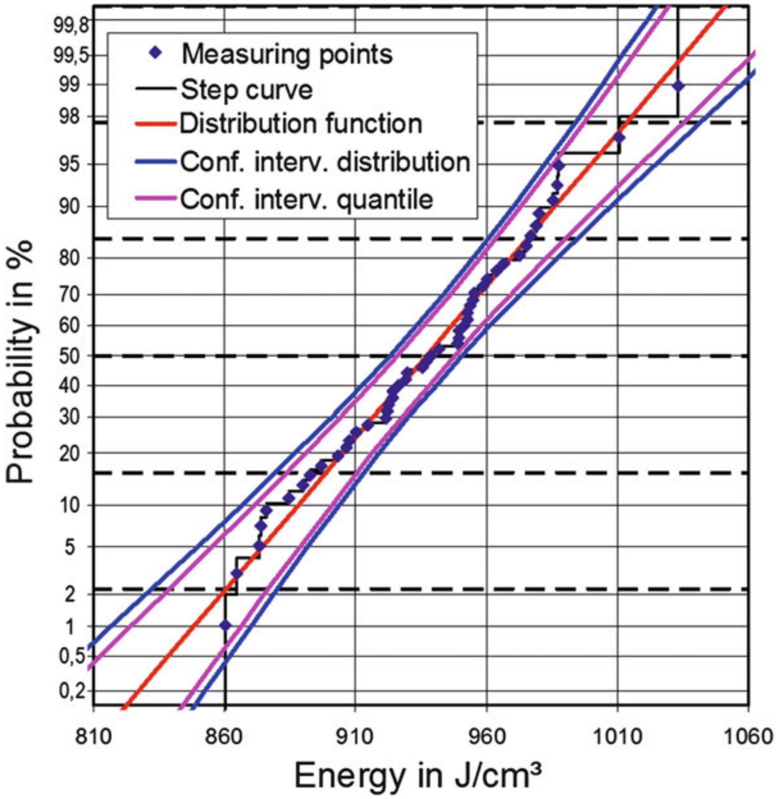


Fig. 15.15 Example of the statistical evaluation (normal distribution) for an alternating current test with 95% confidence interval

more than 20 m, the protection distance due to separation effects (traveling wave phenomena) may be too short, and correct installation of the arresters to effectively protect the equipment against fast-front overvoltages may become a critical issue.

15.8 Summary

Surge arresters are responsible to limit both lightning- and switching-induced overvoltages to a specified protection level, in order to protect transmission system and equipment from excessive overvoltages. The ideal surge arrester would have a nonlinear voltage and current characteristic that starts to conduct at a specified voltage level (switch-on), keeping a certain margin above its rated voltage, holds the specified voltage level without variation for the duration of the overvoltage for expected lifetime, and then ceases to conduct as soon as the voltage across the surge arrester returns to a value below the specified voltage level (switch-off). MOSA significantly contributes to reliable power transmission.

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HVDC Switching Equipment

16

Hiroki Ito

Contents

16.1 Introduction

The application of HVDC transmission has been expanding due to the rapid progress of power electronics technology driven by increasing needs for connection of offshore or remote wind farms and/or large hydropower generators. HVDC transmission brings several technical benefits such as less system stability problems in a

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DC system compared with AC transmission and low energy loss for long-distance transmission. In the near future, multiterminal HVDC transmission connected to offshore wind power generation will be constructed. Figure 16.1 shows the future multiterminal HVDC transmission planned in Europe (Hafner et al. 2011) and the future ASEAN international networks combined with HVAC and HVDC transmissions.

There are two different converter technologies for HVDC transmission: line-commutated converter (LCC) and voltage source converter (VSC).

For LCC HVDC, ± 800 kV HVDC transmission with the converters based on thyristors was put in service up to 8 GW in China and in India, and ± 1100 kV UHV DC transmission is being developed in China. To the contrary, for VSC HVDC, ±320 kV HVDC transmission with converters based on insulated gate bipolar transistor (IGBT) devices was operated up to 1000 MW in 2015.

Multiterminal HVDC networks are required to continuously operate the healthy transmission lines, when a fault occurs at the remote end of the HVDC network. Rapid fault clearing is essential for DC circuit breakers, because a voltage collapse will spread over the network due to the lower impedance in the HVDC systems as compared with AC systems. The required fault clearing time varies depending on the system conditions: (1) DC transmission system configurations, (2) voltage source converter (VSC) design, (3) transmission capacity, (4) DCL reactor connected in series with the line/cable, and (5) impedance of the line/cable.

Since there are no practical applications of DC circuit breakers in multiterminal HVDC networks yet, this chapter briefly describes the state of the art of DC

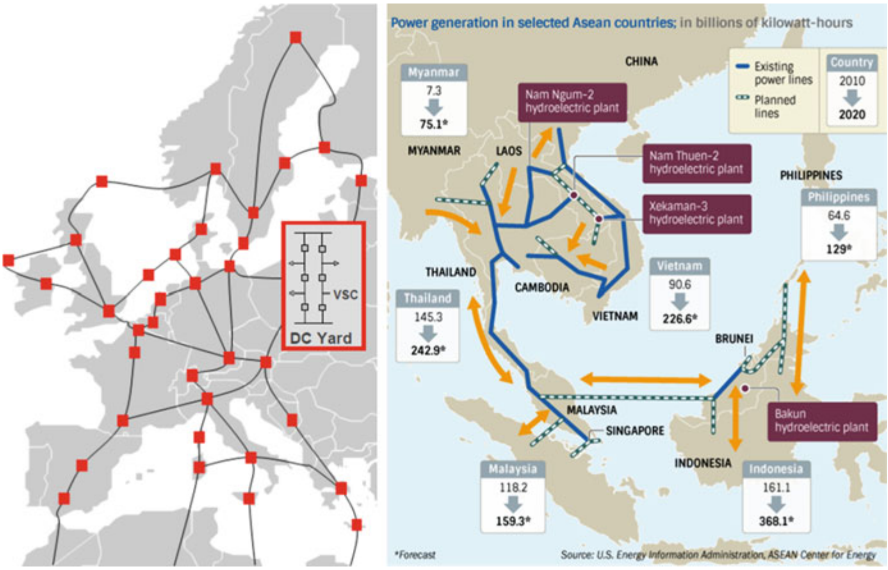

Fig. 16.1 European HVDC and ASEAN international connection. (Right hand figure: Courtesy of EGAT)

switching equipment including the requirements of DC circuit breakers in a simple multiterminal HVDC network and the available information on DC circuit breakers intended for future HVDC applications.

16.2 Definitions of Terminology

DC Circuit Breaker
A switching device capable of making, carrying, and breaking currents under normal DC circuit conditions and also making and carrying for a specified duration and breaking currents under specified abnormal circuit conditions such as those of short circuit due to a DC fault. When a fault occurs, mechanical DC circuit breakers are required to create an artificial current zero for fault clearing (by a certain current zero creation scheme). The DC circuit breaker is also required to carry a load current without excessive heating as well as withstand system voltage during normal and abnormal conditions.

Arc Voltage Current Limiting Scheme
DC current is forced to current zero by increasing the arc voltage induced between the contacts of the circuit breaker. The circuit breaker is required to induce an arc voltage higher than the system voltage in order to create the current zero. This scheme is often applied to low-voltage class DC No-Fuse Breakers (NFB). For example, a 2 kV air-blast-type high-speed switch is used for industrial and railway power systems. The scheme is also applied to most DC disconnecting switches and DC earthing switches used in HVDC LCC and VSC networks.

Passive Resonant Current Zero Creation Scheme
A small perturbation caused in the DC current due to contact separation continues to increase the amplitude of the oscillation which eventually leads to a current zero depending on the arc and circuit conditions. The interaction between the arc and the parallel capacitor and reactor connected across the DC circuit breaker can generate an expanding current oscillation with a frequency range of 1–3 kHz. A circuit breaker which can generate a higher arc voltage across the contacts (e.g., air) has an advantage in creating a rapidly expanding oscillation. A larger capacitance can also contribute to a rapidly expanding oscillation, while reactance has an optimal value to expand the oscillation rapidly.

Active Resonant Current Zero Creation Scheme (Active Current Injection Scheme)
This scheme has an external voltage source which can inject a high-frequency reverse current to the DC current that immediately creates a current zero. The external voltage source is composed of a pre-charged capacitor with a reactor and a high-speed switch (e.g., thyristor switch, triggering gap or mechanical switch) that imposes the required high-frequency (several kHz) inverse current on the interrupting fault and nominal DC current.

Hybrid Mechanical and Power Electronic Switch
This breaker is composed of both mechanical switches and power electronic (semiconductor) devices. The DC circuit breaker commutates the DC fault current from a main circuit composed of a high-speed mechanical switch and a commutating power electronic device to series- and parallel-connected power electronic (IGBT: insulated gate bipolar transistor) devices which can block the current within a few ms.

16.3 Abbreviations

BPS	Bypass disconnecting switch
CB	Circuit breaker
DCL	Series-connected reactor
EMTP	Electromagnetic Transient Program
GTO	Gate turnoff thyristor
HSES	High-speed earthing switch
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IGBT	Insulated gate bipolar transistor
LCC	Line-commutated converter
LIWV	Lightning impulse withstand voltage
MMC	Modular multilevel converter
MOSA	Metal oxide surge arrester
MRTB	Metallic return transfer breaker
MT	Multiterminal
O-C-O	Open-close-open
SIWV	Switching impulse withstand voltage
TRV	Transient recovery voltage
VCB	Vacuum circuit breaker
VSC	Voltage source converter

16.4 DC Circuit Breakers with Different Current Zero Creation Schemes

DC circuit breakers require a current zero creation scheme to interrupt the DC fault current since the DC current does not have periodical current zeros, which is different from AC current. Figure 16.2 shows typical different current zero creation schemes that can force the creation of a zero current crossing.

16.4.1 Arc Voltage Current Limiting Scheme

DC current is forced to current zero by increasing the arc voltage induced between the contacts of a circuit breaker. The circuit breaker is required to induce an arc

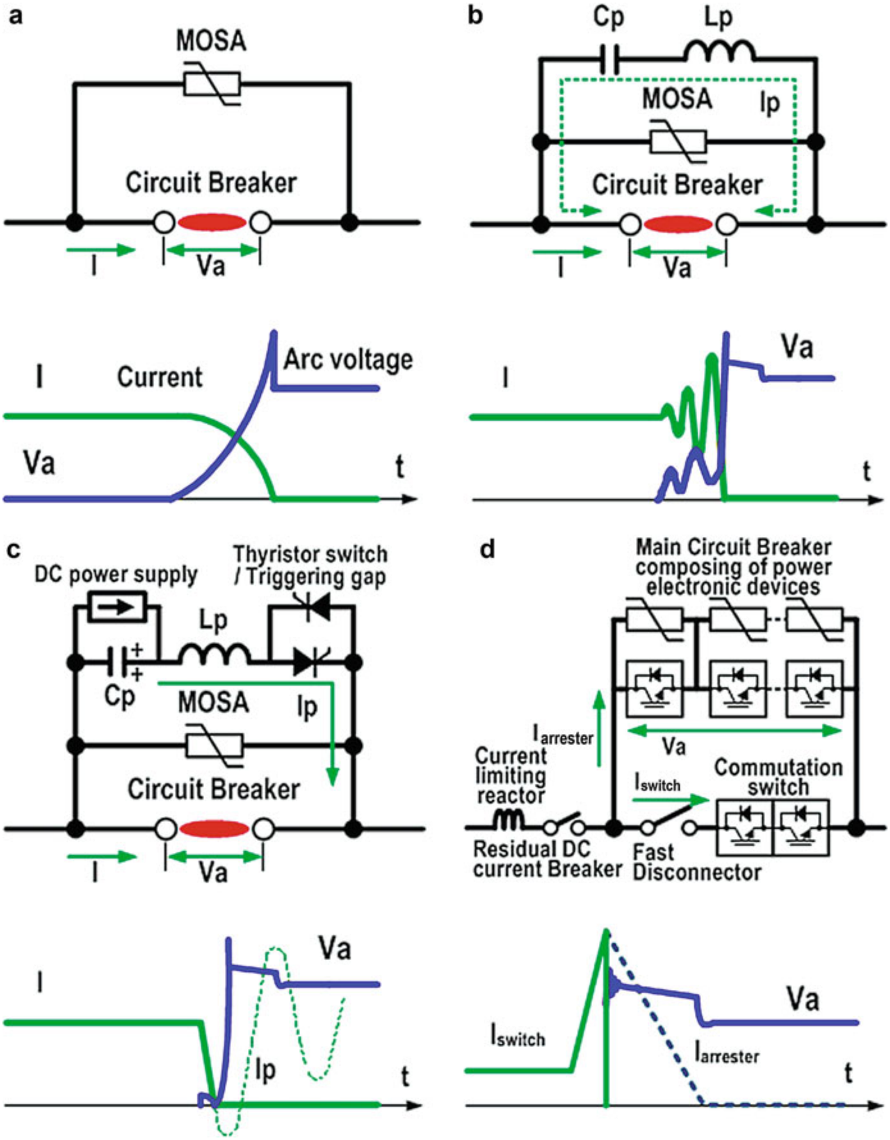

Fig. 16.2 DC circuit breakers with different current zero creation schemes. (**a**) Arc voltage current limiting scheme, (**b**) passive resonant current zero creation scheme, (**c**) active resonant current zero creation scheme with current injection, (**d**) hybrid mechanical and power electronic switch

voltage higher than the system voltage in order to create the current zero. This scheme is often applied to low-voltage class DC No-Fuse Breakers (NFB). For example, a 2 kV air-blast-type high-speed switch is used for industrial and railway power systems. Even though a DC circuit breaker with this scheme can interrupt a large current up to 100 kA, it could be difficult to design HV DC circuit breakers since the arc voltage induced by air or SF_6 across the contacts of the circuit breaker is limited to several kV at maximum. The scheme is applied to most DC disconnecting switches and DC earthing switches used in HVDC LCC and VSC networks.

16.4.2 Passive Resonant Current Zero Creation Scheme

A small perturbation caused in the DC current due to contact separation continues to increase the amplitude of the oscillation which eventually leads to a current zero depending on the arc and circuit conditions. The interaction between the arc and the parallel capacitor and reactor connected across the DC circuit breaker can generate an expanding current oscillation with a frequency range of 1–3 kHz. A circuit breaker which can generate a higher arc voltage across the contacts (e.g., air) has an advantage in creating a rapidly expanding oscillation. A larger capacitance can also contribute to a rapid expanding oscillation, while reactance has an optimal value to expand the oscillation rapidly. This scheme is often applied to metallic return transfer breakers (MRTB) which clear a fault generated on the neutral return line due to a lightning stroke and commutates the current up to a few thousand amperes to the neutral line of the HVDC transmission line after fault clearing. The scheme generally requires 20–40 ms to create a current zero for a fault interruption of a few thousand amperes.

16.4.3 Active Resonant Current Zero Creation Scheme (Active Current Injection Scheme)

This scheme has an external voltage source which can inject a high-frequency reverse current to the DC current that immediately creates a current zero. The external voltage source is composed of a pre-charged capacitor with a reactor and a high-speed switch (e.g., thyristor switch, triggering gap or mechanical switch) that imposes the required high-frequency (several kHz) inverse current on the interrupting fault and nominal DC current. This scheme is potentially applicable to interrupt HV DC fault current in multiterminal HVDC networks, even though a large capacitor is required in accordance with the DC system voltage. A prototype HV DC circuit breaker using an HV AC vacuum interrupter with the scheme has been demonstrated to interrupt DC faults up to 16 kA within 8–10 ms.

16.4.4 Hybrid Mechanical and Power Electronic Switch

This breaker is composed of both mechanical switches and power electronic (semiconductor) devices. The DC circuit breaker commutates the DC fault current from a main circuit composed of a high-speed mechanical switch and a commutating power electronic device to the series- and parallel-connected power electronic (IGBT: insulated gate bipolar transistor) devices which can block the current within a few ms. A 230 kV DC prototype circuit breaker put in service in multiterminal HVDC networks in China and a 500 kV DC circuit breaker have been demonstrated to interrupt DC 25 kA within less than 3 ms (from fault occurrence to current zero of the breaker branch without energy dissipating time by MOSA). Due to rapid developments of higher voltage and large capacity power electronic devices with lower loss, the technology may be applied to an AC circuit breaker in the future.

16.5 Voltage and Current Behavior with DC Circuit Breakers During DC Current Interruption

Figure 16.3 shows a schematic voltage and current behavior during a DC fault current interruption with a mechanical DC circuit breaker with active current injection.

When a DC fault occurs in a DC system, the fault current through the interrupter unit increases, and the system voltage starts to drop. After fault detection, a trip command is issued to the DC circuit breaker, and an interrupting unit (a vacuum interrupter) initiates opening of the electrodes. As soon as the vacuum interrupter can secure a sufficient contact gap, the active resonant current injection circuit will impose the inverse high-frequency current on the fault current and immediately create the current zero. When the vacuum interrupter can interrupt the high-frequency current, the voltage across the DC circuit breaker suddenly increases and exceeds the system voltage. It is then clipped by the MOSA restriction voltage (typically 1.5 times higher than the system voltage). The transient system voltage begins to recover to the nominal voltage, and the MOSA dissipates the energy stored by the inductance in the system.

Figure 16.4 shows a schematic voltage and current behavior during a DC fault current interruption with a hybrid mechanical and power electronic DC circuit breaker with IGBT devices.

When a DC fault occurs in a DC system, the fault current through the interrupter unit increases, and the system voltage starts to drop as described before. After fault detection, first an intermediate order is issued to turn off the load commutating IGBT devices in order to commutate the current to the power electronic branch (power electronic interrupter unit) consisting of many IGBT devices connected in series and parallel, and an ultrafast disconnecting switch connected to the main circuit opens the commutation branch. When the current starts to commutate to the power electronic branch, the voltage across the hybrid DC circuit breaker increases with the current due to the resistance of the power electronic devices. When a trip command is issued after complete current commutation, the power electronic branch turns off all the IGBT devices and blocks the current. After the current blocking, the voltage across the DC circuit breaker suddenly increases and exceeds the system voltage. Then the voltage across the DC circuit breaker is clipped by the MOSA restriction voltage similar to the case of mechanical DC circuit breaker. The transient

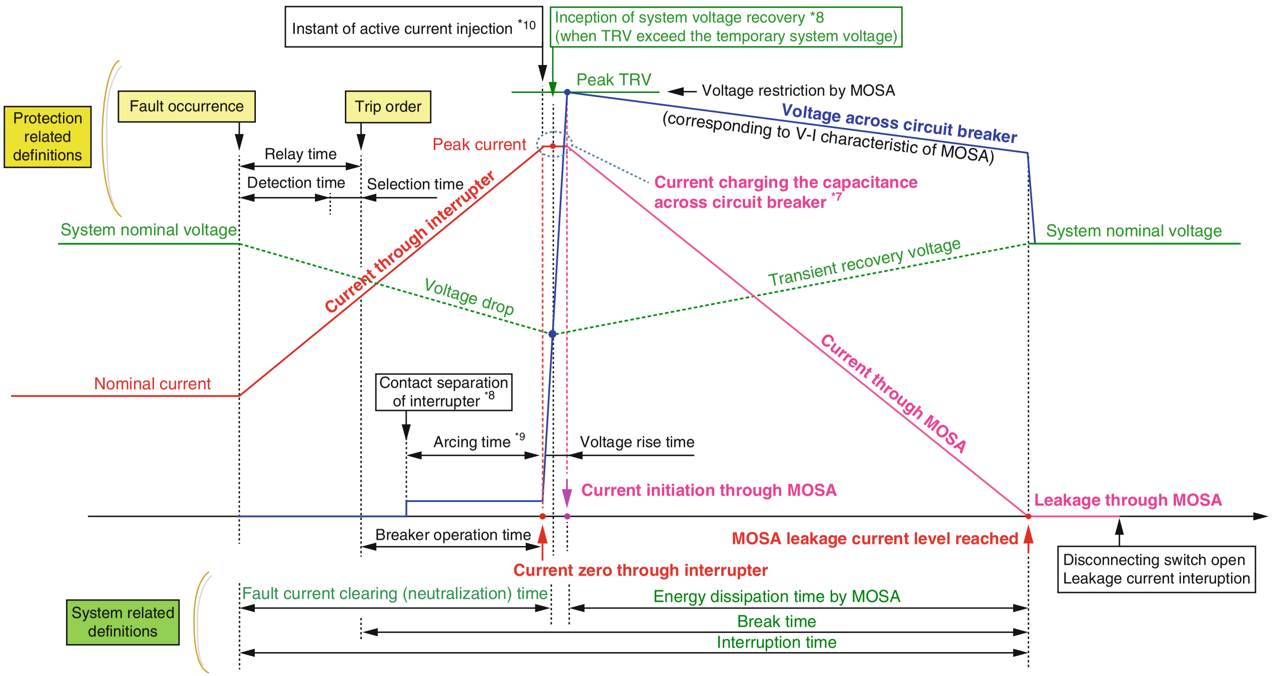

Fig. 16.3 Voltage and current behavior during DC current interruption with mechanical DC circuit breaker with active current injection scheme. Note *8: A mechanical DC breaker with special design needs a few milliseconds to open electrodes (or separate contacts) after receiving a trip order. Note *9: The arc voltage across the vacuum interrupter is almost constant after a contact separation irrelevant to the contact gap. Note *10: The fault current through a vacuum interrupter is forced to make a current zero at the instant of active current injection, and the vacuum interrupter can immediately interrupt this high-frequency current. Note *6: The voltage recovery is initiated when the voltage across the breaker (TRV) exceeds the temporary system voltage. The current through MOSA is initiated when the TRV is clipped by the restriction voltage by MOSA. Note *7: The duration to charge the capacitance across the DC circuit breaker. The capacitance required for active current injection of mechanical DC circuit breaker is on the order of microfarads

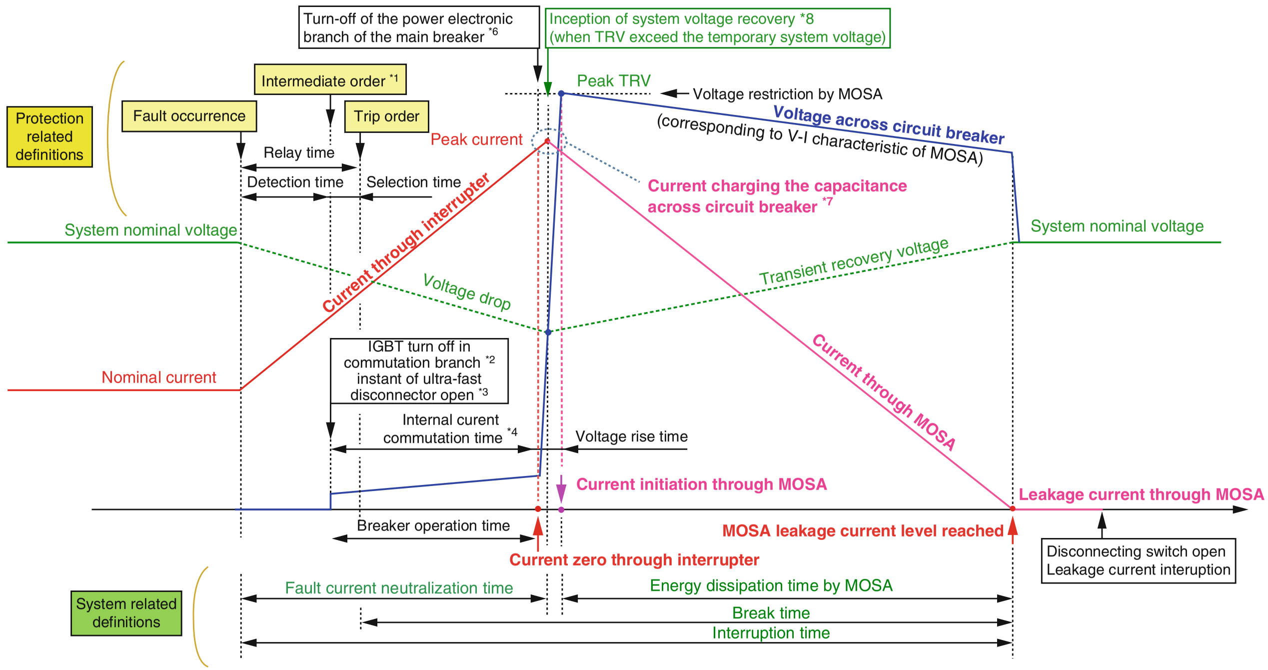

Fig. 16.4 Voltage and current behavior during DC current interruption with a hybrid mechanical and power electronic DC circuit breaker. Note *1: Any order before the trip order to start the interruption process such as operations shown in the notes 2 and 3. Note *2: The instant to turn off the load commutating IGBT devices immediately after a fault detection. The voltage across the hybrid DC breaker increases with the current. Note *3: The instant to open the ultrafast disconnector in commutation branch (main circuit). Note *4: Time required to commutate the fault current from the commutation branch with the load commutating IGBT devices to power electronic branch of the main breaker. Note *5: The instant to turn off the power electronic branch in the main breakers, which immediately block and interrupt the current after a time delay to ensure the voltage withstand of ultrafast disconnector. Note *6: The voltage recovery is initiated when the voltage across the breaker (TRV) exceeds the temporary system voltage. The current through MOSA is initiated when the TRV is clipped by the restriction voltage by MOSA. Note *7: During the voltage rise time, the stray capacitance across the DC circuit breaker is charged

system voltage begins to recover to the nominal voltage, and the MOSA dissipates the energy stored by the inductance in the system.

