362

TECHNICAL REQUIREMENTS
FOR
SUBSTATION EQUIPMENT EXCEEDING 800 kV

Field experience and technical specifications of Substation equipment up to 1200 kV

Working Group
A3.22

December 2008

WG A3.22

Technical Requirements
for
Substation Equipment exceeding 800kV

Field experience and technical specifications of Substation Equipment up to 1200 kV

Members:

H. Ito (Convenor), A. Janssen (Secretary),

J. Amon F., S-W. Bahng, M. C. Bhatnagar, P. Boss, J. Brunke, E. Colombo, R. Diaz, D. Dufournet, Y. Filion, P. C. Fernandez, R. Gorur, A. Gilboulet, J. Jäger, A. Keri, T. Kobayashi, M. Kosakada, E. Kynast, A. Lokhanin, C. van der Merwe, M. de Nigris, V. Rashkes, D. Peelo, B. Richter, H-D. Schlemper, B. Shperling, Y. Shirasaka, R. Smeets, L. Stenström, M. Waldron, A. Wiersma, J-W. Woo, Y. Yamagata, Yao Sili, R. Yeckley, T. Yokota, L. van der Zel

ISBN : 978-2 85873-049-0

Abbreviations

1LG	Single-phase line fault to ground
2LG	Two-phase line faults to ground
3LG	Three-phase line faults to ground
ACSR	Aluminium Conductor Steel Reinforced
AEP	American Electric Power (USA)
AIS	Air Insulated Switchgear
AN	Audible-Noise
BPA	Bonneville Power Administration (USA)
CCGT	Combined Cycle Gas Turbine
CEPRI	China Electric Power Research Institute (China)
CESI	Centro Elettrotecnico Sperimentale Italiano (Electrotechnical Testing Centre, Italy)
CISPR	International Special Committee on Radio Interference
CRIEPI	Central Research Institute of Electric Power Industry (Japan)
CSS	Controlled Switching System
CT	Current Transformer
DS	Disconnector
EHV	Extra High Voltage
EMI	Electromagnetic Immunity
EMTP	Electro Magnetic Transient Program
ENEL	Ente Nazionale Per L'energia Elettrica (National Electrical Energy, Italy)
ES	Earthing Switch
ESDD	Equivalent Salt Deposit Density
FFO	Fast Front Overvoltage
FPD	Fast Protective Device

GCB	Gas Circuit Breaker
GIS	Gas Insulated Switchgear
HSGS	High Speed Grounding Switch
IEC	International Electrotechnical Commission
IREQ	Hydro-Québec's Research Institute (Canada)
ITRV	Initial Transient Recovery Voltage
ITU	International Telecommunication Union
KEPCO	Korea Electric Power Corporation (Korea)
LDC	Line Discharge Class
LI	Lightning Impulse
LIPL	Lightning Impulse Protection Level
LIWV	Lightning Impulse Withstand Voltage
LLF	Long Line Fault
MAIS	Manœuvres Automatiques d'Inductances Shunt (Measure of automatically shunt reactor switching)
MOSA	Metal Oxide Surge Arrester
MOV	Metal Oxide Varistor
NCI	Non-Ceramic Insulator
PD	Optical potential devices
PIR	Pre-Insertion Resistor
RI	Radio Interference
ROW	Rights-of-way
RPTC	Rejet de Production et Télédélestage de Charge (Scheme to reject a large amount of generation and to shed large block of load)
RRRV	Rate of Rise of Recovery Voltage
RIV	Radio Interference Voltage

SA	Surge Arresters
SC	Series Capacitor
SFO	Slow-Front Overvoltage
SiC	Silicon Carbide
SIPL	Switching Impulse Protection Level
SIWV	Switching Impulse Withstand Voltage
SN ratio	Signal to Noise ratio
SPAR	Single-Phase Rapid Auto-Reclosing
SPSR	Solutions aux Problèmes de Séparation de Réseaux (Scheme is a last-resort solution in the case of a risk of total collapse)
SR	Shunt Reactor
SVC	Static Var compensator
TCSC	Thyristor-Controlled series Capacitor
TEPCO	Tokyo Electric Power Company (Japan)
TLF	Transformer Limited Fault
TOV	Temporary Overvoltage
TPAR	Three-Phase Rapid Auto-Reclosing
TRV	Transient Recovery Voltage
UCTE	Union for the Coordination of Transmission of Electricity in continental Europe
UHV	Ultra High Voltage (exceeding 800 kV)
URW	Required Withstand Voltage
VEI	Russian Electrotechnical Research Institute (Russia)
VFT	Very Fast Transient
VFTO	Very Fast Transient Overvoltage
VNIIE	Russian Electric Power Research Institute (Russia)
VT	Voltage Transformer

1 Introduction

1.1 Introductory Remarks and Tasks of WG A3.22

In recent years there has been a renewed interest, both economically and technically, in the development of high voltage ac transmission systems rated in excess of 800kV (known as Ultra High Voltage exceeding 800 kV, UHV). Plans for new commercial developments in countries such as China & India, in conjunction with plans to extend existing trials in countries such as Japan have created a real demand for standardisation in the field of UHV technology. Effective standardisation of UHV requires that experience gathered to date, both from the planned installations and from the major work carried out in Japan, Italy and Russia in the past, should be drawn together and "best practise" identified. In 2006, CIGRE undertook to carry out this pre-standardisation activity and this Technical Brochure in the first stage in completing this task.

UHV pre-standardisation involves, and impacts upon, many different CIGRE Study Committees as shown in Table 1.1.1. In order to progress the early stages of the pre-standardisation activities as fast as possible, CIGRE Working Group A3.22 took a CIGRE-wide lead in surveying the current state of the art in the field of UHV technology. The resulting findings and recommendations, developed in cooperation with other Study Committees and Working Groups within CIGRE, are presented here and form the basis of future work in a number of different technical areas.

***Table 1.1.1** Standardisation tasks and related Study Committee*

Standardisation tasks	Related Study Committee
Review of international experience	A2, A3, B2, B3, C4, D1
Chinese projects, state-of-the-art	A2, A3, B2, B3, C4, D1
Insulation coordination and clearance in air / SF_6	C4, (D1, A2, A3, B3)
Long transmission lines including series compensation, etc	A3, C4, (B2, A2,), WG A3.13
Switching phenomena and transients	A3, (C4)
Special requirements and designs for UHV substation equipment (TRV, high DC component, line faults, etc)	A3, (A2, B2)
Measurement challenges: Testing and service	D1, (A3)
VT and CT designs	A3, WG A3.15
Composite insulators: Substation equipment and overhead lines	WG A3.21, B2, (A2, B3, D1)
Environmental impact: Focus on overhead lines	B2, (C3)
Operating environment: Impact of pollution, wind, ice, earthquake, etc, on performance	C4, (A2, A3, B2, B3)
Electric Magnetic Field Influence	B3, B2
Transformer design and materials	A2, (D1)
Surge arresters and optimum switching practises	A3, (C4), WG A3.17
Optimum substation and equipment layouts	B3, WG B3.22
Designing overhead lines for optimum reliability	B2, (C4)

Considering the document in more detail, it has been prepared by 39 international experts from 17 countries based on more than 300 written technical contributions. It is divided into three main sections dealing with:

- the present state-of-the-art of technical specifications for substation equipment at 800kV and above including general field experience and technical challenges in the operation of various national projects.

- phenomena unique to transmission systems rated 800 kV and above including extrapolations and considerations for future standards for substation equipment applied to UHV systems.
- recommendations regarding specific aspects of technical specifications for systems rated >800kV.

Future work within the various affected CIGRE Study Committees will look to expand upon these topics as necessary in order to provide the necessary basis for standardisation. In particular, WG A3.22 will continue to consider aspects related to switching devices and switching phenomena.

1.2 Specific phenomena peculiar to UHV AC systems

Table 1.1.2 shows several specific issues of UHV AC systems exceeding 800 kV that may have great impact on substation equipment and which are analysed in this Technical Brochure. In particular, the use of multi-bundle conductors with large-diameter as well as large-capacity power transformers provides distinctive phenomena for UHV systems.

***Table 1.1.2** Specific issues of UHV AC systems exceeding 800 kV*

Phenomena peculiar to UHV	Equipment	CIGRE SC	IEC TC
Prominent Ferranti effect and TOV due to large capacitance of overhead lines	Surge Arrester Shunt Reactor	A2, A3, B3, C4	14, 17, 37
Possibly reduced corona onset voltage with increased corona losses and audibel noise	Line Substation (AIS)	B2, B3	11
Prolonged secondary arc extinction time due to higher induced voltage	4-Legged Reactor HSGS, GCB	A2, A3, B3, C4	14, 17, 28
Higher slow front overvoltage at grounding fault occurence due to low damping of traveling waves	Circuit Breaker Surge Arrester	A3, B3, C4	17, 37
High amplitude factor in TRVs due to low losses of power transformers and transmission lines	Circuit Breaker Surge Arrester	A3, B3, C4	17, 37
High TRV peak value for out-of-phase due to low damping of traveling waves	Circuit Breaker Surge Arrester	A3, B3, C4	17, 37
Reduced line surge impedances due to multi-bundle conductors with large diameter	Circuit Breaker	A3, B3	17
Large time constant of DC component in fault current due to low losses of transformers and lines	Circuit Breaker	A3, B3	17
Reduced first-pole-to-clear factor due to small zero-sequence impedance in the UHV systems	Circuit Breaker	A3, B3	17
Severe VFTO due to geometry and topology of UHV substation such as MTS	Circuit Breaker GIS, MTS	A3, B3	17

MTS: Mixed Technologies Substation

In addition to those items listed above, the use of high performance surge arresters 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 also discussed herein.

1.3 Summary of future tasks by equipment type (SC A3 only)

The following sub-sections summarise the main technical topics identified as being of importance for UHV equipment within the scope of Study Committee A3 and which will be developed further within appropriate Working Groups. It is expected that, on the basis of the information presented here other Study Committees will be able to draw up similar summaries and develop the necessary work plans to complete pre-standardisation activities.

1.3.1 Circuit-breakers

- Short-circuit currents
  DC time constants, auto-reclosing time, rated peak withstand current, fault current with high frequency component, etc
- Transient Recovery Voltages (TRV) for terminal faults
  First-pole-to-clear factor, Rate of Rise of Recovery Voltage (RRRV), Transformer Limited Faults (TLF), Transformer secondary faults, Single phase and three phase faults, effect of MOSA, etc
- Parameters for line fault interruptions
  Surge impedance, amplitude factor, line side time delay, 1LG/2LG/3LG, compact line, ITRV characteristics, TRV for Short-Line Fault (SLF), Long-Line-Fault (LLF), series compensated line and by pass switch, etc
- Out-of-Phase switching (making and breaking)
  Amplitude factor, RRRV, breaking current, probability of occurrence, out-of-phase angles, synchronization, etc
- Parameters for no-load line-charging current switching
  Capacitive current, shunt compensated lines, voltage factor, induced-voltages, healthy phase switching, Temporary Overvoltage (TOV), etc
- Parameters for line energization and line reclosing
  With/without MOSA, pre-insertion resistor (PIR), controlled switching, shunt reactors, Metal Oxide Varistor (MOV) across interrupters, etc
- Reactor switching
- Unloaded transformer energization
- Effect of closing and opening resistor on the duties
  TRV for terminal faults and Long-Line Fault (LLF) interruption, etc

1.3.2 Disconnectors (DS), earthing switches (ES) and high speed grounding switches (HSGS)

- Disconnector switching parameters (capacitive, bus-transfer etc)
  Amplitude factor, capacitive current, DS for GIS including Very Fast Transient (VFT), transformer energization, etc
- Earthing switch induced current switching parameters
  Peak voltage of TRV, breaking current, etc
- HSGS parameters
  Peak voltage of TRV, secondary arc current, comparison with a four-legged shunt reactor

1.3.3 Metal oxide surge arrester (MOSA)

- V-I characteristics
- Protection level of surge arrester, energy absorbing capability

- MOSA layout

  Temporary Overvoltage (TOV), energy/currents due to lightning and switching events, different location of MOSA, coordination current, etc

1.3.4 Instrument transformers

- Very fast transient (VFT) for Air Insulated Switchgear (AIS)/ Gas Insulated Switchgear (GIS), etc

2 Field Experience

2.1 Overview of 800 kV and UHV AC projects exceeding 800 kV

The rapid growth in electrical power demand, especially in China, Brazil and India, creates some urgency for the development and construction of UHV transmission systems exceeding 800 kV. Figure 2.2.1 indicates the highest voltage of AC power transmission.

American Electric Power (AEP) began their installation of 345 kV transmission systems in 1952 at the same time that Sweden was building 380 kV lines. Hydro-Québec developed the world's first 735 kV transmission system in 1965, and AEP installed 765 kV lines in 1969. In Brazil, the operation of the first EHV transmission systems, with the voltage levels of 345 kV, 440 kV, 550 kV and 800 kV, started in 1963, 1971, 1975 and 1982, respectively. Tokyo Electric Power Company (TEPCO) started 550 kV transmission in 1973. At the beginning of the 1970s, ENEL (in cooperation with CESI SpA) and TEPCO each launched UHV projects and conducted various field demonstrations of UHV substation equipment in the 1990s.

TEPCO started construction on an 1100 kV double-circuit transmission line in 1988, completing the first section (190 km) in 1993 and the second section (240 km) in 1999. These transmission lines are now operated at 550 kV and will be upgraded to 1100 kV in the mid-2010s.

The voltages in the former USSR (Russia) were upgraded to 420 kV in 1957, 525 kV in 1959, 787 kV in 1967, and 1200 kV in 1985. Their UHV system is now temporarily operating at 525 kV.

In China, the first 550 kV projects were commissioned in 1981 and 765 kV transmission was started in 2005. An 1100 kV pilot project is now being constructed and is scheduled to start transmission in 2008.

In India, a "supergrid" high-capacity 1200 kV AC system along with a ±800 kV HVDC system is being planned.

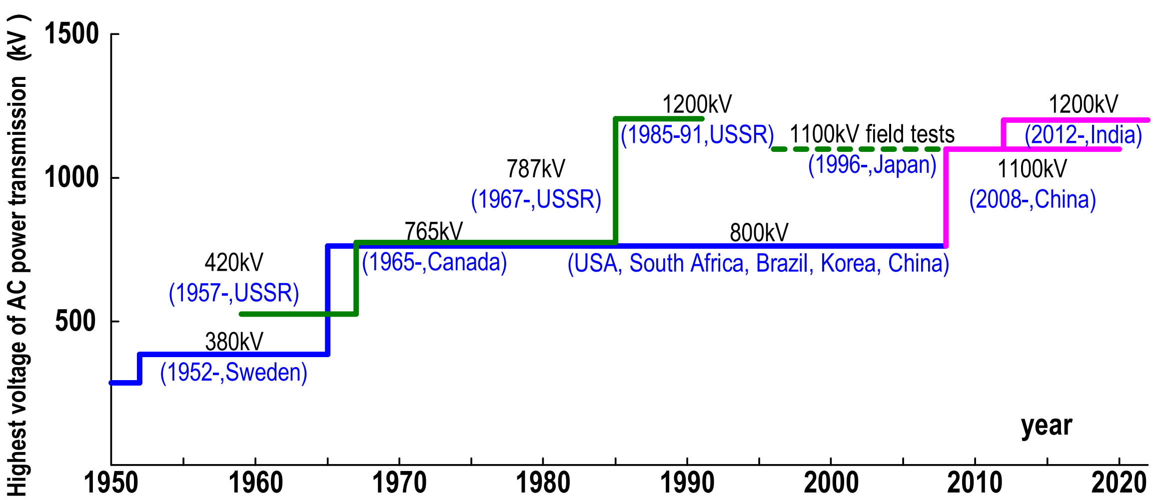


***Fig. 2.1.1** Highest voltage of AC power transmission*

2.2 AEP project

2.2.1 Features of American Electric Power's 800 kV transmission system

American Electric Power (AEP) started conducting studies on Extra High Voltage (EHV) in 1946 and continued through to 1961. Their 345 kV transmission systems were overlaid on existing HV transmission systems. AEP was one of the leaders in the deployment of 345 kV. AEP started 800 kV transmission in 1969 and presently owns more than 3400 km of nominal 765 kV lines and 24 major substations, integrating key generating plants with load centres throughout the eastern AEP system and providing interconnections with neighbouring utilities. AEP has learned a great deal about 800 kV technologies through first-hand experience. [1]

2.2.2 Overview of field experiences and the evolution of AEP's 800 kV transmission network

Over the years, AEP has accumulated abundant experience in planning, designing, engineering, constructing and operating 800 kV transmission networks. This experience involved numerous technical challenges and lessons learned in the field including improvements to existing technologies and development of new technologies.

During the 1980s, several 765 kV auto-transformers failed and seven newly installed single-phase EHV transformers faulted at one substation during a period of three years. Most failures occurred under normal operating conditions and were not accompanied by a major external disturbance. An investigation revealed specific dielectric failure mechanisms. In response to these events, AEP changed the dielectric specifications for EHV transformers in four key areas. [2] Since the modification, no failures have been recorded for 765 kV transformers incorporating the new dielectric specifications.

Four-legged shunt reactor banks are often used to reduce the secondary arc current on 365-550 kV-transposed lines. Since AEP's 800 kV transmission lines are not transposed, a conventional four-legged shunt reactor bank cannot sufficiently reduce the secondary arc current on a long line because of the difference in inter-phase capacitance. Therefore, AEP developed a modified four-legged shunt reactor bank [3] to secure single-phase auto-reclosing of their 800 kV transmission lines. Figure 2.2.1 shows a modified four-legged shunt reactor scheme.

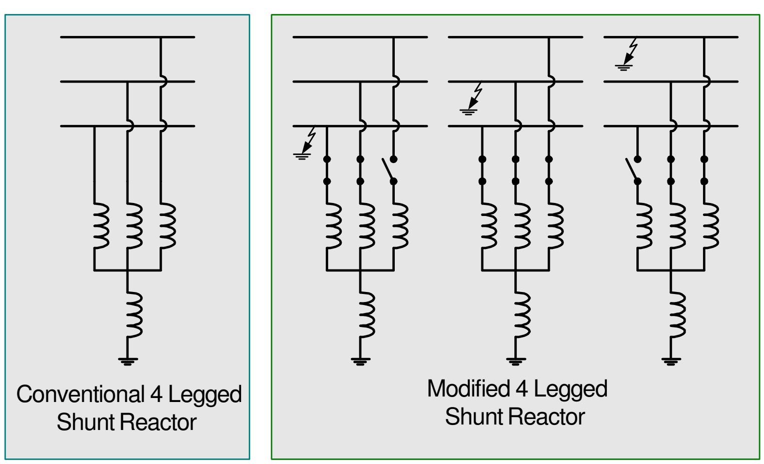


***Figure 2.2.1** Modified reactor schemes*

Field tests demonstrated that successful single-phase reclosing could be achieved if the secondary arc current were limited to less than 40A and extinguished within 0.5 seconds. Since the mid-1980s, single-phase auto-reclosing has been successfully operated once a year per line on average and has greatly enhanced system performance.

The majority of the AEP's 800 kV circuit breakers are live-tank type with closing resistors in order to limit switching overvoltages to 2.0 p.u. In the recent years, AEP installed dead-tank (DT) breakers with no closing resistors. However, arresters were installed along the associated lines in order to limit switching overvoltages to 2.0 p.u. The first transmission line arresters designed for vertical mounting were installed on the 240 km Marysville-Orange-Kammer 800 kV line. EMTP studies showed that a three-phase line arrester set at the one-third and two-thirds locations was required to keep the magnitude of switching surges below the line insulation withstand of 2.0 p.u. The first 800 kV SF_6 dead-tank (DT) circuit breakers were also installed at Oregon Station. AEP currently has 16 DT GCBs with closing resistors to provide improved overvoltage control.

Table 2.2.1 *AEP specifications*

Specifications		
Items	**Circuit breakers**	**Disconnect switches**
Highest voltage	800 kV	800 kV
LIWV (kV)	2050 kV-close, 2255 kV-open	2050 kV
SIWV (kV)	1425 close/1550 kV-open (wet), 1700 close/ 1870 kV-open (dry)	1400 kV, 1750 kV-open
AC voltage	960 kV-open and close	850 kV phase to ground
Metal Oxide Surge Arresters (MOSA) main characteristics		
Maximum continuous operating voltage	476 kV	
Protective levels	1420 kV (lighting surge at 20 kA, 8 μs/20 μs) 1197 kV (switching surge at 3 kA)	
Circuit breakers main characteristics		
First-pole-to-clear factor	1.5	
TRV peak value	1649 kV for T10 1408 kV for T100	
DC time constant	X/R=17 for 63 kA and X/R=50 for 50 kA	

2.2.3 Specific issues and technical challenges for the operation of AEP projects

Throughout the 1970s and 80s, AEP continued their research and development on UHV transmission. The UHV Research Centre located in India was a single-phase facility energized from $1110/\sqrt{3}$ to $2255/\sqrt{3}$ kV line-to-ground using two transformers connected in cascade. The facility included a single-phase test line consisting of three spans (each 305 m long), a station with a 420/835/1785 kV 333 MVA transformer and two test cages with an independent voltage source for testing short lengths of conductor. The maximum test voltage was 900 kV.

AEP conducted extensive research on conductor corona performance with various configurations. Corona performance was evaluated in terms of environmental impact, including audible and radio noise, television interference and corona loss under expected adverse weather conditions. [4]

Their UHV research showed that the 1.6 p.u. switching overvoltage level was achievable using techniques such as closing and opening resistors, controlled switching, surge arresters, shunt reactors, etc. It was concluded that there were no major impediments to the application of UHV technology up to the 1500 kV level. However, slower load growth prevented AEP from pursuing further UHV investigation.

2.3 IREQ/Hydro Québec project

2.3.1 Features of Hydro Québec 765 kV transmission system

The power system of Hydro-Québec is characterized by a large number of high-capacity hydroelectric power plants located at great distances from the major load centres. This situation has basically determined the design of the transmission system. Approximately 85% of the total installed generation feeding the Hydro-Québec system is located at distances varying from about 400 to 1300 km from the closest major load centres (Montréal and Québec City).

Consequently, the transmission system is essentially of a radial nature with two major transmission axes, northeast and northwest, which connect at a point located about 200 km north of Québec City at the Saguenay Substation. The northeast axis delivers power generated from the Manicouagan-Outardes and Bersimis Complexes (installed generation capacity ≈15,000 MW) while the northwest axis delivers power generated by the La Grande River Complex with a total of 15,500 MW of installed generation capacity.

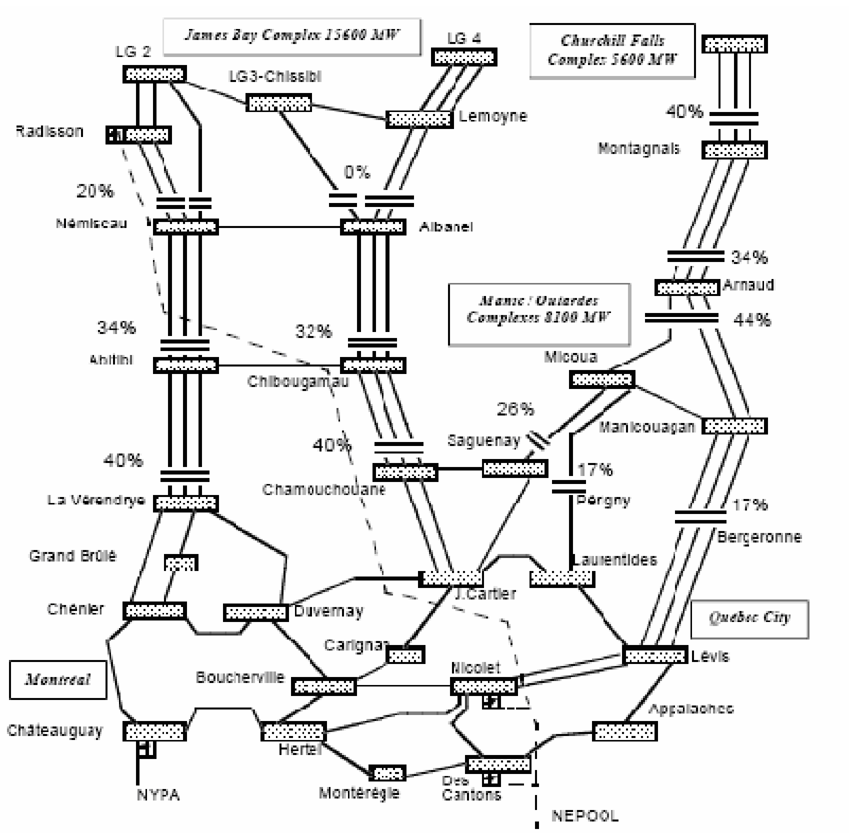


Fig.2.3.1 *Hydro-Québec 735kV series-compensated transmission systems*

With this type of configuration, the transmission design essentially depends on the performance criteria, which specify how the power system should react when subjected to different disturbances. Basically, the system should be designed to **maintain full synchronous operation without any loss of load under so-called normal contingencies**. It became clear from the very beginning (early 1960s) that in view of the power transmission requirements expected from the HQ power system, an extra high voltage (EHV) transmission system would be necessary to cope with stability problems and in fact, this led to the selection of 765 kV AC technology. Using this EHV system allowed a reduction in series impedance of the lines (relative to the impedance of the generators) and consequently allowed the transmission of large amounts of power over long distances and the ability to maintain the stability criteria.

Since the series impedance between generators is the most important factor for stability issues, the number of switching substations has been of prime importance in view of its impact on post-contingency system impedance since normal contingency results in the loss of a line section between adjacent substations. This stability study resulted in the selection of line length varying from 170 to 400 km on the 765 kV systems.

Following investigative studies and the decisions taken in 1962 to develop a 765 kV system for the integration of the Manicouagan and Churchill Falls Complex, the first sections of the 765 kV system were commissioned in August 1965, allowing the transmission of power over a distance of about 650 km.

2.3.2 Evolution of Hydro Québec 765 kV transmission network

As mentioned earlier, harnessing of the rivers on the eastern side of James Bay could generate up to 15,000 MW that would have to be transmitted over a distance of 800-1200 km to reach the main load centres. Therefore, at least four possibilities were studied: AC at 765 kV, AC at 1100 kV and ±500 and ±800 kV DC. From these extensive studies, the following conclusions were drawn:

- Experience acquired from the 765 kV systems at that time, and system studies combined with numerous discussions with major equipment manufacturers resulted in a high level of confidence about the technical feasibility of operating an 1100 kV system for the integration of the James Bay Complex. Detailed studies on the transmission lines at 1100 kV have been performed. These studies essentially focused on a new type of tower design and also on the possibility of using expanded conductors. For dynamic stability issues, it was deemed necessary to add at least 1000 Mvar of voltage support (synchronous condensers were considered at the time) depending on the scenario (number of circuits used to transmit the entire 16,000 MW of power from the James Bay Complex). Corona loss, radio interference and audible noise related to a UHV system were issues that required more detailed study. Four conductor bundle configurations (6×1823", 6×1998", 8×1630" and 8×1863") were considered and tested at IREQ in outdoor test cages under heavy artificial rain and fair weather conditions at the beginning of the 1970s. The results revealed that of the four bundles tested, the 8×1630" conductor gave the best corona performance. However, ice loading conditions may lead to selecting the 6×1863" bundle.