Figure 16.5 shows a magnified plot of the voltage and current behavior around the current zero through the interrupter branch until the instant that voltage across the DC circuit breaker is clipped by the MOSA. The capacitance (stray capacitance in the case of the hybrid DC circuit breaker) across the DC circuit breaker starts being charged when the current is forced to the current zero by either current injection or current blocking.

During the capacitor charging, the current charging the capacitance is almost constant, and the voltage starts to recover. When the recovery voltage attains the restriction voltage by the MOSA, the charging current to the capacitance stops, and

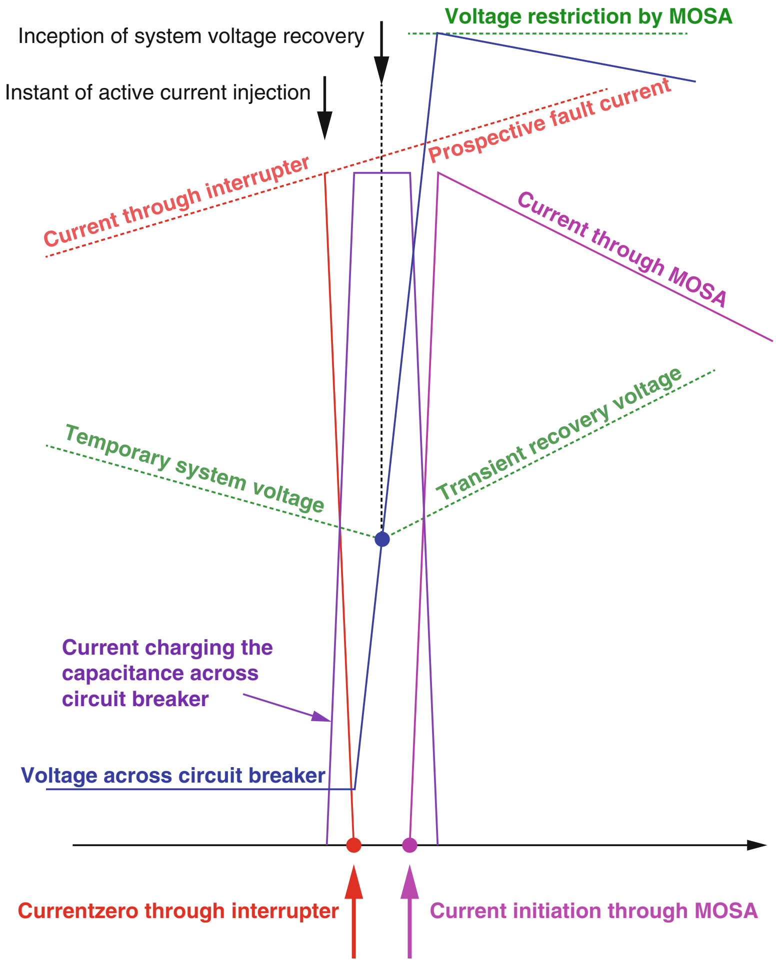

Fig. 16.5 Voltage and current behavior around current zero through interrupter to MOSA activation

the current through the MOSA is initiated and gradually decreases in accordance with V-I characteristic of the MOSA unit.

16.6 DC Circuit Breakers Applied for Different Applications

Figure 16.6 shows a 480 V–10 kA DC circuit breaker (MCCB: molded case circuit breaker) with an arc voltage current limiting scheme used in industrial applications. When the arc voltage between the electrodes of the MCCB is higher than the system voltage, it can limit the current and rapidly create the current zero in about 5 ms. Figure 16.7 shows an example of the current behavior during DC current interruption (t_1: time to the MCCB trip current level; t_2, contact parting time; t_3, time from the instant of contact parting to the instant of current peak; t_4, arcing time; t_T, total time of interruption; q, rate of rise of current).

Figure 16.8 shows a 1500 kV DC circuit breaker with an active resonant current zero creation scheme having an interrupting capability of up to 100 kA used in track

Fig. 16.6 LV DC circuit breakers with arc voltage current limiting scheme

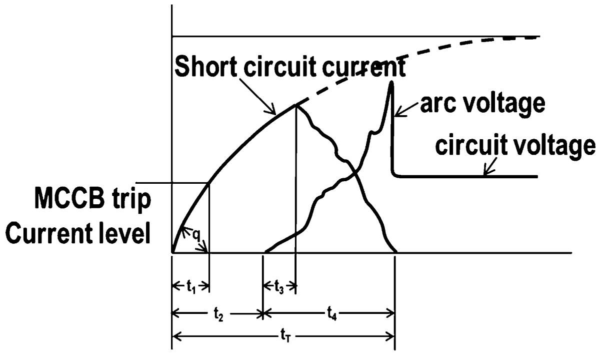

Fig. 16.7 Current behaviors during current interruption. (Courtesy of Mitsubishi Electric)

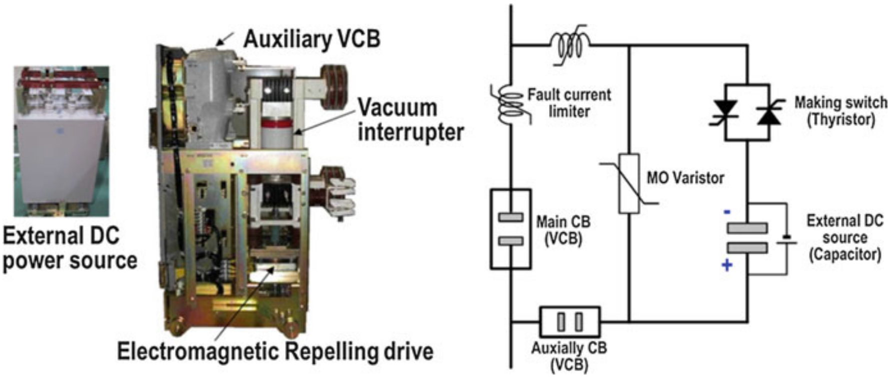

Fig. 16.8 MV DC circuit breakers with active resonant current zero creation scheme

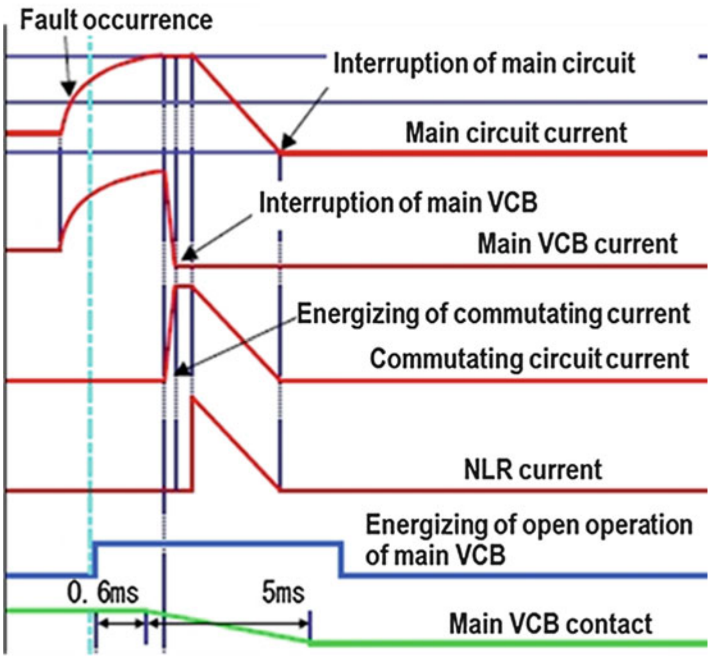

Fig. 16.9 Current behaviors during current interruption. (Courtesy of Mitsubishi Electric)

power systems. It is equipped with a thyristor switch to inject a reverse current charged in the external DC power source on the DC fault current to immediately create the current zero. Figure 16.9 shows typical oscillograms when the DC circuit breaker interrupts the fault current within a few milliseconds. After the vacuum interrupter interrupts the high-frequency current at the current zero, the voltage will recover to the system voltage, and the MO surge arrester will dissipate the energy in the circuit.

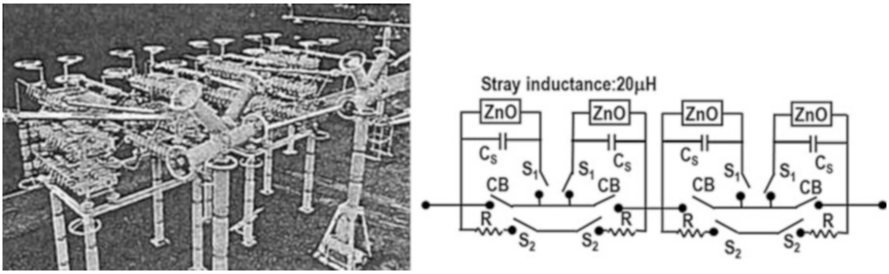

Fig. 16.10 HV DC circuit breakers with passive resonant current zero creation scheme

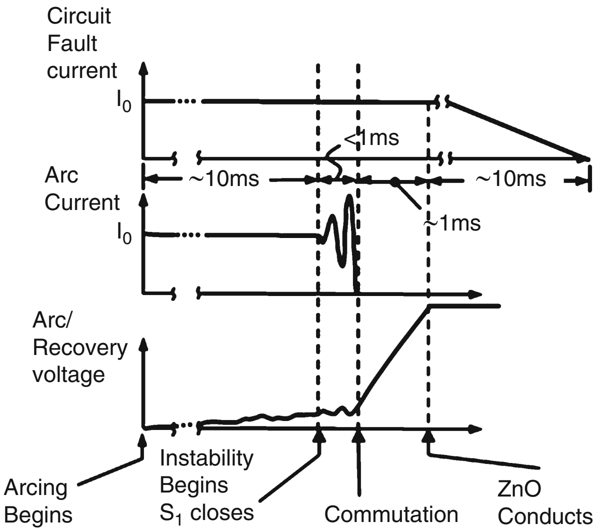

Fig. 16.11 Current behaviors during current interruption

Figure 16.10 shows a 550 kV–2200 A DC circuit breaker with a passive resonant current scheme (often called MRTB: metallic return transfer breaker) tested in the field at Pacific intertie in the United States (Lee et al. n.d.). It can clear a DC fault generated in a neutral line by closing operation and commutate the current back to the neutral line after fault clearing. Figure 16.11 shows typical oscillograms of current and voltage behavior during the current expanding oscillation to create the current zero.

16.7 Fundamental Behavior of Passive Current Creation Scheme

A passive resonant current zero current interruption scheme for DC current is initiated by arcing contact separation. A state change of the arc during interruption (e.g., a local extension or short circuit of the arc caused by gas flow)

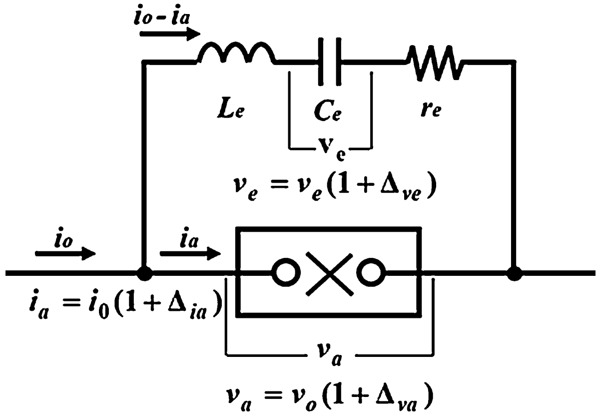

Fig. 16.12 Circuit configuration of DC circuit breaker with passive resonant current zero Scheme. (Ito et al. 1997)

appears as a small perturbation of the arc voltage and arc current which, when the circuit condition is unstable, continues to grow and eventually leads to a current zero.

The influence which such a small perturbation of the arc voltage and arc current exerts on the current oscillation phenomenon can be evaluated by a combination analysis of a mathematical arc model and the interruption circuit. An example of an investigation using a combination analysis using a mathematical arc model which studies the current expanding oscillation phenomenon and optimization of the inductance and capacitance connected in parallel with circuit breaker will be discussed below.

The Mayr arc model has two parameters (θ: arc time constant, n, arc power loss) that express the exchange of thermal energy between the arc and its peripheral gas and is expressed by Eq. 16.1. In addition, from the circuit components of a DC circuit breaker with a passive resonant current zero scheme as shown in Fig. 16.12, the behavior of arc voltage (v_a) and arc current (i_a) in the DC circuit breaker is given in Eq. 16.1 and circuit Eqs. 16.2, 16.3, and 16.4.

$$\frac{dr_a}{dt} = \frac{r_a}{\theta}\left[1 - \frac{v_a \times i_a}{n}\right] \tag{16.1}$$

$$\frac{dv_e}{dt} = \frac{i_0 - i_a}{C_e} \tag{16.2}$$

$$L_e \cdot \frac{d(i_0 - i_a)}{dt} = v_a - v_e - r_e \cdot (i_0 - i_a) \tag{16.3}$$

$$v_a = r_a \times i_a \tag{16.4}$$

In these equations, i_a, r_a, L_e, C_e, and r_e represent interruption current, arc resistance, parallel reactance, parallel capacitance, and stray resistance, respectively. Also, v_e is the voltage across the capacitor. When arc current $i_a = i_0$ and arc voltage $v_a = n/i_0$, Eq. 16.1 is in a balanced state, and arc current and arc current are constant.

The response against a small perturbation of arc current Δi_a can be obtained from Eqs. 16.1, 16.2, 16.3 and 16.4 above by the perturbation method. Thereby, the liner differential Eq. 16.5 can be obtained.

$$L_e \cdot \frac{d^3\Delta i_a}{dt^3} + \left(\frac{L_e}{\theta} + r_e + \frac{n}{i_e^2}\right)\frac{d^2\Delta i_a}{dt^2} + \left(\frac{r_e}{\theta} + \frac{1}{C_e} - \frac{n}{\theta \cdot i_e^2}\right)\frac{d\Delta i_a}{dt} + \frac{1}{\theta \cdot C_e}\Delta i_a = 0 \tag{16.5}$$

This differential equation has either three real solutions or one real and two complex solutions. When the differential equation has two complex solutions, Δi_a is in an oscillation mode. When the real part of the complex solution is positive, the solution Δi_a is unstable, and the perturbation grows with the oscillation. When the differential equation has only real solutions, Δi_a is in a non-oscillation mode (it increases monotonically when at least one real solution is positive, and it decreases monotonically when all real solutions are negative).

An oscillation mode is necessary for the passive resonant scheme DCCB. Based on the assumption that differential Eq. 16.5 can be factorized as Eq. 16.6, a general solution of Eq. 16.6 in the case of an oscillation mode is given by Eq. 16.7.

$$(p - \alpha_0) \cdot (p - \alpha_i - j\omega) \cdot (p - \alpha_i + j\omega) = 0 \tag{16.6}$$

$$\Delta i_a = \Delta_0 \cdot \exp^{\alpha_0 t} + \Delta_1 \cdot \exp^{\alpha_1 t}(\sin \omega \cdot t + \phi) \tag{16.7}$$

It can be shown that the amplification coefficient α_1 and the angular frequency ω are expressed as a function of six parameters (C_e, L_e, r_e, n, θ, and i_0). When arc parameters (n and θ), interruption current i_0, and stray resistance are constant, the dependence of the amplification coefficient α_1 and the angular frequency ω on the circuit parameters (C_e and L_e) can be obtained.

Figure 16.13 shows the calculation result of the influence on the amplification coefficient and the angular frequency of current oscillation due to the varying parallel reactance and parallel capacitor, for given circuit conditions (interruption current $i_0 = 3500$ A, stray resistance $r_e = 0.2\ \Omega$, arc time constant $\theta = 40\ \mu s$, and arc power loss n = 10 MW). From this figure, it can be seen that the amplification coefficient has a maximum value at an optimum reactance when the capacitor value

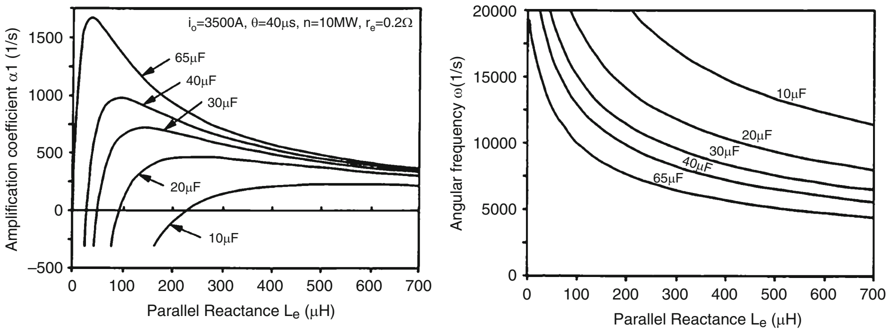

Fig. 16.13 Calculation result of influence on the amplification coefficient and the angular frequency of current oscillation by parallel reactance and parallel capacitor

is given. In addition, it can be confirmed that the angular frequency ω decreases with increasing circuit parameters (C_e and L_e).

In order that the current oscillation grows and eventually leads to a current zero, C_e and L_e must be selected so that the amplification coefficient becomes positive. For example, when the capacitor is 30 μF, a parallel reactor of more than 50 μH is required. However, a larger parallel reactor makes the time until current zero longer.

A circuit breaker has a limit of arc time range (less than about 30 ms) to enable interruption without depending on the interruption scheme (double pressure type or single pressure type). Therefore, it is clear that there is an optimal combination of parallel reactor and capacitor values so that the oscillation leads to a current zero within the arc time range to enable interruption.

Figure 16.14 shows the arc voltage and arc current waveforms from interruption tests which were performed by a DC current generation circuit composed of a three-phase rectifier circuit and smooth reactor. In this case, the interruption current was 3500 A, and the parallel impedance L_e and C_e were 350 μH and 30 μF, respectively. The stray resistance was 0.2 Ω. The model breaker was a puffer type SF_6 gas circuit breaker.

The arc power loss obtained from the arc voltage and interruption current was 10 MW, and the arc constant θ estimated from the amplification coefficient and angular frequency was 40 μs. Figure 16.14 shows the calculated voltage and current waveforms (right side waveforms) which reproduces the observed waveforms (left side waveforms) shown in Fig. 16.14. It can be seen that the calculated result reproduces both the amplification coefficient and angular frequency of the test waveform well.

Figure 16.15 shows the test results while varying the parallel circuit parameters. The combination region of L_e and C_e which makes the interruption successful (amplification coefficient larger than 450 s^{-1}) obtained from the calculation is shaded in this figure. It can be seen from this figure that the test results show good agreement with the interruption success region obtained from the calculation. Furthermore, it is also shown from this figure that L_e is not necessary when C_e is higher than 69 μF and that a value higher than 500 μH of L_e should not improve interruption capability.

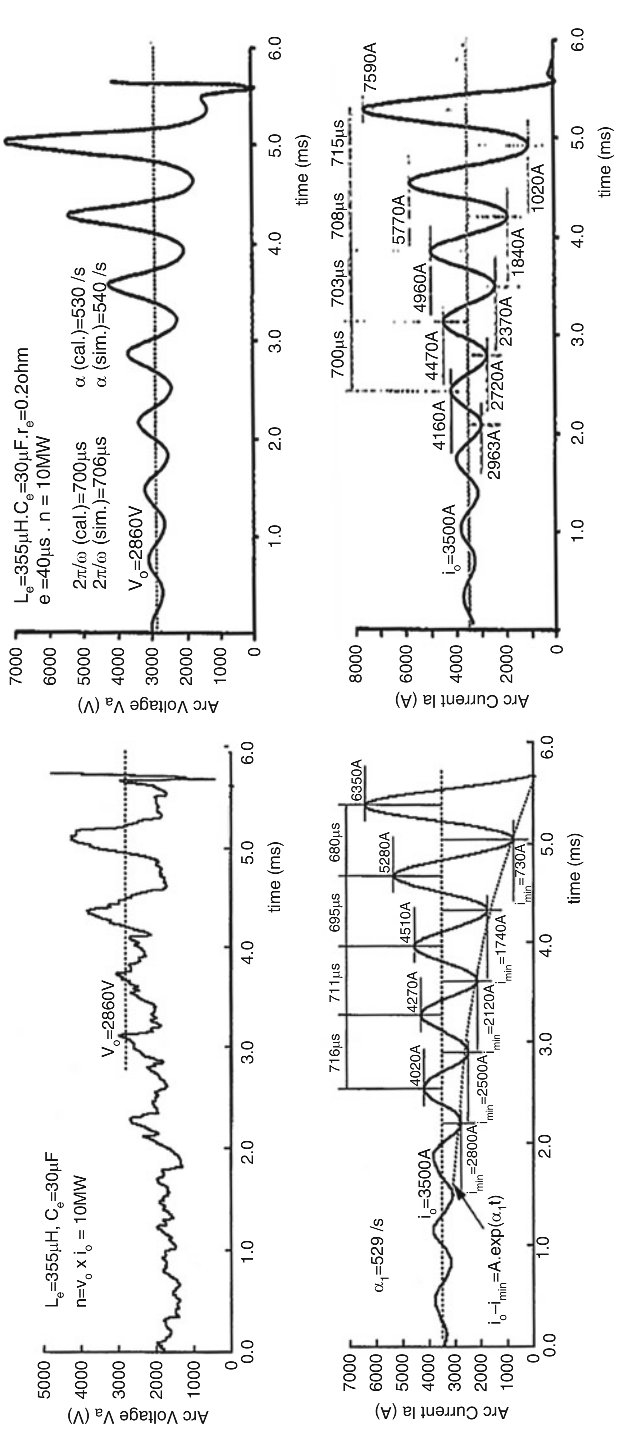

Fig. 16.14 Current and voltage behavior of MRTB with passive resonant current zero creation scheme

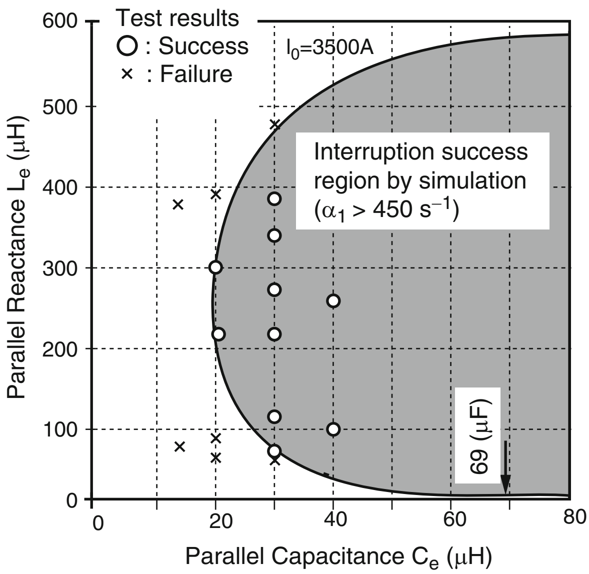

Fig. 16.15 Comparison between interruption test results and interruption success region by simulation

As described above, the investigation of the current oscillation phenomenon and optimization of parallel reactor and capacitor can be performed by the combination analysis of the mathematical arc model and circuit equations.

16.8 Development of HVDC Circuit Breaker with Active Current Creation Scheme

A mechanical DC circuit breaker composed of a HV vacuum interrupter with a rapid operating mechanism was tested with currents up to 16 kA. The active current zero creation scheme was applied to create a zero current crossing by superimposing a high-frequency inverse current on the DC fault current by discharging a pre-charged capacitor connected in parallel to the interrupter.

Figure 16.16 shows the laboratory testing conditions, and Fig. 16.17 shows a schematic test circuit of the DC circuit breaker.