- For DC current transmission scenarios, the selection of voltage level and rated current are of prime importance. This technology does not involve system dynamic stability; indeed, a compromise in the number of circuits had to be found in order to deliver the power with optimum flexibility and reliability while minimizing investment costs. Using a minimum numbers of circuits would certainly reduce the investment costs but on the other hand, since losses are proportional to the square of the current, the best compromise had to be made between acceptable loss and capital investment. Different scenarios at voltage ranging between ±450 kV and ±800 kV have been studied. The rated current varied from 1600 to 3500 A

- The outline on investment costs for the different scenarios studied for the transmission of power generated by the James Bay Complex indicates an increase in the order of 20 to 30% for 1100 kV compared with 765 kV and a difference of +35% for the scenario with DC current at ±600 kV. Of course, not only the investment costs should be considered.

Finally, it was decided to apply the system at 765 kV.

2.3.2.1 Actual 765 kV transmission network

As shown in Fig. 2.3.1, the actual HQ 765 kV transmission network comprises:

- 11,000 km of lines;
- Nine synchronous condensers (250 MVA each) for fast voltage control following a disturbance;
- Eleven 300 Mvar static Var Compensators (SVC);
- 11,000 Mvars of series capacitors installed along 32 line sections providing a degree of compensation between 16 and 44%, which allows transmission of between 2,200 and 2,700 MW per circuit (increased by at least 50% from the original network);
- 165 and 330 Mvar shunt reactor units to compensate for line charging (55 to 65% compensation degree). At initial commissioning, the shunt reactors were not switchable. However, due to the difficulty in controlling the voltage during normal operation with greatly variable line-loading levels, all shunt reactors were retrofitted with circuit breakers.

2.3.2.2 765 kV substation layout

To allow for better operating flexibility and to facilitate maintenance work without impacting the availability of the installation, the 765 kV substations were designed with double busbars, with two circuit breakers per line.

2.3.3 Overview of field experience and the evolution of Hydro-Québec's 765 kV transmission network

Two decades of operational experience revealed the necessity to improve the transmission system reliability (following major outages by the end of the 1970s and beginning of the 1980s). Major revision of the system design and operation performance standards essentially focused on strengthening the system, enhancing voltage control and revising the philosophy on countering extreme contingencies. This was basically achieved by installing series compensation on 32 line sections of the 765 kV system in addition to the use of system-wide fast-acting automatic schemes to switch equipment, reject generation and shed load in order to improve system stability and avoid the loss of synchronism between generators. The most important system-wide protection schemes are listed below:

- Automatism MAIS (Manœuvres Automatiques d'Inductances Shunt): This scheme is used to automatically switch-in or -out the shunt reactors following system disturbances. Special inductive potential transformers with very high-precision requirements are used to measure the voltage on the 765 kV systems. This scheme was implemented in twenty-two 765 kV substations to control a total of 15,000 Mvars.
- Automatism RPTC (Rejet de Production et Télédélestage de Charge): This scheme is used to reject a large amount of generation and to shed large blocks of load in order to prevent a total grid collapse when the system conditions are met. It is implemented in fifteen 765 kV substations.
- Automatism SPSR (Solutions aux Problèmes de Séparation de Réseaux): This scheme is a last-resort solution used when a risk of total collapse is identified that would involve network separation and excessive overvoltage levels. When the system separation conditions are met, the SPSR mainly involves switching of so-called "sacrificial" surge arresters to allow controlled and safe dismantling of the network.

2.3.4 Specific issues and technical challenges for the operation of Hydro Québec projects

Throughout the development of its vast 765 kV network, HQ has faced a number of technical challenges including those mentioned below:

- The major geomagnetic storm that hit the James Bay transmission system tripped all the SVCs, resulting in a total blackout. This storm produced circulation of DC current into the 765 kV system and caused saturation of the step-up generating transformers and consequently, excessive voltage distortion. Series compensation on these lines greatly reduced the risks associated with a geomagnetic storm given its inherent capacity to block DC current.
- Due to massive installation of series compensation, line circuit breakers faced more stringent constraints (increased TRVs, increased switching surges, delayed zero-current, etc.). Performance assessment of existing line circuit breakers (in terms of TRVs) and development of special circuit breakers was necessary in order to meet the specific requirements. [5], [6]
- The exceptional ice storm in the winter of 1998, which left up to 75 mm of radial accumulated ice on the conductors, resulted in the collapse of 150 towers on the 735 kV network. A major program of mechanical reinforcement combined with the use of de-icing equipment for some strategic lines will prevent or minimize further damage in the case of such an exceptional event. [7]
- Energization of unloaded power transformers on a weak network (during restoration of the 765 kV system) may lead to significant TOV if no mitigation measures are taken. With air-blast circuit breaker technology, closing resistors with large pre-insertion time (12–14 ms) have been used to reduce the inrush current and associated TOV. With actual SF6 technology (live tank), closing resistors with such pre-insertion time would have involved major development and significant cost. Therefore, HQ has made major advances in a special controlled switching system (CSS) taking into account the residual flux of the transformer. This special CSS has thus far been used to energize step-up transformers in hydroelectric power plants where frequent energization was foreseen.

Reference [8] shows the detailed solution that was applied.

- More recently, a new fast protective device (FPD) was installed to rapidly by-pass the series capacitors on a 330 kV line for any internal fault, thus eliminating the trapped charge on the series capacitor before the fault is cleared by line circuit breakers. This new device has actually been tested in the field since 2003. Application of this solution to the 765 kV lines will be studied after having verified its performance and reliability on the pilot project at 330 kV. Reference [9] provides full details on this new series-capacitor protection scheme.

Table 2.3.1 *Hydro Québec specifications*

Highest Voltage	***765kV***		
Items	***Transformers***	***CBs (AIS), DS***	***PT and CT***
LIWV (kV)	1950 kV standard wave	2100 (-455 kV) across terminals	2100 kV standard wave
	2145 kV for chopped waves	2100 kV to ground	2310 kV chopped waves
SIWV (kV)	1550 kV	*1175 (-650) kV across terminals*	1550 kV
		1425 kV to ground	
AC voltage	850 kV (2 min) 750 kV (1 hour)	1150 kV across terminal	830 kV
		830 kV to ground	
Metal Oxide Surge Arresters (MOSA) main characteristics			
Protective levels	1620 kV (Steep front 1 μs, 20 kA) 1425 kV (Lighting surge 20 kA, 8 μs/20 μs) 1140 kV (Switching surge, 2 kA)		
Circuit breakers main characteristics			
First-pole-to-clear factor	1.3		
Amplitude factor	1.53 for T10 1.54 for T30	1.5 for T60 1.4 for T100	
DC time constant	75 ms		

2.4 Korea's project

2.4.1 Features of KEPCO 800 kV transmission system

Korea's electricity demand has been steadily expanding in line with an average economic growth rate of approximately 10%. The world's first double-circuit 765 kV transmission system was constructed in Korea in 2002 to transmit large-capacity energy generated at a remote seaside facility to urban areas. The maximum transmission capacity of this system is 14,500 MW (double circuits with 7,250 MW/circuit). The transmission towers, which are 100-150 m high, are equipped with special suspensions using 6×480 mm^2 conductors.

Fig.2.4.1 *KEPCO 765 kV transmission systems*

2.4.2 800kV GIS substation

A full 800 kV GIS with double bus and one and a half CB configuration (800 kV 50 kA, 8000A 2-break GCB) was installed to minimize the installation space as well as to assure safety and environmental friendliness. KEPCO will expand their 800 kV project to 8 circuits of 765 kV transmission lines, 12 circuits of 345 kV lines including 5 units of 2000 MVA transformers and 7 units of 200 MVA shunt reactor banks. The maximum power supply capacity will reach 10,000 MW at the final stage. 5 substations (21,110 MVA) have been operating since 2005. High speed grounding switches (HSGS) can secure multiphase reclosing of the 765 kV lines. [10]

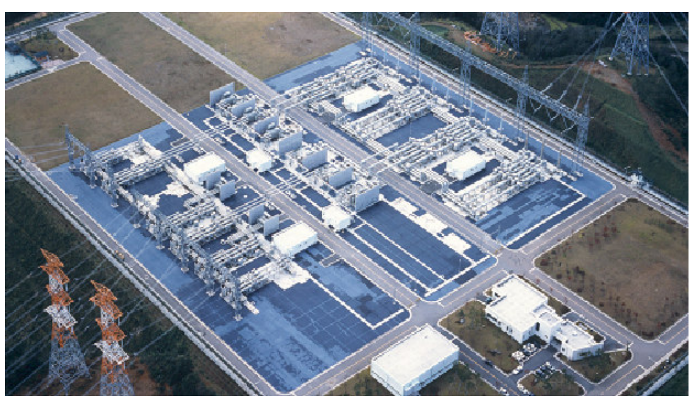


Fig.2.4.2 *KEPCO 800 kV GIS substation*

2.4.3 Insulation level

Power-frequency temporary overvoltage of the sound phase due to phase-to-ground fault or load rejection overvoltage was analysed using GCB equipped with closing resistors as shown in Table 2.4.1. Switching overvoltages are shown in Table 2.4.2.

***Table 2.4.1** Temporary overvoltage (1p.u.=$800/\sqrt{3}$ kV)*

Classification		Overvoltage P.U
Temporary overvoltage	Phase conductor (Bus, line)	1.2 (555 kV)
	Neutral point (Floating)	0.3 (139 kV)

***Table 2.4.2** Switching overvoltage (1p.u.=$800\sqrt{2}/\sqrt{3}$ kV)*

Location	Phenomena	Phase to ground	Phase to phase	Remark
Tower / line	Ground fault, Fault clearing, Energizing/Re-energizing,	1.9 (p.u.)	3.5 (p.u.)	Closing resistor 1000 ohm
Substation	Ground fault	1.6	2.3	Without closing resistor
	Fault clearing	1.7	2.9	
	Energizing/Re-energizing	1.8	3.5	
	Summary	1.8	3.5	
Neutral point of transformer	Single phase ground fault	0.3	–	

Lightning overvoltage was also analysed when flashovers occurred in the substation as well as at the first tower for outgoing transmission lines, as shown in Table 2.4.3.

***Table 2.4.3** Lightning overvoltage*

Equipment	Transformer	Switchgear/Bus	HSGS
Lightning overvoltage	1,710 kV peak	2,015 kV peak	2,025 kV peak

Air clearance between phase-to-ground and phase-to-phase of the 765 kV bus shall be in accordance with Table 2.4.4.

***Table 2.4.4** Air clearance of outdoor bus*

Highest voltage (kV)	Air clearance (mm)	Outdoor	
		Phase to phase	Phase to ground
800	Minimum	11,000 8,500	7,000 5,000

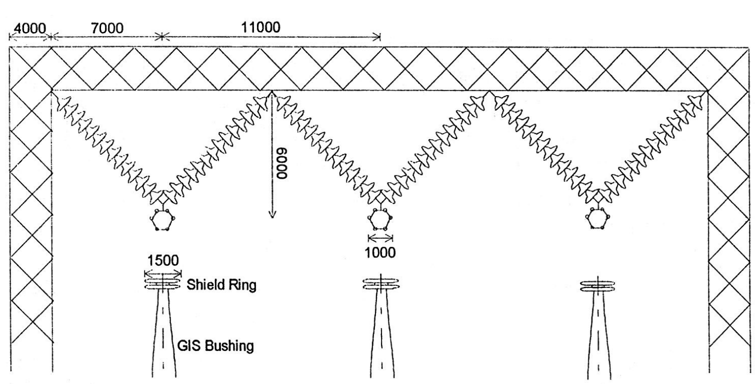


***Fig.2.4.3** KEPCO insulation distance of substation outgoing part*

Table 2.4.3 summarizes the KEPCO insulation level of 800 kV substation equipment.

Table 2.4.3 *KEPCO specifications*

Highest Voltage	**800kV**		
Items	**Transformers**	**CBs (GIS)**	**PT and CT**
LIWV (kV)	2050 kV standard wave	2250 kV across terminal	2250 kV standard wave
	2255 kV for chopped waves	2250 kV to ground	2250 kV chopped waves
SIWV (kV)	1500 kV	1100 kV across terminals	1425 kV
		1425 kV to ground	
AC voltage	800 kV (2 min) 690 kV (1 hour)	1100 kV across terminals	975 kV
		830 kV to ground	
Metal Oxide Surge Arresters (MOSA) main characteristics			
Protective levels	1500 kV (steep front 1/9 μs, 20 kA) 1400 kV (lighting surge 20 kA, 8 μs/20 μs) 1300 kV (switching surge 2 kA, 30/60 μs)		
Circuit breakers main characteristics			
First-pole-to-clear factor	1.3		
Amplitude factor	1.53 for T10 1.5 for T30	1.5 for T60 1.4 for T100	
DC time constant	45 ms		

2.4.4 Technical specifications of 765 kV power transformer

The main power transformer is a single-phase auto-transformer. Each single phase has two divided tanks with primary, secondary and tertiary windings for transportation.

Table 2.4.5 *Technical specifications for power transformers*

Transformer		
Rated voltage	765/√3 kV (Primary)	
	345/√3 kV (Secondary)	23 kV (Tertiary)
Rated capacity	2000MVA/3	
Lighting Impulse Voltage	2050 kV	
Switching Impulse Voltage	1500 kV	

2.4.5 800 kV Gas insulated switchgear

The 800 kV outdoor-type full GIS is composed of CB, DS, ES, HSGS, CT, PT, MOSA and Bushing, etc. The main bus is split into a three-phase separation tank with double bus. The 800 kV 50 kA dead-tank GCB with hydraulic operating mechanism has two interrupters in series per phase. The 800 kV disconnecting switch adopts a resistor-insertion scheme to suppress very fast transient overvoltage (VFTO). The dead-tank gapless-type MOSA is applied in accordance with Line Discharge Class 4.

Table 2.4.6 *Technical specifications for other equipment*

GIS	
Rated voltage	800 kV
Rated nominal current	8000 A (Line and Bus)
Lighting Impulse Voltage	2250 kV
Switching Impulse Voltage	1425 kV
Rated short withstand current	50 kA, 2s

2.5 Brazil's project

2.5.1 Features of Furnas' 800 kV transmission system

This section basically comprises two parts. The first part describes Brazil's experience with long-distance transmission systems (800 kV AC and ±600 kV DC), and also covers the problems and challenges encountered along with some aspects of related technical solutions from the perspective of planning and operating experience. The second part summarizes the trends and future technical challenges regarding the potential use and need of UHV transmission system technologies, such as for solutions associated with major hydro-plants foreseen for the Amazon region, requiring the transfer of huge amounts of power (6,000 to 10,000 MW) across distances as long as 3,000 km. [11]

Consequential impact on the existing network is also considered by pointing out the need to reinforce the receiving network, as well as to investigate procedures for limiting short-circuit current levels that exceed existing equipment withstand ratings. These new challenges may also require a thorough review of IEC standards due to special UHV equipment requirements.

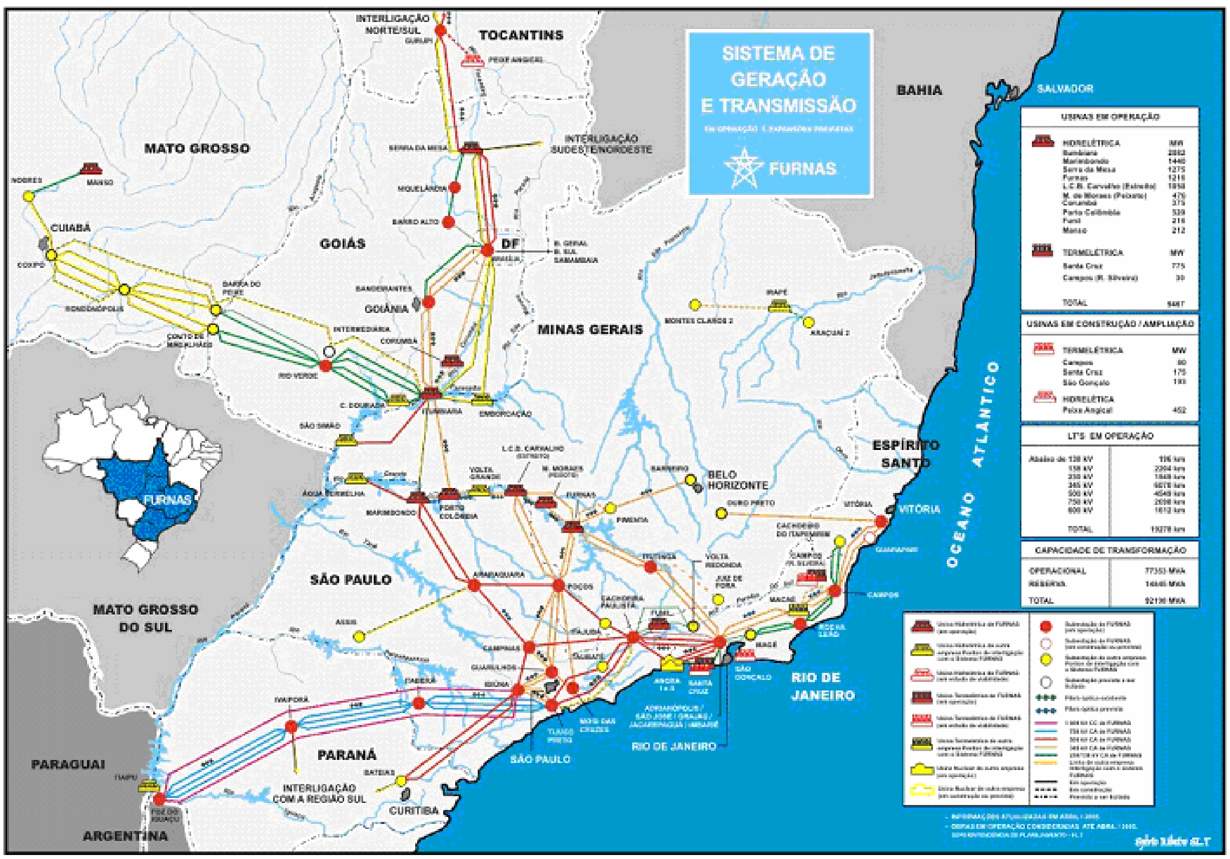


Fig.2.5.1 *FURNAS main assets*

Furnas Bulk Generation and Transmission Company is a Brazilian federal government utility. Furnas is responsible for supplying electric energy to distribution companies, mostly in southeastern and central western Brazil, who in turn supply electricity to 8 states and the Federal District. This region has a population of 90 million people and generates 65% of Brazil's GDP and 55% of the nation's total electric energy consumption. Furnas plays another important role by providing the main interconnections between the southeastern region (the most developed region of the country) and other regional grids, such as the southern regional transmission grid and the northern and northeastern regional grids.

GENERATION: Furnas' present bulk generation assets total about 10 GW of installed power capacity, of which about 9,000 MW is available from 11 hydro power plants and 1,000 MW from 2 thermal power plants. Furnas is presently constructing 6 new hydro power plants at the same time, adding about 1700 MW of installed power capacity. For comparison purposes, the growth of Brazil's total power system load, on average, demands an increase of about 4,000 MW annually in order to cope with the load increase.

TRANSMISSION: The bulk transmission assets of the company total 20,000 km of transmission lines, from the voltage level of 138 kV up to 800 kV, interconnecting 44 substations, where the company has a total rated power transformer capacity of 95 GVA. The transmission lines, and related power equipment operate at rated voltage levels of 138, 230, 345, 500 and 800 kV AC, and ±600 kV DC.

2.5.2 Overview of field experience of 800 kV long distance transmission lines

Bulk electric power supply is typically provided by long EHV transmission lines belonging to the national transmission grid, not only for the purpose of connecting huge-capacity hydroelectric power plants to the main load centres, but also to interconnect power systems of different regions, and from distinct geographical areas. The vast expanse of Brazil means that several transmission lines and substations of 550 kV up to 800 kV had to be built shortly after these voltage levels were introduced in other parts of the world, due to the long distances between the load centres and major generation power plants.

The Itaipu Hydroelectric Power Plant was built on the Paraná River, at the border between Brazil and Paraguay and belongs to the company 'Itaipu Binacional'. The power plant has 20 generating units of 700 MW each, resulting in 14,000 MW of installed power capacity, which enables the production of around 100 TWh of energy per year. As the nominal power frequency differs between the two countries, the frequency for Brazil's generating units is 60 Hz, while that for Paraguay's is 50 Hz. However, Brazil has contracted to buy all of the 50 Hz energy, except for that consumed by Paraguay, which means that 75% of the 50 Hz energy, on average, was consumed by Brazilians last year.

Furnas Centrais Elétricas was responsible for developing the transmission solution for integrating Itaipu Power Plant's generation into Brazil's national transmission network. The company conducted the planning studies, equipment specification, factory and laboratory tests, on-site construction, commissioning tests. Thus, Furnas started operation of the 800 kV AC and ±600 kV DC systems in 1982 and 1984, respectively, integrating the Itaipu Power Plant generation into the national network.

The accumulation of knowledge and experience related to UHV transmission issues started with the initial investigation and planning studies on a system associated with the Itaipu Power Plant, which consisted of an 800 kV AC five-line transmission corridor.

After the Paraguay government's decision to retain its network nominal frequency at 50 Hz instead of accepting Brazil's offer to convert the entire network to 60 Hz, it became necessary to review those first investigation studies in order to define a hybrid transmission system of 3 × 800 kV AC transmission lines and 2 bipole ±600 kV DC transmission system.

The planned hybrid UHV AC/DC transmission system, shown in Fig. 2.5.2, is one of the most important systems in the western world due to its nominal voltage levels, rated power capacity and significance in Brazil's electric industry. It not only uses some of the highest voltage levels in commercial operation worldwide, but it also has some of the highest capacity of transmitted power (rated at 12,600 MW) over long distances (about 1,000 km).

2.5.3 Evolution of Furnas's 800 kV AC Transmission Systems

The HVAC transmission system interconnects the Foz do Iguaçu Substation (near the Itaipu Power Plant) to the Tijuco Preto Substation in the São Paulo area, one of the main load centres of Brazil's electrical network. The Foz do Iguaçu Substation contains both the UHV 800 kV AC switchyard and the ±600 kV DC converter substation (rectifier side). Together, they form one of the largest substations in operation, in terms of power and size.

Fig.2.5.2 *Foz do Iguaçu substation contains both the HVAC switchyard for three 800kV circuits and the HVDC converter substation equipment/switchyard (HVDC link rectifier side)*

The three 800 KV AC circuits, each about 895 km long, as shown in Fig. 2.5.3, are able to transmit to the Brazilian interconnected network the rated generated power from the 10 generating units at the Itaipu Power Plant, operating at a nominal frequency of 60 Hz. The planning criteria of such a transmission system considered the possibility of dispatching this amount of power even in an "n-1" element outage configuration. This 800 kV AC system is also responsible for energy interchange between the southern and southeastern geographic regions of Brazil's interconnected national grid (refer to Fig. 2.5.4).

The electrical requirements for the 800 kV AC equipment were defined in the late 1970s and early 1980s. At the time, Brazil's network consisted of several weakly connected subnetworks. Although each subnetwork could be considered as solidly grounded, the network as a whole could not. Furthermore, the 800 kV network would not be a meshed network but instead a radial one consisting of 3 parallel circuits. Thus, in consideration of the new and unfamiliar voltage levels, the planning engineers at that time decided to adopt conservative requirements for the equipment, derived from system simulations under severe operation and emergency conditions.

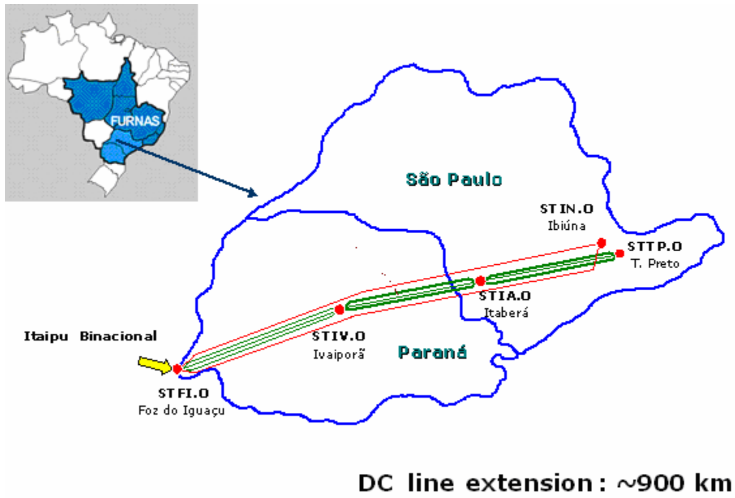


Figure 2.5.3 *General overview of the Furnas transmission system for integrating the Itaipu Power Plant into Brazil's national electrical network*

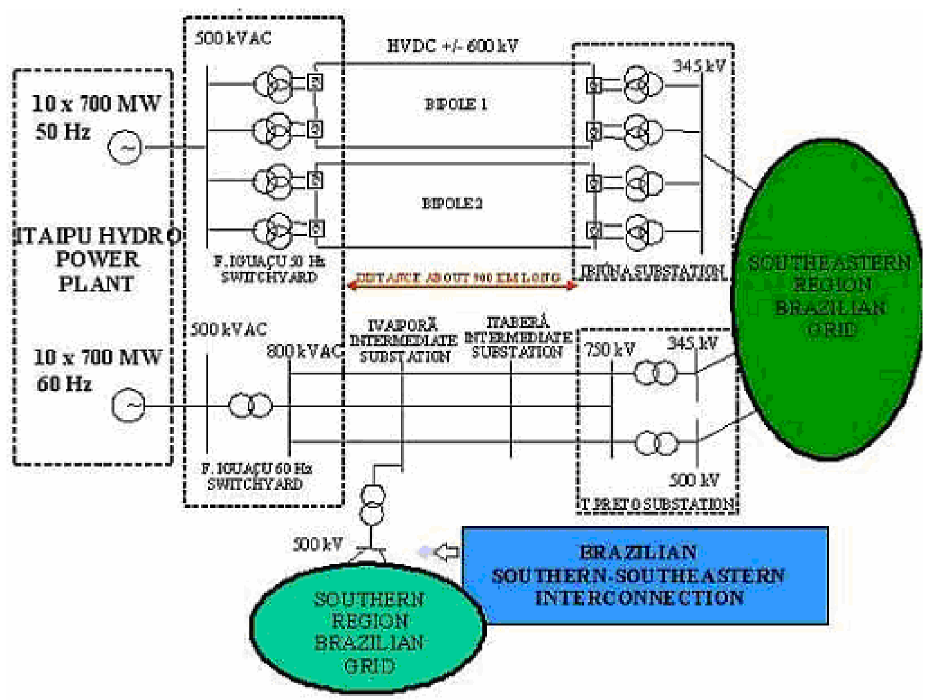


Fig.2.5.4 *Detailed view of the Furnas transmission system for integrating the Itaipu Power Plant into Brazil's national electrical network*

In the mid-1980s, the full power of the Itaipu Power Plant corresponded to more than 35% of the total installed power in Brazil's power network (today, it corresponds to less than 14%, even considering the expansion of the Itaipu Power Plant from 12,600 to 14,000 MW). In the initial stages of the Itaipu Power Plant operation, during the light load period in the late 1980s, its generated power corresponded to more than 50% of the dispatched power in Brazil's interconnected network.