The active resonant circuit consists of a capacitor (C_p), a reactor (L_p), and a spark gap and metal oxide surge arrester (MOSA) which are connected in parallel to C_p. For the DC circuit breaker interruption tests, the discharge time of the pre-charged C_p kept at a constant applied voltage had only a few ms delay after the contact separation of the vacuum interrupter. The active resonant discharge created a current zero by superimposing a high-frequency inverse current injected by the series-connected C_p and L_p. The interrupting current was supplied by an AC current source, which can provide an equivalent DC current when the DC circuit breaker interrupts a power frequency short circuit peak current.

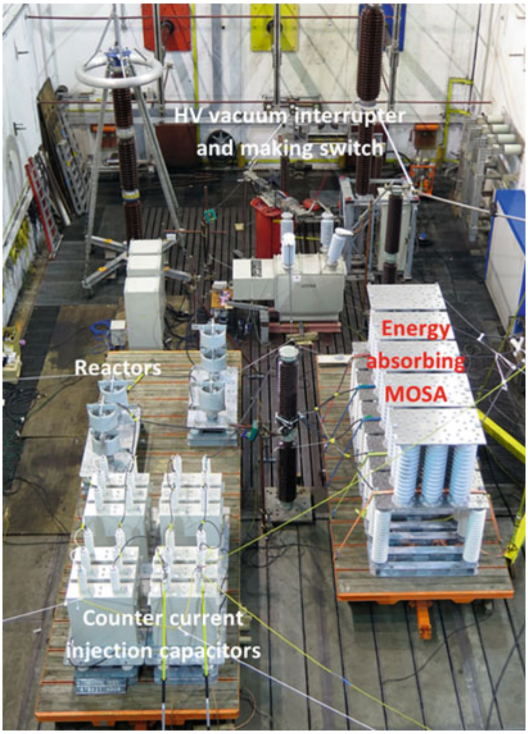

Fig. 16.16 HVDC circuit breaker test conducted at the KEMA laboratory (Belda et al. 2018). (Courtesy of DNV GL, KEMA Laboratories)

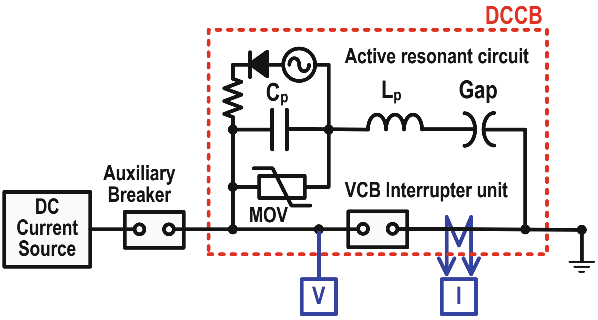

Fig. 16.17 Testing circuit of a DC circuit breaker

Testing conditions were determined in accordance with the dielectric requirements for a high-voltage AC circuit breaker and the DC interrupting currents ranged from 0.5 kA (corresponding to the nominal current) up to 16 kA.

Figure 16.18 shows the whole test sequence waveforms and their magnified waveforms recorded during interruption tests on the DC circuit breaker with interrupting currents of 16 kA and 5 kA, respectively. Tests show that the DC circuit breaker can successfully interrupt the first current zero created by an injected current when interrupting currents of 16 kA and 5 kA.

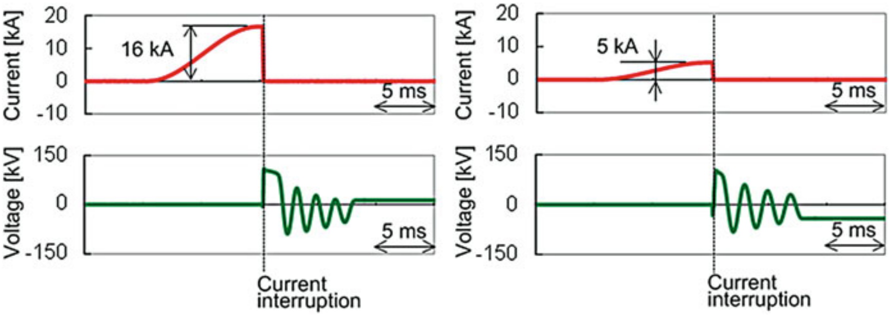

Fig. 16.18 Voltage and current behaviors at current of DC 16 kA and 5 kA

The rate of rise of the recovery voltage given by $L_p \frac{di}{dt}$ becomes more severe for smaller interrupting currents. The overvoltage generated after interruption is determined by the following Eq. 16.8:

$$\mathrm{V_p} = k\sqrt{\frac{\mathrm{L_s}}{\mathrm{C_p}}} \cdot I \tag{16.8}$$

where $\mathrm{L_s}$ is the inductance of the source circuit, $\mathrm{C_p}$ is the capacitor connected in parallel to the interrupter unit, I is the breaking current, and k (<1) is a damping factor caused by the component of the resistance of the circuit. Therefore, overvoltage ($\mathrm{V_p}$) becomes higher when the breaking current I is large, but it is limited by the restriction voltage of the MOSA connected in parallel to $\mathrm{C_p}$.

16.9 Operation Principle of Hybrid Mechanical and Power Electronic Switch

The configuration of a hybrid mechanical and power electronic switch is shown in Fig. 16.19. This type of DC circuit breaker consists of a load commutation switch, an ultrafast disconnector, and a main breaker branch. The load commutation switch has a few power electronic devices. This switch can commutate the DC current to the main breaker branch in a short period after receiving a trip command. The ultrafast disconnector is a fast-opening mechanical switch, which isolates the load commutation switch from the main breaker during interruption. The main breaker is composed of a large number of power electronic devices (IGBTs) connected in series and in parallel. MOSAs are connected across the main breaker branch in parallel to limit the overvoltage after main breaker interruption.

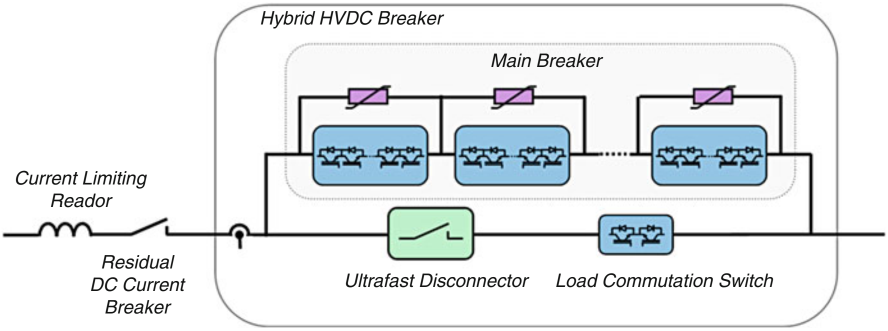

Fig. 16.19 Configuration of hybrid mechanical and power electronic switch. (Derakhshafar et al. 2014)

Fig. 16.20 Operation of hybrid mechanical and power electronic DC circuit breaker. (**a**) Current through the commutation branch. (**b**) Current through the main breaker branch. (**c**) Current through MOSA

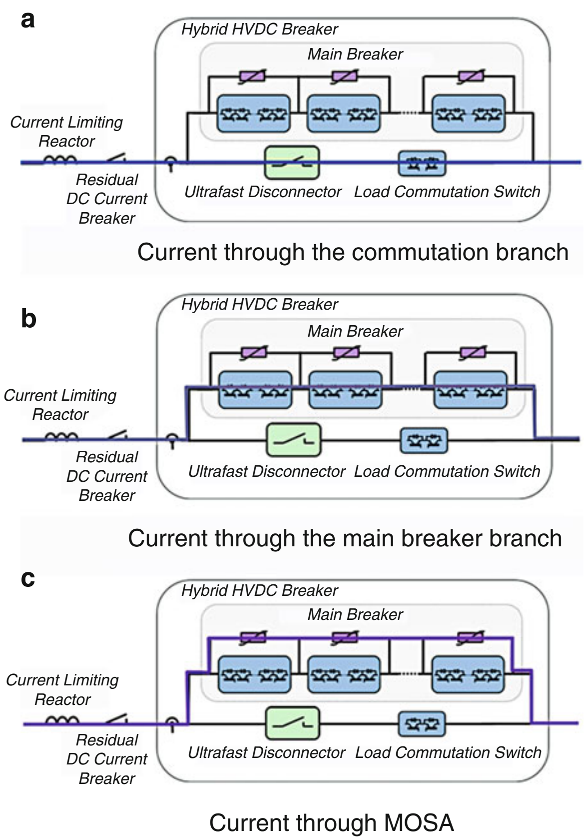

Figure 16.20 shows the operation sequence of this type of DC circuit breaker. During normal operation, the load current flows through the load commutation switch and ultrafast disconnector (Fig. 16.20a). Since a few power electronic devices in the load commutation switch are small and the ultrafast disconnector is a mechanical switch, on-state loss of this current path is relatively low.

When the DC circuit breaker receives a trip command, the load commutation switch turns off, which commutates current into the main breaker branch (Fig. 16.20b). After current commutation, the ultrafast disconnector opens. The turnoff of the power electronic devices in the main breaker branch is performed after a time delay determined by the time for the ultrafast disconnector to achieve the required voltage withstand. By turning off the main breaker, current commutates to the MOSA, and the MOSA dissipates energy (Fig. 16.20c). When the current reaches zero, the residual DC current breaker outside of the DC breaker opens, and interruption is completed.

Figure 16.21 shows a testing result of an 80 kV hybrid mechanical and power electronic switch. In this test, the DC circuit breaker interrupted a fault current of about 9 kA.

Figure 16.22 shows a photo of a prototype 500 kV 25 kA hybrid mechanical and power electronic DC circuit breaker (Yang et al. 2017). Figure 16.23 shows the configuration of the hybrid 500 kV DC circuit breaker. The hybrid HVDC circuit breaker consists of a main load branch and a main breaker branch. The main load branch includes the fast mechanical switch and the IGBT commutation module. The main breaker branch is composed of the series-connected IGBT modules with several diodes and the energy dissipating MOSA connected in parallel. Figure 16.24 shows the DC current interruption process of the 500 kV DC circuit breaker.

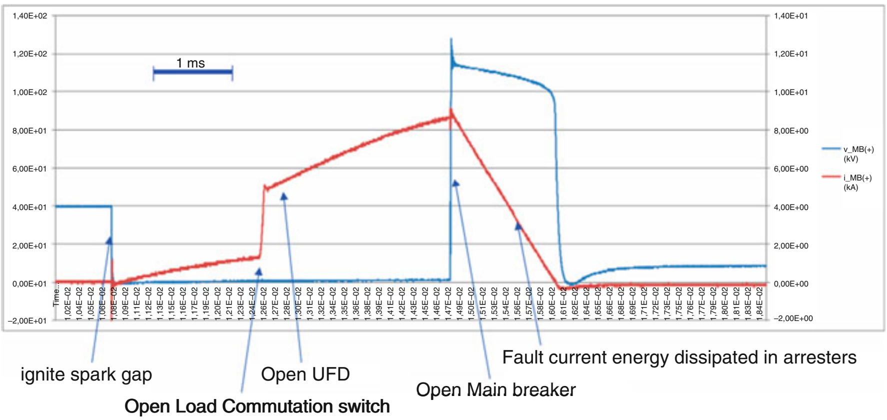

Fig. 16.21 Testing result of hybrid mechanical and power electronic DC circuit breaker (Derakhshafar et al. 2014)

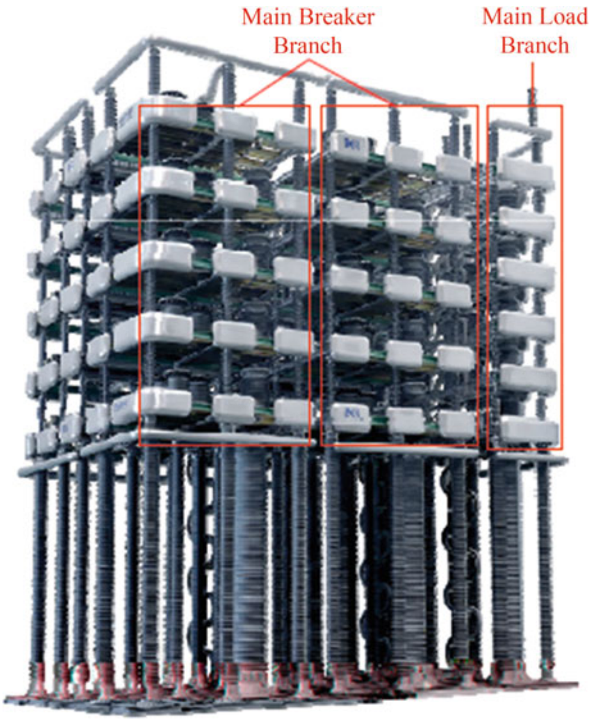

Fig. 16.22 500 kV DC circuit breaker (hybrid mechanical and power electronic switch). (Courtesy of NR Electric, State Grid of Corporation of China)

16.10 DCCB Requirements for Multiterminal Radial HVDC Network

The requirements for DCCB such as DC fault current level and DC fault clearing time are investigated with a simple multiterminal radial HVDC network model shown in Fig. 16.25 (Tahata et al. n.d.). This model consists of a four-terminal HVDC network with four VSC (voltage-commutated converter) stations connected via HVDC cable as shown in Fig. 16.25. The lengths of the cables were set to 120 km, 240 km, and 360 km, respectively. The rated DC voltage of this system is +/−320 kV. The capacities of each VSC converter station (C/S) range from 900 MW to 1200 MW, and the transmission capacity of the system is 2.1 GW. In this analysis, a DC pole-to-pole fault was considered near B-C/S.

Depending on the converter design parameters (e.g., modulation index), a VSC converter cannot continue operation when the DC system voltage drops below a threshold value (e.g., 0.8 PU of the nominal voltage). Therefore, in order to ensure continuous operation without a loss of controllability on a non-faulted line, the DCCB is required to clear a fault rapidly. In this simulation, 0.8 PU of the nominal voltage is set as the threshold value, and the time for the system voltage to drop to this threshold value is defined as DC fault clearing time requirement and is

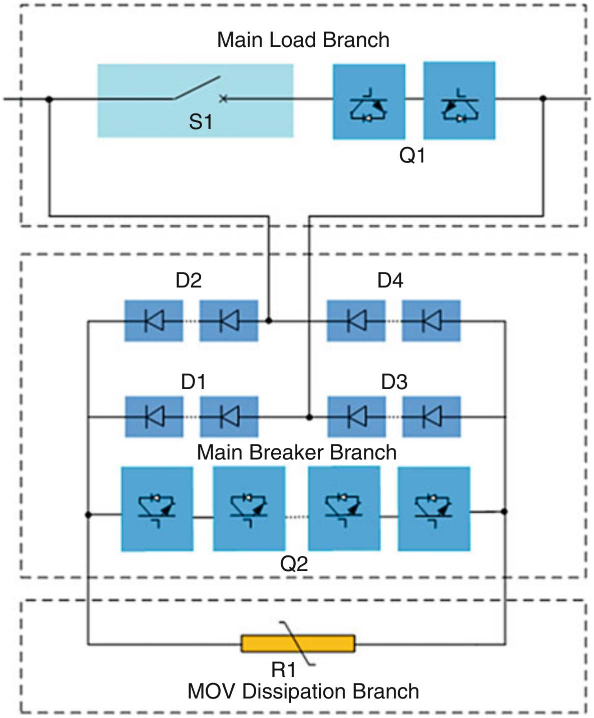

Fig. 16.23 Configuration of hybrid 500 kV DC circuit breaker

confirmed. In the simulation network, a series-connected reactor (DCL) is connected to the DC lines. It is expected to delay voltage drop speed and to mitigate the DC fault clearing time requirement.

Figure 16.26 shows some analytical results of the DC voltage V_{DC} (the pole-to-pole fault voltage shown in Fig. 16.25) at C/S for various DCL values when a pole-to-pole fault occurs near B-C/S. The time of the DC fault occurrence is set at $t = 300$ ms at both line terminals. The voltage at B-C/S near the fault immediately drops at a rate of voltage decay determined by the line impedance and DCL. The voltage at C-C/S, D-C/S, and A-C/S located 240 km to 600 km away from the fault location gradually drops as a result of the fault, but the rate of decay is not as severe since the line sees a significant impedance due to the addition of the DCL and long transmission lengths as well as taking into consideration the travelling wave propagation phenomenon from the fault location.

Simulations showed that by increasing the reactance of the line and having longer distances from the fault location, the voltage drop at a remote converter can be mitigated, therefore allowing a longer DC fault clearing time threshold for the DC circuit breaker.

Table 16.1 summarizes the results of the simulations showing fault clearing times for DCCB determined so that the converter DC voltage would not to drop below 0.8 PU of the system voltage after a fault event while varying the value of the DC reactor

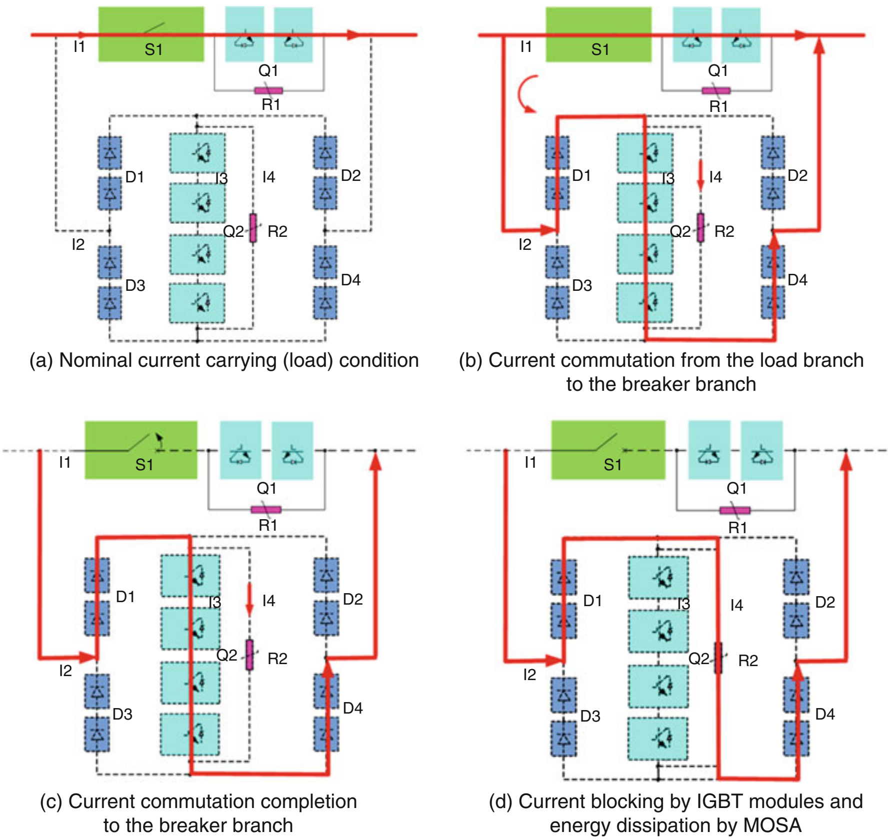

Fig. 16.24 DC current interruption process of the 500 kV DC circuit breaker (Yang et al. 2017). (Courtesy of NR Electric, State Grid of Corporation of China). (**a**) Nominal current-carrying (load) condition. (**b**) Current commutation from the load branch to the breaker branch. (**c**) Current commutation completion to the breaker branch. (**d**) Current blocking by IGBT modules and energy dissipation by MOSA

at each C/S. Although the results do not indicate a perfect correlation between the speed of the voltage drop and distance from the fault due to transient oscillation and system parameter differences of each C/S (e.g., converter capacity), the DC voltage, however, tends to drop slowly with longer distances from the fault. The results indicate that the DC fault clearing time could be longer than 10 ms when a larger DC reactor in the range of 150 mH or more at both line terminals is connected in series to the main circuit (Tahata et al. 2015).

Another important requirement for DCCBs is the DC fault current value, which increases with elapsed time after a fault event depending on the total capacity of the associated converters. In Fig. 16.26 the fault current (I_f) through the cable connected to B-C/S is considered to be the most severe case, because the fault currents from three converters of A, C, and D-C/S flow into the fault location. Figure 16.27 shows

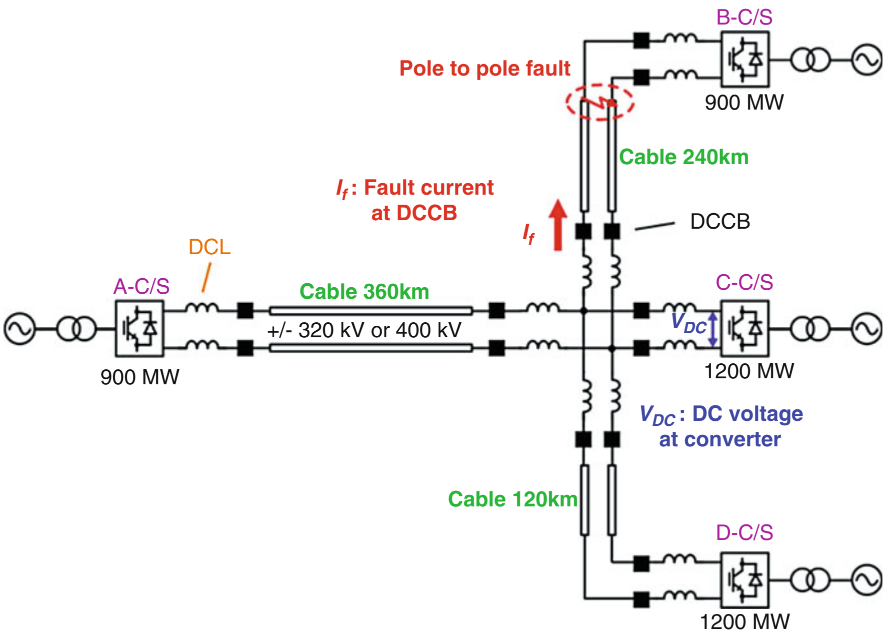

Fig. 16.25 Simple multiterminal radial HVDC network model

Table 16.1 DC fault clearing times for DCCB for various DCL reactance values at each C/S

Time for DC voltage at converter to drop to 0.8 PU, t (ms)				
DC Reactor (mH)	B-C/S (near)	C-C/S (240 km away)	D-C/S (360 km away)	A-C/S (600 km away)
25	0.002	6.52	7.49	12.91
50	0.002	7.71	9.86	14.19
150	3.29	13.88	16.56	18.00

the DC fault current behavior of I_f for different DCL reactor values in the four-terminal HVDC network.

When a fault occurs, the connected poles immediately discharge at the fault location, and, thus, the fault current is in the range of 6–14 kA. Then the discharged current oscillates with a resonant frequency determined by the cable impedance and DCL value. The fault current continues to increase to over 30 kA due to the fault currents flowing from the remote converters located at A, C, and D-C/S. The simulation shows that the DC fault current is 11 kA with a 150 mH DCL reactor and 17 kA with a 50 mH DC reactor in series with the main circuit after 10 ms from when the fault occurs.

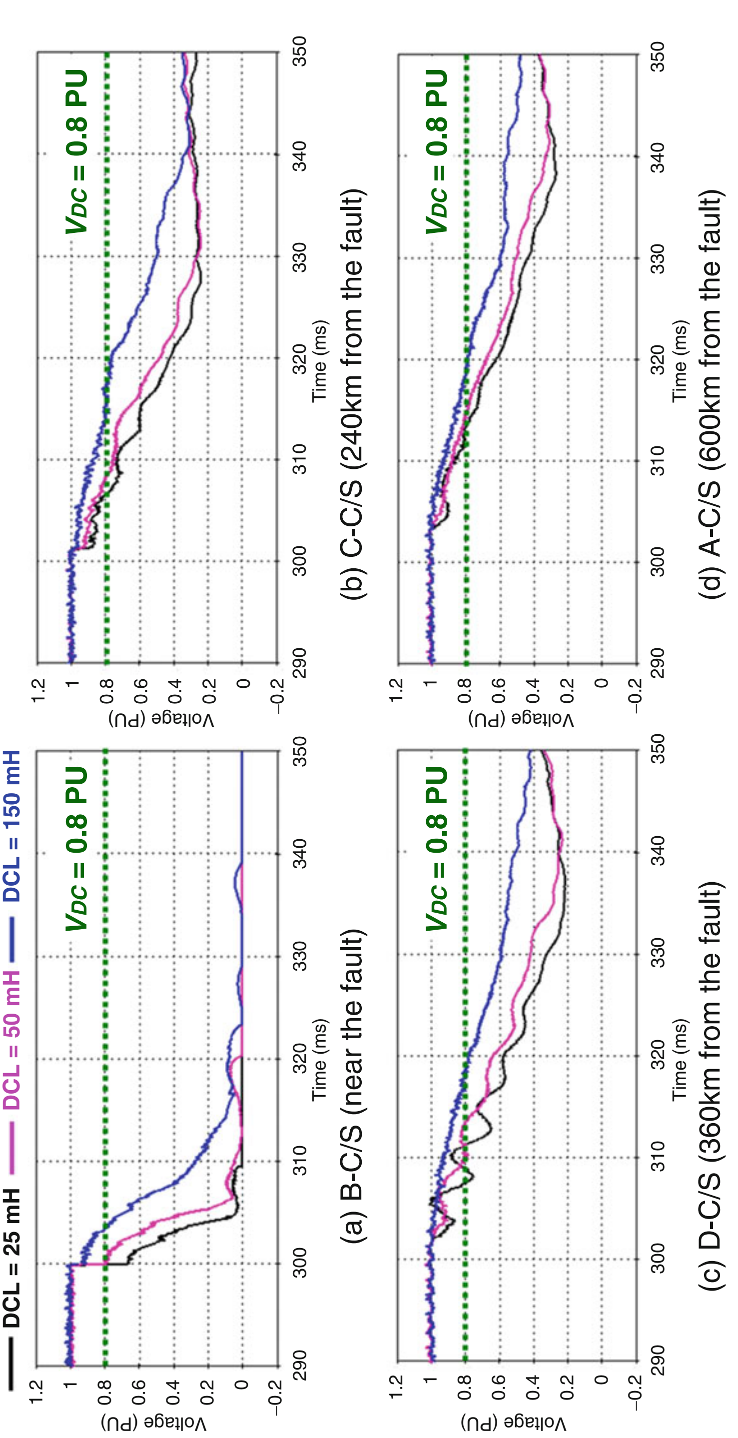

Fig. 16.26 DC voltage behavior at each C/S after a fault occurrence. (**a**) B-C/S (near the fault). (**b**) C-C/S (240 km from the fault). (**c**) D-C/S (360 km from the fault). (**d**) A-C/S (600 km from the fault)

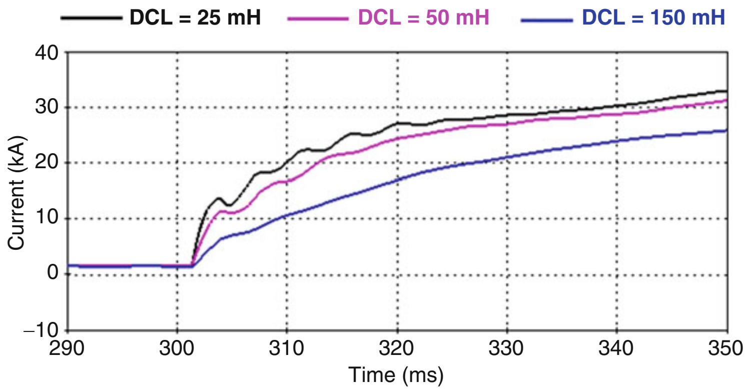

Fig. 16.27 DC fault current behavior of I_f for various DCL reactance values

These analytical trials indicate that the DCL can mitigate both fault clearing time requirements from the point of view of voltage drop and fault current values effectively. For example, the requirements for DC circuit breakers in the four-terminal +/−320 kV radial HVDC network model with 150 mH of DCL are typically less than 16 kA to be cleared within 10 ms in order to continue power transmission at the remote converter station located 240 km away from the fault location. Accordingly, it can be said that DCL can make it feasible to extend the selection range of DC breakers, for example, 10 ms operation time breaker which has low loss and cost effectiveness.

16.11 Field Experience of MRTB

When a DC fault occurs on one pole of a bipolar HVDC system, the operation mode should be shifted from the bipolar operation method to the monopolar operation method. In some applications, the monopolar operation mode is also required to switch from the ground return to the metallic return using the faulted transmission line.

A MRTB connected to a neutral metallic return line is used to clear a DC grounding fault by the closing operation. The return current is split into two paths of the ground return and the ground wire. Since the MRTB is directly earthed to the grounding mesh, the connection with the MRTB reduces the voltage between a fault point on the neutral line and the ground. Accordingly an arc generated due to a lightning stroke cannot sustain its voltage, and the current is rapidly reduced to current zero.

After a DC fault clearing, the MRTB is opened to commutate the current to the neutral metallic return line in order to return to healthy operation of the bipolar operation mode. Figure 16.28 illustrates the system configuration of a bipolar HVDC system with two neutral metallic return lines. Each pole can be operated independently in order to continue power transmission during maintenance work of one pole or fault occurrence on one of the metallic transmission lines.

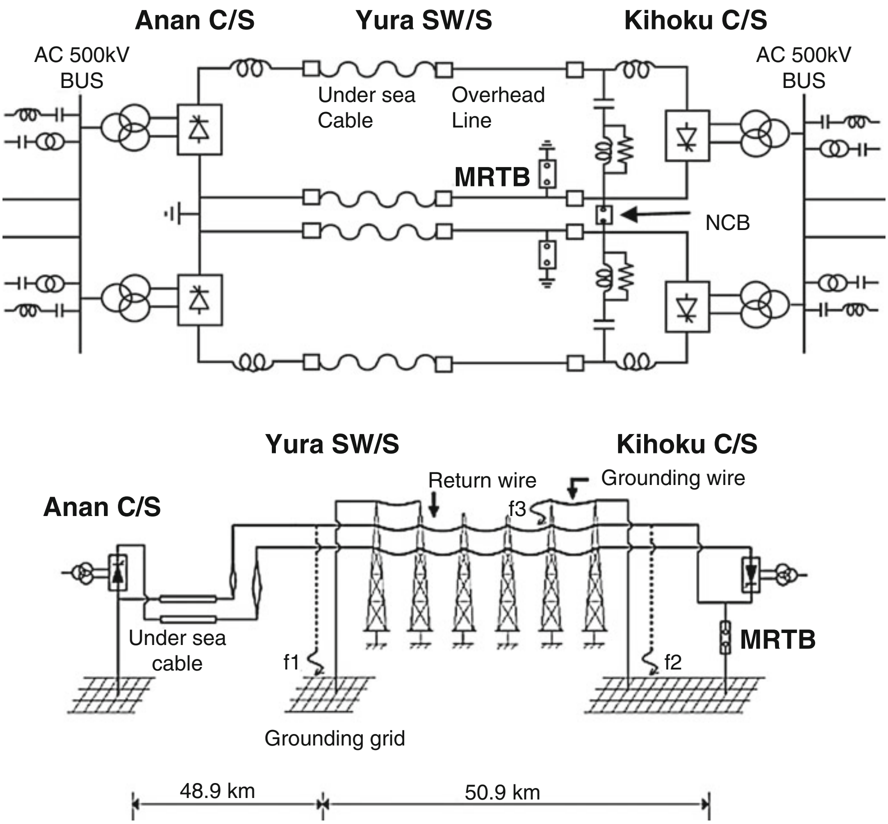

Fig. 16.28 Bipolar HVDC system with neutral metallic return lines. (Hara et al. n.d.)

Since the MRTBs were installed in 2000, they have been operated more than 300 times and successfully cleared a fault that occurred on the neutral line. Figure 16.29 shows an oscillogram after commissioning when an actual lightning fault occurred at a transmission tower about 18 km away from C/S. It can be seen that the return line current reduces and is commuted to the MRTB. Furthermore, the MRTB interrupts the commuted current at 300 ms after its closing, then the return line voltage recovers, and after that the system returns to a healthy condition.

Figure 16.30 shows a prototype of DC switchgear with passive oscillating current zero creation scheme.

16.12 HVDC Disconnecting Switches

HVDC disconnecting switches (DS) are used to disconnect various circuits in HVDC transmission networks. For example, the HVDC DS is applied to switching duties such as line or cable-charging current switching, no-load line, or cable transfer

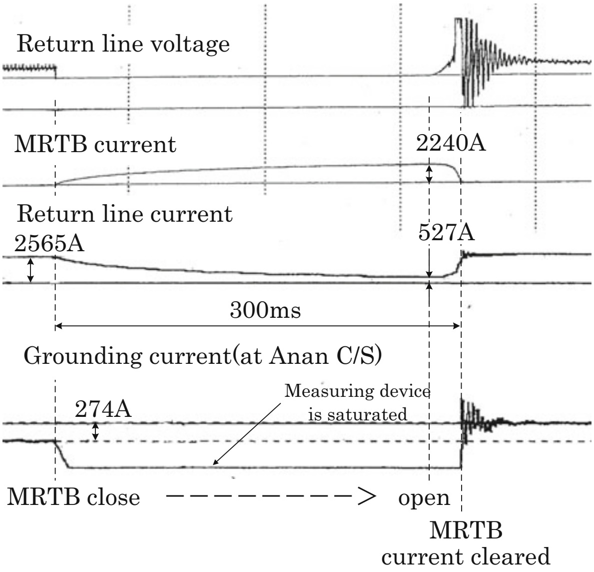

Fig. 16.29 MRTB operation of an actual lightning fault occurred at a transmission tower. (Hara et al. n.d.)

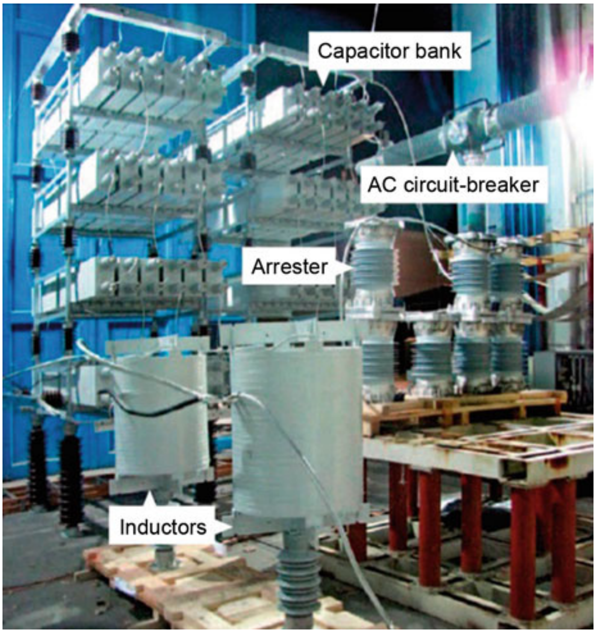

Fig. 16.30 Prototype MRTB. Courtesy of IPH, CESI group produced by Siemens

switching, in addition to disconnecting equipment including a converter bank (thyristor valve), a filter bank, and a grounding line. HVDC DS is also applied to DC switchgear to terminate the residual or leakage current through an interrupter after clearing a fault current.

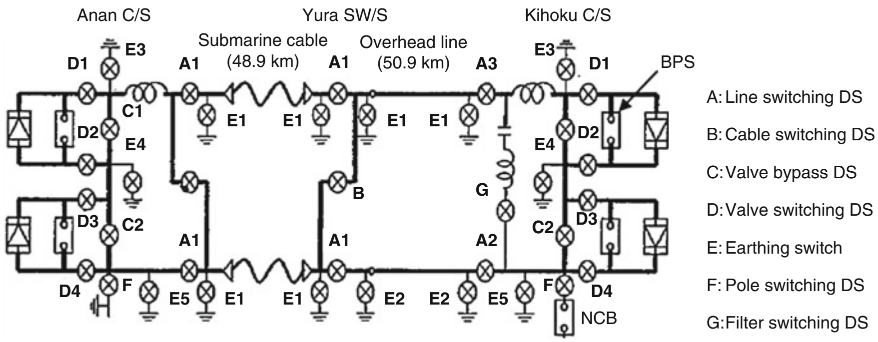

Fig. 16.31 Example of a single pole diagram of HVDC disconnecting switch in bipolar HVDC system

Table 16.2 Main switching duties of disconnecting switch (DS) applied to bipolar HVDC system

Switching duty	DS group in Fig. 22	Switching duty	Specifications
Line discharging current switching	A1, A2, A3	Interrupt the line discharging current flowing through a snubber circuit in a converter due to remaining charges of the lines after a converter is stopped	HVDC 0.1 A
No-load line transfer current switching	B	Switch a circuit connected between no-load positive line and negative line, when a phase to ground fault occurred on the lines the system is stopped prior to DS operation	HVDC 0.1 A
Loop current switching	C1, C2	Transfer the loop current through a disconnecting switch (DS) to a bypass switch (BPS) connected in parallel with a converter unit by opening DS, when a converter unit stops its operation Closing duty is also required when a converter unit starts its operation	LVDC 2800 A
Converter charging current switching	D1, D2	Interrupt charging current through a converter unit, when a converter unit stops its operation. The current includes a ripple current during a converter operation. When a converter unit starts its operation, closing surge is generated by DS operation	HV DC 1 A

Figure 16.31 shows an example of a single pole diagram with related switching equipment (except for MRTBs) in the bipolar HVDC transmission system in Japan. In general, the requirements for HVDC DS and ES in the HVDC system are similar to the HVAC DS and ES used in the AC system, but some equipment includes additional requirements depending on their application. Table 16.2 gives major switching duties imposed on these HVDC DS (CIGRE JWG A3/B4.34 2017).

Group A: The DS is required to interrupt the line discharging current due to residual charges of a submarine cable which has a relatively large capacitance (approximately 20 μF). The residual voltage induced in the line after a converter halt is discharged through a snubber circuit in a converter bank at both C/Ss (Anan C/S and Kihoku C/S) to ground. The discharge time constant is about 40 s, which corresponds to a discharging time of 3 min. The discharge current was set to 0.1 A based on the value calculated from the residual voltage of 125 kV and the resistance of the snubber circuit in the thyristor valve.

Group B: The DS is normally used to switch a faulted transmission line to a heathy neutral line in order to use the neutral line for a transmission line temporarily or permanently after the system is completely stopped. This requires the same specifications as the group A DS.

Group C: The DS is required to transfer the nominal load current from the DS to the bypass switch (BPS) connected in parallel with a converter bank in order to restart the bank unit. The specification of the transfer current is 2800 A in this project.

Figure 16.32 illustrates a nominal current transfer process from the DS to the BPS. At first, the upper converter bank unit is stopped and the lower converter bank unit is operated. In order to operate the upper bank unit from a halted condition, the DS C1 is opened next to commutate the nominal current into the BPS. Based on the analysis with an equivalent circuit of the current transfer process shown in Fig. 16.32c, the requirements for the group C DS are given by the voltage of DC 1 V at a nominal current of 2800 A, where the voltage was calculated with the resistance and inductance per unit length corresponding to the current transfer length including DC-GIS.

Group D: The DS is required to interrupt a converter bank charging current when a converter bank unit is stopped. Even if the thyristor valve is halted, a ripple current flows through stray capacitance of the converter bank. The analytical result shows that it is highly probable that the ripple current is chopped less than 1 A, and the recovery voltage due to the difference between the residual DC voltage of the converter side and the DC voltage of the line side which includes ripple components is less than 70 kV as shown in Fig. 16.33.

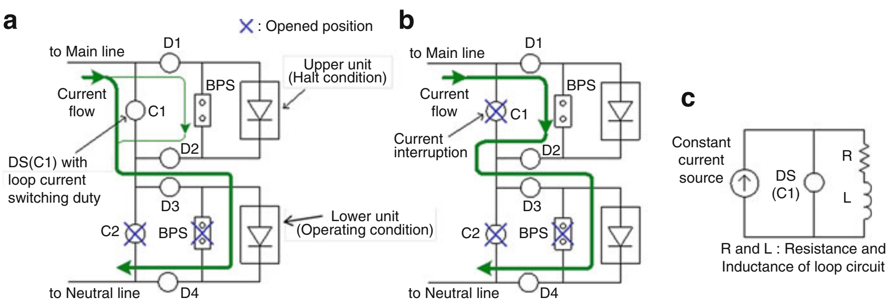

Fig. 16.32 Current transfer DS operation of group C. (**a**) DS close position, (**b**) DS open position, (**c**) equivalent circuit of DS

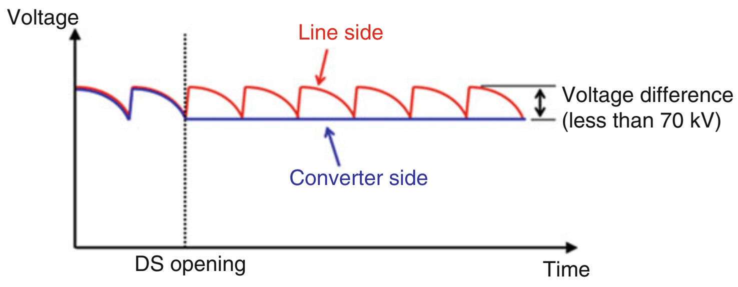

Fig. 16.33 Voltage difference between DS contacts

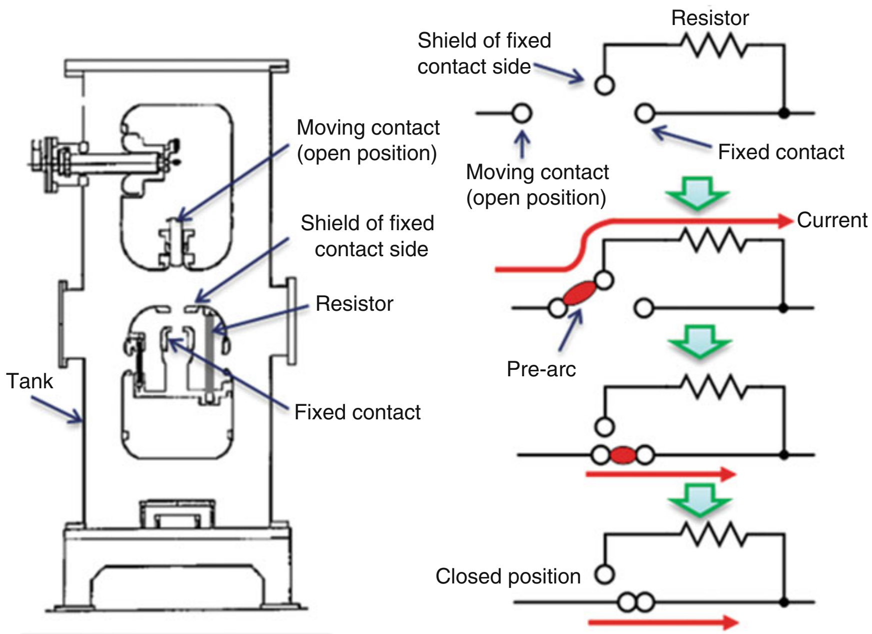

Fig. 16.34 DC 500 kV DS with closing resistor and its operating sequence

Furthermore, the DS is equipped with a closing resistor of 1 kΩ in order to suppress the switching surges due to the DS operations. Figure 16.34 shows a schematic drawing of the DS with closing resistor and closing operation sequence. The purpose of applying this resistor is to suppress the closing surge; however, a resistor is also inserted in case of an opening sequence due to the structure of DS.

The switching performance of all HVDC DSs of groups A to D was designed based on the AC DS, and its performance was confirmed by factory tests with the testing conditions shown in Table 16.2. There are no significant design differences

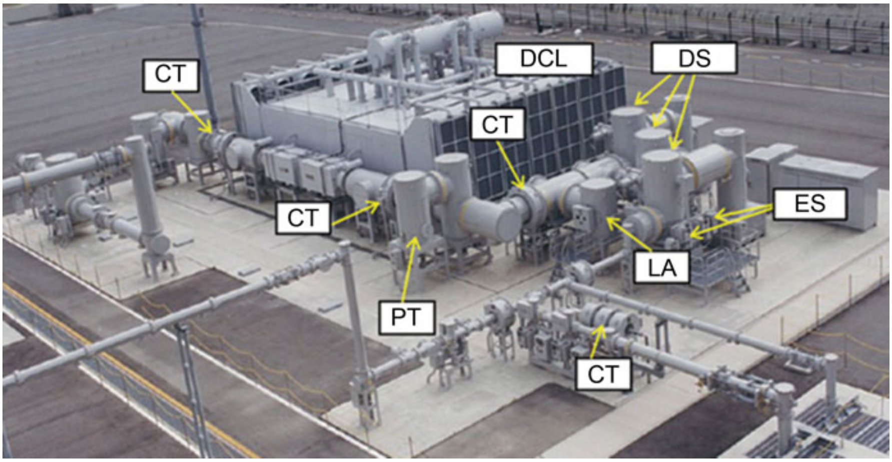

Fig. 16.35 DC-DS&ES, DC-CT&VT, DC-MOSA (LA) used for 500 kV-DC GIS

between HVAC DS and HVDC DS except for the creepage distance, which is about 20% longer for HVDC applications.

Gas-insulated switchgear (DC-GIS) composed of several HVDC DS and earthing switches (ES) is also applied in HVDC networks close to a coastline. Figure 16.35 shows an example of DC-GIS including DC DS and DC ES that were installed at the converter station in the bipolar HVDC system, which was commissioned in 2000.

Figure 16.36 shows an air-insulated HVDC-DS with loop current switching shown in Table 16.2.

16.13 Summary

DC circuit breakers with different current zero creation schemes have been applied in many industrial applications. MRTBs are commonly applied to bipolar HVDC systems. However, there is still no field demonstration of HVDC circuit breakers in the multiterminal HVDC networks. CIGRE will continuously update the development of HV circuit breakers applicable for the future multiterminal HVDC networks.

Intensive studies to investigate the requirements of HVDC circuit breakers have been conducted in different HVDC network configurations. For example, a study using a four-terminal +/−320 kV radial HVDC network model suggested that the rate of rise of fault current can be mitigated by inserting DC reactors connected to the lines in series and that the DC fault clearing times are longer than 10 ms in order to maintain the power transmission at a remote converter station located 240 km away from the fault location, for the case where DC reactors of 150 mH are connected to the line terminals. The requirements make it feasible to apply a mechanical DCCB with an active resonant current zero creation scheme along with a hybrid mechanical and power electronic switch for future multiterminal HVDC grid line protection.

Fig. 16.36 800 kV DC DS corresponding to group C (Mikli et al. 2012). (Courtesy of Siemens)

Both air-insulated and gas-insulated HVDC disconnecting switches (DS) have been applied to many bipolar HVDC systems. There are no significant design differences between HVAC DS and HVDC DS except for the creepage distance, which is about 20% longer for HVDC applications.

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Lifetime Management on Equipment

17

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17.1 Introduction

Life management of equipment such as circuit breakers covers all periods of the life of a group of equipment (specification, development, manufacturing, testing, acceptance, erection, on-site commissioning, inspection, maintenance, diagnostics and monitoring, refurbishment, dismantling and disposal, and all necessary administrative actions). But more specifically speaking, the term "life management" is related to the decision-making process with respect to the equipment's (e.g., a circuit breaker) residual life. The term "residual life" refers to the equipment's remaining technical life. Relevant moments in the life of equipment in the case of a circuit breaker are given in the definition in Fig. 17.1.

This chapter describes the behavior of equipment during its lifetime including ageing impacts on the performance and possible causes of major failures and mitigation measures to prevent a failure and lifetime extension.

17.2 Definitions of Terminology

Circuit Breaker

A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in the power system from damage caused by excessive currents, typically resulting from an overload or short-circuit conditions. When a fault occurs, circuit breakers quickly clear the fault

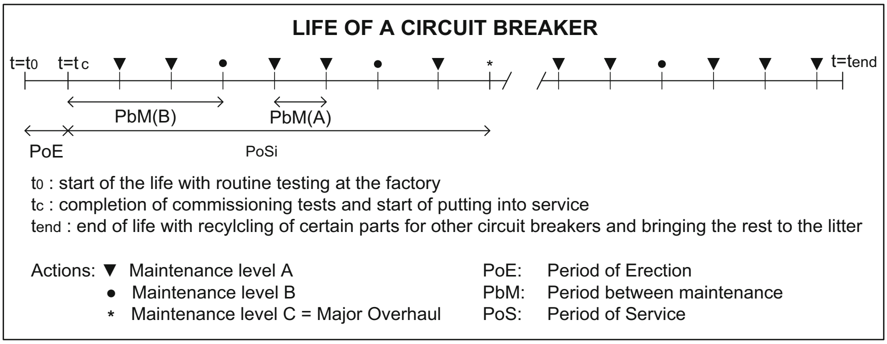

Fig. 17.1 Definition of a typical circuit breaker life (WG A3.08 2000)

to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Electrical Stresses
Electrical stresses imposed on equipment include overvoltages and overcurrents generated by routine network conditions, switching operations, influence of other electrical equipment, and fault occurrence.

Mechanical Stresses
Mechanical stresses imposed on equipment include the mechanical forces due to its own operation (switching); operations of other equipment, e.g., vibrations from rotating machines and vibrations from circuit breaker operations; and impact of an earthquake.

Environmental Stresses
Environmental stresses imposed on equipment include degradation of the components due to soil and air including temperature, humidity, rain, pollution, earth movements, and other influences caused by natural phenomena.