Therefore, in this context, the Itaipu transmission system was of major importance to Brazil's electric bulk network. Its design had to take into consideration, on one hand, Brazil's first-time use of such high voltage levels, equipment rated power and all related technological aspects and, on the other hand, the absolute necessity to assure that the equipment withstand levels would cope with the system requirements, as reliably as possible.

The shunt reactors (fixed at line-ends and switchable at busbars and transformer tertiary), series capacitors and synchronous condensers provide, respectively, transient switching overvoltages mitigation (fixed SR at line-ends), voltage regulation (switchable SR at busbars and transformer tertiary) and system dynamic stability (series capacitors and synchronous condensers).

2.5.3.1 Application philosophy for 800 kV Shunt reactor (SR)

Furnas use SRs in system transmission OH lines for two main purposes: (a) switchable SRs at busbars or tertiary windings of power transformers for steady-state voltage control issues; and (b) fixed SRs at OH line ends to deal with switching transient overvoltage requirements related to line closing and/or opening operation (including fast auto-reclosing). Therefore, the same philosophy is followed for the SRs installed in this 800 kV transmission system, giving 70% shunt compensation for line charging. Figure 2.5.5 shows the existing SR application philosophy installed in such transmission system.

For transient switching overvoltage mitigation, fixed SRs have the aid of arresters installed at the line ends. Over the last 30 years, two very distinct functions relied on such duty, depending on the evolution of technology and materials applied by arrester manufacturers: when the only arresters used were those with active gaps and nonlinear resistance made of silicon carbonate (SiC), the first arrester that sparked its active gaps was the only one responsible for draining all the surge energy as well as controlling the switching overvoltage in conjunction with the fixed SR at the line end.

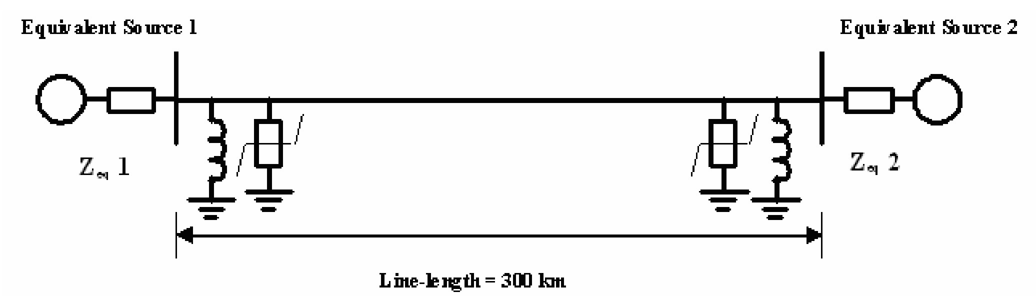


Fig.2.5.5 *Fixed shunt reactor application for transient switching overvoltage mitigation on OH line*

Regarding gapless MOSAs, those installed to protect SRs against lightning impulses could also be used in conjugation with MOAs installed at the OH line ends. Thus, by using this set of surge arresters (not only the ones installed at the OH line ends, but also those protecting the fixed SR against lightning surges), control of switching transient overvoltage as well as draining of switching surge energy, could be achieved more efficiently and reliably, thus helping with mitigation/control of TOV as mentioned.

For switchable SRs, used to mitigate/control switching transient overvoltage generated when switching off the SR, it is now possible to use CBs equipped with opening resistors or controlled switching. In the case of using CBs equipped with opening resistors, for optimal transient switching overvoltage control, the ohmic value in each phase should be of the same magnitude as the characteristic impedance of the SR (surge impedance). At the 800 kV level, the normal range of surge impedance values for SRs is 2.000 to 4.000 ohms.

In the 1980s, the 800 kV switchable SRs in the Furnas transmission system had CBs equipped with opening resistors for transient switching overvoltage mitigation, as defined at the planning and design stages, developed in the late 1970s and early 1980s. The design criterion for dimensioning the CB opening resistors was to use the same ohmic value range for SR surge impedance, meaning it was necessary to provide CBs with opening resistors in the range of 3.000 ohms. In this case, there was no control over the arcing time of the SR current in the CB chambers during switching off procedures. Consequently, this could lead to reignition within the CB chambers when the arcing time was too small, causing a new overvoltage with very high front steepness.

During the first decade of switchable SR operation, this phenomenon caused some major damage to SRs and related CBs, even leading to the explosion of a switchable SR CB at the Itaberá Substation. After this accident, the Furnas decided to replace the CBs equipped with opening resistors with controlled switching. The controlled switching technology demonstrated very good performance in mitigating transient switching overvoltage, completely avoiding possible reignition during the switching off procedures. Extensive field tests/measurements confirmed the expected performance during several switching off operations of the existing 800 kV busbar SR. On the other hand, the longer arcing times, provided by the CB equipped with a controlled switching device, would lead to more prominent ‘current chopping’ overvoltage that should be investigated, in principle, as a significant concern, in order to avoid undesirable damage to SRs, or even to CBs.

This transient phenomenon is related to the fact that, during SR switching off, the nominal current is suddenly forced to zero prior to the natural power-frequency-zero-crossing within the CB chambers, leading to the phenomenon known as ‘current chopping’. Thus, current chopping, meaning a sudden change to zero at the magnitude of the SR nominal current, forces the ‘magnetic field’ energy stored in the reactor coil to be converted to ‘electric field’ energy stored within the stray capacitance, thereby causing a sudden change in the load-side transient voltage. This energy transfer phenomenon is known as ‘chopping overvoltage’. The lower the stray capacitance is, the higher the chopping overvoltage will be during the occurrence of the current chopping.

However, the field experience of Furnas showed that it was much more reliable and secure to have complete control over avoiding reignition during SR switching off, by means of using CBs equipped with controlled switching, compared to the increase in current chopping overvoltage. In the case of 800 kV switchable SRs, the increase in chopping overvoltage, derived from the increase in minimum arcing time (given by CBs with controlled switching), is very small, due to the fact that the stray capacitance of the SR windings is quite significant.

2.5.3.2 Application philosophy for 800 kV Series Capacitor (SC)

800 kV series capacitors (SCs) provide system dynamic stability when dispatching huge amounts of power through the 800 kV transmission system from the Itaipu Power Plant and/or high interchange between the two interconnected regional grids. The existing SCs were designed to offer compensation of 40 to 50% related to the OH line longitudinal inductive reactance, depending on the location in the 800 kV transmission system. Under these dispatch conditions,

the voltage profile along the transmission system must be as close as possible to the maximum continuous operating voltage level (at nominal frequency), or 800 kV rms between phases.

The SCs were intended to operate with two series segments, each segment corresponding to 20 or 25% of the longitudinal reactance of the transmission lines. SC segments can operate together or separate from each other, thus increasing the reliability of the SCs themselves and of the 800 kV transmission systems as a whole. The maximum operative voltage level (800 kV rms between phases) of this transmission system is measured right after the SC (at the line side) in the Ivaiporã and Itaberá substations, since a sudden increase in voltage profile occurs in the presence of the capacitive reactance in series with the line inductive longitudinal reactance. (refer to Fig. 2.5.6)

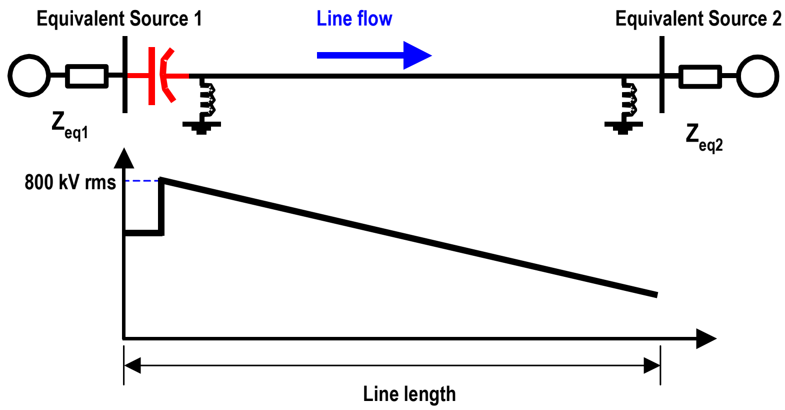


Fig.2.5.6 *Voltage profile caused by Series-Capacitor placed in an OH line*

During the planning stages, SCs having capacitive reactance to compensate for part of the line inductance, should be designed in such a way that some main technical and economic requirements regarding the SC equipment itself could be achieved: (a) SC self-overvoltage-protection devices (in the presence of short circuits); (b) protection coordination of parallel lines with series-capacitor compensation; and (c) sub-synchronous resonance.

In the presence of SCs connected to the transmission lines, as they compensate the line inductive reactance, short-circuit currents tend to increase (due to the lower values of short-circuit equivalent impedance of the system), and transient overvoltage caused by short circuit flowing through the SCs also tends to be greater. In order to control such short-circuit currents as well as transient overvoltage during the flow of short-circuit currents in the compensated lines, SCs have a ‘self-overvoltage-protection device’, as shown in schematic detail in Fig. 2.5.7.

Regarding the transmission line voltage profile, the higher the short-circuit current flowing through the SC, the greater the rise in transient voltage at the SC terminal. The design of such self-overvoltage-protection device level is driven mostly by economic reasons regarding insulation withstand requirement costs. Thus, the nonlinear varistor and gap-protection-circuit operate whenever necessary, bypassing the SC, in order to keep the transient overvoltage values within the designed withstand levels of the SC components.

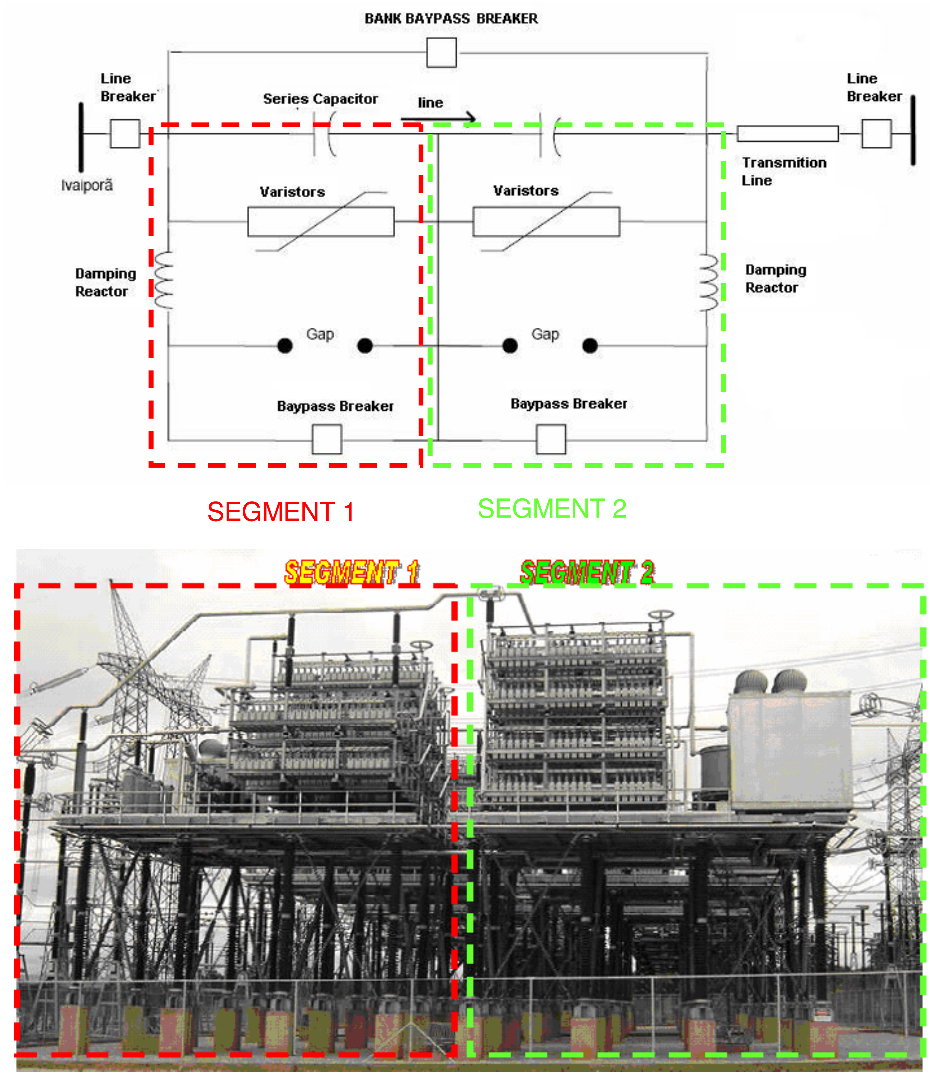


***Fig.2.5.7** (a) (b) Detailed view of the 800 kV AC series-capacitor at Itaberá Substation*

The main role of the varistor is to operate as an electronic switch, bypassing the SC while short-circuit current flows through it. The purpose of the parallel gap and the SC-segment-bypass breaker is to protect the varistor when draining high amounts of energy during severe transient overvoltage in the presence of larger short-circuit currents.

In addition to this self-overvoltage-protection scheme, the main conventional protection features of the SC are as follows:

- Gap operation
- Platform failure
- Current imbalance (alarm or activation of SC bypass)
- Fibber optics failure
- Bypass breaker failure
- SC bank overload

- Air-compressed central failure (the gap operates with air-compressed blast, provided by a dedicated central SC)

Protection coordination of parallel lines with series-capacitor compensation, also an issue of significant concern, has to do with the distribution of short-circuit current among parallel circuits, which may cause undesirable protection operation of such parallel (and not faulted) lines. This may happen due to overvoltage protection or SC bypass malfunction.

'Sub-synchronous resonance' may occur when thermal turbines are in close electrical proximity to series-compensated line. Depending on the compensation degree provided by the SCs, they might activate a natural oscillation mode having typical values of resonance frequency below the rated power frequency in conjunction with line inductance. Normally, thermal turbines also have mechanical natural oscillation modes in that frequency range, thus possibly leading to sub-synchronous resonance.

2.5.3.3 Other notable aspects of 800 kV transmission system

Figure 2.5.8 shows the 800 kV line-phase transposition design criterion.

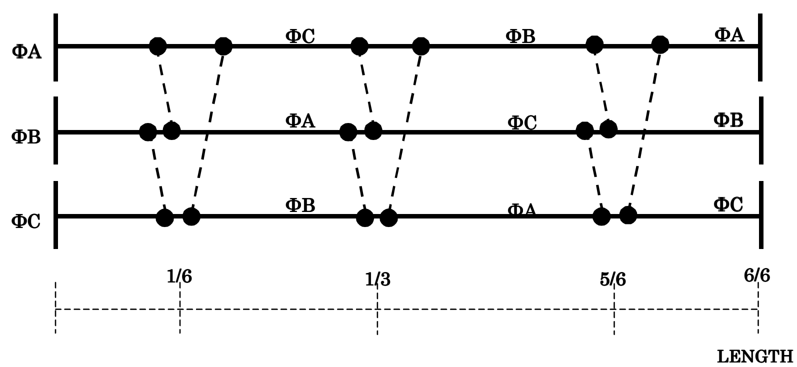


Fig.2.5.8 *800 kV line phase transposition criterion*

Regarding fast auto-reclosing of the Itaipu 800 kV transmission system, the main related data is that only 3-phase fast auto-reclosing is in operation. Dead time is 600 ms for all line segments (all 3 circuits: Foz do Iguaçu – Ivaiporã; Ivaiporã – Itaberá and Itaberá – Tijuco Preto). The leader terminal for auto-reclosing is Ivaiporã for all lines between Foz do Iguaçu / Ivaiporã substations, and Itaberá for all lines between Ivaiporã / Itaberá and Itaberá / Tijuco Preto substations. The determination of leader terminal is related to the minimum power-accelerating impact in hydro generators at the Itaipu Power Plant and other hydroelectric plants located in the southern regional grid (refer to Fig. 2.5.9).

For equipment requirements, the 800 kV transmission system should take into consideration the worst possible conditions regarding switching transients. Thus, it was decided at the beginning of the design stage to take into account, for instance, the criteria for switching transients derived from total 'opposition-of-phase' - OP (i.e., 180 instead of 120°, foreseen in international standards at that time). This was considered reasonable, since the 800 kV AC system would be, in practical terms, not only connecting the Itaipu Power Plant to Brazil's interconnected grid, but also acting as the main interconnection tie between Brazil's southern and southeastern regional transmission grids, the two major subsystems of the country at that time. Before the Itaipu transmission system existed, the two regional transmission grids were weakly interconnected with only a few tie-lines at voltage levels of 88, 138 and 230 kV at the border between the state of São Paulo (southern border of the southeastern regional grid) and the state of Paraná (northern border of the southern regional grid).

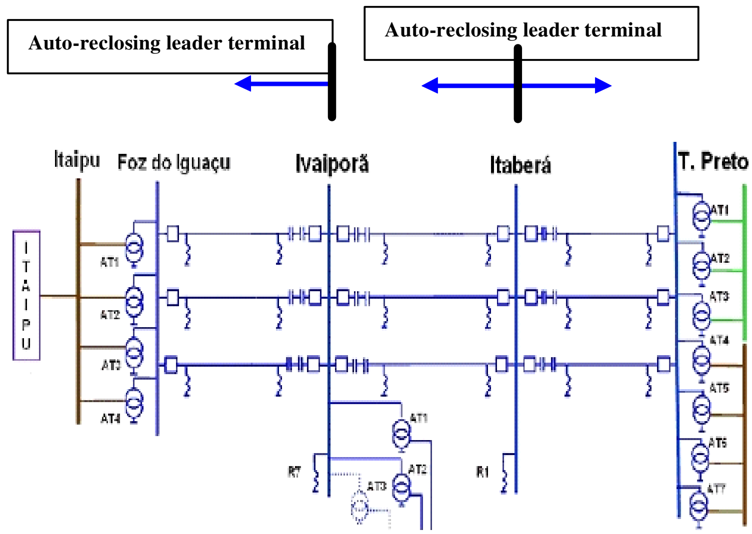


Fig.2.5.9 *Auto-reclosing terminal*

Considering the same reason for the choice of OP, a value of 2.0 was adopted for the out-of-phase factor for all TRV parameters. The reason for the use of an amplitude factor of 1.64 for Uc of TRV, instead of 1.25 as stipulated by IEC, is the adopted 'grounding criteria.' Although each regional grid could be considered as solidly grounded, the 800 kV system as a whole could not, as it was radial and not a meshed network like the two regional grids interconnected by means of this AC transmission link.

Following this idea of adopting conservative criteria for defining the equipment withstand requirements, derived from system simulations under severe operation and emergency conditions, it was also found necessary to define other requirements based on strict premises, such as the maximum over-speed during total load rejection in the 800 kV AC system as 1.1 of nominal frequency (66 Hz), instead of adopting the standardized value of 1.05 fn (63 Hz). This strict over-speed criteria was used to verify the possibility of self-excitation regarding the Itaipu generators, and also to define the withstand requirements of switching equipment due to overvoltage transients caused by full load rejection.

Finally, as other example, the value of 800 kV was defined as the 'maximum operating voltage' for the Itaipu transmission system, which means only 1.045 p.u. of the nominal operating voltage (765 kV). In all other voltage levels in Brazil's power system, the maximum operating voltage (non-continuous operating voltage limit, for emergency operating conditions) is 1.10 p.u. of the rated or nominal voltage value (138/152 kV; 230/253 kV; 345/380 kV; 440/484 kV; 500/550 kV).

2.5.4 Notable aspects of the ± 600 kV DC Transmission System

The HVDC transmission system consists of two ±600 kV AC bipoles, each about 900 km long, one AC/DC rectifier side at the Foz do Iguaçu Substation and one DC/AC inverter side at the Ibiúna Substation, located very close to São Paulo city, as shown in Fig. 2.5.10.

The system is rated to transmit 6.300 MW from the power produced by the 10 other 50 Hz generating units owned by the Paraguayan side of the bi-national Itaipu Power Plant. In order to increase Brazil's know-how on HVDC transmission, being used for the first time in the country, the following constraints were established: Services, equipment and products should be nationalized; Brazilian enterprises/engineers should take part in the planning, designing, building and operation of the HVDC transmission system; and technology transfer through "on-the-job training" should be practised.

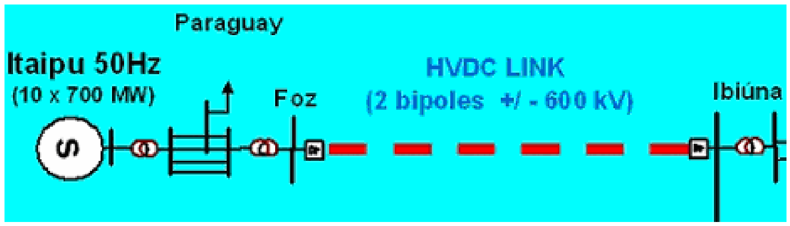


Fig.2.5.10 *± 600 KV DC transmission corridor subsystem*

The main characteristics of the ±600 kV DC transmission system are as follows:

- Two substations: Foz do Iguaçu (rectifier side) and Ibiúna (inverter side);
- Nominal power: 6,300 MW;
- Nominal voltage: ±600 kV (DC);
- Nominal current: 2,625 A (DC);
- Two bipoles (±600 kV);
- Each bipole composed of two poles;
- Each pole composed of two 300 kV series-connected converters.

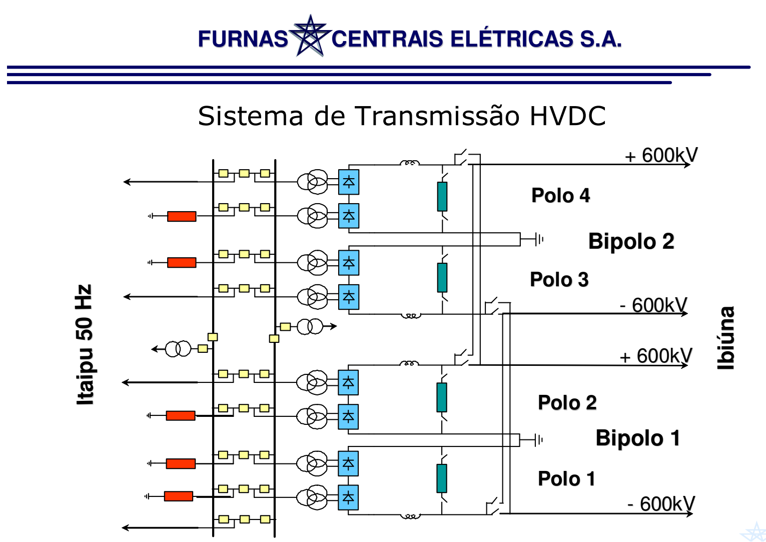


Fig. 2.5.11 *FURNAS +/-600 kV HV DC main features (AC in-feed lines, rectier AC busbar, converter transformers, AC filters, 12-pulse valves, DC lines)*

2.5.5 Specific issues and technical challenges for the operation of Furnas' long transmission systems

It is important to point out that, at that time, there were no existing IEC standards for such a huge HVDC transmission system. In this sense, from the perspective of planning and operating experience, some of the aspects and problems related to the hybrid HVAC and HVDC features and equipment required thorough investigation right from the start. For new long-distance transmission systems, some important features and concerns related to equipment withstand requirements should also be thoroughly investigated, such as:

A. Comparison between ‘equivalent’ solutions for HVAC and HVDC systems and between ‘equivalent’ GIS and AIS equipment, in terms of engineering and economics issues (considering environmental and regulatory issues);

B. Characteristics of HVDC system facilities, such as the so-called ‘dynamic performance feature’ (concerning the impact on AC systems connected to the converter substations, both ‘rectifier’ and ‘inverter’ HVDC system sides, in terms of mitigation/elimination of dynamic electromechanical transients/oscillations); HVDC transmission system ‘forced isolation protection scheme’ (implemented to protect against electrical transients derived from partial or total load shedding); ‘high MVar consumption’ operating mode; ‘automatic fast switching’ from one faulted DC line to another under unrecoverable short-circuit conditions in the first line;

C. Specification of HVDC reliability features (ability of the system to transmit the rated power under contingency conditions and outages) including operation mode (bipolar/monopolar) and related engineering and environmental issues; temporary overloading/overcurrent capacity; AC system faults/configurations that may create commutation failures mainly at the inverter station;

D. Importance/advantages of analogue/digital simulation facilities for HVDC/HVAC transmission systems (necessity/usefulness of simulation tools for HVDC transmission systems in terms of planning/specification/operational optimization and economics);

E. DC switchyard bushing isolation problems and implemented mitigation solutions;

F. Issues related to filtering requirements (short-circuit level criteria, filter overloading, use of “active filters” since they are not a sink for harmonics other than their own, which can be decisive in filtering performance, etc);

G. HVAC shunt and series compensation devices (and the related inherent aspects in terms of voltage profile control, overvoltage transients and protection issues);

H. Importance of defining equipment withstand requirements in the planning phase, taking into account the possible/foreseen evolution/expansion of the AC grid/network (upgrading in short-circuit level requirements);

I. Enterprise staging definition, i.e., intermediate stages of transmitting power capacity considering cost constraints, necessity of scaling the power transmission, time interval between stages, etc. (series connection of converter groups per pole easily allows the staging of 25, 50, 75 and 100% of the total rated power);

J. Oil chemistry issues related to HVDC converter transformers;

K. Possibility of controlled switching usage.

2.5.6 Future challenges regarding UHV transmission in Brazil

Stepping into the future and trying to foresee the possible needs, trends and challenges related to the use of UHV transmission in Brazil, [12] we have, on one hand, 180 GW corresponding to the unused portion of Brazil’s hydroelectric potential. According to official estimates, a high percentage (around 70%) is located in the Amazon region. On the other hand, the consumption of energy is spread throughout the country according to the following geographical distribution:

- Isolated systems in Amazon region (2% of consumption)
- Interconnected system in north/northeast (19% of consumption)
- Interconnected system in south/southeast/central-west (79% of consumption)

In terms of growth, it is reasonable to say that Brazil will have to transport huge amounts of energy produced mainly in the Amazon region to the main load centres of the country, covering distances of more than 2,500 km, as shown in Fig. 2.5.12. Under such circumstances, the use of UHV transmission systems (DC links and/or AC overhead lines) appears to be a competitive and suitable alternative, both economically and environmentally. In this case, it would not be necessary to change the frequency from the rectifier AC side to the inverter AC side, since it is simply a matter of a set of issues: stability, loss reduction, compactness, environmental friendliness and transmission cost over the long distance from the power plants in the Amazon to the main load centres.