Major Failure
Major failures prevent equipment from performing one or more of its fundamental functions. A major failure will result in an immediate change in the system operating conditions, e.g., the backup protective equipment will be required to remove the fault, or will result in mandatory removal from service within short duration (typically 30 min) for unscheduled maintenance (ref. IEC 60694).

Minor Failure
Minor failure modes allow equipment to perform its basic function but with restrictions. Any failure of a constructional element or a subassembly which does not cause a major failure of the equipment is also called minor failure.

Mitigation Technique
All kinds of activities (e.g., repair, refurbishment, replacement) that address the anomaly with the equipment or reduce the risks due to the equipment.

17.3 Abbreviations

CB	Circuit breaker
DS	Disconnecting switch (disconnector)
ES	Earthing switch
DE	Disconnecting switch and earthing switch
OH	Overhead
GIS	Gas-insulated switchgear
AIS	Air-insulated switchgear
IPO	Independent pole operation
RV	Recovery voltage
TRV	Transient recovery voltage
MOSA	Metal oxide surge arrestor

17.4 Life Management of Equipment

In 2000 CIGRE WG 13.08 reported its findings on life management in a CIGRE Technical Brochure (WG A3.08 2000). The working group conducted two international surveys on circuit breakers under electrical and environmental stresses in service, as well as on maintenance policies of utilities. Further information from two worldwide surveys on the reliability of high-voltage circuit breakers (Mazza et al. 1981; WG 13.06 1994) was used along with input from WG 13.09 (2000). An overview has been given of many aspects of life management: maintenance, maintenance management, residual life assessment, life extension, end-of-life decisions, financial and environmental issues, service experience, stresses in service, and parameters for diagnostic techniques.

The international enquiry on electrical stresses in service revealed that by far most short-circuit currents have to be interrupted by circuit breakers connected to OH-lines. The number of faults per 100 km is more or less inversely proportional to the voltage class, while the average line length is proportional to the voltage class. Therefore, the number of faults per OH-line is about constant and can be expressed in an average number of 1.7 faults per year and the mean value (50% percentile) of 1.2 faults per year, while 90% of the OH-lines show less than 3.3 faults per year.

The maximum expected short-circuit current to be interrupted as a percentage of the rated short-circuit current of the involved circuit breakers gives an average value of roughly 50%, with 90% of the circuit breakers having a value less than about 75%. The actual short-circuit current though is lower with an average of 20% of the rated short-circuit current and a 90% percentile of 35%. The large margin between actual fault current and circuit breaker rating is caused by standardization of the ratings, designing substations for the worst conditions, specifying circuit breakers for possible developments in the future, etc.

Figure 17.2 shows an example of the electrical stress level of a gas circuit breaker for fault current clearing in comparison to a 50% of rated short-circuit current event, which is expressed as the equivalent number of interruptions (N) (Pons et al. 1993). Of course, the design of a circuit breaker, especially in the case of a thermal-assisted type, may show a different electrical wear dependence. The figure shows 10 times longer electrical endurance in the case of a 20% of rated short-circuit current as compared with that of a 50% of rated short-circuit current.

Most operating sequences designed to accommodate two auto-reclosings of the circuit breaker are only partially used since 80% of the line faults extinguish during the first “dead-time” and another 5% during the second “dead-time.” In only 15% of the cases does a full sequence have to be performed. This leads to the conclusion that the electrical endurance of line fault clearing is only 45% of the stress during type tests, which uses a sequence of O-t_1-CO-t_2-CO.[1] The number of poles (phases) involved in fault current clearing is also limited, since 70% of the faults (lower transmission voltages) or 90% of the faults (higher transmission voltages) on OH-lines are single phase faults, while 20% and 10%, respectively, are two-phase faults. Statistically the most stressed pole will see 64% of the total number of faults on an OH-line.

The results of the study of WG A3.08 led to the present requirements for electrical endurance in the IEC Standard 62271-100 for transmission voltages (IEC Standard 62271-100 2008).

The mechanical stresses have been reported by WG 13.06 and lead to a 90% percentile of 80 CO-cycles per year. During 25 years this leads to a total of 2000 cycles. This is the figure used in the IEC Standard 62271-100 (2008) for the number of operations in a circuit breaker’s life. Most cycles come from testing the circuit breaker during maintenance. Since modern circuit breakers require less maintenance, it may be expected that the given number has dropped to a lower value. For circuit breakers applied under conditions with very frequent switching, such as for shunt capacitor banks or for shunt reactors or for peak load power plants, a special type test with 10,000 CO-cycles has been defined.

Whether 10,000 cycles are enough to cover a reasonable period of service depends on the (daily) operation of the circuit breaker. Users have to take this into consideration. Another aspect to be considered in such cases is electrical endurance. This will not be a problem for a circuit breaker without defects, but as soon as restrikes take place with a puncture of the nozzle, wear and ageing start and may accumulate to a level that results in a dielectric failure.

The findings of WG 13.08 showed that most environmental stresses in service are covered by IEC 62271-1 (2017). But there are two exceptions: 26% of the population that took part in the international enquiry faced a pollution level more severe than class II defined in the standards, and 14% of the circuit breakers have been applied under conditions with a higher average humidity than 90%.

[1]Note: C for close and O for open, CO for close immediately followed by open.

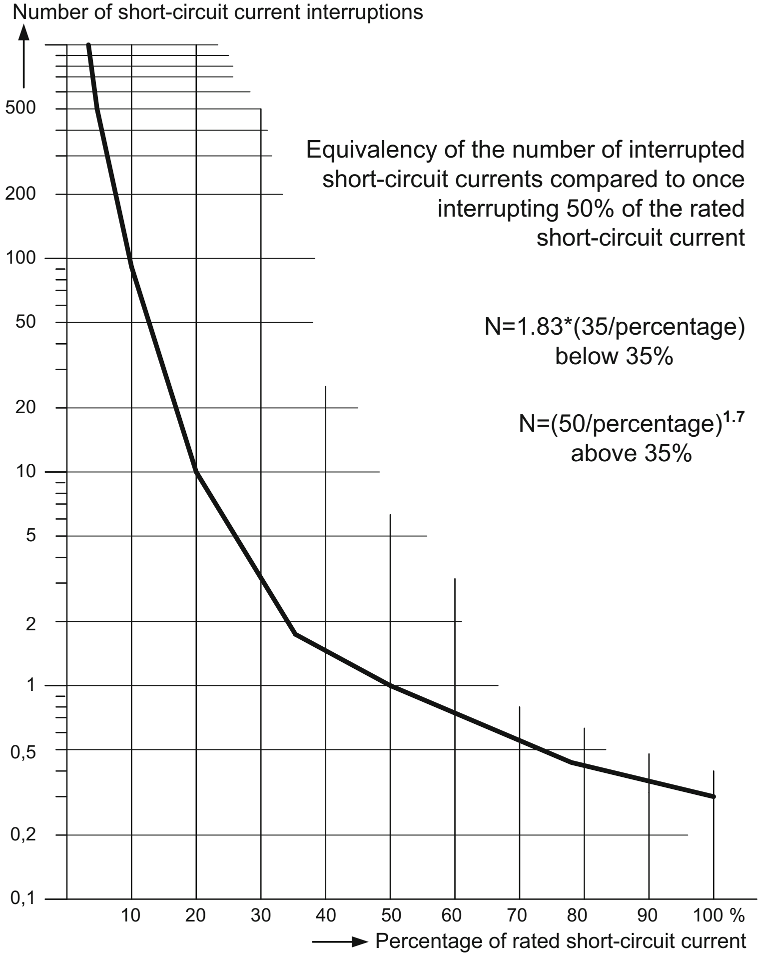

Fig. 17.2 Stress level of a fault current clearing in comparison to 50% of rated short-circuit current, expressed as equivalent number of interruptions (N) (Pons et al. 1993)

Reliable statistical information is a prerequisite for modern decision-making processes like end-of-life assessment based on hazard rate curves (see Fig. 17.3), risk management, and reliability-centered maintenance. For the assessment of the residual life of a subpopulation of circuit breakers, the results from diagnostic test techniques and monitoring devices as well as results from inspections, maintenance activities, and service experience have to be collected in an information system to facilitate user's drawing statistical relevant conclusions.

For modern circuit breakers, the diagnostic techniques are mainly for the SF_6 gas density (monitor) and quality (inspection, test), the main and arcing contacts (test), the operating mechanism and kinematic chain (monitor, test), the control and

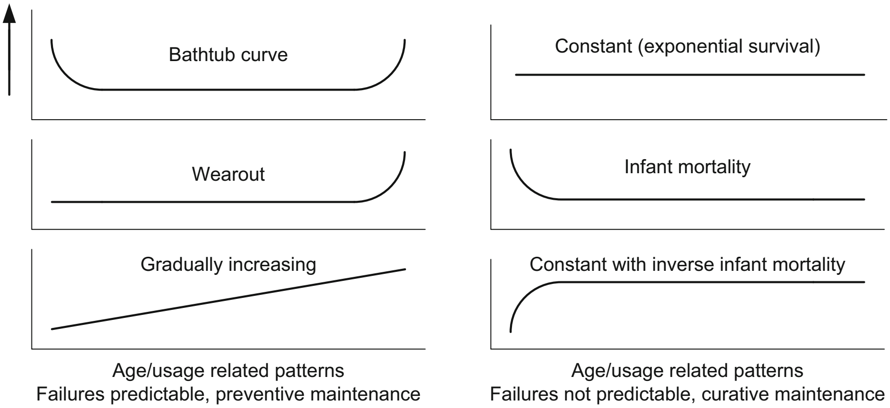

Fig. 17.3 Hazard (failure) rate curves as a function of age (WG A3.08 2000)

auxiliary contacts (monitor, test), and the inspection of corrosion, pollution, overheating, leakage, lubrication, and foundations.

Compared with modern circuit breaker technologies, the maintenance and overhaul intervals of old technology breakers are rather short; for instance, an interval of only 7 years has been reported for bulk oil breakers. Whereas the trend for single pressure SF_6 gas circuit breakers used to be 15–20 years for a major overhaul, the tendency nowadays is generally not to undertake any maintenance that requires dismantling of an SF_6 gas circuit breaker at all. One of the most important functions of diagnostic techniques for modern circuit breakers is to prevent unnecessary dismantling. Dismantling, if not done properly, has the potential to introduce defect. In the meantime, life expectancy may be more than 30 years depending on the operating conditions.

Due to the low capital costs and operating costs of modern technologies, the life extension of old technology breakers beyond 40 years is exceptional. Obsolete technology, the lack of spare parts, tools and know-how, and their relatively low availability contribute to the choice for replacement rather than refurbishment. Retesting old circuit breakers is complicated and is highly dependent on its application and the utility's policy, where necessarily supported by the manufacturer's experience. Nevertheless some types of old technology breakers have been shown to be very robust and capable of dealing with requirements of even the latest edition of the standards (Janssen et al. 2014a).

Among the end-of-life criteria, changes in network conditions (inadequate rating) are among the most important parameters. Other criteria are safety, condition, obsolescence, age, availability, maintainability, orphans, economics, environmental, legal, and risk. Orphans are equipment that is unusual (low number) for the user and, therefore, difficult to maintain and manage. Availability is the possibility to de-energize the equipment for large maintenance; a lack of skilled staff, tools, or workshops and a lack of redundancy in the network for the time period involved are factors that contribute to a lack of availability. Although important, safety is seldom the decisive reason to replace equipment.

A less important criterium, that often is used, is age. Age is a rather simple criterion and follows the simple rule that old is bad and new is good. However, there is another mechanism that has to be taken into consideration: survival of the fittest. As a consequence older populations of equipment may show a better reliability than younger populations. Ideally end-of-life decisions should be based on ageing analysis rather than age itself. However, precise ageing diagnostics for HV equipment is not trivial and asks for much data to be collected during the equipment's life. CIGRE working group WG A3.29 collected available knowledge on ageing analysis for substation equipment and provided recommendations to utilities and manufacturers (WG A3.29 2018).

Another important aspect for equipment life management is overstress. Overstress is understood as a worsening of the stress pattern applied to HV equipment, whereas the equipment withstand is not kept unchanged due to good maintenance policy, as represented in Fig. 17.4.

As a consequence of the regulatory changes in power systems initiated in the 1990s, utilities have been confronted with an increasing unpredictability of the stresses applied to equipment and installations (Carvalho et al. 2016). This situation may lead to equipment overstress, and, therefore, action must be taken prior to its occurrence. This is particularly true for circuit breakers, which can be subjected to short-circuit levels, load currents, and system time constants (X/R) exceeding their ratings (Carvalho et al. 2008). As well, switching transient patterns of evolving networks can lead to transient recovery voltage stresses exceeding the standardized values. Therefore, utilities are devoting increasing attention to check for the possibility of electrical overstress that might affect not only circuit breakers but also the series-connected equipment, such as disconnectors, current transformers (CT), and line traps. An often applied process is to define a minimum set of system relevant overstress parameters and correlate them with the substation equipment, thus establishing routine checking for overstress. Commonly analyzed overstress parameters are listed in Table 17.1.

Another relevant kind of circuit breaker overstress is the operation voltage. Nowadays many utilities have no control of the reactive power output and voltage

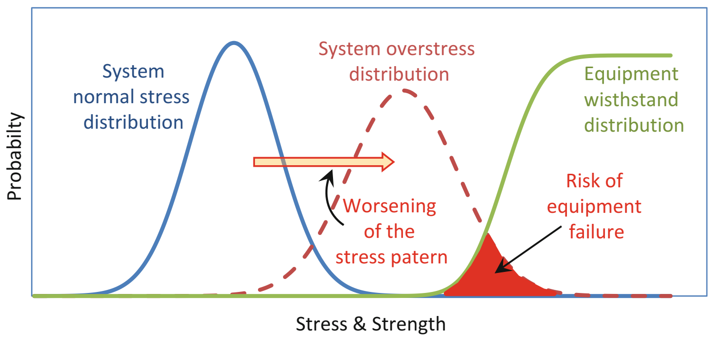

Fig. 17.4 Overstresses and equipment's withstand strength

Table 17.1 Overstress parameters for equipment

Overstress parameter		Circuit breaker	Disconnector	CT	Line trap
1	Short-circuit current	X	X	X	X
2	Rated current	X	X	X	X
3	Time constant (X/R)	X		X	
4	TRV	X			

regulation of large generators. Moreover, the system has become very complex, especially with long lines and/or many cable circuits. As utilities all over the world are looking for means to utilize their grids further, increasing the operating voltage at high load conditions is one the cheapest possibilities, albeit at the cost of less margin to the rated voltage of equipment (CIGRE Technical Brochure 336 2007). Also under low load conditions, there will be a fair risk that the operating voltage becomes higher than the rated voltage. For emergencies or unintended short-term operation, the risk may be acceptable. However, a continuous operating voltage above the rated voltage leads to a higher overvoltage (temporary and switching) in the grid and higher TRV-stresses across circuit breakers than the design parameters. Special attention has to be paid to saturation effects of transformers, generators, shunt reactors, series capacitors, inductive voltage transformers, and surge arresters. Reduced margins with a higher risk of flashover and consequently safety issues apply to electrical clearances (CIGRE Technical Brochure 336 2007).

As an example for voltage overstressing, the EU grid code “Requirements for Generators” (Entso-e Proposal Requirements for Generators 2016) put forward for category D power plants (larger than 75 MW and connected to a grid with a voltage level of 110 kV and above) the following requirements related to operation at higher operating voltages. First the reference voltage (1 pu) for grids with a nominal voltage of 380 kV or 400 kV is defined to be 400 kV. Table 17.2 gives the upper operating voltage and the time period that power plants have to stay connected and operating normally. The table gives an operating voltage between 1.05 and 1.10 pu for 20–60 min. TSOs may decide to require a higher voltage and time duration values. Note that the rated voltage for equipment is 420 kV (i.e., 1.05 pu).[2]

Other kinds of overstresses than electric and dielectric can also affect circuit breakers specially those of an environmental nature, like temperature, earthquake, flood, tsunami, etc. These and other relevant aspects of overstress on HV substation equipment are covered by CIGRE working group A3.30, whose Technical Brochure will be available in the future.

[2]Note: that especially under system conditions with a voltage above the rated voltage of equipment, TSOs tend to switch off shunt capacitor banks, unloaded cables, and OH-lines and that such switching duties are rather severe for high-voltage circuit breakers.

Table 17.2 Upper and lower operating voltage and the time period that power plants have to stay connected and operating normally (Table 6.2 of EU grid code 2016/631)

Synchronous area	Voltage range	Time period for operation
Continental Europe	0,85 pu-0,90 pu	60 min
	0,90 pu-1,05 pu	Unlimited
	1,05 pu-1,10 pu	To be specified by each TSO, but not less than 20 min and not more than 60 min
Nordic	0,90 pu-1,05 pu	Unlimited
	1,05 pu-1,10 pu	To be specified by each TSO, but not more than 60 min
Great Britain	0,90 pu-1,05 pu	Unlimited
	1,05 pu-1,10 pu	15 min
Ireland and Northern Ireland	0,90 pu-1,05 pu	Unlimited
Baltic	0,88 pu-0,90 pu	20 min
	0,90 pu-1,097 pu	Unlimited
	1,097 pu-1,15 pu	20 min

17.5 Ageing Phenomena of Equipment

17.5.1 Introduction

Managing an ageing high-voltage asset population is a key task for all asset owners (including utilities and private asset owners). Different opinions exist regarding the expected life of equipment assets and the factors that dictate this life. However, generally speaking, assets are being expected to remain in service much longer than ever before.

The results of the CIGRE international reliability surveys on equipment show that equipment wear and ageing is one of the predominant causes of equipment failure. Therefore the utilities involved in asset management require a more holistic and comprehensive view of ageing of high-voltage equipment and possible mitigation techniques. For this purpose, CIGRE set up a working group (WG) A3.29 to evaluate deterioration of ageing high-voltage equipment and possible mitigation techniques. (CIGRE Technical Brochure will be published soon (WG A3.29 2018)).

“Ageing” can be defined as a process that causes a change in equipment properties as the equipment is exposed to stresses. The change in equipment properties is likely to affect its performance in relation to its intended function.

Ageing is a result of stresses being applied on equipment. These stresses can be electrical, mechanical, or environmental and can be normal or abnormal. Normal stresses are those that are within the equipment's rated parameters and defined service conditions. This includes short time overload, where the short time overload is a rated parameter defined for the equipment by the manufacturer. Abnormal stresses include conditions that are beyond the rated parameters of the equipment or the defined service conditions. Here the focus is on ageing due to normal stresses (i.e., stresses within the rated parameters and defined service conditions of the equipment).

Maximizing the added value of high-voltage equipment and reducing the cost of ownership of the equipment is of major concern for most equipment owners. High-voltage equipment has a major impact on electricity reliability, safety, and environment and is capital intensive. It is therefore imperative that structured processes and well-informed decisions guide the lifetime management of such equipment. Understanding ageing allows equipment owners to make well-considered decisions with respect to management of the equipment and reduce the risks of equipment failing to perform its function. Knowledge about equipment ageing and detection of stresses enable equipment owners to manage the risks of equipment failures more effectively.

Detailed standards on asset management (e.g., ISO 55000 series) and dependability management (e.g., IEC 60300 series for reliability-centered maintenance, life cycle costing, failure mode effect analysis) exist. (WG A3.29 2018) recommends a simplified yet comprehensive approach to consolidating information on ageing within a structured format, i.e., ageing tables. The ageing tables are a result of a structured approach that includes defining equipment function and capability, understanding equipment components and technology variations, understanding the stresses that can lead to ageing, understanding degradation processes of the equipment, major and minor failure modes, and identifying detection and mitigation techniques for ageing and stresses. This process has been applied for high-voltage equipment under consideration including circuit breakers, disconnectors and earthing switches, instrument transformers, capacitors, surge arresters, and post insulators. In (WG A3.29 2018) ageing tables for all the above equipment are presented.

Prognostic methods for equipment life prediction are presented as well with examples of application. When no knowledge of equipment condition is available (absence of diagnostics), experience-based techniques (statistical methods) are the only way to determine remaining useful life. This is the easiest way to perform a prognostic since it only requires past commissioning and failure dates. It is then used to compute parameters such as failure probability, average lifetime, and probability to remain in function after a given number of years.

Key observations from the work, applicable to all equipment, include:

- Equipment standards provide a prescription on type, special, and routine tests that can be undertaken to verify equipment capability to withstand stresses. It is important to understand the limitations of these tests and their applicability to test performance for all stresses that cause ageing. Furthermore, these tests may need to be modified to verify capability of an aged equipment in service.

- Detection and mitigation of stresses can be an effective method to understand ageing and mitigate the risks of ageing, by reducing excessive stresses to the aged equipment.
- Environmental stresses are seen as a key factor influencing ageing of almost all high-voltage equipment. The influence of environment seems to be the major impact on ageing. It is observed that the environmental influence over lifetime is only partially or inadequately covered in the equipment standards. It is therefore challenging to understand the equipment's capability and ageing performance in response to environmental stresses over their lifetime, sometimes in excess of 40–50 years. Thus, the users have the responsibility to appropriately define and assess equipment capability against environmental stresses over their lifetime. Further work could be undertaken to understand and guide users on how to assess equipment capability to withstand environmental stresses over their lifetime.
- Consideration could be given to design equipment for higher stresses, so that over the lifetime (as the equipment properties deteriorate), the equipment continues to retain residual strength to operate safely. This is particularly an area of consideration for performance in relation to environmental stresses.
- Ongoing exchange of service experience between users, manufacturers, and other experts is recommended. Manufacturers are encouraged to be more transparent on the equipment capability to withstand stresses, with special emphasis on components that are most likely to age and reduce the overall equipment reliability.
- Enhanced focus on equipments' ability to withstand stresses over their lifetime (as opposed to when purchased) would enable utilities to better elect equipment with life cycle costs in mind.
- From the analysis of ageing tables, it is concluded that, in some cases, there are many different stresses influencing a single ageing process. It is hard to pinpoint which stress is more dominant. Moreover, the ageing can be caused by improper treatment of the device (manufacturing deficiency, improper rating, and improper maintenance). Despite these uncertainties, the failure modes are easy to derive, and for every ageing process theoretically, there exists a possibility to detect the ageing or consequences of ageing. Different mitigation techniques are also available.
- Adoption of more accurate condition monitoring tools could improve knowledge of equipment ageing and allow users to make well-considered management decisions in relation to their lifetime management.

Ageing phenomena for each equipment are summarized below.

17.5.2 Circuit Breakers

Circuit breakers perform several important functions in power systems. They connect and disconnect a circuit including equipment, energize and de-energize loads, transmission lines, cables, and other components and interrupt and isolate a fault in power systems.

The results of the reliability surveys revealed that more than 40% of major failures of high-voltage circuit breakers were caused by "wear or ageing." Equipment stresses which cause ageing of circuit breakers include short-circuit current stresses, normal continuous current stresses, dielectric stresses, number of operations and mechanical load, as well as the environmental stresses such as ambient temperature, humidity, pollution, UV, and seismic/vibration stresses. Survey results show that the number of operating cycles as a mechanical stress is regarded as the most influencing factor.

Ageing phenomena are categorized into three types of degradation processes: "electrical degradation" such as an increase of contact resistance and loss of dielectric strength, "mechanical degradation" such as wear and fatigue, and "material degradation" such as corrosion and contamination. According to the survey results, wear, fatigue, corrosion, leakage, and lubrication problems are frequently observed ageing phenomena in circuit breakers. Figure 17.5 shows an example of mechanical degradation observed in the flange surface of aged GIS. Figure 17.6 shows an example of electrical degradation observed in the fixed main contacts of the circuit breaker due to switching arc exposure.

Detection techniques and mitigation techniques corresponding to each ageing phenomenon were investigated and revealed that "visual inspection" is still the most common diagnostic method for circuit breakers. "Replacement with new or improved parts" and "overhaul and servicing" are regarded as the major techniques of mitigation. Apart from counters, SF_6 gas density, and other conventional alarms, monitoring systems are still less common.

Survey results also suggest that the number of observed ageing phenomena of circuit breakers increases above ages of 30–40 years. Ageing phenomena have also been reported earlier than this period.