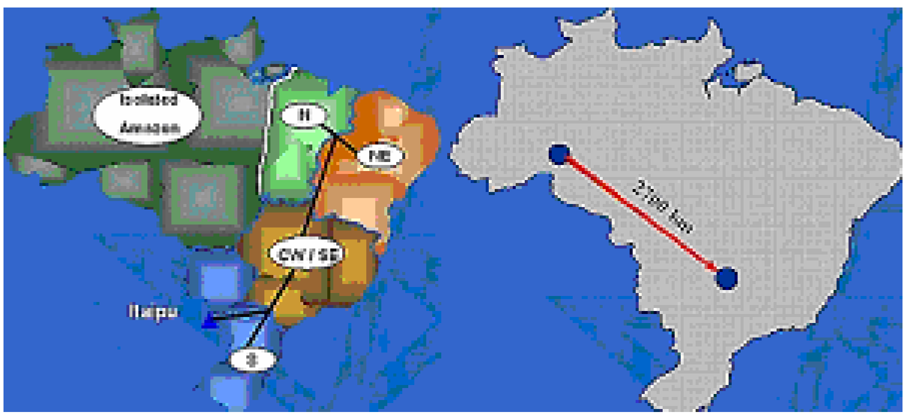


Figure 2.5.12 *Geographical distribution of load centres in Brazil (left) and average distance between the main load centres and future Madeira river complex (right)*

The Amazon region has abundant water resources in quite a plain geographic area without waterfalls, and the rivers are huge with sustained water flow. Thus, generation of electricity can be obtained by water flow rather than by potential energy. In order to minimize the environmental and social impact, preliminary prospective studies of the region suggest the construction of hydroelectric power plant dams with very low height.

The next project in the Amazon region, under consideration by the Brazilian federal government, is the *'Madeira River Project'*. It consists of a business complex including two hydroelectric power plants on the Madeira River: 'Santo Antonio' near Porto Velho city, the capital of the state of Rondônia, and 'Jirau' near the border between Brazil and Bolivia, both businesses bringing a total installed power of 6,450 MW. The complexity inherent to the project requires considerable effort on the part of the government to obtain the environmental licenses needed to start the installation process. According to Brazil's regulatory rules for the electric sector, the business owners, who will be responsible for the construction and operation of the hydroelectric power plants, as well as for the transmission system regarding the plants' integration into the national electrical network, will be defined by public bidding. This procedure will be announced in the near future by the Brazilian Regulatory Agency for the electric sector - ANEEL. [13] Furthermore, the long distances to be covered and access difficulties to resolve bring challenges to new transmission corridors in the Amazon region, concerning equipment size, logistics and transportation.

The following topics must be analysed in detail in order to establish the reference UHV transmission alternatives (DC, AC or hybrid transmission systems):

- Line configuration /insulation/ clearances;
- Corona and field effects line performance;
- Level of power to be transmitted;
- Weight and size of equipment for shipping and transport (mainly the transformers);
- Power loss;
- Spare parts;
- Series connection of converter groups per pole (DC alternative);
- Overload /stability requirements;
- Need for reinforcing the receiving network;
- Need for investigating procedures for limitation of short-circuit current levels exceeding existing equipment ratings.

Despite Brazil's experience with hybrid parallel AC 800 kV and DC ±600 kV systems, the country faces huge challenges related to the foreseen Amazon transmission system requirements, and depending on the outcome of the UHV transmission alternative references, the existing IEC standards may not cover all of the equipment special withstand requirements. This would lead to the necessity of developing new specification standards possibly concerning planning and design.

2.5.7 Summary

Brazil's electric power is mainly supplied through long EHV transmission lines. Consequently, the building knowledge and experience on long-distance transmission systems were accumulated. The initial investigation studies for integration of the Itaipu Power Plant into the national interconnected grid took part in this role as well. The Itaipu transmission system, planned, built and operated by Furnas, is one of the most important in the western world due to its nominal voltage levels, rated power capacity and significance in Brazil's electric industry. It is important to point out that, at the time, there were no existing IEC standards covering all necessary technical-related aspects for such a huge long-distance transmission system, particularly for the HVDC link.

Around 70% of Brazil's unused hydroelectric potential is located in the Amazon region, while the consumption of energy is spread throughout the country, mostly near the shores. Thus, it will be necessary in the near future to transport huge amounts of energy covering distances of more than 2,500 km. Due to the huge challenges related to the Amazon transmission system requirements, the existing IEC standards may require a review of equipment withstand requirements, leading to the necessity of developing new standards/specifications related to UHV concerns.

To meet these challenges, several Brazilian scientific organizations, universities and utilities are preparing themselves by means of studying new technologies and developing know-how.

2.6 Italy's project

2.6.1 Features of Italy's 1000kV transmission system

The fundamental features of the 1000 kV system were identified assuming that this future network would have to connect three or four new, powerful generating centres of the order of 4000 MW each, to the main load areas located at a distance of about 200-250 km.

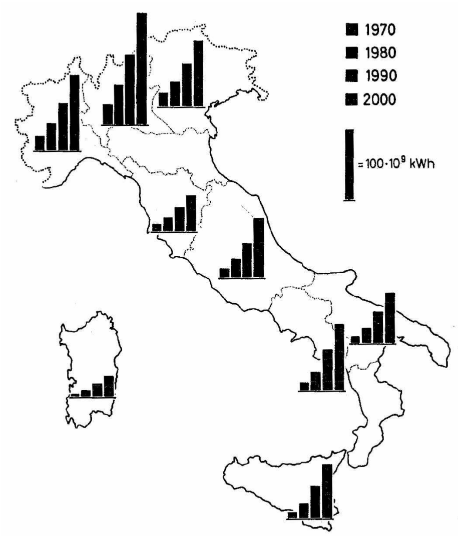


Fig. 2.6.1 Assumed energy demand trend in Italy

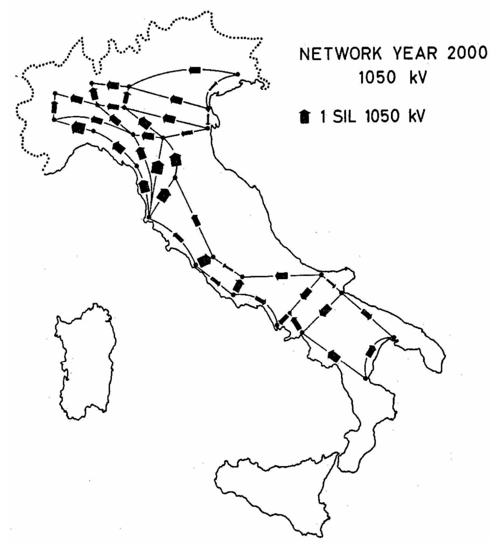


Fig. 2.6.2 Assumed energy demand network

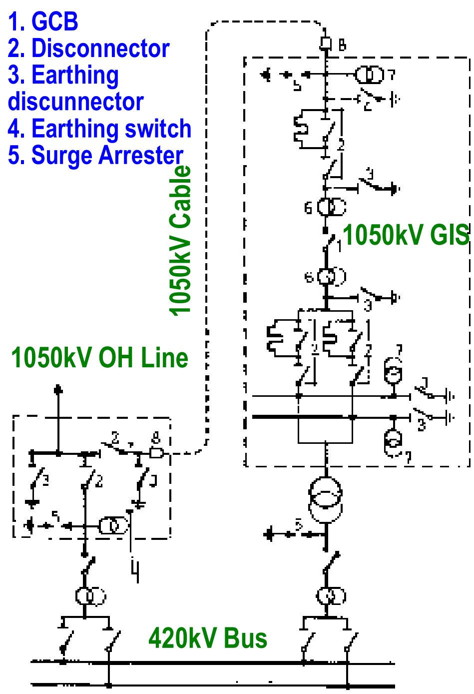
The basic rationale for this scenario stems from Italy's robust growth in demand for electric energy experienced at the end of the 1960s. At that time, electricity consumption showed a trend of doubling every ten years, as seen in Fig. 2.6.1. This need was previously met by introducing larger generating plants and periodic (about every 20 years) increases in network voltage levels (145-245-420 kV). The new 1000 kV level is considered appropriate to keep the amount of land occupied by overhead lines within acceptable limits and for dealing economically with the increasing need for power transmission.

Investigations were conducted on connections from the Po River estuary to the Milan load area; from the coast between Tuscany and Lazio to the Roma load area; and from Puglia to Naples. In all cases, the use of two lines at 1000 kV, having SIL (surge impedance loading) of about 4000 MW (doubled in emergency conditions), was confirmed as being an economic and reliable solution (Fig. 2.6.2).

These 1000 kV lines were considered mainly for the connection of large power plants; thus, sufficiently high short-circuit power would be ensured and power flow essentially directed one way from the generation facility to the load centre. This configuration is favorable for voltage profile control by generators/switchable Var compensation devices and line energization without the need for enhanced Var compensation equipment such as FACTS devices.

Furthermore, since Italy's existing EHV transmission grid was highly meshed, the connection of a large-capacity link at 1000 kV did not require large network reinforcements in the underlying voltage levels (400 and 220 kV) that would warrant security conditions, such as those stipulated in the UCTE (Union for the Coordination of Transmission of Electricity in continental Europe, see www.ucte.org) rules.

The feedback from three years of operating the 1000 kV pilot plant (Fig. 2.6.3) was considered very positive, even though application of this technology across Italy was put on hold due to changing conditions in the electricity sector, i.e. much lower demand growth compared to what was foreseen in the 1970s; new generation technology such as CCGT (combined cycle gas turbine) was based on mid-size plants scattered throughout the country instead of on large power plants. However, the practical experience gained from operating a 1000 kV UHV line, substation and associated cable connection provides an important reference for future wider applications of AC UHV corridors. An extensive presentation of the outcome of Italy's 1000 kV project was recently presented in [14].



Fig, 2.6.3 *1050 kV Pilot Plant configuration*

2.6.2 Overviews of field experiences of the projects

Extensive commissioning tests on the GIS substation were performed in 1994 and in early 1995. During tests to prove the adequacy of the mounting, and during commissioning of the installation, the following problems were encountered and subsequently solved:

- Solid particles inside the enclosure were revealed by partial discharge measurement using the acoustic method; the subject compartments were cleaned and from then on they maintained satisfactory performance;
- Oil leakage due to the lack of sealing from a case door bolt washer that had thermally aged due to the eddy current circulating in the case frame;
- One discharge occurred on an inner insulator and on an operating rod of the circuit breaker units. Subsequent analysis revealed the need to reduce the voltage stress on the rods and modify the quality assurance procedures adopted by the manufacturer of the

circuit breaker for acceptance of the rods.

During service, two minor failures were recorded in the cooling system for the cable and the autotransformer, respectively, and in the LV/MV supply system.

An additional cause of interruption was a scheduled out-of-service due to maintenance on high-voltage equipment and auxiliary systems, or following a request from the Regional Dispatching Centre, when the EHV at the Suvereto substation exceeded 420 kV to avoid a situation in which the additional Var contribution of the UHV would cause excessive steady-state voltage values at the 400 kV level.

The above incidents revealed, in hindsight, the following:

- GIS: More attention should be paid to compartment cleaning during on-site assembly;
- Autotransformers: Major attention should be paid to tightening and transportation aspects and to ensuring good local electrical conductivity in order to avoid high eddy-current density.

2.6.3 Specific issues and technical challenges for the operation of projects

Due to the unusual electrical, mechanical and environmental constraints related to this UHV level, the following aspects have undergone exhaustive study in the development of Italy's 1000 kV project, as they required an original non-standard attitude in providing the most suitable solution from a technical, economical and environmental point of view:

- Control of overvoltage;
- Performance of air and surface insulation;
- Electric fields on conductors and accessories and related effects (corona loss, audible noise, radio interference);
- Effects of the electric field at ground and that of wind and ice on bundled conductors (vibration, sub-span galloping);
- Mechanical and electrical behaviour of conductors and accessories in the event of short circuit
- Necessity to limit the extension of rights-of-way and the visual impact on the environment, within the framework of sustainable development;
- Additional losses in the conducting materials of transformers, cables, etc., due to the presence of alternating electromagnetic fields of relatively high intensity;
- Electrodynamic problems associated with short circuits;
- Withstand capability against earthquakes;
- Testability of large components;
- Transportability (especially of transformers).

Identification of the solutions to the following specific problems was a challenge:

- Adoption of single-phase reclosure; this operation requires particular consideration with respect to actual arc phenomena in order to ensure the extinction of the secondary arc. In this respect, fast grounding switches were considered with the relevant capacitive/inductive switching duties;

- Presence of high and repetitive very fast transient overvoltages (VFTO) and the consequences on equipment insulation, mainly transformers;
- Trapping charges in the GIS and the corresponding reduction of the lightning impulse (LI) withstand.

Testing of UHV equipment may present problems basically related to the huge overall dimensions of air-insulated technologies compared with those of the test laboratories.

Within this context, a number of challenges must be met, including the following:

- Dielectric testing of UHV apparatus when the volume of the unit under test exceeds the availability of the indoor test room, which should be higher than 30×30×30 m;
- Performance of certain tests as withstand tests under wet conditions and partial discharge or RIV tests;
- Verification of performance under contaminated conditions and other electrical-environmental stresses;
- Configuration of the short-circuit withstand test for switching apparatus;
- Configuration of the unit test for circuit breakers equipped with switching resistors, which cannot be tested as a whole.

In principle, all tests could be performed in accordance with the present standards by investing in adequate new laboratories and facilities. However, there are some constraints to be considered:

- Return on investment. At this time, the investment may not be reasonable for a third party interested in the business aspect alone. Different considerations may be applicable to manufacturers and utilities concerned with the field reliability of the future high-power system. A large investment in a new laboratory may be negligible when compared to the cost of a fault in service;
- Time required for creating or updating facilities versus the stringent time schedule of some projects.

Should the component testability remain an impassable challenge, alternatives may be studied and recommended with CIGRE IEC support for UHV equipment, such as:

- Revision of test parameters accurately taking into account future system characteristics, such as the use of continually more efficient surge arresters;
- Adoption of non-standard test procedures to achieve the required stress on the equipment;
- Development of suitable and well-proven "virtual testing" techniques;
- Development of a suitable on-site test program providing sources and instrumentation for commissioning and field testing;
- Application of suitable monitoring systems, including measurement such as:
  - Local temperature measurements in the winding and core of transformers and reactors

○ Partial discharge detectors in GIS

○ Ground current detectors on transformer bushings

A report on the testability of UHV components was recently presented in [15].

2.6.4 Overviews of field experiences of the projects

The technical specifications of UHV substation equipment are summarized in the Table 2.6.1.

***Table 2.6.1** Rated electrical characteristics of the 1050 kV pilot plant*

System (general)		***Circuit-breakers***					
Rated voltage	1050kV	***Terminal fault***		***Short-line fault***		***Capacitive switching***	
LIWV	2250 kV	Short-circuit breaking current	63 kA	Surge impedance	300 ohm	Breaking current	900 A
SIWV	1800 kV	Short-circuit current time constant (ms)	45 ms	Amplitude factor	1.6	Voltage factor	1.2
PFWL	1050 kV	Short-circuit making current	160 kA	Out-of-phase Switching (out-of-synchron.: 90°)		Uc (1-cos)	2.060 kV
Rated current busbar bay	8000 A 4000 A	Applied voltage during making operation	606 kV	Breaking current	25 kA		
Earthing Switch		1st pole –to-clear factor	1.3	Voltage factor	1.4	***Autotransformer***	
Induced current electrostatic electromagnetic	50 A 1000 A	Transient recovery voltage		Transient recovery voltage		Voltage kV	1000/√3/400/√3/12.2
Induced voltage electrostatic electromagnetic	50 to 95 50 to 70	T10: Uc (kVp) dV/dt (kV/µs)	1640 11.5	Uc (kVp) dV/dt (kV/µs)	1890 3.0	Rated power	400/400 MVA (single-phase unit)
Oil-filled cable		T60:Uc (kVp) dV/dt (kV/µs)	1520 3.3	Applied voltage during making operation	849 kV	Rated LI WV	2250/1300/95 kV
Rated voltage	1100 kV	T100:Uc(kVp) dV/dt (kV/µs)	1370 3.3			Rated SIWV	1800 kV/consequent
Rated power GVA	7 normal 9 except.					Short circuit voltage (%)	15

***Table 2.6.2** Italy's specifications*

Highest voltage	***1050 kV***	
Items	***Transformers***	***CBs (GIS)***
LIWV (kV)	2250 kV	2250 kV
SIWV (kV)	1800 kV	1800 kV
AC voltage	1000 kV	1050 kV
Circuit breakers main characteristics		
First-pole-to-clear factor	1.1	
Amplitude factor	1.53 for T10	1.3 for T60 1.3 for T100
DC time constant	100 ms	

2.7 BPA 1200 kV Lyons R&D project

2.7.1 Features of BPA's 1200 kV research project

2.7.1.1 Background

Bonneville Power Administration (BPA)'s 1200 kV Transmission Line Test and Development Program was initiated in the mid-1970s to meet the need for economical transportation of large amounts of electric power over limited rights-of-way and with minimum power loss. There are several advantages to a 1200 kV transmission system, the most important of which are better utilization of available right-of-way, reduced environmental impact (compared to multiple 550 kV lines), and reduced losses. Before committing to a commercial transmission system at 1200 kV, BPA needed to test the proposed design, solve technical problems, eliminate economic uncertainties, and gain public acceptance. So, they set out in 1974 to build a prototype 1200 kV line and evaluate its performance.

The Lyons 1200 kV prototype line was the first transmission line operating at the 1100-1200 kV level utilizing actual 1200 kV construction. As such, the line is a prototype of the commercial 1200 kV line as opposed to being a test facility designed strictly for research. In 1974, BPA authorized the construction of a three-phase, 1200 kV prototype transmission line in order to investigate the technical, economical and environmental feasibility of transmitting electric power at this voltage. After the 1200 kV test facility was completed in 1977, an extensive testing and evaluation program was launched. This section summarizes the results of electrical investigations, substation equipment performance, and electric field effect studies. Field experience includes both transmission line and substation component failures. [16]

2.7.1.2 Design of the Lyons facility

The three-phase 1200 kV line at Lyons was 2.1 km long and was built on an existing 230 kV right-of-way parallel to the Detroit-Santiam No. 1, 230 kV line. The dead-end tower at the far end of the line was a self-supporting, lattice type while the substation dead-end tower and the midpoint angle tower was a guyed tubular steel pole construction.

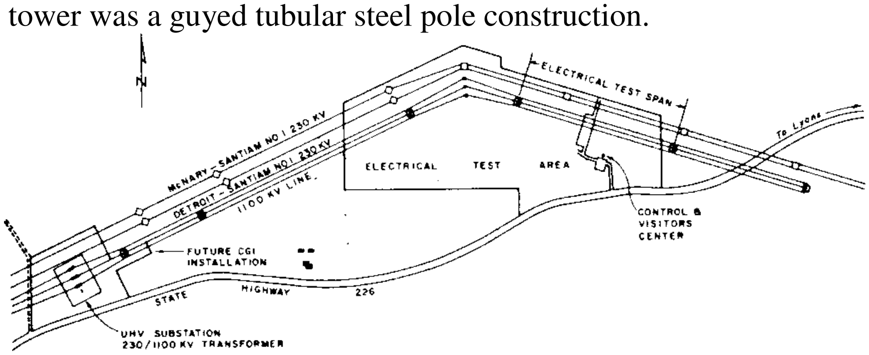


Fig.2.7.1 *Plot plan for the Lyons test facility*

2.7.1.3 Line configuration

A triangular configuration was used for the three phases in order to minimize right-of-way requirements. The design of the self-supporting, lattice type suspension tower for the Lyons 1200 kV line is shown below.

As seen in Fig. 2.7.2, the spacing between the two lower phases will be 22.0 m for the major portion of the line. The location of the OH grounding wires provides a shielding angle of about 5° at the towers.

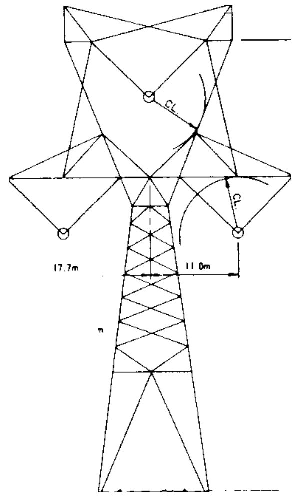


Fig.2.7.2 *Self-supporting suspension tower for Lyons line*

2.7.1.4 Air gap clearances

The line was designed for a switching surge factor of 1.5 per unit. Based on a maximum design voltage of 1200 kV, this results in a minimum air gap clearance of 620 cm between conductor and workman. To allow for tower inspection and tightening of bolts on an energized line, another 30 cm of air gap clearance is provided. This results in a minimum conductor-to-steel clearance of 650 cm.

A minimum conductor-above-ground clearance of 23.2 m was adopted. In the electrical test area, however, the height of all three phases was varied so that the minimum height above ground for the lower phases could be adjusted to between 17 and 25 m.

2.7.1.5 Line insulation

V-strings were used in all phases of the suspension towers to minimize conductor swing. Glass, polymer and porcelain cap-and-pin insulators were used with an M&E rating of 535 kN. Each leg of the V-strings can accommodate 29 units of 240×380-625 mm insulators. This results in a leakage distance of 17.6 m, which is equivalent to a specific creepage distance of 2.5 cm/kV rms. Each dead-end insulator consists of four parallel strings, each composed of 29 units of the same type as used for the suspension towers.

2.7.1.6 Line conductors

The 1200 kV line was initially strung with an 8×40.7 mm (Chukar) conductor per phase and equipped with two overhead ground wires. This was expected to result in an audible noise level of approximately 49 dB (A) at 30 m lateral distance from the centre line at 1100 kV.

Preliminary calculations indicated that the optimum bundle diameter should be slightly more than 75 cm. Due to anticipated mechanical problems associated with sub-conductor oscillation, a bundle diameter of 107 cm was selected. This will result in a voltage gradient (at the conductor) of about 13.5 kV/cm, at a voltage of 1100 kV.

2.7.1.7 UHV substation design

The 230/1100 kV power transformer consists of three single-phase units, each rated 50 MVA (150 MVA 3-phase rating) at a 55ºC rise. The transformer was equipped with no-load taps for a voltage range of 1100 to 1250 kV. Special surge arresters permitted a reduction of the SIWV of the 1100 kV winding to 1800 kV. The LIWV was specified at 2050 kV.

Table 2.7.1 *Technical specifications of power transformer*

1200 kV Transformer	
MVA rating	150/168 MVA (55C/65°C rise)
LIWV (BIL)	2050 kV
SIWV (BSL)	1800 kV
HV taps	1250 kV 1212 kV 1175 kV 1137 kV 1100 kV
LV taps	241.5 kV 239.0 kV 236.0 kV
Impedance	18 %
Weight	336,000 lbs
Height	47 ft

Table 2.7.2 *Technical specifications of surge arrester*

Surge arresters		
Duty cycle rating	770 kV	
MCOV	692.8 kV	
Protective levels		
LIWV	1860 kV	26 kA, 8×20 μs
SIWV	1470 kV	1 kA, 45×90 μs

2.7.2 Overview of field experience of BPA's 1200 kV project -Electrical test and development program

2.7.2.1 Corona Studies

Long-term corona measurements were conducted on the 8×41 mm and 7×41 mm configuration at the Lyons facility. For both configurations, the horizontal phase spacing was 22 m, vertical phase spacing was 18.3 m, and the bundle diameter was 1.07 m. The vertical height of the outside phases was 16.8 and 22.9 m for the 7 and 8 conductor bundle configurations, respectively. [17], [18], [19]

Table 2.7.3 *Conductor corona performance*

Location	**Lyons prototype line (Oper. voltage 1150 kV)**		**BPA single circuit, delta 550 kV lines (Oper. voltage 525 kV)**	
Electrical effect	8×41mm	7×41mm	2×41mm	3×33mm
AN: (dBA)	53	56	56	46
RI: Fair/Foul weather, QP 0.5 MHz (dB/uV/m)	46/65	58/77	52/70	46/68
TVI: QP 75 MHz (dB/uV/m)	13	12	26.5	24
Ozone: (ppb)	ND*	ND*	NM*	NM*
Corona loss: (kW/km)	NM*	43	NM*	NM*

The above table shows the corona performance of typical BPA 550 kV lines, and clearly demonstrates that with a suitable selection of conductor design and ground clearances, the corona performance of 1200 kV transmission lines can be made comparable with the already accepted performance of 550 kV lines.

The results indicate that decreasing the number of subconductors from 8 to 7 increases AN by 3 dBA and RI by 12 dB. However, TVI is essentially unaffected by the conductor configuration. Results also indicate that TVI is caused primarily by insulator and hardware corona rather than conductor corona. No increase was found in mean ozone concentrations at line height or at ground level, which could be attributed to conductor corona.

Corona loss levels are reported only for the 7-bundle configuration. Since only half the line was conductored with this configuration, and since corona sources from the entire line contribute to the measured losses, the losses from a line strung with a 7×41 mm bundle can be expected to differ slightly. Studies were also carried out on 1200 kV tower and insulator hardware in a laboratory environment. Single-phase corona tests for suspension-type tower hardware conducted in the laboratory agreed satisfactorily with 3-phase corona tests performed at Lyons.

However, single-phase corona tests carried out on dead-end hardware in the laboratory did not agree with 3-phase tests performed at Lyons. It is suspected that the primary cause of this disagreement is the influence of other phases on the electric field environment. Over a period of years, additional tests were conducted to evaluate the impact of mid-span clearance and phase-to-phase spacing on RIV, AN, TVI, ozone generation and corona loss.

Table 2.7.4 *Line configurations used at Lyons 1200 kV facility*

Line configuration	***Number and diameter of subcon***	***Energized phases and arrangement***	***Mid-span clearance (m)***	***Phase A-C spacing (m)***
I **Nov. 1977 to Sept. 1978**	8×41 mm	B C • A • •	24.4	22
II **Jan-May 1979**	7×41 mm	Grnd. B o A • •	22.9	22
III **June-Nov. 1979**	7×41 mm	Grnd. B o A • •	19.8	22
IV **Jan-April 1980**	7×41 mm	B C • A • •	16.8	22
V **May- 1980**	7×41 mm	B C • A • •	16.2	13

Table 2.7.5 *Corona effects for different line configurations at Lyons 1200 kV test facility*
Operating voltage=1150kV

Line configuration	**I**	**II**	**III**	**IV**	**V**
AN*- A-wt. L_{50} level during rain (dBA), 15 m from outside phase	53	47	50.5	56.5	61.0
RI*- QP L_{50} level (dB,μV/m), 15 m from outside phase a) 1 MHz. ANSI, Fair/Rain b) 0.5MHz. CISPR, Fair/Rain	42/61 46/65	43/62 47/66	46/64 50/68	54/73 58/77	50/71 54/75
TVI – 75MHz. QP L_{50} level during rain (dB,μV/m), 40m from outside phase	13	12	13	12	9
Ozone --- (ppb)	None detect.	None detect.	None detect.	None detect.	–
Corona Loss – L_{50} level. kw/km, during rain	–	22	24	43	45

***Table 2.7.6** Comparison of predicted AN .RI. and TVI levels for 1100 kV with 735 and 500 kV transmission lines used in the USA and Canada*

Voltage (kV)	Line	Bad weather AN (dBA)	Fair weather RI (dBµV/m)	Bad weather TVI (dBµV/m)
1150	8 × 41.7 mm	53.0	38.6	13.9
1150	7 × 41.7 mm	56.3	43.4	18.7
735	4 × 35.2 mm	51.9	44.4	21.9
735	4 × 30.4 mm	55.8	48.9	26.4
525	2 × 41.7 mm	55.3	49.7	27.3
525	3 × 33.1 mm	47.0	42.6	20.3
525	4 × 24.1 mm	43.0	37.5	15.1
525	4 × 21.6 mm	45.2	30.4	18.0

***Table 2.7.7** Line configurations – Reduced and normal phase spacing*

Line parameter testing period	Normal phase spacing Jan. April 1980	Reduced phase spacing Jan. April 1981
Line length	2.1 km	2.1 km
Sub-conductor number	7	7
Sub-conductor diameter	40.7 cm	40.7 cm
Outside phase Conductor height	16.8 m	17.8
Centre phase conductor height	35 m	35 m
Horiz. phase spacing (Outside phases)	22 m	12.4 m
Conductor surface grad (based on 1150kV)	$E_{A.C}$ =15.7 kV/cm E_B=14.8 kV/cm	$E_{A.C}$ =17.1 kV/cm E_B=15.2 kV/cm

***Table 2.7.8** Corona effects for different phase spacing*

Electrical Effect	7 × 41 mm Lyons 30, Voltage = 1150kV, Reduced Phase Spacing	7 × 41 mm Lyons 30, Voltage = 1150kV, Normal Phase Spacing
AN*- A-wt. L_{50} level during rain (dBA), 15 m from outside phase	60	56.5
RI*-QP L_{50} level (dB,µV/m), 15 m from outside phase a) 1MHz, ANSI, Fair / Rain b) 0.5MHz, CISPR, Fair / Rain	49/71 53/75	54/73 58/77
TVI – 75MHz. QP L_{50} level during rain (dB,µV/m), 40m from outside phase	14	13
Electric field – Maximum at mid-span. (kV/m). 1m above ground	12	14
Corona Loss – L_{50} level. kw/km, during rain	47	43

2.7.2.2 Electric Field Measurements

The vertical clearance used for the 8×41 mm configuration was 22.9 m (outside phases) to give a maximum electric field comparable with one of BPA's typical 550 kV transmission lines. The maximum measured electric field (1 m above ground) was 7.5 kV/m.

To investigate higher field strengths, the outside conductors were lowered to 16.8 m by introducing additional conductor sag. The maximum measured electric field was 14 kV/m.

Measurements of induced current and voltage (for various vehicles and fences) under the Lyons test line indicate that, even for the largest vehicles, the maximum induced current at road crossings will not exceed the 5 mA criteria established by the National Electric Safety Code.

To investigate the effects of 1200 kV transmission on wood poles, a simulated 115 kV wood pole distribution line was built under the Lyons Test Line. Testing included long-term monitoring of surface and internal pole leakage current, electric field and space potential measurements, and evaluation of the various wood pole hardware installations. It was found that, with the wood pole line conductors grounded, four of the nine poles showed signs of burning in areas exposed to the highest electrical stresses. Ungrounding the wood pole line significantly increased burning. The electric field measurements were obtained on the configurations tabled on Table 2.7.8.

Table 2.7.8 *Electric Field Measurements (1150 kV)*

Line Configuration	Electric Field Maximum at mid-span (kV/m 1m above ground)
I	7.3
II	9.9
III	12.5
IV	14.1
V	11.5

2.7.2.3 Insulation studies

The primary objectives of the insulation studies were to:

(1) Evaluate the 60-Hz performance of insulation systems;

(2) Evaluate the lightning and switching impulse performance of insulation systems;

(3) Evaluate the performance of non-ceramic insulators; and

(4) Obtain data on the dielectric strength of air gaps and insulators necessary to optimise 1200 kV insulation systems.

The corona performance of different types of porcelain, glass, and non-ceramic insulators was studied at Lyons by means of night-viewing devices and high-speed photography. The ceramic insulators performed as expected. However, some non-ceramic insulators (NCIs) experienced surface erosion due to corona and arcing, pointing out the need for adequate grading of NCIs. One NCI failed dielectrically and separated after about 6 months of operation due to severe internal discharges. [20]

The Lyons 1200 kV line insulators that were exposed to natural contamination and washing have performed well, with one exception. During a snowstorm, after a heavy layer of wet snow had built up on the insulators, two flashovers occurred on dead-end insulators. No problems have occurred with the 1200 kV substation insulators.

A long-term test program was conducted to investigate the 60 Hz performance of artificially contaminated insulator strings. The insulators on the two outside phases of the line were artificially contaminated at equivalent salt deposit densities (ESDD) found on BPA's 550 kV system. Preliminary results indicated that insulator contamination may be a more serious problem at 1200 kV than at lower voltages.

Lightning and switching impulse testing on 1200 kV air gap configurations was conducted at BPA's laboratory in Vancouver, where there is an outdoor test tower and a 5.6 MV, 448 kJ outdoor impulse generator. Impulse tests were performed on basic conductor-to-tower air gaps with and without insulators, as well as on the Lyons 1200 kV prototype suspension and dead-end tower designs. The effects of geometrical and electrical conditions were also investigated.

A simulated Lyons suspension-type tower without insulators and a positive 250/2500 µs switching impulse waveform provided a dry, minimum critical flashover voltage of approximately 1800 kV for both centre and outside phase configurations. For a positive 1.2/50 µs lightning impulse waveform, the critical flashover voltage was 3600 kV. The Lyons dead-end tower was about 5% greater in dielectric strength than the suspension tower.

2.7.3 Specific issues and technical challenges for the operations of BPA projects

2.7.3.1 Transformer design

Lyons had three 230/1200 kV autotransformer units with a rating of 150/168 MVA at a 55/65ºC rise, respectively. These can be considered power transformers for practical insulation purposes with no-load taps from 1100 to 1250 kV. The BIL of the 1200 kV windings is 2050 kV, the lowest possible in the present state-of-the-art. The SIL is 1800 kV, the impedance 18%. Extensive factory acceptance testing, including a one-hour partial discharge test, was performed at 960 kV on each unit.

BPA's transformer operating experience has been good, except for the failure of one unit. The failure was caused by a manufacturing defect: during assembly, an excessive amount of glue (or voids in the glue) was used to bond the inner surface of the static plate between coils 25 and 26. Also, magnetic particles were found on the surface of the insulating washers between these coils. The flashover arc path was between the washers. After repair, all factory tests were successfully passed. The transformer was reinstalled and has since performed satisfactorily.

2.7.3.2 Surge Arrester design

Based on the sustained dynamic overvoltages at Lyons under fault conditions and line energization, special conventional current-limiting gapped surge arresters were necessary. The arresters' control gaps and blocks needed to be specifically designed and carefully graded so that both the switching surge and lightning impulse protective levels would be maintained as low as practical. Manufacturers indicated that a protective level of 1530 kV could be obtained with an arrester rated at 768 kV. This corresponds to a protective level of 1.56.

Following the construction of the test facilities, field tests were conducted to assess the overvoltage magnitude and waveform of the switching transients. Surge arrester sparkover occurred at Lyons in practically all switching performed by the 230 kV circuit switches, limiting the line overvoltage to 1450 kV (1.5 per unit) and below.

A total of four arrester failures have occurred since the initial installation of the current-limiting gap arresters. These failures are associated with improper grading of the units, causing external flashovers as well as the overheating of the internal grading circuits.

Metal oxide surge arresters were installed at Lyons in 1980 and 1981. Field tests conducted in 1981 confirmed the switching surge protective level and the surge currents under various switching modes. The arresters maintain a protective level of 1.5 per unit.

Thermal stability of the metal oxide arresters was a concern since the maximum 60-Hz voltage is about 10% higher than the stress on typical commercially available arresters. Since that time, BPA has purchased and successfully applied 1.5 p.u. arresters to the 230 and 500 kV systems.

Table 2.7.4 *BPA specifications*

Highest voltage	1200 kV
Items	**Power Transformer**
Rated voltage	1200 kV
LIWV (kV)	2050 kV
SIWV (kV)	1800 kV
AC voltage	1250 kV
Metal Oxide Surge Arresters (MOSA) main characteristics	
Maximum continuous operating voltage	770 kV
Protective levels	1860 kV (Lighting surge at 26 kA, 8 μs/20 μs) 1470 kV (Switching surge at 1 kA, 45 μs/90 μs)

2.8 Russia's 787-1200 kV interconnected grid

2.8.1 General characteristic of Russia's interconnected grid

The former USSR was 22.4 million km^2 in area with a population of 286 million people; after dissolution of the USSR, the remaining territory of Russia equalled 16.9 million km^2 and the slowly declining population is now about 140 million. Russia is extremely rich in natural resources (45% of the world's natural gas, 23% of the coal, 6% of the oil), but its main sources of energy, including hydro, were concentrated in the Asian part of the USSR, whereas the population was concentrated mainly in the European and southern parts, leaving vast areas in the polar region and Siberia almost completely uninhabited. As a result, the distance required to transport bulk electric energy was generally quite long, requiring higher voltages.

Following several decades of continually increasing demand for electric energy, Russian electrical engineers designed and built a huge EHV AC interconnected grid with 363-525-765-1200 kV nominal voltage (maximum operating voltage, respectively, 363-525-787-1200 kV). EHV and UHV voltages were attained as follows: 420 kV in 1957, 525 kV in 1959, 787 kV in 1967, and 1200 kV in 1985. In 1990, just before the dissolution of the USSR, the EHV/UHV interconnected grid consisted of:

- 363 kV lines: 3110 km
- 420–525 kV lines: 4330 km (420 kV lines applied to international transmission only)
- 787 kV lines: 7300 km
- 1200 kV lines: 1900 km (900 km operated at 1150 kV, the rest at 500 kV).

That year, total electricity production in the USSR was 1850×10^3 GWh and the total capacity of power plants was 344 GW, with 290 GW being connected to the interconnected grid. Together with the interconnected grid of East European countries, 11 time zones were covered. The entire grid was equipped solely with Russian electrical equipment.

The USSR's power industry was state owned, government ruled and highly centralized, which was favorable for implementing large-capacity units and large power plants as the most economical. Maximum unit capacity at that time was 1200 MW at steam power plants, 950 MW at hydro power plants and 1500 MW at nuclear power plants, with the maximum capacity of a single power plant reaching 6400 MW for steam or hydro and 6000 MW for nuclear. About 100 regional power companies operated power plants and transmission and distribution networks under the auspices of the Ministry of Electric Power and Electrification (over the years the name of this Ministry changed several times). These networks were united in 11 regional power pools with a capacity ranging from 5 to 45 GW each. In total, the USSR's interconnected grid produced and transmitted up to 89% of the entire Soviet electricity production (in 1990) leaving 11% to relatively small local power utilities in remote areas. With the East European countries, this interconnected grid stretched from east to west over a distance of almost 9000 km. Industry centralization was favorable for unifying technical specifications on the equipment, standards, design and operational norms on a state-wide scale, as well as for analysis of operational data.

The dissolution of the USSR into 15 independent states in 1991 partially destroyed the integrity of the grid, and the economic crisis that followed the dissolution drastically reduced the demand for electric power (in 1993, Russia's GDP dropped to about 50% of that in 1990 and electric energy consumption decreased to 75%). This situation made the full-voltage operation of the 1200 kV transmission system economically ineffective, and it was turned into 500 kV. Only in the last few years has Russia's electric power industry recovered from this crisis.

After the disintegration of the Soviet Union, the lion's share of natural resources remained in Russia, as well as the major part of the EHV grid. As of 1995, Russia had 3690 km of 500 kV lines, 2800 km of 750 kV lines and 950 km of 1150 kV lines. Russia's interconnected grid still extends to 7000 km, and is the second largest grid in the world. It includes 5 regional power pools, and its share of Russia's total power plant capacity reached 93% (205 and 193 GW, respectively) in 2001 at a total electric energy production of 8880 GWh (in the same year). The entire interconnected grid divided between 15 newly independent republics still exists, but its operation and power exchange suffer from numerous intergovernmental contracts and pricing problems and it is far below the technical capability of 9-10 GW estimated in 1990.

Although some privatization has touched Russia's power industry, it still is mainly owned by the state, especially in terms of major power plants and EHV/UHV transmission systems; electric energy and heat tariffs are still controlled by the government. As of 2005, the Russian state joint stock company "Interconnected Grid of Russia owned:

- Total shares of fossil plants with a capacity of 1 GW and over, and of hydro power plants with a capacity of 0.3 GW and over;
- 49% shares of all local electric utilities owning smaller power plants and local electric grids;
- All EHV transmission systems and substations forming the interconnected grid;
- Central and all regional boards of the power pool;
- Design and research organizations serving electric utilities.

This stock company has started the process of radical changes aimed at further decentralization and privatization that is scheduled for completion in 2008.

When the implementation of 1200 kV transmission was initially decided, the transmission systems had to bring bulk power from Siberian coal fields (where huge power plants were planned) to the central part of the Soviet Union. The maximum power transmitted through 1200 kV lines was estimated as 5.5 GW and required the implementation of FACTS technology. The total length of prospective 1200 kV transmission lines at that time was estimated as 10,000 km with individual line lengths ranging from 300 to 600 km. The transport had to be supplemented with +750 kV, 6 GW HVDC transmission lines 2400 km long. The first four

1200 kV lines were built and put into operation, with two of them (total length about 900 km) operating under full voltage for testing purposes. However, the planned power plants were not constructed in time and the disintegration of the USSR led to a drop in consumer demand for electric energy; therefore, after two successful years of operating under full voltage, these two 1200 kV lines, as well as all newly built 1200 kV lines were changed to 500 kV to save on losses and maintenance expenses.

Russia's GDP and electric energy production has shown steady growth during the last several years. In the period of downturn, the construction of new transmission lines almost came to a complete standstill, but with the start of economic recovery, the construction of EHV lines resumed, including one 1150 kV line 445 km long temporarily operated at 500 kV. The designing of new 1150 kV lines resumed, with the goal of reshaping the grid according to the changed state boundaries. The main energy transit is now expected to be between Siberian power sources and the Urals area. The total length of already designed 1150 kV lines exceeds 1600 km. The construction of +500 kV DC transmission lines, 1800 km long, is under discussion, and DC back-to-back substations will be used to increase the export of Russia's electric energy to UCPTE that has more stringent requirements on the quality of electric energy compared to Russia. Initial predictions published in 2001 were for an increase to 1400-1600×10^3 GWh in Russia's electric energy production by the year 2010; the total capacity of 100 GW must be refurbished or built; new nuclear plants of about 25 GW and new gas turbine and combined cycle fossil power plants of about 30 GW must be built. In 2006, the Russian government approved a more moderate program stating that newly built power capacities will reach 21.8 GW in 2006-2010 and at the same time, 4.2 GW of aged equipment would be taken out of operation. The construction of 10,000 km of new HV lines at 220 kV and above is expected, with an investment of about $6 billion in 2006 and $20 billion annually starting in 2008.

2.8.1.1 Selection of nominal and maximum operating voltages

In the past, the USSR had two systems of nominal transmission voltages,

- 35-150-330 kV in the western and southern parts of the country (400 kV was retained on several connections to adjacent countries);
- 35-110-220-500 kV in the central and eastern parts of the country.

As industry and power consumption grew, the need arose for an overlaid EHV 'supergrid' in both systems. Economic analysis showed that every next nominal voltage had to exceed 2–2.5 times the previously existing highest voltage in the system. So, a nominal voltage of 750 kV was selected for upgrading the first system and 1150 kV for the second one. In the European part of the USSR, the two systems became entangled, which required, in addition to obvious 330/750 and 500/1150 kV connections, the use of 220/330, 330/500 and 500/750 kV autotransformers.

The following areas of application of 750 and 1150 kV were economically determined for maximum load duration of 5000-7000 hours a year:

- 750 kV compared to the existing 500 kV transmission: at a distance of 700 km if transmitted power exceeds approximately 1.2 GW, or at a distance of 400 km if power exceeds 2.2 GW;

1150 kV compared to the existing 750 kV transmission: at a distance of 700 km if power exceeds approximately 2.8-3 GW, at a distance of 400 km if power exceeds 3.6-3.8 GW.

2.8.1.2 Maximum operating voltage

Taking into account problems with electrical equipment insulation and corona effects on overhead lines, the following margins between the nominal and highest permissible operating voltages were approved in the USSR:

- 500 and 750 kV: 5% (i.e., 525 and 787 kV, respectively)
- 1150 kV: 4.3% (i.e., 1200 kV).

Line length, number of circuits, transposition: In the erected 750 kV grid, the line length varies between 300 and 550 km. In both the constructed and designed 1150 kV grids, the line length varies from 400 to 700 km.

In accordance with Soviet practise, all lines are single-circuit lines; analysis showed that double-circuit lines are more prone to the loss of both circuits compared to two separate single-circuit lines, especially if routed via different rights-of-way. For this reason, if the capacity of one line is not sufficient for carrying the required power, two lines may be constructed leading to different areas of consumption, creating "loops" within the grid.

All constructed and planned 750-1150 kV lines have a full cycle of transposition, thus reducing asymmetry and improving the conditions for applying single-pole auto-reclosing.

2.8.1.3 Shunt reactor positioning and connection - Degree of line capacitance compensation

In all cases 787 and 1200 kV shunt reactors with their surge arresters are placed on line ends and made switchable. Their circuit breakers are equipped with air-gaps for instant connection of switched-off reactors to the line. That permits to use the reactors effectively not only to balance reactive power in operational modes, but also for limiting temporary, switching and even lightning overvoltages.

Only one design of 787 kV single-phase shunt reactor is in usage with the capacity of the group 330 MVAr, so the degree of shunt compensation varies with the length line being usually 60-90%. For 1150 kV lines also only one design of shunt reactor was adopted with group capacity of 900 MVAr, and desired shunt compensation was estimated as 90-100%.

Neutral point insulation in shunt reactors permits to use them in four-legged schemes to suppress the secondary arc at single pole auto-reclosings.

Series compensation didn't receive practical application in the existing 787-1200 kV Grid, although may be considered for some future projects.

2.8.1.4 System of limitation of temporary, switching and lightning overvoltages

The system for limiting temporary overvoltages and switching surges in the Soviet/Russian 750 kV transmission system that inherited the positive experience of 500 kV transmission included:

- Positioning shunt reactors on the ends of EHV/UHV lines;
- Equipping their circuit breakers with air gaps for instant connection of reactors to the line if a reactor is switched off in the pre-failure operational mode;

- Automatic mechanism for closing, without time delay, the reactor circuit breaker in all poles if shunt reactor current appears in at least one pole, or in the event of an automatic command to switch off at least one pole of the line;
- Automatic mechanism for connecting switched-off shunt reactors to the line and then, if necessary, switching off the line in the event of a temporary overvoltage. This automatic mechanism checks the peak value of overvoltage and delays switching off the line in accordance with permissible TOV characteristics;
- Automated operation of planned and failure switching of the line;
- Application of switching surge arresters on transformers and shunt reactors.

The 1150 kV transmission system also includes pre-inserted resistors in line circuit breakers. A view of Russia's 1150 kV shunt reactor circuit breakers with air gaps is shown below. [21]

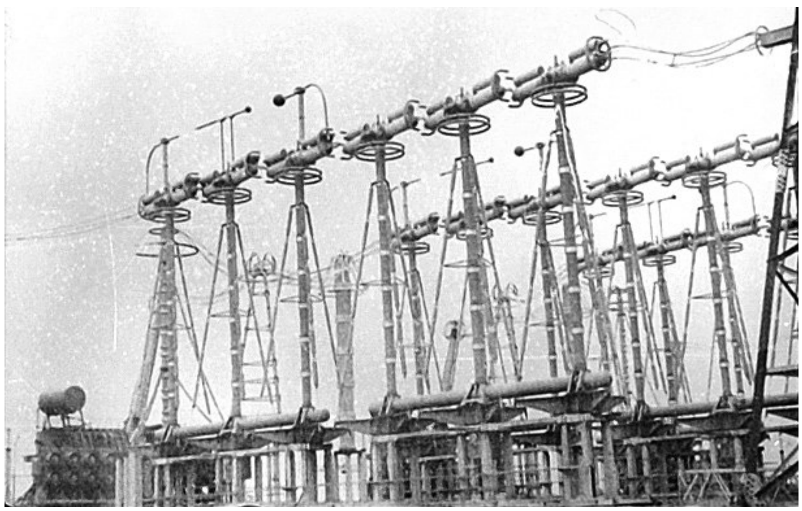


Fig. 2.8.1 *1200 kV circuit breakers applied to shunt reactor*

As Russia's EHV/UHV lines are generally long, and at the first stages of grid development some of the connected systems may have increased reactance, the limitation of temporary overvoltages plays a decisive role in overvoltage protection of UHV transmission. Russian standards for EHV/UHV equipment include norms for permissible TOV levels versus their duration and frequency of repetition. These norms are jointly determined by manufacturers and customers and are based on "natural" insulation capabilities of different types of equipment for which the insulation is traditionally designed based on operational voltage and permitted switching and lightning overvoltages.

2.8.1.5 Levels of overvoltage limitation and arrester characteristics

Switching surge (and lightning overvoltage) limitation levels were initially selected for zinc-oxide gapped arresters available in the USSR, and all existing equipment in the Soviet's 787-1150 kV transmission systems corresponds to those levels. Later, when MOVs became available, lower limitation and withstand voltage norms were adopted for equipment that may be developed and installed in the future (see Table 2.8.1).

Table 2.8.1. *Overvoltage limitation and arrester currents in the Soviet EHV/UHV transmissions*

Parameter	Nominal voltage, kV	750	1150
	Arrester type		
Switching surge limitation, p.u. of crest value	GSOA*	2.1	1.8

of L-G rated voltage	MOV**	1.85	1.6
Switching surge current, kA $_{peak}$	GSOA* MOV**	1.8 1.8	1.5 2.2
Lightning impulse limitation, p.u. of crest value of L-G rated voltage	GSOA* MOV**	2.57 2.05 (2.15^x)	2.05 1.8
Lightning impulse current, kA $_{peak}$	GSOA* MOV**	10 10 (15^x)	14 15

*Notes: * Overvoltage protection system with gapped zinc-oxide surge arresters (GSOA). All installed equipment corresponds to this row.*
*** Overvoltage protection system with MOVs can be used with newly developed equipment having lower insulation levels (see below); ^{x} In rare cases of increased current impulse.*

Insulation levels: Russia's standards prescribe mandatory levels of withstand test voltage for EHV/UHV equipment with special attention paid to IEC recommendations. Some extracts are provided in Table 2.8.2. These norms are valid for a maximum location altitude of 500 m above sea level. In order to use the 4-legged reactor scheme to suppress secondary arc current at single-pole rapid auto-reclosing, shunt reactors must have their neutrals insulated from the ground. Insulation class of the neutral is 35 kV for 750 kV reactors (1-min test voltage of 85 kV); for the neutral of 1150 kV shunt reactors, the 1-min test voltage is 120 kV.

***Table 2.8.2** Technical specifications of 787 and 1200 kV Equipment*

Applied test voltage	*50 Hz (kV rms)*		*SI (kV peak)*		*LI (kV peak)*	
Rated voltage and type of equipment	1 min	Long applied	Smooth rise	*FW*	*FW*	*CW*
750 kV transformers/ shunt reactors *(two values if different)*, (L-G)	800/900 (750)	635		1550/1675 (1425)	2100/2250 (1800/1950)	2250/2400 (1950/2100)
750 kV equipment, CT, capacitive PT, (L-G)	950 (830)			1550 (1425)	2100 (1950)	
750 kV circuit-breaker, between the contacts of the pole	1400		1550/ 1350^x	2250 (2000)	2100	2550
750 kV insulator string, (L-G)		530^		1500		
750 kV air gap, (L-G)				1550 (1425)		
750 kV air gap, (L-L)				2550 (2400)		
1150 kV transformers/ shunt reactors, *(two values if different)*, (L-G)	1100 (1000)	900 (900)	1300*	2100 (1800)	2550 (2250)	2800/3200 (2550)
1150 kV apparatus, CT, capacitive PT, (L-G)	1150 (1100)	900** (900**)	1300*	2100 (1800)	2900 (2400)	
1150 kV circuit-breaker, internal and external insulation between contacts when open	2000		2000	3100	2900	3200

*Notes: * For equipment developed prior to 1985; ** CT only; ^ Under contamination conditions; ^{x} Dry and rainy conditions, respectively; ^{xx} For transformers and shunt reactors, respectively.*
(SI: switching impulse; LI: lightning impulse; FW: full wave; CW: chopped wave. Without brackets: equipment now used in transmission systems and protected by gapped zinc-oxide surge arresters; With brackets: values for newly developed equipment protected with MOV)

2.8.1.6 Line parameters

To facilitate the construction of lines and to reduce corona noise and losses at moderate current loads, Russia's bundled phases have an increased number of smaller-diameter Aluminium Conductor Steel Reinforced (ACSR) sub-conductors. The typical line parameters are shown in Table 2.8.3. All lines of these voltages are transposed, single-circuit, and protected with two shielding wires that are also used for high-frequency communication transmission. Guyed support towers are widely used.