17.5.3 Disconnecting Switch and Earthing Switch

A disconnecting switch (disconnector) is a mechanical switching device which energizes and de-energizes parts of an electrical circuit. An earthing switch is a mechanical switching device which earths parts of an electrical circuit. An earthing

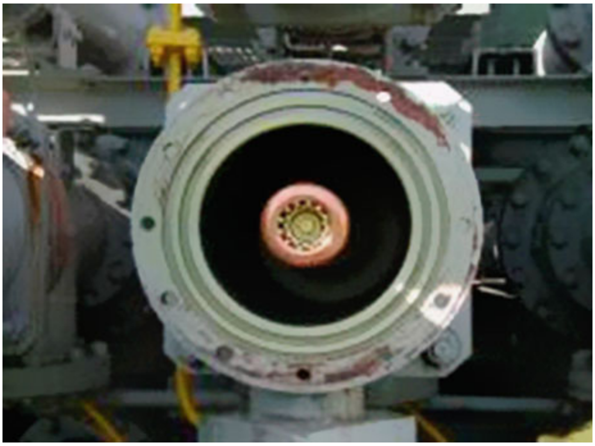

Fig. 17.5 Corrosion of a flange surface observed for 34-year-old GIS

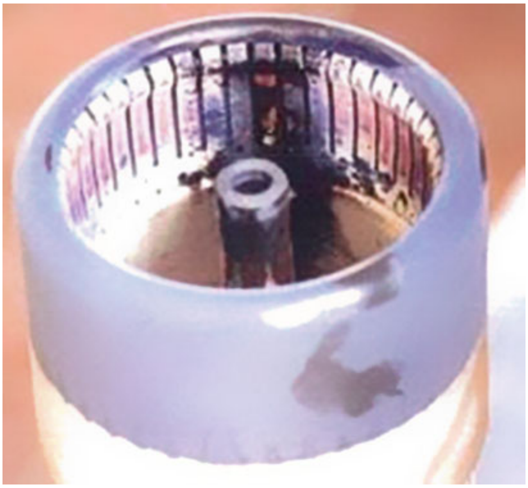

Fig. 17.6 Electrical wear of fixed main contacts. (Courtesy of Red Eléctrica de España)

switch is predominantly used to make parts of the circuit, including equipment, safe to access by bringing them to earth potential. An earthing switch may be combined with a disconnecting switch or may be independent of a disconnecting switch.

The results of the third international reliablity survey in 2004–2007 on reliability of high voltage equipment (CIGRE TB511 2012) showed that many failures are caused by wear and ageing. The main stresses for disconnecting switch and earthing switch ageing are caused by the number of operations, rain, moisture, and other environmental factors. The ageing phenomena of corrosion, loss of lubrication and change of resistance are often experienced. Figure 17.7 shows an example of electrical degradation observed in the primary contacts of a pantograph disconnecting switch due to switching arc exposure.

The main detection techniques used for assessing the ageing phenomena and condition of the disconnecting switches and earthing switches are visual inspection. The main mitigation technique used is complete unit replacement of disconnecting and earthing switches. Some utilities apply redundant installations of such equipment (e.g., N-1 reliability policy) in order to conduct safely some maintenance work such as greasing, cleaning, and readjustment.

17.5.4 Instrument Transformers

Instrument transformers transform a high current or high voltage into a measurement signal (low current or low voltage) to provide a true representation of the primary signal. The low-voltage measurement signal may be used for indication, metering, and protection systems.

The results of the third international reliablity survey in 2004–2007 on instrument transformers (CIGRE Technical Brochure 512 2012) and CIGRE Technical Brochure

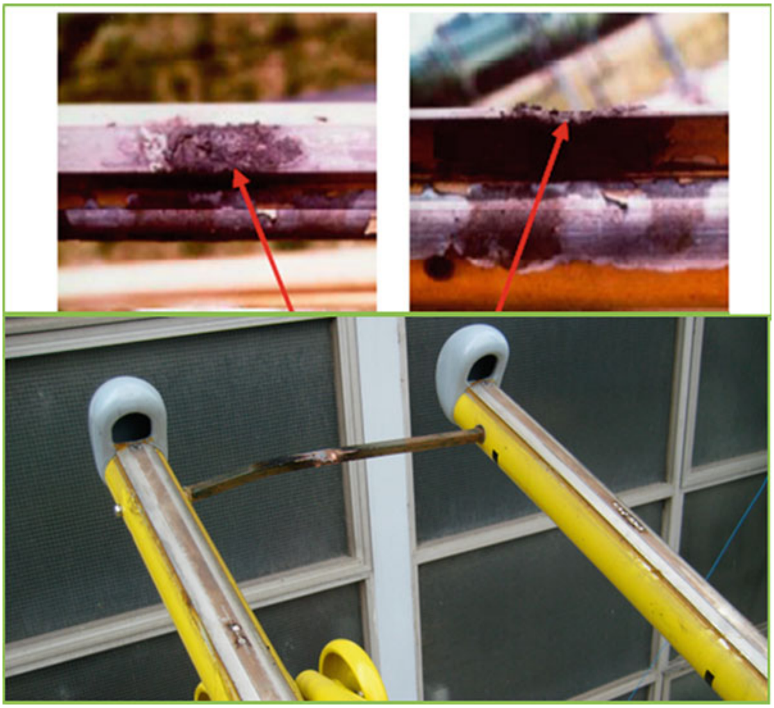

Fig. 17.7 Deteriorated primary contact of pantograph disconnecting switch after qualification tests (above: old design, below, new design). (Courtesy of Amprion, Germany)

394 (CIGRE Technical Brochure 394 2009) show that a significant number of failures, and to a less extent equipment explosions, were caused by ageing.

The main dominant stress for instrument transformer ageing is environmental stress such as rain and moisture. Thermal stresses and electrical stresses such as overvoltages and overcurrents across instrument transformers are also reported.

The main ageing phenomena for instrument transformers are corrosion, leakage of internal insulation, and insulator cracking. The main detection techniques used for assessing the ageing phenomena and condition of the instrument transformers are visual inspection. Thermography, capacitive testing for capacitive voltage transformers, pressure monitoring, and insulation medium leakages are also reported. The main mitigation technique used is complete replacement of instrument transformers. The most dominant period for instrument transformers ageing is between 30 and 40 years.

17.5.5 Surge Arresters

Surge arresters are equipment designed to protect other equipment in power systems. They limit lightning and switching overvoltages to a value that corresponds to the design levels of the equipment. For this purpose, surge arresters have to withstand severe stresses generated in power systems due to lightning strokes and switching operations.

Lightning and switching voltages and currents may lead to ageing of equipment which could change the characteristics of the metal oxide (MO) resistors of a MO surge arrester. Environmental influence and moisture are as well very important influencing factors. They influence the ageing phenomena of nearly all parts of a surge arrester on the outside as well as the inside of the equipment.

During lifetime, the MO surge arresters can tend to an "increase of leakage current," an "increase of power loss," and a "loss of dielectric strength." This leads to a change in the electrical functional characteristics and thus to the loosing of thermal stability, eventually ending in an internal breakdown of the surge arrester. The ageing phenomena in surge arrestor are reported to be detected mainly at an age of 25–30 years. Some ageing phenomena have been observed much earlier.

To detect ageing, visual inspection and thermographic inspection play a major role. In order to detect the ageing of the active part, leakage currents are measured. To mitigate against ageing, complete surge arrester replacement is a very common mitigation technique.

17.5.6 Conclusion

Ageing can be defined as a process that causes change in equipment properties as the equipment is exposed to electrical, mechanical, and environmental stresses under operating conditions. Ageing is one of major causes of equipment failure. Continuous developments are required to evaluate the remaining life of equipment and to select appropriate maintenance methods and mitigation techniques based on the investigations on field experience of ageing equipment and their reliability analysis.

17.6 Reliability Survey on Equipment

17.6.1 Introduction

Reliability of switching equipment in power system is of major concern especially for transmission and distribution system operators. Since circuit breakers have an important function by isolating a faulty circuit in the system, they should operate reliably to remove a fault at any moment. Failure of switching equipment could result in significant system outages with the associated power restoration efforts as well as possible safety implications. There are also financial implications in case of poor reliability. In addition to the cost of a system outage and its restoration, poor reliability will also contribute to higher system operating and maintenance costs to the operators and, ultimately, their customers.

For these reasons, CIGRÉ periodically executes an international reliability survey on equipment in power systems that provide good feedback on the validity of international standards.

The first reliability survey was carried out in 1974–1977 and covered nearly 78,000 circuit breaker years of service. All breaker technologies such as oil, air blast, and SF_6 double pressure and single pressure puffer types were included. The results were published in 1981 (Mazza et al. 1981) and had a significant impact on IEC standardization work, including mechanical and environmental test procedures.

In the second survey, data was collected for the period 1988–1991, and almost the same number of circuit breaker years was covered, but the survey was limited to single pressure SF_6 technology. CIGRÉ Technical Brochure 083 (WG 13.06 1994) remains a very valuable source of information for the circuit breaker community. Later, the CIGRÉ Technical Brochure 165 (WG A3.08 2000) provides further considerations on life management of circuit breakers.

The third reliability survey included not only circuit breakers but also disconnecting switches, earthing switches, instrument transformers and gas insulated switchgear (GIS). The time period covered was 2004–2007, and the enquiry covered equipment rated for voltages greater than or equal to 60 kV (CIGRE TB509 2012). The results from the circuit breaker part were presented in an extensive CIGRÉ Technical Brochure (CIGRE TB510 2012) and several conference contributions (M. Runde, 2013), (Anton Janssen, et al, 2014). Only single pressure SF_6 circuit breaker technology was included in the third survey. Therefore in practice, equipment installed before around 1970 was excluded. Both circuit breakers installed in air-insulated and gas-insulated substations were covered. The scope of the third survey is mainly based on the structure and questions contained in the second survey. Therefore, in many instances trends and comparisons can be made.

A fourth reliability survey on high-voltage equipment is under consideration and intended to expand the scope to cover generator circuit breakers, vacuum circuit breakers, and surge arresters, in addition to circuit breakers, disconnecting switches, earthing switches, instrument transformers, and GIS focusing on major failures.

The following sections present a summary of results of the third circuit breaker survey. Emphasis is put on frequencies and types of the major failures and on comparisons between the second and third surveys. Initially, the methods and procedures used to collect the information in the third survey are briefly reviewed.

17.6.2 CIGRE Reliability Survey on Equipment

The numbers of the equipment populations and their failures are required to be recorded. Population enquiry cards were completed annually during the survey period, whereas failure detail was filled in on a failure card each time a failure occurred within this time span.

The population enquiry cards asked for the installation year (equipment age) and the number of the equipment grouped by voltage ratings, applications, technologies, designs, and maintenance strategies. However, the first and second reliability surveys had fewer categories on both the population and the failure cards.

The failure enquiry cards requested certain types of information about the failed equipment, together with information describing the failure itself, such as its origin and cause, what subassembly failed, whether this was a minor or major failure, if environmental stress contributed, and so on. However, detailed analyses on the minor failures faced a certain difficulty, because the definition of the minor failures seems to differ among the utilities, which makes it impossible to provide information about the minor failure frequency after the third reliability survey.

The equipment population and failure enquiry cards were distributed to utilities worldwide. They participated by filling in and returning the forms to a CIGRÉ working group, which carried out the subsequent analyses. The information was collected directly and solely from the utility sector, not from manufacturers or others. All incoming information has been treated as confidential.

17.6.3 Definitions of Failures

A main objective of the CIGRE international reliability surveys is to identify trends by comparing the findings from one survey with those from previous ones. Consequently, the majority of the definitions and questions are nearly identical to those applied in the past surveys. In particular, failure definitions are very important in the present context, and the terms major failures (MaF) and minor failures (MiF) as defined in the IEC circuit breaker standard (IEC Standard 62271-1 2017) were adopted.

A switchgear major failure is defined as "failure of a switchgear and control gear which causes the cessation of one or more of its fundamental functions. A major failure will result in an immediate change in the system operating conditions, e.g., the backup protective equipment will be required to remove the fault, or will result in mandatory removal from service within 30 min for unscheduled maintenance."

Correspondingly, a switchgear minor failure is "failure of an equipment other than a major failure or any failure, even complete, of a constructional element or a sub-assembly which does not cause a major failure of the equipment."

Only major failures will be dealt with in the summary of the results that follow.

17.6.4 CIGRE Reliability Survey: CB Population

Table 17.3 provides an overview of the participation and time periods covered by the past three circuit breaker reliability surveys.

As can be seen, the third circuit breaker reliability survey included 281 090 circuit breaker (CB) years of service experience. This is around four times as much as each of the previous ones. Population and failure inquiries were received from between 22 and 30 countries, but the size of the contribution from the individual countries varies a lot. In the third survey, 39% of the service experience originates from one dominating country. 46% of the experience in the third survey relates to live tank circuit breakers, 30% to GIS, and the remaining 24% to dead tank circuit breakers.

Figure 17.8 shows the surveyed service experience classified by voltage ratings and kind of applications. Equipment rated for above 700 kV constitutes only 0.14% of the surveyed population of circuit breakers and is not visible in the chart.

There was a significant shift in operating mechanism technology in the populations in the third and the second survey (see Fig. 17.9). The fraction of the circuit breakers

Table 17.3 International circuit breaker reliability surveys carried out by CIGRÉ

Reliability surveys	1st survey	2nd survey	3rd survey
Period	1974–1977	1988–1991	2004–2007
Objective	All types of CB (In service after 1964)	Single pressure SF6 CB (In service after 1978)	Single pressure SF6 CB (No limitation)
Voltage class	63 kV and above	63 kV and above	60 kV and above
Participation (world)	120 utilities from 22 countries	132 utilities from 22 countries	83 utilities from 26 countries
Number of CB-year	77,892 CB-year	70,708 CB-year	281,090 CB-year

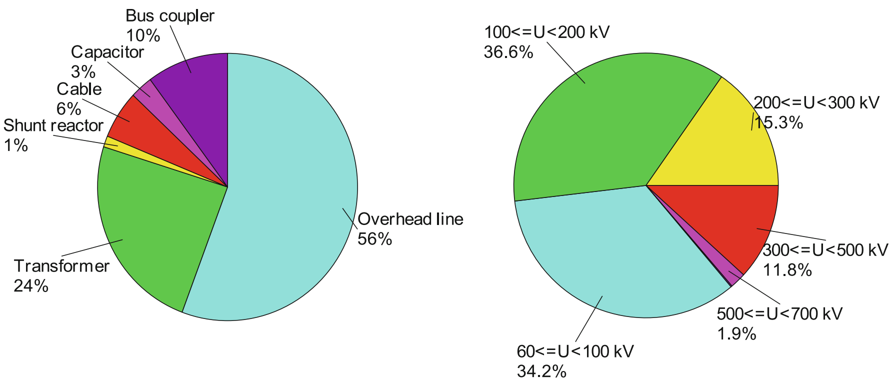

Fig. 17.8 Surveyed service experience according to kind of service (left) and voltage (right)

that are equipped with hydraulic drives reduced from 52% to 26%, while the portion with spring drives increased from 18% to 51%. In the period 2004–2007, pneumatic drives still accounted for as much as 22% of the surveyed experience.

17.6.5 CB Failure Frequencies and Characteristics

Table 17.4 lists the major failure and minor failure frequencies for all three circuit breaker surveys as a function of voltage level. The third survey did not provide the minor failure frequency. It can be observed that the overall major failure frequency decreased by a factor of more than two from the first survey (average 1.58 MaF per 100 CB year) to the second (average 0.67 MaF per 100 CB year) and again, by approximately the same factor, from the second survey to the third (average 0.30 MaF per 100 CB year). This indicates significant improvement in overall CB reliability, especially for extra high-voltage levels.

Major failure frequencies as a function of voltage ratings are plotted in Fig. 17.10. The much higher failure frequency at higher voltages in the first survey may be

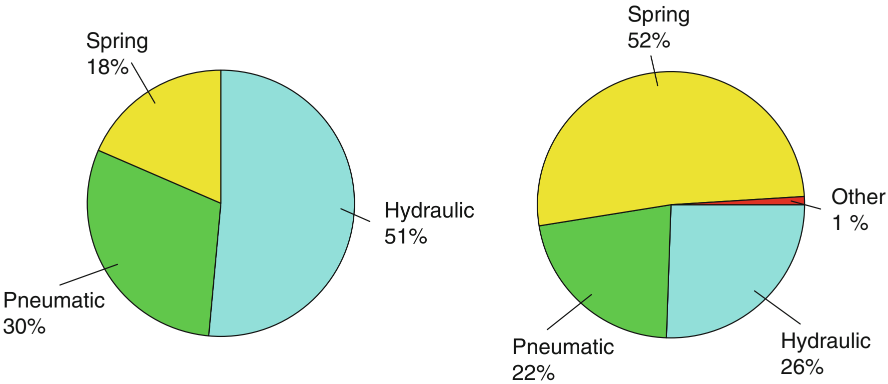

Fig. 17.9 Comparison between the second (left) and third (right) circuit breaker surveys with regard to type of operation mechanism used

ascribed to early, pioneering designs and design immaturity at that time. The reliability at these voltage levels is drastically improved in the second and third surveys, but even in the third survey, the failure frequency increases with increasing voltage level.

The third CB reliability survey correlated failure frequencies to the CB application, i.e., whether it switches overhead lines, cables, transformers, reactors, etc. The results are shown in Fig. 17.11.

Large differences are observed. The major failure frequencies for circuit breakers operating on shunt reactors are around one order of magnitude higher than for line and transformer breakers. It is assumed that this partly, but not entirely, can be attributed to the fact that the former ones in general are operated more frequently.

Figure 17.12 shows the major failure frequency of different type CBs as a function of year of installation, derived from the 2004–2007 survey. Hence, general ageing effects but also changes in design and quality are expected to influence on this relationship.

For AIS and GIS there is a tendency that newer equipment has less major failures than older equipment, and the difference is substantial. For the surveyed dead tank population, no such relationship is visible.

The major failure mode distribution is shown in the left part of Fig. 17.13. "Does not close on command," "Does not open on command," and "Locking in open or closed position" are the most common major failure modes.

When identifying the sub-component responsible for the major failures, the distribution becomes as shown in the right part of Fig. 17.13. Roughly half of the major failures occur in the operating mechanism, and a large portion is caused by malfunctions in the electrical control and auxiliary circuit. These findings are approximately the same as in the previous survey.

The third survey also asked for the utilities to identify the primary cause for major failures. Table 17.5 and Fig. 17.14 show the distribution of the responses.

Almost half of the failures were attributed to wear and ageing. Other than this, no other cause stands out. However, the fact that nearly 25% of the failure cards were

Table 17.4 Major failure and minor failure frequencies from international circuit breaker reliability surveys carried out by CIGRÉ

	Major Failure, /100 unit-year			Minor Failure, /100 units-year		
	1st Survey	2nd Survey	3rd Survey	1st Survey	2nd Survey	3rd Survey
Ratings	1974–1977	1988–1991	2004–2007	1974–1977	1988–1991	2004–2007
60–99 kV	0.41	0.28	0.13	1.65	2.23	–
100–199 kV	1.63	0.68	0.28	4.18	4.75	–
200–299 kV	2.59	0.81	0.35	6.39	6.97	–
30–399 kV	4.55	1.21	0.78	16.35	7.76	–
500 kV and above	10.46	1.97	0.48	4.93	8.18	–
World data	1.58	0.67	0.30	3.55	4.66	2.37

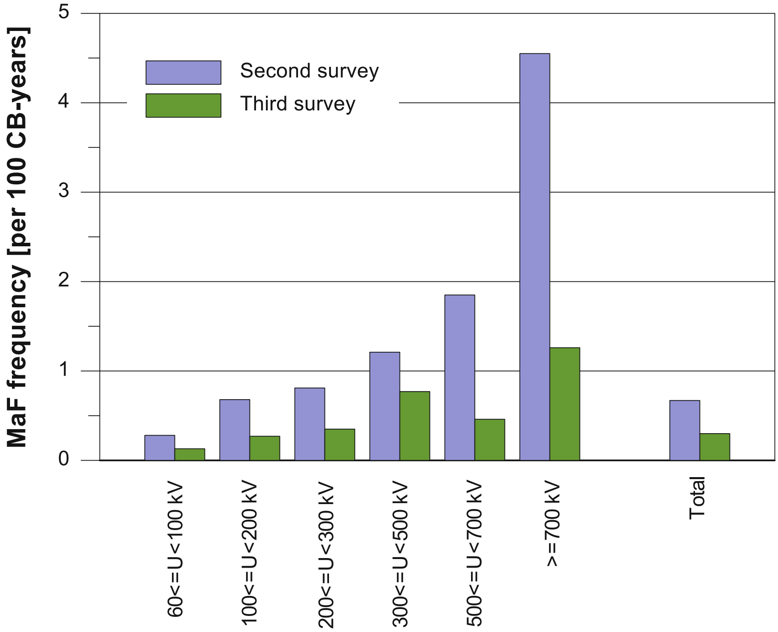

Fig. 17.10 Major failure frequency as a function of voltage level for the 1988–1991 and the 2004–2007 surveys

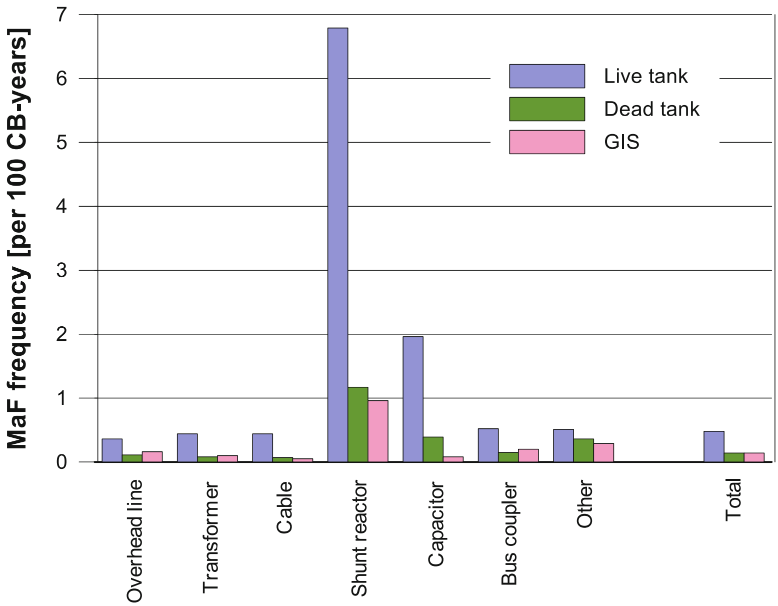

Fig. 17.11 Circuit breaker major failure frequencies for different kinds of service

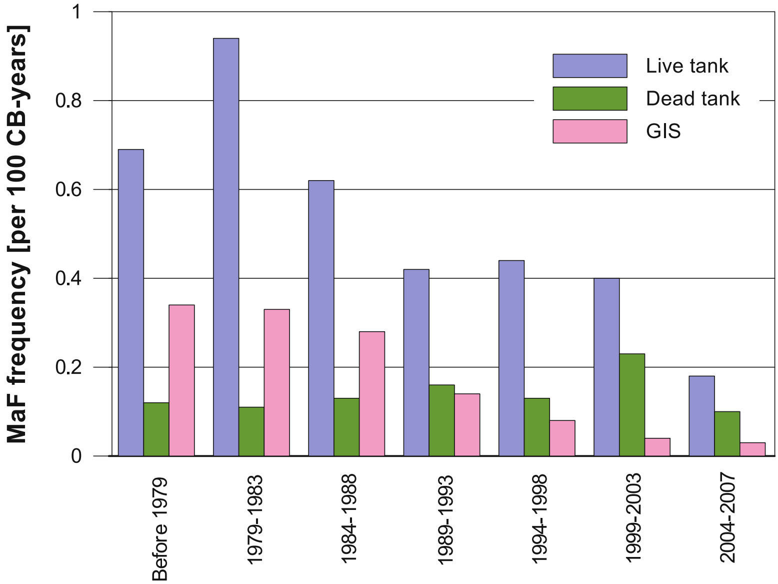

Fig. 17.12 Major failure frequencies as a function of year of installation for the different SF_6 circuit breaker technologies

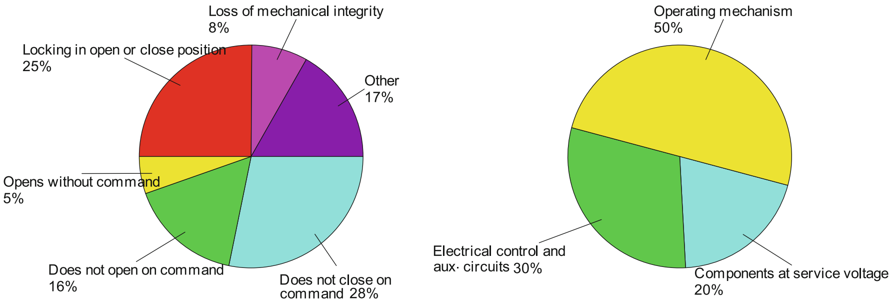

Fig. 17.13 Distribution of circuit breaker major failure modes (left) and sub-components responsible for the major failure (right) as found in the third survey

checked for "unknown" or "others" may suggest that identifying the primary cause for the failures is not always easy.