***Table 2.8.3** Parameters of Russian 787 and 1200 kV lines*

Nominal voltage	750 kV	1150 kV
Typical length, km	300-550	400-700

Maximum transmitting capacity, GW	1.0-2.1	4-6*
Phase conductor (AL only) cross section, mm^2	1200-2000	2600-3200
Typical bundling of the phase, conductor diameter and spacing in the bundle	5xAS-240/56; 2.24cm, 30cm	8xAS-330/43; 2.75cm; 40cm
	4xAS-400/93; 2.91cm; 60cm	8xAS-400/51; 2.75cm; 40cm
	4xAS-500/64; 3.06cm; 60cm	
Phase-to-phase distance, m	17.5-19	21.5-25
Surge impedance in positive sequence Z_W, Ohm	~265	~250
Same in zero sequence Z_{W0} , Ohm **	455/520	435/505
Inductance in positive sequence X_1, Ohm/km	0.29	0.27
Same in zero sequence X_0, Ohm/km **	0.65/0.85	0.63/0.85
Capacitive conductivity in positive sequence b_1, μS/km	4.02	4.36
"Natural surge load" of the line, GW	~2100	~5300
Capacitive charging current of the line I_1, A rms/100km	~180	~290

*Notes: * Using controllable shunt compensation (FACTS) and automatic regulation in the adjacent grid.*
*** Prior to the slash, shielding wires are grounded at both ends of each anchor span; after the slash, shielding wires are grounded only from one side of each anchor span to reduce power losses.*

2.8.1.7 Auto-reclosing application

In 787–1200 kV lines, single-pole faults are almost the only kind of faults observed in operation. Most occur through arcing and can potentially be resolved using rapid auto-reclosing. Accordingly, Russia employs single-pole auto-reclosing as a mandatory method, and three-pole auto-reclosing is usually used as the second line of defence if during the dead time at single-pole opening of the line, the secondary arc did not extinguish. Using single-pole auto-reclosing is particularly important for single-circuit UHV lines, as it minimizes the disturbance experienced by the grid at line faults. As the lines are transposed, the secondary arc current is less than that in untransposed lines, and the application of four-legged reactors effectively reduces it. In symmetrical mode of line operation, the neutral reactor is shunted by a circuit breaker, and to protect the neutral insulation when the neutral reactor is de-shunted, an arrester is placed in parallel to the neutral reactor. Additional measures can be used if the 1200 kV lines are heavily loaded and HSGS fully resolves the problem of secondary arc extinction.

2.8.2 Overviews of field experience and evolution of Russia's 787 and 1200 kV transmissions

2.8.2.1 Organization of research, designing and testing

EHV/UHV equipment development, and transmission system design and testing were executed in the USSR based on state programs with government funding. Particularly, the development of 787 kV equipment and prototype testing started in the 1960s. In 1965, the experimental 787 kV commercial transmission system, 87 km long, with two 787 kV substations at its ends (Bely Rast and Konakovo), was put into operation, and various tests were performed jointly by a group of researchers from equipment manufacturers and the power industry, represented, respectively, by the All-Union Electrotechnical Institute (VEI) and the All-Union Electric Power Research Institute (VNIIE). Numerous improvements were made to the equipment following the tests. From 1967 until about 1988, each newly constructed 787 kV transmission line was subjected to similar tests performed in accordance with national programs developed annually and approved by the Ministry of Electric Power and Electrification and the Interconnected Grid Pool. The tests were executed by VNIIE and VEI with the participation of utilities as the owners of the respective transmission systems.

A similar process was adopted for the creation of the 1200 kV transmission system. Field tests on prototypes of the 1200 kV equipment were conducted by VEI at the manufacturer's test site, and starting in 1973, were jointly executed by VNIIE and VEI at the 1200 kV test site built as an extension to the 787 kV Bely Rast substation. Tests were conducted on the first 1200 kV transmission line commissioned in 1985, and then on the second 1200 kV transmission line.

The designing of all 787 kV and 1200 kV transmission systems as well as of the entire grid was performed by the state-owned Design and Research Institute, Energoset project, which more or less monopolized this field of engineering activity. Overall, the monopoly led to high quality and uniformity of projects, as well as to prompt improvements when operating experience showed the need for a particular change.

2.8.2.2 Pilot program for the next possible UHV level

A state-funded pilot program was adopted in the USSR in the 1980s to determine the highest possible AC transmission voltage. The rated voltage was determined as 1800 kV, with L-G switching surge limitation of 1.45 p.u. The bundled line phase had 11 ACSR conductors 240 mm^2 positioned in a circle 3 m in diameter. A number of equipment prototypes were tested, but development halted when it became clear that such transmission would not be in demand in the near future, and further technical progress would likely make today's technical solutions obsolete.

2.8.2.3 Operating experience

The USSR runs an annual operational analysis on the entire grid under the auspices of the Ministry of Electric Power and Electrification. A portion of the most significant data is presented in Table 2.8.4. Generally, the operational experience of the 787 kV lines and the first 1200 kV lines was satisfactory. The increased level of 1200 kV transformer failures and especially the lengthy restoration time are clearly signs of "growing pains" for the first equipment and transmission samples.

As the operational duration for full-voltage 1200 kV transmission was relatively short, not all parameters in Table 2.8.4 are determined; they are marked with notes. Further long-term experience in operating 1200 kV lines at 550 kV made it possible to identify some mechanical problems in the lines.

Table 2.8.4 *Operational data for Russia's 787-1200 kV transmission systems*

Equipment	Parameter	787 kV	1200 kV
Line	Failure rate, per 100 km per year	0.2	0.12
	Single –pole failures, %	98	100*
	Successful single-pole reclosures, %	52	**
	Total successful single- and triple-pole reclosure, %	52	**
	Average restoration time, in hours, if reclosing was unsuccessful	5.8	10.5
Transformer	Outages, per phase per year	0.107	0.13
	Average restoration time, hours	112	5,090x
Shunt reactor	Outages per phase per year	0.068	0.25x
	Average restoration time	198	23x

*Notes: * Insufficient observation time; ** Devices for automatic reclosure and schemes of 4-legged reactors were not properly established during the relatively short period of tests and operation; ^{x} Initial period of "growing pains"*

Extinction of secondary arcs at single-pole auto-reclosing application: In very long arcs typical of EHV/UHV insulation, non-uniformity along the arc length and internal exchange of energy between sections of the arc channel play a more important role in secondary arc extinction compared to elongation, creating intermittent arcing characteristics. [22] It was often possible to observe several sequential unsuccessful attempts to extinguish the arc followed by re-strikes along the arc that would not be possible to extinguish in a uniform elongating arc. In this situation, it was decided to estimate the required extinction time using exclusivity tests and failure recording data for 330–750 kV lines. The total number of test points approached 720. Strong wind reduces the extinction time, but this factor was impossible to control in field tests, which increased the scattering of test data.

All extinction times were statistically analysed as a function of the crest value of a steady-state secondary arc current. Initially, the data was separated into two groups: lines without shunt reactors and lines with shunt reactors (including 4-legged reactor schemes). Lines without shunt reactors provided a small recovery voltage (0.1–0.2 of L-G voltage), but with a short time to peak. Lines with shunt reactors and 4-legged reactor schemes showed a longer voltage recovery time, and the peak value ranged from small to very large (in schemes close to resonant conditions up to 1.5 of L-G voltage). For this reason, the lines were subdivided into two subgroups: lines with recovery voltage below 0.5 L-G voltage, and those above. Statistical analysis showed, however, that the influence of the steady-state magnitude of secondary arc current is statistically much stronger than the influence of the presence or absence of shunt reactors. Therefore, all data was presented as a function of only the peak value of steady-state current. For 90% reliability in extinguishing the secondary arc current, the following extinction times were established for EHV lines:

- At 40 Apeak - 0.7 s,
- At 60 Apeak – 1.2 s,
- At 90 Apeak – 2.6 s.

The single-phase rapid auto-reclosing (SPAR) dead time can be determined as the time needed for extinguishing the secondary arc plus approximately 0.5 s for dissipation of the initial power arc cloud and attenuation of initial transients in the secondary current. In addition, for dynamic stability of Russia's interconnected grid, the maximum SPAR dead time usually had to be limited to 3.0-3.5 s. For these reasons, the secondary current had to be limited to below 90 A in the 787 kV lines. At currents above 90 A peak, extinction becomes more problematic: it is still possible, but the percentage of successful extinction drops.

As the insulation length is usually designed to be directly proportional to the maximum operating voltage, and the non-uniformity in longer arcs is more pronounced, the extinction of secondary current arcs in tests on 1000-1200 kV lines occurred more quickly and at higher currents in comparison to that observed in the operation of 330-787 kV lines. [23]

2.8.2.4 Radio and audio interference, corona losses

Designing the 787 kV and 1200 kV lines was preceded by measuring corona losses and TV, radio and audible noises on experimental short prototype lines and then was followed by field measurements on lines in operation. [24], [25], [26] The maximum gradient on the conductor surface in 1150 kV bundles must not exceed 90% of the starting gradient of total corona, thus providing some margin for a possible increase over the rated voltage, lower position of the conductors in the midspan and reduced air density at altitudes up to 500 m. Radio noise 100 m from the line was prescribed at levels of 48 to 30 dB for frequencies, respectively, from 0.15 MHz up to 1000 MHz. Acoustic noise at a distance of 300 m must not exceed 55 dB (A) during daytime and 45 dB (A) at night.

On bundled phases of 787 and especially 1200 kV lines, extremely high corona loss is possible in bad weather. As an effective measure for reducing corona loss, a temporary reduction of operating voltage was recommended. To assist interconnected grid dispatchers, a system for monitoring on-line corona loss was developed for trial operation on several 787 kV lines.

Taking into account strong electrical fields at UHV substations and near UHV lines, standards were developed for electric field exposure of both utility personnel and general population:

- Limited duration of unprotected personnel staying in electric substations depending on the field gradient;
- Limited permissible gradients for the general population depending on the land designation (city/town, agricultural use, non-populated areas);

2.9 TEPCO 1100 kV project

2.9.1 Features of TEPCO's UHV transmission system

Tokyo Electric Power Company (TEPCO) has been working to expand their 550 kV network since the mid-1970s, but it is difficult to obtain multiple power transmission routes in Japan. Countermeasures against the increase in short-circuit current due to network expansion were also required. To cope with these problems, TEPCO decided to introduce UHV (1100 kV) transmission system with a capacity of 3 to 4 times that of the 550 kV network.

By 1999, TEPCO had already constructed UHV-designed double-circuit transmission lines that ran 240 km from east to west and l90 km from north to south, totally 430 km, as shown in Fig. 2.9.1. These lines are now operated at 550 kV and they will be upgraded to UHV in the mid-2010s.

UHV systems are required to deliver very large power transmission (approximately 13GW/route) and to ensure high reliability. Additionally, various new technologies had been developed for substations. To establish carefully these technologies towards UHV upgrading, field-testing of substation equipment has been carried out since 1996 connecting to the actual grid. [27]-[30]

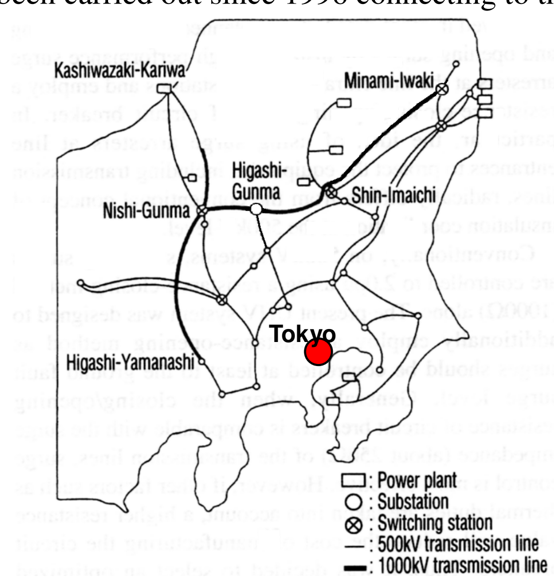


Fig.2.9.1 *TEPCO trunk transmission systems*

2.9.1.1 Considerations for UHV systems and equipment

The UHV (1100 kV) system has a number of distinctive features such as large line-charging MVA (nearly 4 times that of the 550 kV system), low transmission loss due to the adoption of 8-bundle conductors with 810 mm^2 ACSR (partially 8-bundle conductors with 610 mm^2 ACSR in mountainous areas) for transmission lines to suppress corona noise (radio interference and audible noise).

Secondary arc at a line fault lasts longer due to electrostatic induction from other healthy phases. To quickly extinguish the secondary arc and successfully secure high-speed multi-phase reclosing within one second, the high-speed grounding switch (HSGS) is introduced. AC temporary overvoltage (ACTOV) tends to be higher due to the Ferranti effect and load rejection. Attention must be paid to these tendencies.

Low transmission loss also affects the performance of substation equipment. The DC time constant of a fault current slowly decays and goes up to nearly 150 ms. Zero-miss current may occur depending on the load conditions and fault timing. Attenuation of high-frequency component in a fault current becomes slow, which may increase di/dt at around current zero. These phenomena have a significant effect on the circuit breakers. Magnetic saturation of CT applied to busbar protection requires an air-core CT and/or some type of measures in the protection relay system.

As the system voltage increases, surge voltages induced in the secondary circuit also tend to increase in severity. Optical potential devices (PD), which are hardly affected by surge voltages, are adopted.

2.9.1.2 Concept of insulation coordination and specifications

Double-circuit vertical line configuration is adopted for the transmission lines. Suppressing switching overvoltages as much as possible is important for making the transmission lines compact, which leads to a reduction of construction costs as well as environmental impact.

For substations, full GIS is adopted as the main circuit from the transmission line entrance to the transformer terminal taking into account space constraints, earthquake, pollution, maintenance, etc. The determination of rational LIWV is important, because lightning overvoltages dominate the non-self-restoring internal insulation design of GIS and transformers.

Designs for insulation coordination throughout transmission lines and substations were carefully studied based on the development of a high-performance metal oxide surge arrester (MOSA) with the protection level of 1620 kV (at 20 kA) by precise computer-aided calculations.

To suppress lightning overvoltages effectively, MOSAs are installed at adequate locations of substation circuit. With respect to very fast front overvoltages (VFTOs), these levels are suppressed to be 1.3 p.u. or below with application of resistor fitted disconnectors with a 500 ohm resistor. This scheme is also effective to suppress electromagnetic interference in the secondary circuit of CT, VT, and protection/control system.

Switching overvoltages are suppressed to the same level as that of ground fault overvoltages (1.6 p.u. in the north-south route and 1.7 p.u. in the east-west route) with MOSAs installed at both ends of the transmission lines and circuit breakers with closing and opening resistors. The required resistance value is 700 ohm for closing, and 1000 ohm for opening. Thus, 700 ohm was chosen for common use for both operations.

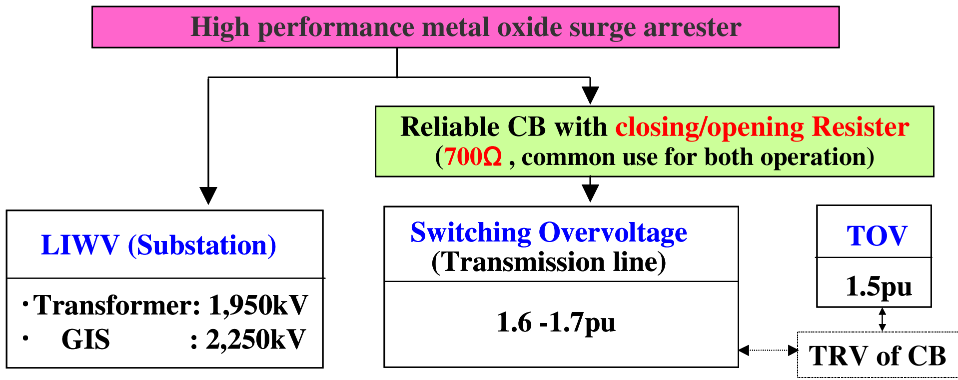


Fig.2.9.2 *Insulation coordination based on high performance surge arrestors*

The suppression of switching overvoltages to 1.6-1.7 p.u. from the conventional level, (which is 2.0 p.u. in 550 kV system), reduces the distance between the line and the tower to be approximate 6 m from 9 m and above. This insulation design reduces the tower height, which would be 143 m in accordance with the 550 kV technologies, to 110 m as shown in Fig. 2.9.3.

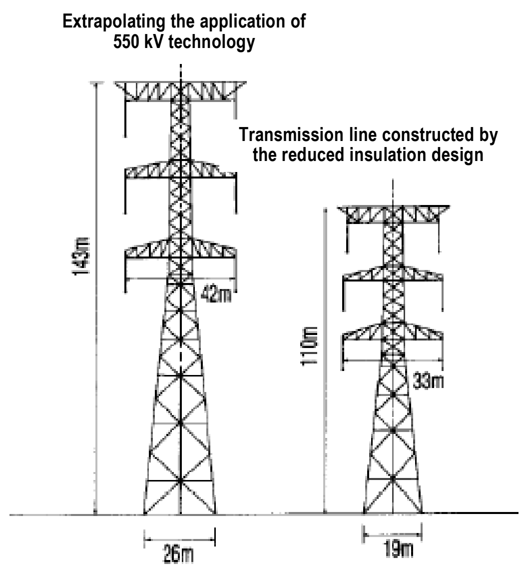


Fig. 2.9.3 *Compact design of UHV Tower*

Table 2.9.1 *Insulation levels of substation equipments*

Highest voltages	*1100kV*	
Item	*Transformer*	*GIS*
LIWV (kV)	1950 kV	Phase to earth: 2250 kV Across terminal: 2250 kV + 1100x ($\sqrt{2}/\sqrt{3}$) kV (For CB and DS)
SIWV (kV)	1425 kV*	1550 kV*
PFWV (kV rms)	1.5E (30 min) – $\sqrt{3}$ E (1 min) - 1.5E (30 min)	

** Transformer SIWV was specified to check the internal oscillation caused by slow front overvoltages although LIWV is a decisive factor for the design. GIS SIWV is for the gas bushings at the line entrance.*

2.9.2 *Specific issues and technical challenges for substation equipment - Specifications for substation equipment*

Various UHV substation equipment was developed for field testing. Tables 2.9.2 and 3 show the general specifications and main characteristics of this equipment.

- The transformer is a forced-oil circulating, single-phase, autotransformer (3000 MVA bank). Single-phase transformers are transported in two units and assembled on-site due to transportation constraints. The divided unit was designed to meet the same capacity as that of a typical 500 kV transformer (1500 MVA bank), while it must withstand twice the voltage. Insulation technologies to ensure high reliability under long-term operation were developed. On-site assembly and connection technologies were also developed.

- MOSA plays a key role in insulation coordination for the UHV system. In order to improve the protection characteristics and heavy discharge duties, 4-MO columns are electrically connected in parallel, the elements of which were developed for UHV arresters and are well proven in the field as 550 kV high-performance arresters. During development, focusing on mainly severe ACTOV duty of 55 MJ specified in consideration of load rejection, various tests were performed, such as energy injection destructive tests for many of the elements to ensure quality stability and current uniformity tests between each MO column, etc.

- 1100 kV / 50 kA two-break GCB with resistor closing and opening scheme was developed. The main and resistor contacts are operated separately by their own hydraulic mechanism, because the resistor contact precedes the main contact by 10 ms in closing and lags by 30 ms in opening. The delay time of 30 ms was specified considering interruption failure by multiple lightning discharges and possible missing current zero.

Reliability of the resistor closing and opening scheme was confirmed by the following aspects and has been verified by long-term field testing.

1. 550 kV CB with resistor closing scheme has been standardized and is well proven in field operation in Japan.
2. Refined and proven hydraulic operating mechanisms are applied to both the main and resistor contacts.
3. Two operating mechanisms are controlled by a single valve to secure synchronization.
4. FMEA studies applied to various failure modes of the operating mechanism was carried out. (Example 1: Hydraulic pipe broken between the main and resistor cylinders should not be driven in a closing operation. Example 2: Orifice between main and resistor cylinder shut by trouble shall be opened by both the main and resistor contacts.)
5. Quality control in cooperative actions between manufacturers and utilities using appropriate standardized specifications.

- HSGS was developed based on CB technology such as a hydraulic operating mechanism that enables high-speed switching and a puffer cylinder for the interrupter. The specifications of HSGS include extended current interruption duration up to 80 ms considering current zero phenomena that occurs when another ground fault (second fault) takes place during the interruption of electromagnetic induced current.

- Resistor-fitted disconnectors are adopted to suppress VFTOs. In addition to ordinary tests such as the capacitive current interruption test, multiple discharge tests by simulating restriking surges were performed to ensure that resistor withstand multiple discharges and restriking currents commutate to the resistor without bypassing.

- Gas bushings at the entrance of substations employ porcelain housing to ensure long-term reliability. For seismic design, porcelain housing was developed by enlarging the diameter with improved shed shapes. Contamination withstand voltage tests were carried out with non-uniform contamination along vertical and diametrical directions to confirm the performance of large bushings based on data from exposure tests in the field, where a typhoon occurred. Switching impulse withstand voltage tests were performed not only under dry conditions but also wet conditions considering the tendency towards lower performance under wet conditions.
- Optical PD is adopted considering equipment compactness, cost reduction, surge-proof characteristics, etc. It was developed focusing on the accuracy of voltage control throughout the entire network.

Table 2.9.2 *Specifications and main characteristics of UHV transformer*

Rated voltage	Primary		$1050/\sqrt{3}$ kV
	Secondary		$525/\sqrt{3}$ kV
	Tertiary		147 kV
Rated capacity			3000 MVA/3
Tertiary capacity			1200 MVA/3
Primary tapping range			$\pm$7% (27 taps)
Impedance			18 %
Test voltage	LIWV	Primary	1950 kV
	AC	Primary and Secondary	1.5E (1 hour) - $\sqrt{3}$ E (5 min) - 1.5E (1 hour)
Surge capacitance			10,000pF (Design characteristic)

Table 2.9.3 *Specifications and main characteristics of 1100kV GIS*

GIS (Common)	Rated voltage		1100 kV
	Rated continuous current		8000A (Line and Bus)
	Rated short-time withstand current		50kA, 2 s
	Test voltage	LIWV	2250 kV
		AC	1.5E (30 min) – $\sqrt{3}$ E (1 min) - 1.5E (30 min)
GCB	Breaking current		50 kA
	Making/Breaking resistor		700 Ω (used for both making and breaking)
	Standard operating duty		O-θ-CO-1 min-CO
	Thermal duty of resistor		BTF 'O' + Out-of-phase 'CO'
GCB (System characteristic)	First-pole-to-clear Factor		1.1
	Amplitude Factor		1.4 (with opening resistor and MOSA)
	DC time constant		150ms
	Surge impedance for SLF		450 ohm
Disconnector	Surge suppression resistor		500 Ω Thermal duty: CO (Continuous one operation)
	Small capacitive current switching		Recovery voltage: 635 kVrms (= $1,100/\sqrt{3}$) Load side capacitance: 2000 pF
	Loop current switching		Recovery voltage: 300 Vrms Loop Current: 8000 A
HSGS	Electromagnetic induction current interruption		Interrupting current: 5800Arms Recovery voltage: 640kVp
	Electrostatic induction current interruption		Interrupting current: 1200Ap Recovery voltage: 900kVp

	Standard operating duty	C - 0.5s - O (Synchronized with CB operation)
ZnO surge arrester	Continuous operating voltage	$1100/\sqrt{3}$ kV
	Residual voltage	1550 kV (at 10 kA), 1620kVp at 20kA
	Steep wave response	V(1 μ s)/V(8 μ s) at 10kA $\leq$ 1.1
	ACTOV duty	55MJ
Gas bushing	SIWV	1550 kV
	Contaminated withstand voltage	762 kV (1.2E)
	Seismic withstand (targeted value)	3 cycle sine waves of 0.3G at the bottom of the supporting structure, safety factor of 2
Earthing switch	Duty of interrupting induced current	Switching current: 1000A Recovery voltage: 70kVrms Rate of rate of recover voltage; 160kV / µs
	Duty of interrupting electrostatic induce current	Switching current: 40A Recovery voltage: 50kVrms

2.9.3 Specific issues and technical challenges for the operation of TEPCO's 1100 kV projects - Field tests

The developed UHV equipment was installed at the UHV test station (550 kV Shin-Haruna Substation) and full-scale field tests have been carried out since May 1996. The configuration of the UHV test station is shown in Figs. 2.9.4 and 5, and a photograph is provided in Fig. 2.9.6 The test station has one three-phase power transformer bank and one GIS bay with the control and protection systems. Each single-phase transformer comprises two split units each equipped with one on-load voltage regulator, enabling current to flow through the coil by using the tap-voltage difference between same-phase tanks. The GIS has an additional loop circuit with a power current transformer. Test currents up to 10,000 A can be achieved by reverse excitation of the power current transformer. Tables 2.9.4 and 5 summarize the accumulated duration of long-term verification tests and the testing items. [31]-[41]

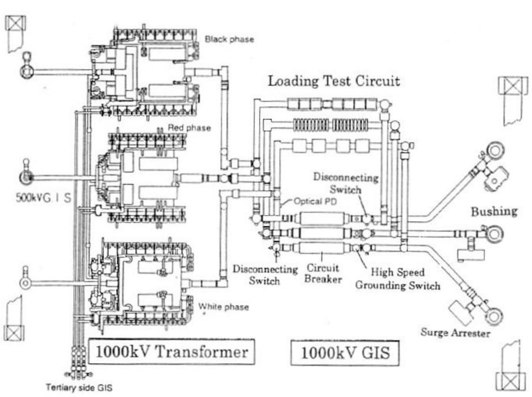


Fig. 2.9.4 *Configuration of UHV Field test*

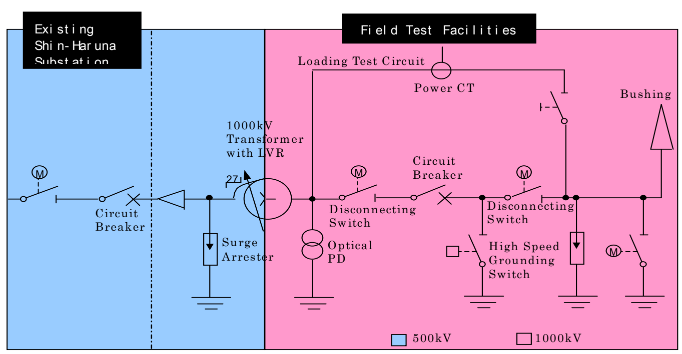


Fig. 2.9.5 *Single line diagram of UHV field test site*

2.9.4 Summary

To secure high reliability and economy of transmission lines and substation, the specifications for UHV equipment were determined based on detailed network analyses. Additionally, the developed UHV equipment including the three single-phase transformers, MOSA, CB, HSGS, disconnectors and gas bushings, etc, have been verified at the UHV test station since May 1996 and their long-term reliability and performance have been confirmed.

Fig. 2.9.6 *TEPCO testing station*

Table 2.9.4 *Operation records (August 2007)*

Item	Hours
Cumulated operation time of UHV Test Site	60456
Current carrying time of GIS	9995
Current carrying time of transformer by using the tap-voltage difference	7918

Table 2.9.5 *Field test items*

Equipments		***Testing items***
Transformer	Common	Long-term energizing and current carrying
	Periodical inspection	Dissolved gas analysis, insulation oil characteristics measurement
		Leakage current measurement at neutral terminal
		Noise, vibration measurement
	Inrush test	
GIS	Common	Long-term energizing / loop current carrying, temperature and thermal behaviour measurement
	Periodical measurement	Partial discharge, surge arrester leakage current
		Operating characteristics
		Optical PD accuracy
	Surge measurement	DS operating surge
		HSGS making surge
		Transient response of grounding system
		Residual DC voltage damping characteristics
	Surge arrester's temperature and thermal behaviour	
	Gas bushing vibration test	

2.10 China's project

2.10.1 Brief summary of China's 1100 kV projects

China's UHV grid will be used to interconnect the large coal-fired thermal power plants and hydro power plants in the northern and western parts of China with the load centres in the east and central parts of China. Around 2010, the total installed capacity of synchronized power will be about 514 GW, increasing to about 770 GW in 2020. The UHV AC transmission system will form the backbone of the synchronized power system, replacing the weak 500 kV connections and enhancing the transfer of bulk power between regions and improving the system stability. [42]

Research and feasibility studies with the involvement of CEPRI (China Electric Power Research Institute) have led to the optimum achievable voltage level for bulk transmission and system performance in China. According to the economic and technological evaluation, 1100 kV AC is a reasonable voltage level for UHV AC transmission in parallel with an 800 kV DC system. This hybrid system offers benefits with respect to security and stability performance, as an emergency control function will be adopted by the UHV DC system.

In system fault simulations, based on the period 2015 to 2020, the hybrid UHV AC/DC system shows a high capacity to maintain stability under contingencies such as monopole failure (no overloading and no voltage or frequency problems) and bipolar blocking (stable by means of tripping some hydro plants) by specifying a 10% long-term overloading capability in the UHV DC system.

According to China's "Criteria of electric power system security and stability," three coordinated defence lines will be implemented in the UHV transmission system:

- Preventive measures against system collapse through protection and automatic control of generators and other equipment;
- Security and stability control per area;
- Corrective measures through the coordinated tripping of generators, load shedding, grid separation, etc.

For the UHV AC system, the fault clearing times can be identical to those applied in the 500 kV grids. At increasing transmission capacity, thyristor-controlled series compensation will be needed and further investigation is required to suppress sub-synchronous resonance oscillations. Besides conventional control techniques, advanced control by means of FACTS and HVDC should be adopted.

Real-time UHV AC/DC simulations have been performed in order to study the system dynamics. Commutation failures in one or more converters, faults in the UHV DC lines and coordinated control actions in the UHV DC lines have been simulated in order to study the impact on the UHV AC system. The results of this research form the basis for implementing the first phase of the UHV AC / UHV DC system. Protection and control systems for the UHV AC system have been simulated and tested separately in relation to the system's dynamic and transient behaviour, leading to the protection policy and selected protection relays for the UHV AC system.

Studies with respect to overvoltage and insulation coordination for the UHV AC system revealed the following possibilities:

- TOVs limited to 1.3 p.u. in substations and to 1.4 on OH-lines
- SFO phase-to-ground limited to 1.6 p.u. in substations and 1.7 on OH-lines
- SFO phase-to-phase limited to 2.6 p.u. in substations and 2.7 on OH-lines
- Proposed methods for overvoltage limitation are MOSA (rated voltage 828 kV) along OH-lines, neutral reactor applied for shunt reactors giving SPAR time of 1 s, closing resistor and MOSA to limit switching overvoltages.

2.11 India's project

2.11.1 Features of India's transmission projects - Power generation and demand scenario in India

India's power system is poised for accelerated growth. Peak demand is expected to increase to more than 450 GW by 2025 and beyond from the present level of about 100 GW for which an installed capacity of about 600 GW is required.

It is estimated that peak demand by 2012 would be about 157 GW for which an installed capacity of about 210 GW is envisaged. Additional generation is envisaged at only a few locations for which the development of a strong transmission network would be required to connect these generation complexes to various load centres.

In order to ensure optimal utilization of dispersed energy resources, the high-capacity national grid of 16,600 MW inter-regional capacity, comprising 400 kV AC and HVDC system is already under operation, and shall be progressively enhanced to more than 37,700 MW by 2012 through a high-capacity 765 kV AC and +800 kV, 6000 MW HVDC system. To meet the long-term power transfer requirement by 2025 and beyond, large transmission networks interconnecting the generating resources with load centres are being planned. Preliminary work on the 1200 kV UHVAC system has already started and various alternatives are being studied for the selection of the UHVAC corridor.

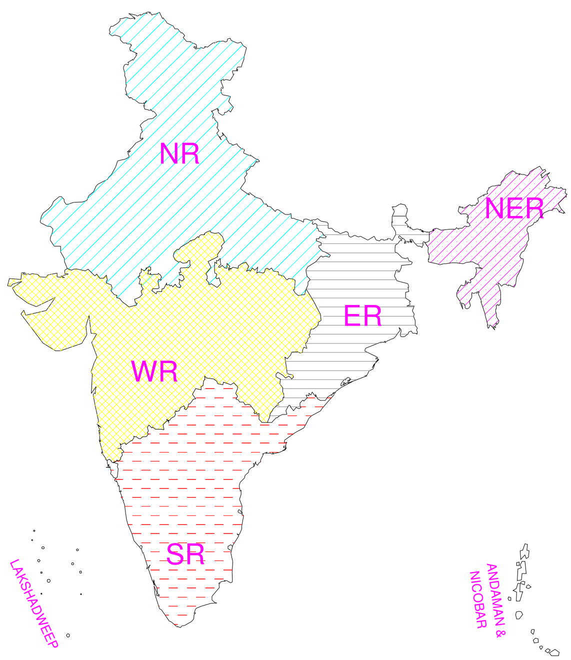


Fig. 2.11.1 *Region of India's power system*

2.11.1.1 Present transmission network of India

The present transmission network in India is a hybrid system comprising an EHVAC system up to 765 kV and an HVDC long-distance bipole and back-to-back system. The transmission network consists of about 1700 ckt.km of 765 kV lines, 190,000 ckt.km of 400 kV/220 kV lines, and about 5870 ckt.km of HVDC lines. Four (4) HVDC back-to-back systems (capacity 500-1000 MW) are presently in operation. In addition, fixed series compensation, thyristor-controlled series capacitors (TCSC) and static var compensators (SVC) are provided on various 220/400 kV transmission systems. Other technologies such as upgrading/uprating of transmission lines, high temperature endurance conductors, tall towers, GIS/compact substations, remote operation & substation automation, GIS/GPS-based line route survey techniques, etc. are also integrated in the system.

2.11.1.2 Future transmission network of India (with time frame)

By 2012, in addition to the existing network, India's system shall comprise a strong 765 kV and 400 kV network along with ±500 kV, 2500 MW and ±800 kV, 6000 MW long-distance HVDC links. The addition of about 9000 ckt.km of 765 kV AC lines and fifteen 765 kV substations are envisaged apart from a large number of 400 kV substations and transmission lines. Preliminary work on the 1200 kV AC system has already started and the first 1200 kV link is expected to be operational by 2012-13. The adoption of transmission voltage level in India's power system is shown in Fig. 2.11.2 below.

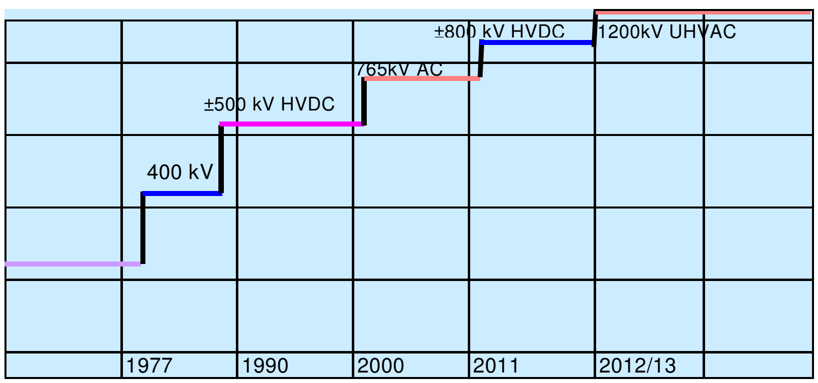


Fig. 2.11.2 *Adoption of transmission voltage level in India's power system*

2.11.2 Consideration for transmission development

Additional generation is envisaged at only a few locations in eastern and northeastern regions of India. This necessitates the transfer of large amounts of power across the region. Considering the demand and availability scenario of each region, it is estimated that about 90 GW of power is to be imported from NER/ER to NR/WR/SR (See the regions in fig.2.11.1). For this, the development of a large number of transmission corridors is required. However, the development of a large transmission network for transferring bulk power across the regions poses a number of challenges, as described below:

- Rights-of-way (ROW);
- Environmental considerations;
    - Optimization of cost;
    - Faster project implementation;
    - Coordinated development of transmission corridor together with other infrastructure;
- Transmission capacity enhancement through upgrading;
    - Reduction of loss;
- Integration of emerging technologies.

Keeping the above in view, a high-capacity transmission system interconnecting the eastern, western, northern and northeastern regions through a high-capacity ±800 kV, 6000 MW HVDC system and 765 kV ring has already been planned. However, taking into consideration the increased power transfer requirement to meet the above challenges, an alternative 1200 kV AC transmission system between various regions is also being explored. The 1200 kV AC technology would yield benefits in terms of fewer ROW corridors as well as savings in transmission line cost compared to using a 765 kV transmission system to transfer a similar amount of power.

2.11.3 Electrical design considerations for transmission lines

Preliminary design of the 1200 kV transmission lines has been carried out. Studies included:

a. Clearances and tower configuration analysis;

b. Thermal and surge impedance loading;

c. Conductor surface gradient and corona onset gradients;

d. Insulation/insulator design;

e. Electric field at ground;

f. Interference studies (RIV, AN);

Various bundle configurations were analysed and Octagonal ACSR conductor configurations named Bersimis, Moose and Lapwing were selected for further study. For finalization of bundle configuration, corona cage studies have been undertaken.

The phase conductor shall be placed in delta configuration. The insulator shall be in I-V-I configuration. Power frequency air gap clearance of 2.3 m under 55° swing conditions and switching surge clearance of 10 m under stationary conditions are being considered. (Tests for air gap clearances are in progress.)

Insulator string length of 10-11 m is envisaged comprising 55×320 kN or 50×420 kN porcelain disc insulators providing 21,600 mm creepage distance at 18 mm/kV

Phase-to-phase conductor clearance of 27.5-30 m and ground clearance of 20-23 m are being considered. The electrical field below the conductor shall not exceed 10-12 kV/m. Some electrical parameters are given in the following tables.

Table 2.11.1 (a) *Corona measurement (1)*

S.No.	Bundle conductor	Conductor surface gradient kV/cm		Corona onset gradient KV/cm	
		Mean	Max	Fair weather	Bad weather
1	Octa Moose	14.34	17.01	21.1	14.89
2	Octa Bersimis	13.02	15. 7	20.89	14.75
3	Octa Lapwing	12.0	14.67	27.73	14.64

Table 2.11.1 (b) *Corona measurement (2)*

S.No.	Bundle conductor	RIV (dB)		AN(dBA) L_5 level		AN(dBA) L_{50} level	
		Max	At 50 M ROW	Max	At 50 M ROW	Max	At 50 M ROW
1	Octa Moose	39.1	31.6	61.3	58.6	57.6	54.9
2	Octa Bersimis	36.5	29.1	60.3	57.6	55.9	53.2
3	Octa Lapwing	34.8	27.4	59.4	56.7	54.4	51.6

ACSR conductor size: 528.5 mm^2 for Moose, 689.7mm^2 for Berimis and 807.5 mm^2 for Lapwing

2.11.4 Preliminary study results for 1200 kV UHV AC systems

Preliminary studies are being carried out on the 1200 kV AC transmission system to limit switching and temporary overvoltages under different network conditions and varied source strength and line length.

For study purposes, 60% line shunt compensation is being considered. In addition, 40% reactive compensation is provided on the sending as well as receiving end buses. Studies are also being carried out to observe the impact on reactive power flow on the line in case of an increase in active power flow with and without line reactive compensation. Study results are shown in Fig. 2.11.3.

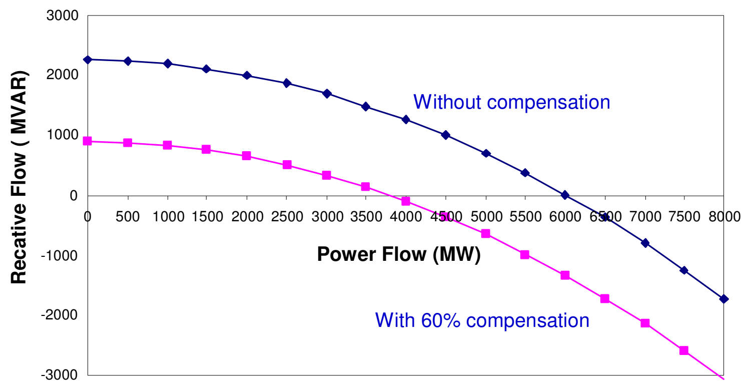


Fig.2.11.3 *impact on Reactive power flow*

2.11.5 Overvoltage studies

Deterministic studies are being carried out to find the optimal pre-insertion resistor (PIR) value to control switching overvoltages within the stipulated limits. The results of preliminary studies with and without PIR are listed below.

Table 2.11.3 *Switching Over Voltages (SOV)*

Case	**Switching overvoltage (P.U)**			
	W/o PIR	300Ω/ 10 ms	600Ω/ 10 ms	700Ω/ 10 ms
Source Short circuit-15,000 MVA; Line length-350 km	2.17	1.36	1.55	1.58
Source Short circuit-15,000 MVA; Line length-450 km	2.22	1.45	1.62	1.69

From the above results, it was observed that the optimal size for a PIR could be in the range of 600–700 ohm. Further statistical studies are also being carried out to ascertain the frequency of occurrence of maximum voltage encountered during SOV studies with the above PIR values, the results of which are shown below in Figure 2.11.4:

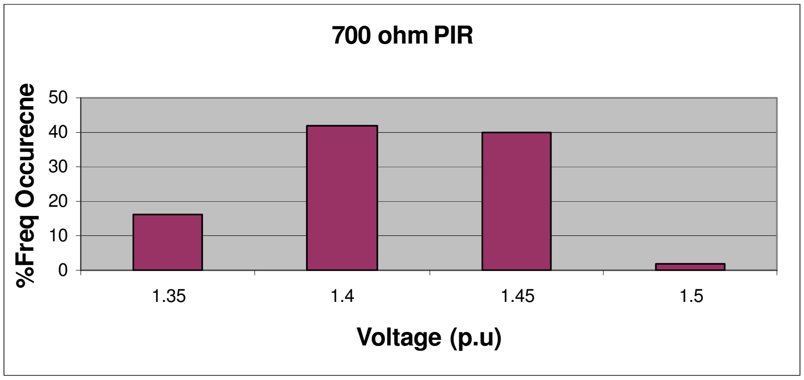


Fig. 2.11.4 *Switching Over Voltages in case of 700 ohm*

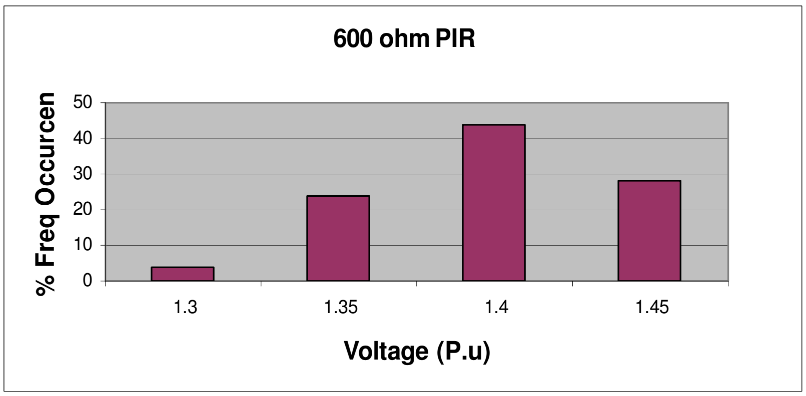


Fig. 2.11.5 *Switching Over Voltages in case of 600 ohm*

Keeping the above in view, the following protection level was selected for the 1200 kV AC system:

- Switching impulse withstand level (SIWV) (Switchgear/Bushings/Transformer windings) - 1800 kV
- Lightning impulse withstand level (LIWV) (Switchgear/Bushings) - 2400 kV
- Lightning impulse withstand level (LIWV) (Transformer windings) - 2250 kV
- Transformer rating 3×1000 MVA (Three single-phase units) with 18% impedance.
- Short-circuit levels - 50 kA

Temporary overvoltage studies are also being carried out to observe the level of overvoltage encountered by the system in the event of sudden load throw-off, etc. The results of TOV studies with different line lengths and without/with reactive compensation are listed in Table 2.11.4:

Table 2.11.4 *TOV with Power flow of 3200 MW at 0.92 pf., 15000 MVA Source strength*

	W/O Line reactor	**With Line Reactor**
340 km long line	1.48 p.u.	1.31 p.u. (500 MVAR LR)
400 km long Line	1.60 p.u.	1.34 p.u. (660 MVAR LR)

In addition to the above, studies are also being carried out to determine the appropriate surge arrester rating for the optimal insulation level of electrical equipment. Based on the study results, the following surge arrester is recommended:

Table 2.11.4 *Surge Arrester Parameters*

SA Class	5
Rated Voltage	826 kVrms
Continuous Operating Voltage(COV)	702 kVrms
Nominal discharge current	20 kA
Lightning Impulse residual voltage	1675 kVp at 10 kA 1790 kVp at 20 kA
Energy level	30 MJ

Typical V-I characteristics of the surge arrester are considered : 1460 kV at 1 kA, 1520 kV at 2 kA, 1575 kV at 5 kA, 1675 kV at 10 kA and 1790 kV at 20 kA.

2.12 Summary

Chapter 2 reviewed the state-of-the-art of project and national technical specifications for substation equipment at voltages of 765kV and above. The rapid growth in electrical power demand especially in China, Brazil and India is pushing the development and construction of new UHV transmission systems. The transmission capacity of UHV transmission systems with two routes has reached about 10GW, which is three times larger than that of 550kV transmission systems. The reviews identified the areas of commonality and of divergence that will be discussed further in chapter 3. The operations of 800kV transmissions provided several valuable field experiences that help new technical challenges for UHV transmissions.

The pioneering investigations of corona noises provided the fundamental designs of the multi-bundle conductors for UHV transmission lines. The use of the multi-bundle conductors with large diameters can reduce the line surge impedances but increase the time constant of the DC component in a fault current. Furthermore, the use of large capacity power transformers reduces the first-pole-to-clear factor due to the small zero-sequence impedance of the system. Low losses of power transformers and transmission lines increase the amplitude factor of the TRV. Surge arresters also play an important role in reducing the TRV values.

The various national technical specifications described in chapter 2, are compared and evaluated in chapter 3 carefully considering the technical maturities, economic and reliability aspects. Then, the best practises for UHV specifications are recommended along with some comprehensive explanations of their technical background.

References

[1] T. J. Nagel et al., “Development of the American Electric Power System Transmission Network: From 345kV to 765kV to UHV”, CIGRE Session 32-13, 1974

[2] L. B. Wagenaar et al., “EHV transformer Dielectric Specification Improvement”, IEEE Transactions on Power Delivery, Vol.9, No.1, January 1994

[3] A. J. F. Keri et al., “The use of Reactor Switches on Single Phase Switching”, CIGRE Session 13-06, 1980

[4] H. N. Scherer et al., “AEP-ASEA UHV Research Project-Results to 1983”, CIGRE Session 38-04, 1984

[5] CIGRE WG 13.04 “Specified Time Constants for Testing Asymmetric Current Capability of Switchgear”, ELECTRA No.173, pp.19-31, 1997

[6] Khodabachian et al., “TRV and the non-zero phenomenon in Hydro-Québec’s projected series-compensated system”, CIGRE 13-303, Session 1992,

[7] A. Déry, J.-P. Gingras, "Hydro-Québec TransÉnergie De-icing project at Lévis Substation," presented at the 11th Int. Workshop on Atmospheric Icing of Structures, Montreal, Canada, June 2005.

[8] A. Mercier et al. “Transformer Controlled Switching Takinng into account the core residual flux, a real case study” CIGRE 13-201, Session 2002

[9] J. Redlund et al., “A new fast protective device for high voltage series capacitors”, IEEE No 1-4244-0493, 2006

[10] S. D. Baik et al., “Introduction of KEPCO’s 765kV AC Transmission System”, International Conf. of UHV Power Transmission Technology, pp.24-31, 2006

[11] Motta and H. A. M. Fadini “Itaipu Transmission System – Consolidation of FURNAS Experience” - Book published only in portuguese under the coordination of S. S. G. ISBN 85-85996-01-3 - Rio de Janeiro, 1995

[12] “Achieving its Potential in Electrical, Electronic and Multimedia Technologies” IEC Latin America Regional Centre Seminar 2007 (IEC-LARC) - May 2nd and 3rd, São Paulo, Brazil

[13] ‘Regulatory Acts’ Library of the Brazilian Regulatory Agency for electric energy

[14] Italian Panel on UHV “Open aspects and possible alternative technologies following the UHV 1000 kV Italian experience”, IEC/CIGRE UHV Symposium 2007, paper 1-1-2

[15] Italian Panel on UHV “Open Testing challenges for UHV equipment”, IEC/CIGRE UHV Symposium Beijing 2007, paper 4-1

[16] Annestrand, S. A., Parks G. A., “Bonneville Power Administration Prototype 1100/1200 kV Transmission Line Project,” IEEE Transactions on Power Apparatus and Systems, Vol 96, March/April 1977, pp. 357-366

[17] Klinger, et al., “Experience of a 6 year 1200 kV Transmission Line Test and Development Program at the Bonneville Power Administration,” CIGRE Conference on Large High Voltage Electric Systems, Aug. 29- Sept. 6, 1984, Paper 38-08

[18] Perry, D. E., et al., "BPA 1100-kV Transmission System Development Corona and Electric Field Studies," IEEE Transactions on Power Apparatus and Systems, Vol 98, Sept/Oct. 1979, pp. 1728-1730).

[19] Stearns, R. D., and T. D. Bracken. "Corona and Electric Field Performance of the BPA Prototype 1200 kV Transmission Line," (CIGRE Symposium 22-81, 1981rPaper 232-06)

[20] Nellis, C. L., et al., “BPA 1100 kV Transmission System Development Insulation Studies,” IEEE Winter Power Meeting, Feb 9, 1979

[21] V. Kovalev et al, “Prospects for Creation of New Generation of Ultra-High Voltage Equipment”, IEC-CIGRE UHV Symposium, Beijing, 18-21 July 2007, Paper 2-4-2

[22] N.N. Belyakov, et. al., "Results of internal overvoltages and electrical equipment characteristics measurements in the Soviet 750 kV networks", CIGRE Session 1978, 33-08
[23] N.N. Belyakov, et. al., "Application of single-phase auto-reclosing in a complex EHV network containing 1200 kV transmission lines", CIGRE Session 1990, Paper 34-207
[24] N.P. Emelyanov, et al., "Investigation of corona effects on EHV and UHV transmission lines", CIGRE Session 1984, Paper 36-11
[25] L.V. Timashova, Ecological Influence and Electromagnetic Compatibility for Overhead Electric Transmission Lines, VNIIE Herald (Proceedings), 2004, pp.42-63, in Russian
[26] Methodology of calculating corona losses is described in the book A. Tamazov, Corona on Conductors of AC Overhead Lines, Sputnik Co Publishing House, Moscow, 2002, 316 pp., in Russian
[27] T.Watanabe et al., "Required duty for 1000kV circuit breaker (phase 1)(UHV-1)",1993 JEEA, Power and Energy Meeting, No.54.
[28] Y.Yamagata et al., "Required duty for 1000kV circuit breaker (phase 2)(UHV-2)",1993 JEEA, Power and Energy Meeting, No.55.
[29] Y.Yamagata et al.,"Capacitive current switching test method for 1000kV GCB",1994 JEEA, Japan Review, No.1455.
[30] Y.Yamagata et al.,"Field test of 1000kV gas insulated switchgear," CIGRE 2000 Paris Session SC13-209
[31] T.Tanabe et al., "Interrupting Duties and Test Specifications of 1,100kV Gas Circuit Breaker and Its Development for Future UHV Power Transmission System in Japan", Colloquium of CIGRE SC13, Report 1.2, 1995 Florianopolis.
[32] Y.Yamagata et al., "Development of 1,100kV GIS-Gas Circuit Breakers, Disconnectors and High-speed Grounding Switches", CIGRE 1996,13-304
[33] A.Nakamura et al., "1100kV AC Transmission Project in Japan ", IEC/CIGRE UHV Symposium Beijing 2007, 1-2-1
[34] E.Zaima et al., "System Aspects of 1100kV AC Transmission technologies in Japan: Solutions for Problems Specific to UHV AC Transmission System and Insulation Coordination ", IEC/CIGRE UHV Symposium Beijing 2007, 2-1-1
[35] M.Isozaki et al., "Special design and arrangements of UHV AC Conductors and subconductors taking reduction of environmental impact into consideration", IEC/CIGRE UHV Symposium Beijing 2007, 2-2-4
[36] G.Sun et al., "Suitable Configuration of Switchgear for UHV AC substation", IEC/CIGRE UHV Symposium Beijing 2007, 2-3-2
[37] T.Kobayashi et al., "Basic design / specifications of GIS for UHV AC and its verification test at site", IEC/CIGRE UHV Symposium Beijing 2007, 2-3-3
[38] N.Qiu et al., "Environmental Considerations for UHV substations", IEC/CIGRE UHV Symposium Beijing 2007, 2-3-5
[39] Y.Yamagata et al., "Development of 1100kV Gas Circuit Breakers – Background, Specifications, and Duties - ", IEC/CIGRE UHV Symposium Beijing 2007, 2-4-3
[40] K.Hidaka et al., "Development of 1100kV AC GIS-arrester and the verification Tests", IEC/CIGRE UHV Symposium Beijing 2007, 2-5-2
[41] T.Kawamura et al., "Development and long term field tests for UHV, 3000MVA Transformer in Japan", IEC/CIGRE UHV Symposium Beijing 2007, 2-6-5
[42] Yin Yong-hua, et al., Research and application of UHVAC transmission technology, IEC/CIGRE UHV Symposium Beijing 2007

3 Specific topics

3.1 Insulation coordination

With higher system voltages, especially UHV exceeding 800 kV, the technical and economic consequences of the insulation levels become increasingly important. Experts involved in UHV (pilot) projects therefore pay considerable attention to reducing the overvoltage to as low a level as possible. Optimal insulation coordination is thus extremely important for UHV systems. Based on past experience and studies from several places around the world, an overview is given of the insulation coordination policies applied or foreseen for UHV systems.