17.6.6 Disconnector and Earthing Switch Reliability

Only one major international survey on disconnecting switches (DS) and earthing switches (ES) (referred to collectively as DE in the figures below) service experience has been carried out. It was organized by CIGRÉ SC A3 and was a part of the large,

Table 17.5 Distribution of primary cause for failure

Primary cause for major failures	[%]
Design fault	5.8
Manufacturing fault	7.6
Incorrect transport or erection	3.6
Lightning overvoltage	1.8
Mechanical stress	1.3
Wear/ageing (incl. corrosion)	46.7
Incorrect operation	1.1
Incorrect monitoring	1.7
Mechanical failure of adjacent equipment	1.3
Incorrect maintenance	3.3
External damage	1.0
Others	8.3
Unknown causes	16.5

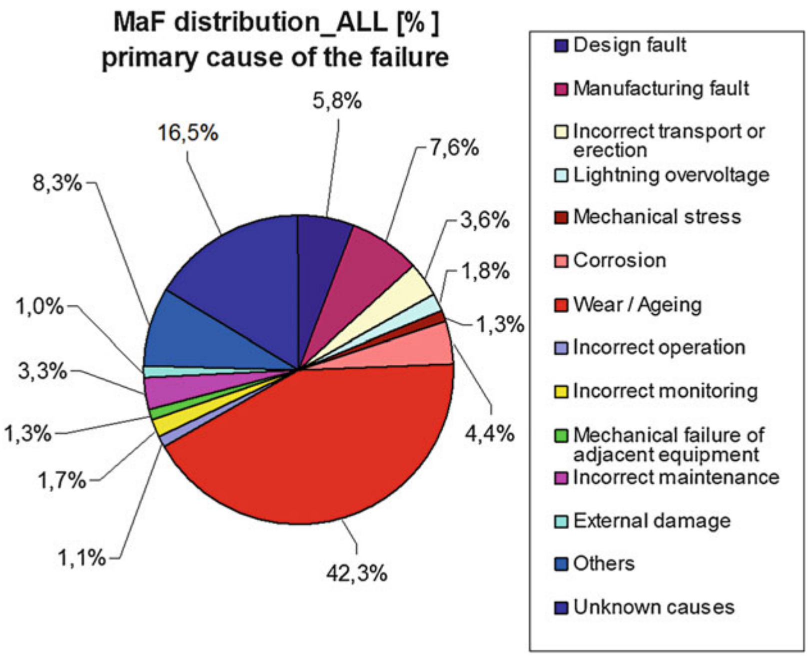

Fig. 17.14 Distribution of primary cause for failure

worldwide reliability survey that collected data in the period 2004–2007 for circuit breakers, disconnecting switches and earthing switches, and instrument transformers and gas-insulated switchgear.

As opposed to the circuit breaker part of the survey where only SF_6 technology was included, there was no limitation in age or technology for disconnecting switches and earthing switches. Both equipment installed in air-insulated (AIS) and gas-insulated substations (GIS) are covered. CIGRÉ Technical Brochure 511 presents all results from the disconnector and earthing switch part of the survey (WG A3.06, "Final Report of the 2007). The most important findings will be reviewed here but only for major failures.

17.6.7 CIGRE Reliability Survey: DE Population

The survey covered over 900,000 equipment years of experience for disconnectors and earthing switches collected from 25 countries (counted per three-pole assembly). The contributions were not evenly distributed over the responders given that one country contributed 52% of all service experiences. Seventy seven percent of the surveyed experience relates to disconnectors and 23% to earthing switches. AIS equipment constitutes approximately 67% of the survey base, the rest being GIS equipment. AIS disconnectors come in a variety of designs (see Fig. 17.15).

Figures 17.16 and 17.17 show the distribution of the surveyed service experience of AIS equipment sorted by voltage level, duty, and design.

As can be seen, the AIS disconnecting switch designs used at the different voltage levels differ substantially. The double-break technology dominates below 100 kV, whereas center break type is the more popular design at higher voltage levels.

The disconnecting switch to earthing switch ratio of GIS equipment is approximately 2:1, while in AIS equipment only one earthing switch per roughly four disconnecting switches is installed. This is caused by the possibility of using of portable earthing devices in AIS.

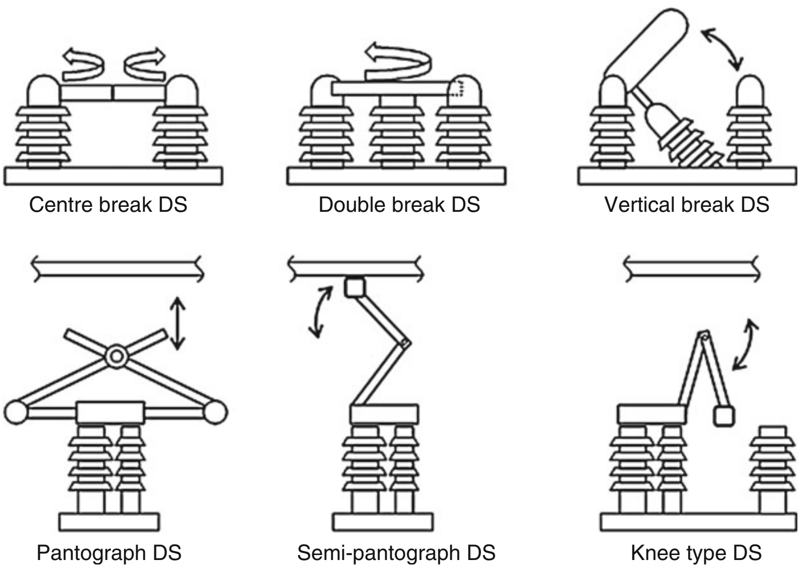

Fig. 17.15 AIS disconnector designs

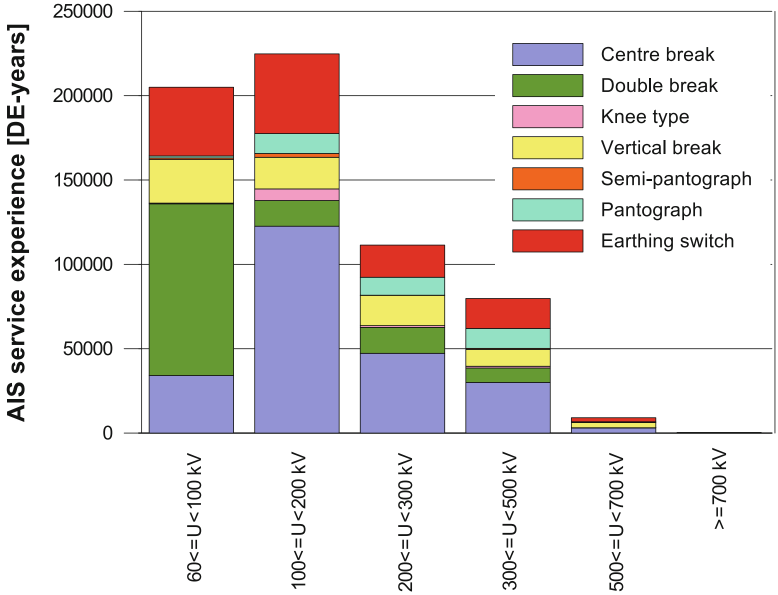

Fig. 17.16 AIS disconnecting switch and earthing switch designs at different voltage ranges

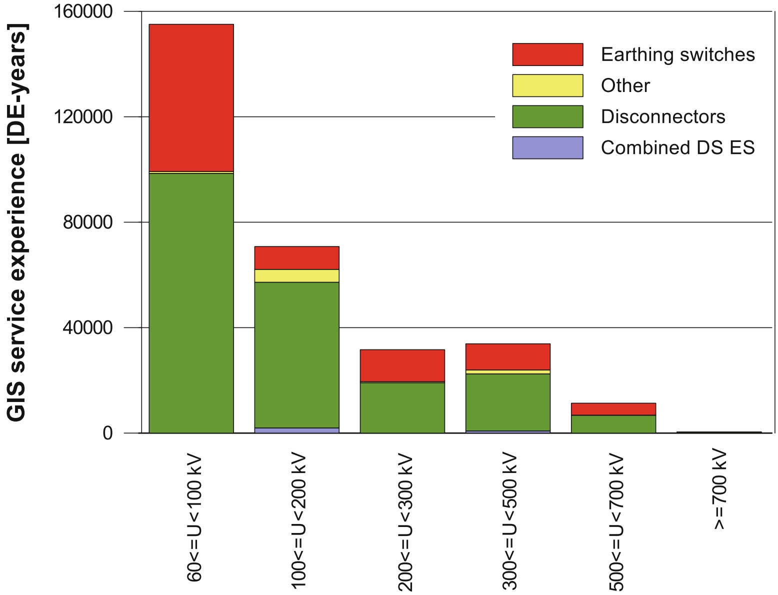

Fig. 17.17 GIS disconnecting switch (DS) and earthing switch (ES) duties at different voltage ranges

17.6.8 DE Failure Frequencies and Characteristics

Considering the surveyed disconnecting switch and earthing switch population as a whole, the overall major failure (MaF) frequency was determined to be 0.21 per 100 DE years of service. The corresponding number for circuit breakers in the same survey is 0.30, which suggests that disconnecting switches and earthing switches have somewhat less major failures than circuit breakers. This is an important observation, as the reliability of circuit breakers versus that of disconnecting switches and earthing switches has been a matter of debate within the community for many years. Note however that per circuit breaker several DE are installed.

The overall major failure frequency was found to be 0.29 and 0.05 MaF per 100 DE years of service for AIS and GIS equipment, respectively. Hence, the GIS disconnecting switches and earthing switches are, therefore, substantially more reliable in the considered equipment population as shown in Fig. 17.18.

As opposed to the case for circuit breakers, there is no obvious influence of voltage level (refer to Fig. 17.18). Equipment rated for greater than 700 kV is not included in this figure since the surveyed population at such voltages was very small.

When disregarding the (rather small) population of AIS knee-type disconnectors, the many different designs used for AIS disconnectors show failure frequencies that are within a factor of two (see Fig. 17.19). Thus, the survey provides no support for assertions that certain designs are significantly more reliable than others.

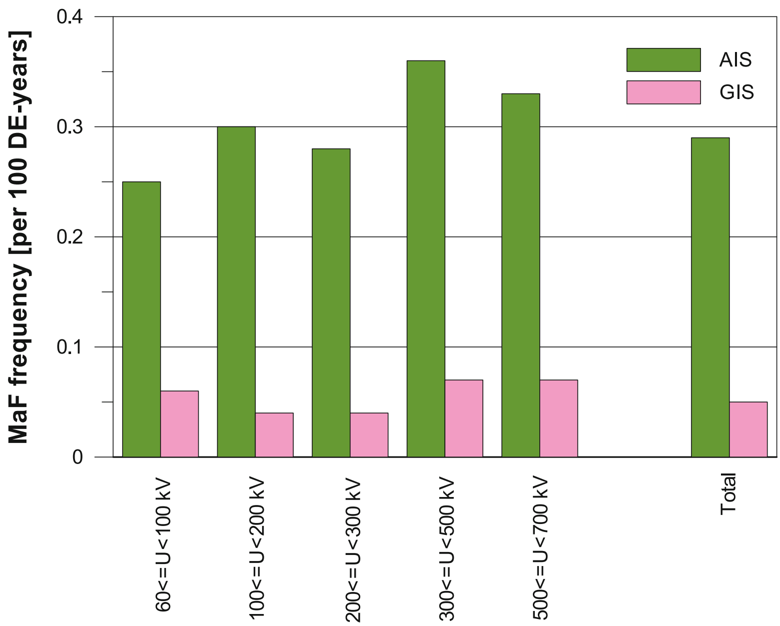

Fig. 17.18 Major failure frequency for disconnectors and earthing switches as a function of voltage

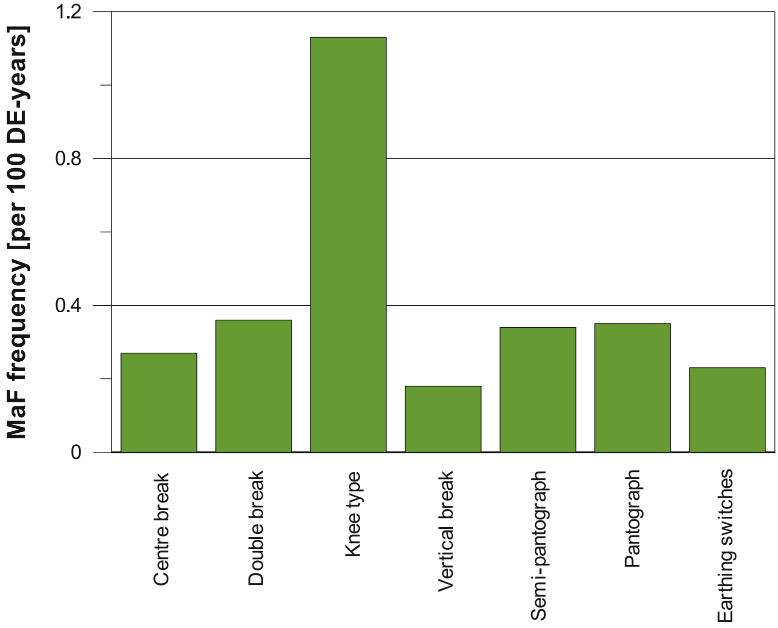

Fig. 17.19 Major failure frequency for the different AIS disconnector and earthing switch designs

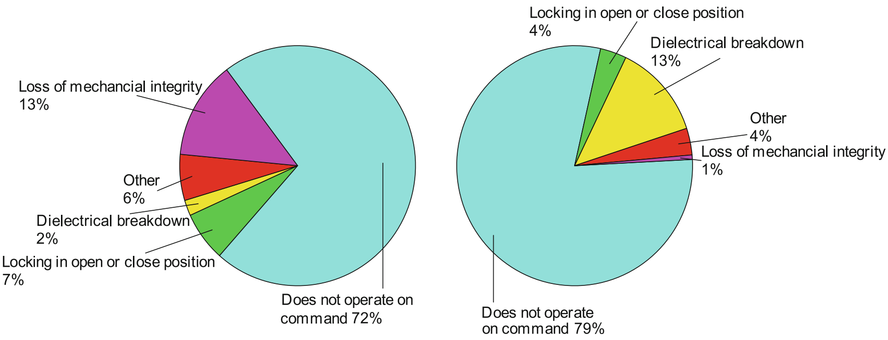

Fig. 17.20 Distribution of major failure modes for AIS (left) and GIS (right) disconnecting switches and earthing switches

As for circuit breakers, the most common major failure mode for disconnecting switches and earthing switches is "Does not operate on command," accounting for roughly three out of four major failures (see Fig. 17.20). Moreover, as could be expected, "Dielectric breakdown" constitutes a larger portion of the major failures in GIS than in AIS, and for "Loss of mechanical integrity," the opposite is seen.

17.6.9 Summary of DE Reliability Survey

Only one major international reliability survey concerned with disconnectors and earthing switches has been conducted. More than 200 000 devices rated for 60 kV and above were surveyed over a four-year period from 2004. The major failure frequencies were determined to be 0.29 and 0.05 MaF per 100 component years of service for AIS and GIS equipment, respectively. Major failure frequencies were almost the same at all voltage levels and only increase a little with equipment age. “Does not operate on command” accounted for roughly three out of four major failures.

17.6.10 Control System Reliability Evaluation

The third circuit breaker reliability survey showed that approximately 30% of the major failures of circuit breakers in service were caused by control circuit or auxiliary system failures. This was the second highest cause of failure after operating mechanisms and was essentially the same as the second survey. Since this observation is of concern to the operating utilities and manufacturers, CIGRÉ further investigated the nature of control circuit failures and made recommendations on how to improve the reliability and performance of circuit breaker control systems. This evaluation was performed after the second (1988–1991) reliability survey at about the time that the third survey was being initiated. The initial objective of the evaluation was to determine the nature of control system failures and to identify possible corrective actions for performance and reliability improvements.

In order to achieve the above objective, a limited survey concerning the frequency and nature of circuit breaker control system failures was conducted by Circa in 2002–2003) (CIGRE TB319 2007). Note that this survey was separate from the third reliability survey described above and much less detailed. This gave a worldwide overview of experience with different technologies and general practices and was intended to determine what the nature of the causes of the control system failures were and what corrective actions could be implemented to improve reliability.

The study initially covered all three types of circuit breakers (SF_6, oil, and air blast) but later focused on single pressure SF_6 CBs for detailed evaluation and improvement recommendations, the same as the second and third circuit breaker reliability surveys. The key conclusions from the study and the nature of the failures were:

- As with the third reliability survey, the most frequent failure mode was failure to operate.
- Six (6) components were responsible for 91% of all of the failures. These six components were (see Fig. 17.21):
  – Coils (including associated resistors and capacitors)
  – Relays
  – Density monitoring system (including associated piping)

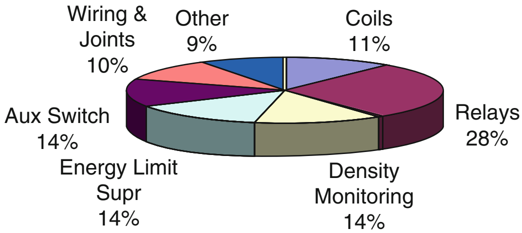

Fig. 17.21 Failures by components

  - Energy limit supervision
  - Auxiliary switches
  - Wiring and joints
- Relays were the most frequently observed component (28%) responsible for failure. The other components were approximately equally distributed (9–14% each).
- Failure rates were highest during the first 2 years of operation.
- The failure rate was observed to decrease 1–2 years after maintenance.

The possible causes of failure were then summarized for each of the above components and corrective actions proposed for each component. In many cases the reported data did not contain enough information to determine a cause of failure. In particular, relays and auxiliary switches had a high percentage of cases where insufficient information was available to identify the nature of the failure (~40% and ~30%, respectively). In the remaining cases, sufficient information was available to identify the nature of the failure. This information was supplemented with the experiences of the working group members and used to identify potential improvements and corrective actions that would reduce the failure causes identified in the survey. Detailed recommendations for improvement are described in Chapter 3 and in Appendix B of reference (WG A3 2007). Some of the general conclusions are listed below:

- Many of the observed failures resulted from external factors, such as poor environmental control of the control cubicle (e.g., moisture) due to design, project coordination and/or maintenance, site voltage conditions, and maintenance errors.
- As stated above, poor environmental control was observed as a contributor to the failures in several components. Since these problems were due to design issues as well as project coordination and maintenance, attention in the specification and design (proper environmental ratings of the cabinets, selection of components, etc.) stages as well as in maintenance could lead to improvement in control system reliability.
- Electrical contact-related issues were observed to some extent on all of the components which involved contacts (auxiliary switches, relays, energy supervision, and gas density monitoring). Some of these also involved poor environmental control. The use of self-wiping contacts was suggested as an improvement for some situations. The use of industrial grade components will also tend to reduce these defects.

- The observation was made that there was a decreasing trend of failures with years since the last maintenance operation was performed. This was thought to demonstrate the potential for human error whenever work is performed on a circuit breaker. This observation highlights the need to maintain a skilled, properly trained workforce for maintenance activities, particularly in light of an ageing workforce. Outsourced labor was also felt to be a potential contributing factor.

17.6.11 Summary of Reliability Survey

Different CIGRÉ working groups have conducted in different periods as mentioned above three reliability surveys on high-voltage circuit breakers. Emphasis has been on SF_6 technology. More than half of the circuit breakers in the last survey are used for switching overhead lines. From around 1990 (second survey) to around 2005 (third survey), a shift in the preferred operating mechanism technology has taken place: spring drivers have taken over from hydraulic drivers as the most common type.

The overall major failure frequency for circuit breakers was in the last survey found to be 0.30 major failures per 100 circuit breaker years of service, which is substantially lower than in the previous ones. Live tank circuit breakers have three times higher failure frequencies than gas-insulated switchgear or dead tank breakers. Shunt reactor switching is associated with considerably higher failure frequencies than other switching duties. The operating mechanism remains the most unreliable part or sub-component of the circuit breaker. The most reported cause for failures is wear and ageing.

Comprehensive and detailed information about circuit breaker service experience is available in several CIGRÉ Technical Brochures.

17.7 Summary

This chapter explains some experience on life management of equipment, which is expected to keep the specified performance during the lifetime. Life management is related to the decision-making process with respect to the equipment's residual life. Since ageing phenomena of equipment is a primary factor of degradation and performance change of equipment, exploration of ageing phenomena for different equipment, as well as mitigation techniques, effective monitoring and end-of-life decision are very important subjects to maintain reliable and efficient power systems.

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Future Trends and Developments

18

Lou van der Sluis and Hiroki Ito

Contents

Keywords
Substation equipment · FACTS · Future interrupting technologies

18.1 Introduction

Electrical power systems have not changed in essence since their first appearance more than a hundred years ago. In the design and construction of power transformers, motors, generators, cables, and transmission lines, it is better to speak of

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H. Ito (ed.), *Switching Equipment*, CIGRE Green Books,
https://doi.org/10.1007/978-3-319-72538-3_18

evolution rather than revolution. But a lot of advanced technologies and techniques are applied in today's power system.

The fundamental design of the power transformer has not altered much over the years, but the efficiency of the larger modern power transformers is now better than 99%. Active noise reduction or noise cancellation is sometimes applied to reduce the noise level of power transformers especially those installed in densely populated areas. The mechanical tap changer for adjusting the voltage level will be gradually replaced by power electronic voltage controllers.

Developments in the field of generators can also be mentioned, as one of the leading multinationals in power technology introduced the "Powerformer" to the market (Powerformer, record performer 1999). This generator unit is in fact a combination of a generator and a transformer. The generator produces power at a higher voltage level between 20 kV and 400 kV, making a step-up transformer unnecessary.

For the transmission and distribution of electricity in urban areas, the application of underground cables comes into wide use. In particular in metropolitan cities like New York and Tokyo, the demand for electricity is steadily increasing, and the transmission and distribution voltages should be raised to higher voltage levels to prevent high ohmic losses. Underground cables, with voltage ratings up to the 500 kV level, are applied, and field experiments with superconductive cables are carried out.

The demand for electricity grows rapidly in some countries such as China and India and also grows a few percent annually in other countries. Table 18.1 shows populations and electricity supply trends in some countries. World population is assumed to rise from four billion in 2008 to eight billion people in 2020. Twenty percent of the world population cannot get access to electricity yet. Global energy supply increases by 30% in the period toward 2020. Eighty percent of electricity supply growth arises in non-OECD countries. China is the world's largest electricity supplier surpassing the United States since 2013.

In 2015, the ENTSO-E (European Network of Transmission System Operators for Electricity) reached 3,278 TWh, which represents a 1.4% increase compared to the previous year (UCTE 2006). Every year the power system is operated closer to its limits, and FACTS devices will play a more dominant role in the future in order to maintain stability (Edris 2000). The application of FACTS devices, however, does increase the complexity of the power system even further.

Table 18.1 Populations and electricity supply trend

	Population (100 million)			Electricity supply (1000TWh)		
IEA/OECD data	2008	2016	2020	2008	2016	2020
China	13.4	13.7	13.9	3.5	6.0	6.6
India	11.9	12.6	13.9	0.8	1.4	1.6
Germany	0.8	0.8	0.8	0.6	0.7	0.7
Japan	1.3	1.3	1.2	1.1	1.0	1.0
USA	3.1	3.2	3.4	4.3	4.3	4.3
Russia	1.4	1.4	1.4	1.0	1.0	1.0
World	40	72.8	76.5	20.1	24.7	25.7

Interruption technologies experience a development that is driven by increasing environmental protection concern to reduce the application of SF_6 gas with high global warming potential (GWP), in spite of considerable effort that has been made to reduce the leakage of gas from gas-insulated equipment. Circuit breakers with insulation and with interrupting media of non-SF_6 gas with lower high global warming potential (GWP) have been demonstrated in the field. Another solution without SF_6 gas is a circuit breaker composed of power electronic devices. Semiconductor switching equipment is still rather expensive and has the advantage of rapid current interruption at any phase angle of the current waveform.

Apart from technical developments, economical changes also take place. In the majority of the developed countries, the generation companies and the utilities are now restructured under the legal force of deregulation and liberalization. The market is the playing field, and the utilities have to operate on an international scale and make strategic alliances to survive these open markets. A parallel with the earlier-liberated telecom market may be considered but with the big difference that the mobile telephone infrastructure has no counterpart in the electrical power system. The daily practice currently is that industrial companies and individual customers can choose their supplier of electricity.

Power systems evolve continuously. This is not only driven by technical developments but also by politics: governments have a steering role in certain tendencies and trends within the branch. Of course, the liberalization of the electricity companies was initiated by the government. But also in the field of alternative energy sources, as well as emission and pollution restrictions, the government sets the direction in which technical driver has to develop.

In addition, public opinion and rejection or acceptance of certain technologies, such as nuclear energy, have their impact on the system and its operation too. Action committees, raised by environmentalists, villagers, and/or other involved parties, cause tremendous delays in the case of network expansion and installation of power plants and have considerable influence on the network operation and planning.

18.2 Definitions of Terminology

Circuit Breaker

A circuit breaker is an electrical switch which has the function of opening and closing a circuit in order to protect other substation equipment in power systems from damage caused by excessive currents, typically resulting from an overload or short circuit conditions. When a fault occurs, circuit breakers quickly clear the fault to secure system stability. The circuit breaker is also required to carry a load current without excessive heating and withstand system voltage during normal and abnormal conditions. Unlike a fuse, a circuit breaker can be reclosed either manually or automatically to resume normal operation.

Noise Cancellation or Active Noise Reduction (ANR)

A method to reduce unwanted sound by generating a second sound with reverse amplitude specifically designed to cancel the first unwanted sound.

Powerformer™
The Powerformer can generate electricity at high voltages between 20 kV and 400 kV. It is a type of generator with round high-voltage cables in the stator slots, using proven cross-linked polyethylene (XLPE) insulation technology, that replace the complex structure of square-section insulated copper conductors that form the stator winding of a conventional generator. Powerformers can produce high output voltages, so step-up power transformers are not necessary any longer.

Superconductor
A superconductor has zero electrical resistance and excludes magnetic flux fields. The electrical resistance of a metallic conductor decreases gradually as temperature is lowered. In ordinary conductors, such as copper or silver, this decrease is limited by impurities and other defects. To the contrary, a superconductor shows zero resistance, when the material is cooled below its critical temperature. An electric current through a loop of superconducting wire can circulate forever without a voltage source.

Flexible Alternating Current Transmission System (FACTS)
Power electronic-based high-voltage devices that are able to control one or more AC transmission system parameters in order to control and to increase the power transfer capability. FACTS improve transmission quality and efficiency of power transmission by supplying either inductive or reactive power to the grid.

Global Warming Potential (GWP)
Global warming potential (GWP) is a relative value to compare the abilities of different greenhouse gases to trap heat in the atmosphere. GWPs are based on the heat-absorbing ability of each gas relative to that of carbon dioxide (CO_2), as well as the decay rate of each gas. The GWP of the greenhouse gases has different global warming values over time periods. For most greenhouse gases, the GWP declines as the time horizon increases due to natural decomposition. For example, methane (CH_4) has a potential of 34 over 100 years but 86 over 20 years. However, sulfur hexafluoride (SF_6) with stable properties is reported to have a GWP of 23,500 over 100 years but 16,300 over 20 years.

Short-Line Fault (SLF)
A short-line fault refers to a fault that occurs on a line a few hundred meters to several kilometers down the line from the circuit breaker terminal. When a circuit breaker clears the SLF, a TRV with a steep rate of rise occurs due to high-frequency oscillation generated by the travelling waves on the line that reflect at the circuit breaker terminal and the fault point.

18.3 Abbreviations

C4-PFN	Iso-C4 perfluoronitrile, $(CF_3)_2$-CF-CN
C5-PFK	C5 perfluoroketone, $CF_3C(O)CF(CF_3)_2$

CB	Circuit breaker
DG	Decentralized generation
ENTSO-E	European Network of Transmission System Operators for Electricity
FACTS	Flexible alternating current transmission system
GWP	Global warming potential
ODP	Ozone depletion potential
SLF	Short-line fault

18.4 Role of Renewable Energy

Concern on the change in the Earth's climate, formalized in the Kyoto Protocol in 1997, stimulates research, promotion, development, and increased use of renewable energy. In power systems, the application of electricity generation based on renewable sources is not new, but a future large-scale implementation of these renewable energy sources will cause structural changes in the existing distribution and transmission networks due to the following reasons:

- Most renewable energy generators are connected to the distribution network, for example, solar panels on the roofs of houses, small wind farms, and individual windmills. This is in contrast with the current layout of the system, where most of the generation is connected to the transmission system.
- Most renewable energy generators are connected to the grid by means of power electronic interfaces. This gives a quite different behavior compared with synchronous generators.
- Most renewable energy generators depend on natural and uncontrollable sources, such as the wind and the sun, and the electrical power output cannot be controlled. If there is no wind, the windmill does not deliver energy. However, most renewable energy generators are connected to the grid by power electronic interfaces, which offer the possibility and flexibility to control the power output – given a certain power input – in some way. In case of photovoltaic systems, for example, the converter of a solar panel is programmed to maximize the energy yield (by means of a maximum power point tracker).
- Many renewable energy generators, e.g., wind turbines and photovoltaic systems, have an intermittent character. A large-scale implementation of this type of generators can lead to strong power fluctuations in the grid.

18.5 Decentralized or Distributed Generation

Most of the power plants are large industrial sites located at strategic locations, nearby a river or a lake for cooling water and close to energy resources or supply routes. These large power plants are connected to the transmission network by step-up transformers and are controlled in order to take care of the voltage and frequency stability of the power system. This is what we call “centralized generation.” Until now, the power system is for the greater part supplied by this centralized generation, and we therefore say that the system is “vertically” operated, as illustrated by Fig. 18.1. We can see from the system layout that there is a “vertical” power flow in the system: at the top, power is generated by a (relatively small) number of large power plants, and, via the transmission and distribution systems, power finds its way down to the consumers connected at the lowest voltage levels.

Nowadays, the trend is to integrate more and more decentralized generation (DG, also called distributed or dispersed generation) into the system, by means of connecting small-scale generators at the lower voltage levels. Examples of DG units are windmills, solar panels, or combined heat-power units (producing steam for industrial processes and electricity as a by-product). When this trend continues, large-scale implementation of these DG units will lead to a transition from the current “vertically operated power system” (Fig. 18.1) into a “horizontally operated power system” in the future, as shown in Fig. 18.2. Because of the increasing amount of DG, the most uneconomical and/or aged power plants are taken out of service. This leaves a power system with the bulk of the consumption and the generation connected to the distribution networks so that a more or less “horizontal power flow” through the system results.

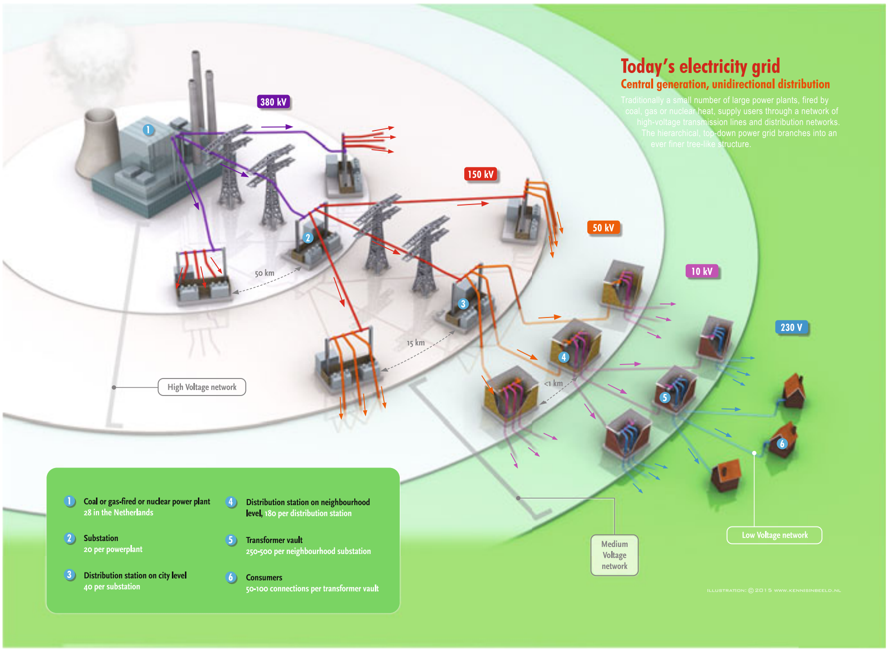

Fig. 18.1 Today’s electricity grid: central generation, unidirectional distribution. (Illustration by Eric Verdult, www.kennisinbeeld.nl)

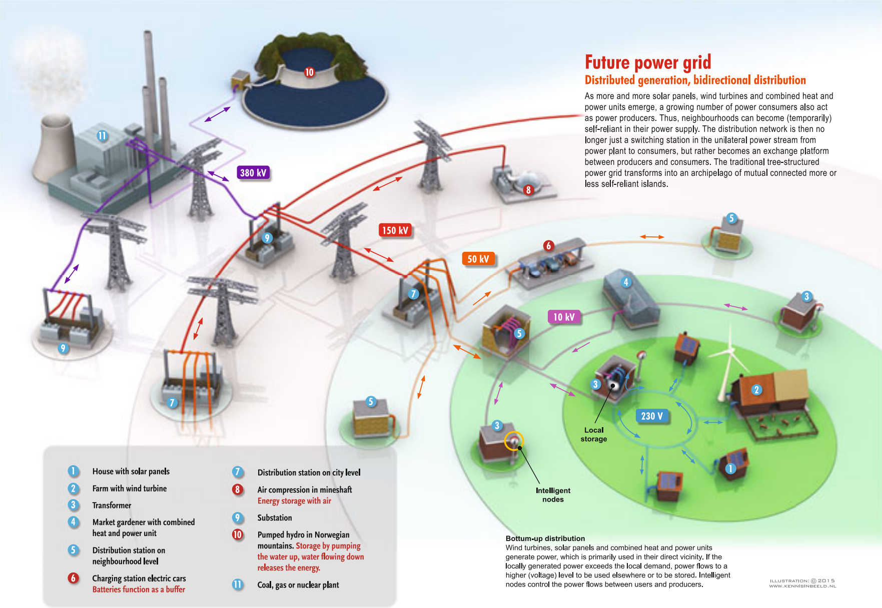

Fig. 18.2 Future power grid: distributed generation, bidirectional distribution. (Illustration by Eric Verdult, www.kennisinbeeld.nl)

Possible developments and/or consequences of the transition from the current "vertically operated power system" into a future "horizontally operated power system" for the power system are (Reza et al. 2003):

18.6 Future Developments in Current Interruption

Components follow system developments in the first place, but there are other drivers as well: the market and our environment, for instance.

There is a Danish saying: "It is difficult to make predictions, especially about the future." Also when we are looking for guidance to plan our future steps in component development, we better remember Alice in Wonderland when she asked the Cheshire Cat: "Where should I go?" the answer was "That depends where you want to end up."

System and component development is rather a matter of evolution. A revolution, however, has been caused by the maturation of power electronics. When thyristors, IGBTs and GTOs, became available at affordable prices, we can speak of a game changer in the previously steadily and quietly evolving power grid.

Vacuum breakers will dominate the distribution systems and in the coming years will be more compact and will have a separate electromagnetic drive for each phase.

A promising development is the self-actuating vacuum interrupter: no bellows, no moving external parts, and no external operating mechanism. A 145 kV vacuum breaker is already available, and the next steps will be a 245 kV double break and a 550 kV with four vacuum interrupters immersed in oil.

Short circuit currents will increase, and a substation equipped with fault-current limiters would be a widely appreciated development. A pilot with a 110 kV resistive FCL, however, has been stopped.

As the application of superconductivity in the power system comes within reach, various projects have been started worldwide. But will superconductivity be a game changer or will it only play a role in specific cases where the old and proven technology cannot be applied?

For long-distance transmission of bulk power, the choice will be made either for AC or for DC, and of course the decision has to be made whether it will be done with overhead lines, underground cables, or gas-insulated transmission lines. For DC transmission a DC breaker has to be developed, and AC has to be built for 1100 kV and 1200 kV connections.

While the short circuit power of the grids is gradually increasing, the interrupting capacity per break is now 550 kV voltage rating with 63 kA breaking capability, which enables to the design and construction of a 1100 kV double-break circuit breaker. On the other hand, the general trend is to reduce the size and complexity of the interrupting devices.

SF_6 has excellent dielectric properties and is a great extinguishing medium. But outside the power engineering society, it is not appreciated because of its negative influence on the environment. This will be an ongoing discussion, so the only path to follow is to search for alternatives. The alternative gasses are already applied in GIL and in current transformers.

18.6.1 Circuit Breaker Application with SF_6 Alternative Gases

SC A3 published a reference paper (Seegar et al. 2017) on interrupting performance with SF_6 alternative gases including C5 perfluoroketone (C5-PFK, F-ketone, $CF_3C(O)CF(CF_3)_2$) (3M™ Novec™ 5110 Dielectric Fluid 2015) and Iso-C4 perfluoronitrile, (C4-PFN, F-nitriles, $(CF_3)_2$-CF-CN) (3M™ Novec™ 4710 Dielectric Fluid 2015). The reference paper claims that there are no alternative interrupting media comparable to SF_6 covering the complete high voltage and breaking current ranges as needed by today's power systems with the same reliability and compactness as modern SF_6 circuit breakers.

SF_6 alternatives often lead to larger interrupters (often multibreaks) with a higher gas pressure that requires the use of a larger driving energy of the operating mechanism. Therefore, the high GWP value, 23,500 of SF_6 alone, is not adequate to measure the environmental impact of electric power equipment based on SF_6 technology. The environmental impact of any specific application should be evaluated and compared using the life cycle assessment approach from its production to disposal as regulated by ISO 14040.

There are still missing scientific data showing why a small amount of F-ketone or F-nitriles in CO_2 can significantly improve the interrupting capability. However, short-line fault (SLF) interruption performance (thermal interruption performance) with a mixture of F-ketones with CO_2/O_2 (7–8 bar) is 80% compared to SF_6, which causes a 245 kV GIS to be derated to 170 kV. Interrupting performance with a mixture of F-nitriles with CO_2 (7 bar) was cleared for 145 kV, which is unknown compared with SF_6.

In conclusion, the use of a 245 kV (50 kA for SF_6) GIS design using an operating mechanism with larger mechanical energy under higher gas pressures (7–10 bar for non-SF_6) can provide a 170 kV GIS (31.5–40 kA for non-SF_6).

18.6.2 Properties of SF_6 Alternative Gases and Mixtures

The properties of the selected alternative gases with reference to SF_6 are shown in Table 18.2. The GWP for the various gases are different: the C4-PFN has a much higher GWP than CO_2 or C5-PFK that are both around 1. All the gases of interest are not flammable, have no ozone depletion potential (ODP), and are nontoxic according to safety data sheets available from the chemical manufacturer (3M™ Novec™ 5110 Dielectric Fluid 2015; 3M™ Novec™ 4710 Dielectric Fluid 2015; Mantilla et al. 2016). The dielectric strength of pure C4-PFN and C5-PFK is nearly twice that of SF_6. CO_2 has a dielectric withstand comparable to air (Niemeyer 1998; Juhre et al. 2005), significantly below that of SF_6.

The properties of gases and mixtures when used in switchgear are shown in Table 18.3. The concentration of admixtures of C4-PFN and C5-PFK with the buffer gas is given in the second column and is typically below 13% (mole). Note that for the use of C5-PFK in CO_2, additionally an oxygen admixture is used. Due to a reduced dielectric withstand of the mixtures compared to SF_6 at the same pressure, the minimum operating pressure needs to be slightly increased to about 0.7–0.8 MPa

Table 18.2 Properties of pure gases compared to SF_6

	CAS number[c]	Boiling point/°C	GWP	ODP	Flammability	Toxicity LC50 (4 h) ppmv	Toxicity TWA[a] ppmv	Dielectric strength/pu at 0.1 MPa
SF_6	2551-62-4	−64[b]	23,500	0	No	–	1000	1
CO_2	124-38-9	−78.5[b]	1	0	No	>300,000	5000	≈0.3
C5-PFK	756-12-7	26.5	<1	0	No	>20,000	225	≈2
C4-PFN	42532-60-5	−4.7	2100	0	No	12,000	65	≈2

[a]The occupational exposure limit is given by a time-weighted average (TWA), 8 h
[b]Sublimation point
[c]A unique numerical identifier assigned to every chemical substance described in the open scientific literature

Table 18.3 Properties/performances of gases and mixtures in MV and HV switchgear applications

	C_{ad}[a]	p_{min}/MPa[b]	T_{min}/°C[c]	GWP	Dielectric strength[d]	Toxicity LC50 ppmv
SF_6	–	0.43…0.6	−41…−31	23500	0.86…1	–
CO_2	–	0.6…1	≤−48[f]	1	0.4…0.7	>3e5
CO_2/C5-PFK/O_2(HV)	≈6/12	0.7	−5…+5	1	≈0.86	≥2e5
CO_2/C4-PFN (HV)	≈4…6	0.67…0.82	−25…−10	327…690	0.87…0.96	≥1e5
Air/C5-PFK (MV)	≈7…13	0.13	−25…−15	0.6	≈0.85[e]	1e5
N_2/C4-PFN (MV)	=20…40	0.13	−25…−20	1300…1800	0.9…1.2	>2.5e4

[a]Concentration of admixture is in mole % referred to the gas mixture
[b]Typical lock-out pressure range
[c]Minimum operating temperature for P_{min}
[d]Dielectric strength compared to SF6 at 0.55 MPa. For the scaling of SF6, breakdown field Ed with pressure correction in the form of $Ed = 84 \cdot p^{0.71}$ was used
[e]Compared to SF_6 at 0.13 MPa, measurements were for a mixture at −15 °C.
[f]Calculations with ref. https://www.nist.gov/srd/refprop

for C5-PFK and C4-PFN when using CO_2 as the buffer gas for HV application. For Air/C5-PFK mixtures in MV applications, 0.13 MPa can be kept, and the dielectric withstand of SF_6 is approached. The high dielectric withstand of mixtures with relatively low admixture ratios of C4-PFN or C5-PFK can be explained by a synergy effect (Simka et al. 2015), i.e., a nonlinear increase of the dielectric strength with the admixture ratio, as is known in SF_6/N_2 mixtures. The GWP of mixtures with C5-PFK is negligible, at the cost of a higher minimum operating temperature. Low temperature applications of, e.g., −25 °C for HV, can be covered by pure CO_2 or CO_2 + C4-PFN mixtures.

18.6.3 Interrupting Performance of SF_6 Alternative Gases and Gas Mixtures

The switching performance is mainly focusing on thermal interrupting capability, corresponding to the short-line fault (SLF) testing duty and the capacitive switching capability. Preliminary information on the switching performance of pure CO_2 and CO_2 mixtures is collected in Table 18.4. The performance of SF_6 is given for comparison. With an enhanced operating pressure compared to SF_6, the cold dielectric strength, which is a measure of the performance in capacitive switching, can reach the same level as that of SF_6. In the scanned literature, only qualitative statements on the switching performance of C4-PFN and C5-PFK mixtures could be found. For CO_2 a few quantitative comparisons exist. Very roughly, for pure CO_2 at an increased fill pressure of about 1 MPa, about 2/3 of both the dielectric and

Table 18.4 Switching performance of gases and mixtures compared to SF_6 at increased operating pressures in HV applications

	Operating pressure [MPa]	Dielectric strength/pu	SLF performance compared to SF_6/pu[a]	Dielectric recovery speed/pu
SF_6	0.6	1	1	1
CO_2	0.8…1	0.5…0.7	0.5…0.83	>0.5
CO_2+C5-PFK/O2	0.7…0.8	close to SF_6	0.8…0.87	close to SF_6
CO_2/C4-PFN	0.67…0.82	close to SF_6	0.83…[b]	close to SF_6

[a]At same pressure buildup
[b]Same performance as SF_6 is stated, but it is not clear if this was under same conditions

thermal interruption performance of SF_6 might be expected. With the admixture of C4-PFN and C5-PFK into CO_2, the dielectric performance can be closed to SF_6. The SLF switching performance for the mixtures of CO_2/O_2/C5-PFK is reported to be 20% below that of SF_6 (Simka et al. 2015). For an adapted circuit breaker (CB) with CO_2/C4-PFN, a SLF performance similar to that of SF_6 is stated (Kieffel et al. 2016). There are, however, also direct comparisons of pure CO_2 with CO_2/C4-PFN and CO_2/C5-PFK mixtures using identical geometry and pressure, which show similar thermal interruption performance of CO_2 with and without admixtures (Owens 2016). IEC test duties L90 (SLF) and T100 (100% terminal fault) with the new mixtures have been passed with some design modifications (Hammer 2016) or certain derating (Simka et al. 2015), suggesting that the switching performance of the new mixtures is not significantly lower than that of SF_6. This has also been shown to be valid for the bus transfer switching duty of disconnector switches, e.g (Hammer 2016; Gautschi 2016).

Formation of critical by-products under repetitive switching in a small volume is discussed in (Juhre et al. 2005). Considerably more experience seems to be needed on the post arcing toxicity of the potential SF_6 substitute gases. Additional reported issues are material compatibility (Tehlar et al. 2015) (e.g., effects on sealing and grease), gas tightness, and gas handling procedures. Therefore, it should not be expected that existing HV equipment can be filled with the new gases without design or material changes. Internal arc tests were done with all mixtures and no critical issues are reported (Kieffel et al. 2016; Tehlar et al. 2015; Hyrenbach et al. 2015).

With the C5-PFK mixtures for HV (GIS with 8 bays for 170 kV, 31.5 kA, based on a 245 kV, 50 kA design) and MV (primary switchgear, 50 panels, 22 kV, nominal current: 1600 A for feeder, 2000 A for busbars), pilot installations have been in operation successfully since 2015 in Switzerland (Tehlar et al. 2015; Söderström et al. 2012) and Germany. Pilot installations with the CO_2/C4-PFN mixture are planned in several European countries (3M™ Novec™ 5110 Dielectric Fluid 2015), such as a 145 kV indoor GIS in Switzerland, 245 kV outdoor current transformers in Germany, and outdoor 420 GIL in the UK (Kieffel et al. 2016; Hammer 2016).

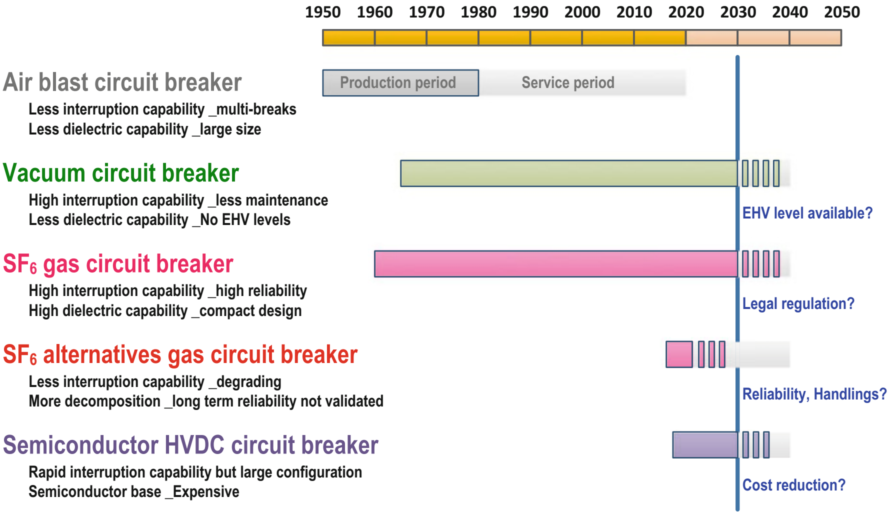

Fig. 18.3 Manufacturing period of circuit breakers with different technologies along with technical subjects to be solved for wider applications

Fig. 18.4 500 kV DC circuit breaker (hybrid mechanical and power electronic switch). (Courtesy of NR Electric, State Grid of Corporation of China)

18.6.4 Future Interrupting Technologies

Figure 18.3 summarizes the manufacturing period of circuit breakers with different technologies along with technical subjects to be solved for wider applications. The subjects include the development of compact EHV vacuum interrupters, long-term reliability of circuit breakers with SF_6 alternatives, and cost reduction of semiconductor circuit breakers. Figure 18.4 shows a photo of 500 kV DC circuit breakers composing of power electronic devices.

18.7 Summary

Switching equipment of the future is introduced, that could be applied in future power systems under changing conditions due to several factors such as massive installation of intermittent distributed renewable sources as well as energy storages, that are often directly connected to distribution networks. They result in less clear boundaries between transmission and distribution, and the role of switching equipment in transmission and distribution is also changing.

New equipment applied with new materials such as superconductors, new insulators with grading properties, and power electronics will be developed and applied to meet future requirements in power systems.

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