Insulation coordination throughout transmission lines and substations is a key factor for realizing a reliable and economical UHV system. Optimal insulation coordination can be achieved based on high-performance MOSAs, as demonstrated in UHV projects of the 1990s and later in Japan, Italy and China. Sophisticated design of insulation coordination by means of accurate computer-aided calculations and simulations is common practise for such projects, while withstand voltage can be roughly estimated by IEC's simplified method as described further in section 3.1.6.

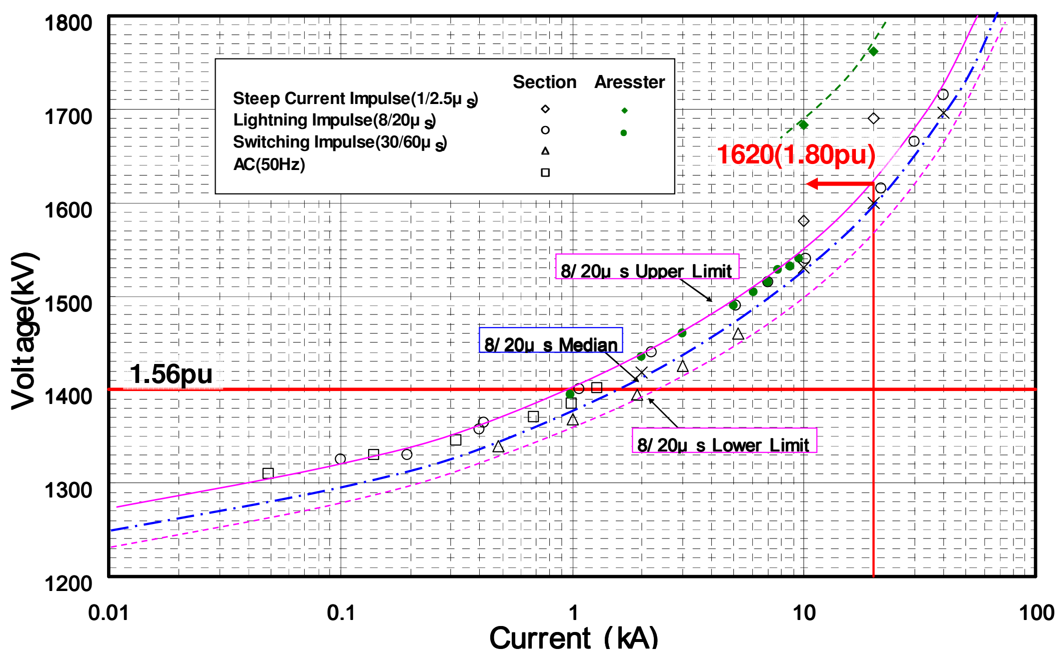


Fig. 3.1.1 *Example of V-I characteristics of high-performance surge arrester*

Suppressing switching overvoltages as much as possible is a prerequisite for air clearance to insulation in order to reduce the height of transmission towers and the dimensions of open-air parts in substations. As lightning overvoltages dominate the non-self-restoring internal insulation design of equipment such as GIS and transformers, here it is important to rationalize LIWV by means of MOSA arrangement. To effectively suppress lightning overvoltages, single or multiple high-performance MOSAs must be installed at an adequate number of locations, such as at line entrances, busbars and transformers. To suppress switching overvoltages, pre-insertion (closing, closing/opening) resistors are often applied in addition to MOSAs. Other options include the installation of MOSAs along OH lines and controlled switching, but these technologies are not widely applied. An example of the V-I characteristics of high-performance surge arresters is given in Fig. 3.1.1. Furthermore, VFTO caused by GIS disconnectors can be reduced to 1.3 p.u.

or less by means of pre-insertion resistors in GIS disconnectors.

Another important aspect of insulation coordination is the utility's policy regarding withstand margins for severe lightning or switching conditions with a very low probability of occurrence. As precise computer simulations accurately show the impact of such severe conditions, consideration might be given to omitting the additional safety factor, especially when some stress factors are less severe than those defined in the standards. A good example is lightning discharge currents, where the front duration tends to be longer with larger amplitude of lightning stroke current, as shown in Fig. 3.1.2 [1].

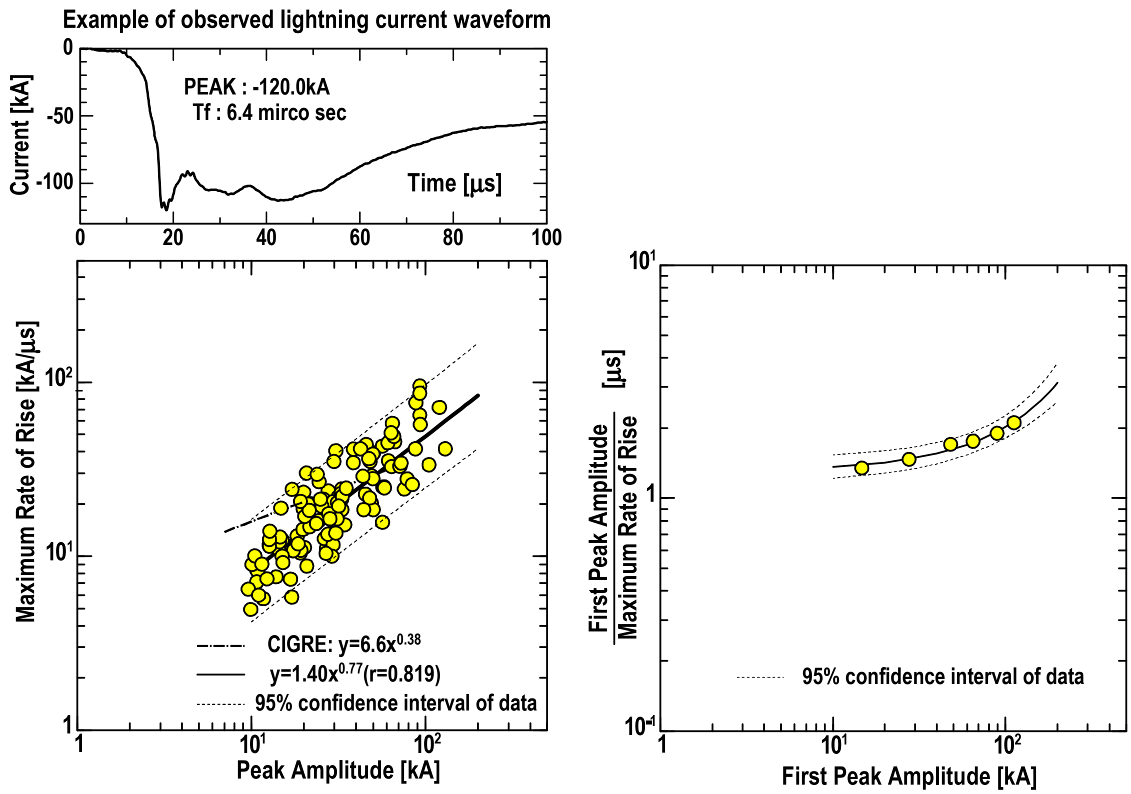


Fig. 3.1.2 *Relationship between lightning stroke current amplitude and rate-of-rise*

3.1.1 Power frequency voltage

Table 3.1.1 indicates that the maximum operating voltage does not differ greatly in the UHV pilots and projects, apart from one or two exceptions [2]. IEC doc 1241/8/CDV proposes 1100 kV and 1200 kV (under consideration) as highest voltage for equipment.

Table 3.1.1 *Highest voltage of UHV projects*

Project	**Italy**	**Russia**	**Japan**	**China**
Um (kV)	1050	1200	1100	1100

The exceptions are related to pilot projects that have since been discontinued and that included maximum operating voltages of 1600 kV (USA) and 1800 kV (Russia). The values given in Table 3.1.1 are used as a reference level for that specific country. For power frequency voltages, 1 p.u. $= Um/\sqrt{3}$; and for transient overvoltages and transient recovery voltages (TRV), 1 p.u.$=Um\sqrt{2}/\sqrt{3}$.

3.1.2 Temporary overvoltage (TOV)

TOV is an important power frequency voltage level, which expressed in p.u. must be as low as possible. TOV in large systems is mainly caused by Ferranti effect, (ferro)-resonance phenomena and single-phase faults. One special resonance phenomenon in relation to shunt reactors, is that under SPAR (single-phase rapid auto-reclosing), it might be energized by capacitive coupling from the healthy phases. [3] If the inductance of shunt reactors connected to the faulted line phase and the line capacitance are very close to parallel resonance at power frequency, the recovery voltage on this phase may be limited by corona loss (depending on the corona onset voltage). Calculations of the voltage level on Russia's 750 kV lines, confirmed by field tests, showed that steady-state voltage in this case reached 1.4-1.5 p.u. In a 420 kV case [3] with a low visible corona onset voltage of 1.35 p.u., the TOV level is limited to 1.6 p.u. In the presence of a neutral reactor, this voltage is usually less, due to detuning from resonance conditions.

Another special resonance phenomenon is the energization of large power transformers or shunt reactors in a weak network, as may occur during the initial stage of UHV network or during system restoration. TOV up to 1.45 and 1.55 has been reported, line to ground and lasting for seconds. [4],[5] Ferro-resonance overvoltages on second harmonics were observed during one-side switching of 750 kV lines even from powerful feed networks where they were generated by nonlinearity of shunt reactor and/or transformer magnetization curves. These TOV could be especially dangerous for EHV/UHV equipment if protective overvoltage relays operate on effective, not peak, voltage values and are not able to detect the TOV.

As suitable countermeasures are available, it is assumed that resonance and ferro-resonance phenomena would be anticipated and prevented or at least limited in magnitude and/or duration. The two remaining causes of TOV are single-phase faults and Ferranti effect.

In the case of single-phase faults, the relationship between TOV and k_{pp} (first-pole-to-clear factor) results in an overvoltage of 1.27 p.u. for k_{pp} = 1.3, of 1.16 p.u. for k_{pp} = 1.2 and of 1.06 p.u. for k_{pp} = 1.1. Only in cases of relatively high k_{pp}, the TOV reaches a certain importance. Single-phase fault clearing will take several tens to several hundreds of ms. The relationship between the healthy-phase power frequency voltage and the X_0/X_1 ratio can be seen in Fig. 3.1.3. When the impedance is indicated in p.u., the impedance of OH lines is nearly in reverse proportional to the square of the system voltage. In UHV systems, the ratio of line impedance to total system impedance, seen from the fault location, becomes smaller and, thus, the earth-fault factor tends to be smaller.

The Ferranti effect is normally controlled by shunt reactors (and, when applied, series capacitor banks) that are switched on before the OH line is energized and switched off at high loads or, sometimes, after switching off the OH line. In the case of sudden load rejection at a heavily loaded long line, the voltage jump due to Ferranti effect will lead to a TOV, which lasts until either the OH line is tripped at both sides or the shunt reactors are switched on. The amplitude of the TOV under such circumstances is system dependent, but computer simulations show a typical maximum TOV of 1.4 to 1.5 p.u. lasting < 0.5 s. This applies to studies performed in Italy, Russia, Japan and China. [2],[6],[7]

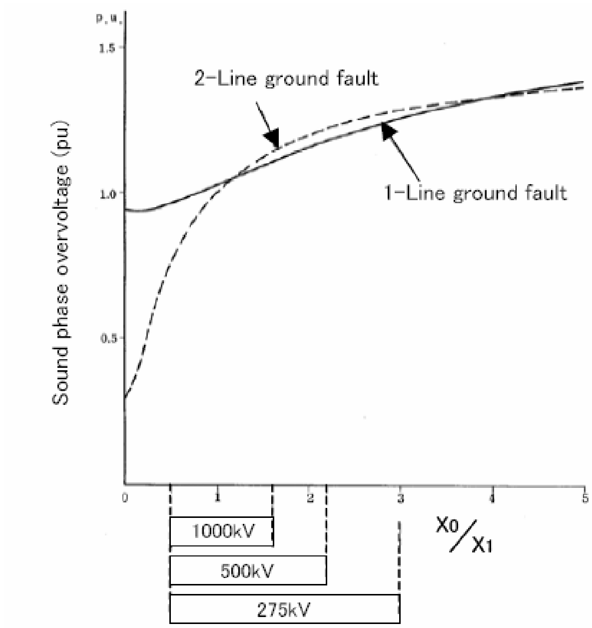


Fig. 3.1.3 *General tendency of earth-fault factor in Japan*

For TOV control during load rejection, it is vital to apply automatic high-speed insertion of shunt reactors and transfer-tripping to the other side of the OH line. In some countries, for extreme contingencies that lead to higher TOV than stated above, MOSAs are used to limit the TOV to 1.7-2.0 p.u. [8] At the 800 kV level, in Canada, sacrificial switchable MOSAs are used to control the TOV to 1.6 p.u., as may be necessary under severe system conditions. Normally, however, surge arresters are not used to limit TOV, as it would be less than 1.4 p.u. A contingency may be a case in which a phase-to-earth fault occurs in combination with load rejection, reaching TOV values higher than stated above for the occurrence of single-phase faults. In Japan, the TOV during load rejection can reach 1.4 p.u. or higher due to Ferranti effect under self-excitation phenomena, and when an earth fault follows the load rejection, TOV can reach around 1.5 p.u. with a trapezoid waveform due to the clipping voltage of MOSAs. The energy capability of MOSAs is specified as 55 MJ or more to ensure this TOV level. If necessary, an overvoltage protection relay system to open the no-load OH line is applied to avoid excessive energy absorption. [9]

It is important to recognize that in EHV/UHV transmission, it is impossible to completely exclude TOV, but it is possible to reduce its magnitude and duration to acceptable limits. From this point of view, it would help to ask UHV equipment manufacturers to provide information about permissible TOV magnitude versus time of application for equipment with insulation, magnetic core and energy absorption designed to withstand operating voltage and switching and lightning overvoltages. Such information, based on the “natural” insulation strength, already exists in Russia’s standards. [5]

3.1.3 Slow front overvoltage (SFO)

Slow-front overvoltage or switching overvoltage is controlled by means of such technologies as pre-insertion resistors (closing resistors or PIR), opening resistors, controlled switching, and application of MOSAs and of MOVs across the arcing chambers. Without taking certain measures, the switching surge at line energization can lead to a maximum SFO of 3 p.u. By means of PIR, the switching surge is reduced to 2.0-2.2 p.u., and by two-step PIR even further to 1.5-1.6 p.u. The application of controlled switching leads to switching surges less than 2.0 p.u., while MOSAs lead to SFO of 1.7-2.2 p.u., depending on the SIPL. A combination of measures, such as controlled switching with PIR and MOSAs, could decrease the SFO to 1.6 p.u. These SFO levels are along the OH line and are higher than at the line ends and at the substation busbar side. Phase-to-phase switching overvoltages along the OH line are 2.6 to 2.9 p.u.

Without taking measures, SPAR leads to SFO of less than 2.4 p.u., but by means of the measures mentioned above, it is possible to achieve SFO similar to that with line energization. TPAR (three-phase rapid auto-reclosing) gives an SFO between 3.8 and 4.0 p.u. (with trapped charge) or up to 3.0 p.u. (without trapped charge). The application of PIR, controlled switching and/or MOSAs decreases the SFO to less than 2.5, 2.0 and 1.7 p.u., respectively. [8] When such low SFO values are reached, the SFO caused by clearing single-phase faults becomes quite important, as it may be larger: 1.8-2.1 p.u. Opening resistors will reduce the SFO at clearing short-circuit currents for single-phase faults as well as three-phase faults. [2]

Note that for systems with series compensation, the given values for SFO may be higher due to the residual charge on the series capacitor bank. This depends on the network topology in combination with the location of the capacitor banks, as well as on the protection measures implemented for the series capacitor bank: MOV, triggered spark gap, bypass breaker and its protection scheme, etc.

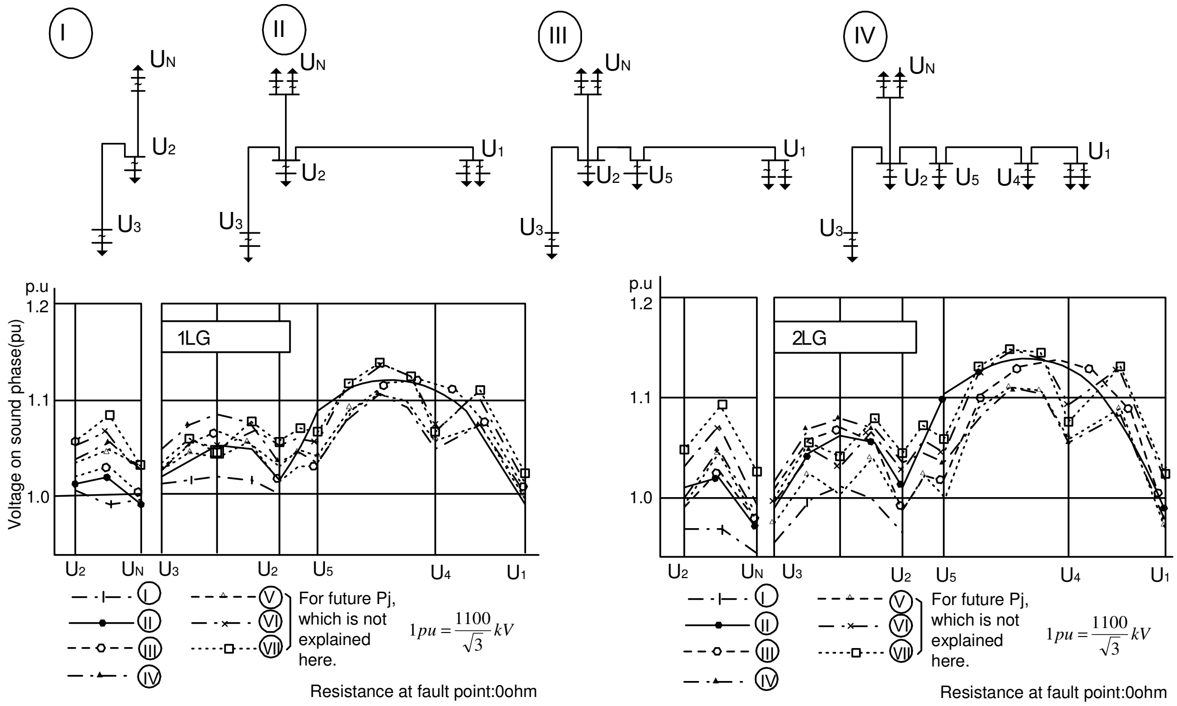


Fig. 3.1.4 *TOV in healthy phases during ground faults (Japan)*

At the occurrence of a single-phase-to-ground fault (1LG), the phase voltage changes to zero potential instantaneously. The voltage jump leads to travelling waves in the faulty phase and induces travelling waves in the healthy phases. In the process of propagation and reflection in the healthy phases, transient voltages are superimposed on the AC voltages, leading to overvoltages. These ground fault overvoltages are regarded as SFO and are highest when the earth fault occurs near the peak value of the power frequency voltage. Maximum SFO tends to appear in the middle of the OH line, where TOV is highest; see Fig. 3.1.4 where TOVs are simulated for TEPCO's future 1100 kV system. A simplified model of the system with simulated fault locations is given in Fig. 3.1.5 and ground fault overvoltages along the system are shown in Fig. 3.1.6 (i.e. maximum SFO for any fault location and any phase angle of the earth fault). Figure 3.1.7 gives an example of the waveforms for the maximum SFO at the location of the highest SFO value (1.62 p.u.) for each phase. The travelling waves can be clearly distinguished.

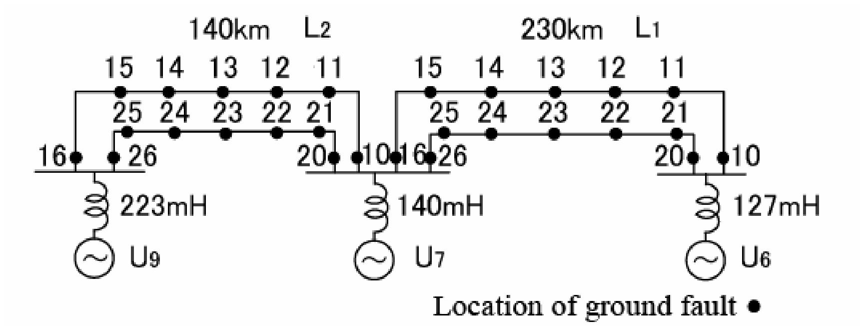


Fig. 3.1.5 *Simulated future UHV system planned by TEPCO*

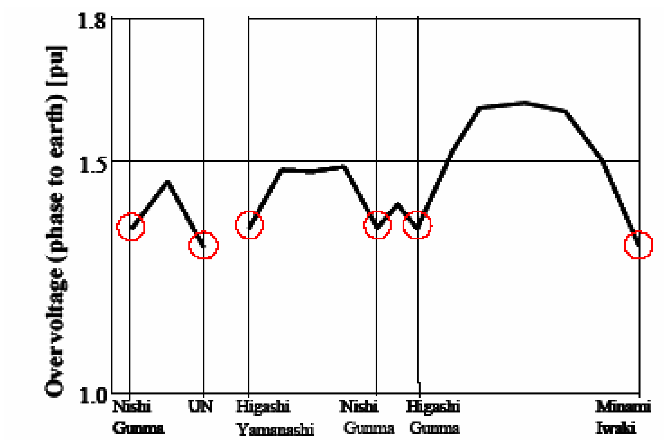


Fig. 3.1.6 *Ground fault overvoltages (maximum SFO at healthy phases) along UHV system*

As reported in Ref. [10], the SFO is proportional to the earth-fault factor and may reach values as high as 1.5 p.u. in systems with an earth-fault factor of 1.25 to 1.3. However, as reported in References [10] and [11], in the future UHV system in Japan with k_{pp} as low as 1.1 (earth-fault factor as low as 1.06), the overvoltage at healthy phases may reach 1.6 p.u. in substations and 1.7 on OH lines, as shown in the above figures. In a UHV system, transmission losses are very low because multi-bundle conductors are applied in order to suppress corona noise. Surge voltage propagates along the OH lines in line-to-earth and line-to-line modes. The results of measurement on an actual UHV OH line reveal that line-to-line waves hardly attenuate during propagation along 200 km.

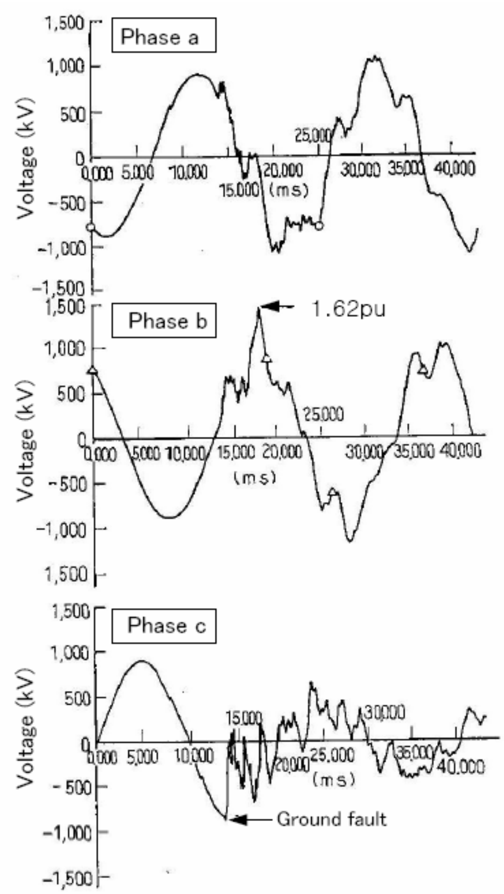


Fig. 3.1.7 *Analysed waveform of maximum SFO at single phase to ground fault (near location U_6, SA protection level: $V_{20\,kA}$ = 1620 kV)*

Moreover, the topology of UHV systems is radial and rather simple, leading to far less refraction of travelling waves compared to that in meshed EHV systems. Both characteristics of UHV systems lead to SFO at the occurrence of a phase-to-ground fault as high as 1.6-1.7 p.u., even in the case of low earth-fault factors.

For UHV systems, the following calculations for SFO have been reported [2],[12],[13]:

Table 3.1.2 *Slow front overvoltages (SFO)*

SFO (pu)	***Italy***	***Russia***	***Japan***	***China***
Line ph-gr	1.7	1.8 (1.6)	1.6/1.7	1.7
Substation ph-gr		1.8 (1.6)	< 1.6	1.6
Line ph-ph	2.7		2.6/2.8	2.9
Substation ph-ph			2.6/2.8	2.8

Note that switching overvoltages in Japan are reduced to the same level as ground-fault overvoltages by means of closing/opening resistors. Additionally, UHV OH lines in Japan are rather short in length compared to those in Russia and China. For Russia, the values without brackets apply in cases of gap-type SiC arresters; the values within brackets are those when MOSAs would be used and are comparable with the other countries. Brackets are used for the same reason in other tables.

3.1.4 Fast front overvoltage (FFO)

Fast front overvoltage or lightning overvoltage is a less important parameter for UHV OH lines in comparison to EHV and HV OH lines. The specified TOV and SFO determine the dimensions of the OH lines. Furthermore, the accepted number of outages due to lightning determines the shielding angles, tower footing resistance, etc.

For substation equipment, the specified LIWV is of interest. Table 3.1.3 gives the general specifications for LIWV and SIWV in substations, as required in several countries. [2],[12],[13]

Table 3.1.3 *Insulation level for substation equipment*

(kVpeak)	*Italy*	*Russia*	*Japan*	*China*
Max. operating voltage	1050 (kVrms)	1200 (kVrms)	1100 (kVrms)	1100 (kVrms)
SIWV	1675	2100 (1800)	1550	1800
pu	1.95	2.14 (1.84)	1.73	2.00
LIWV	2250	2900 (2400)	2250	2400
pu	2.62	2.96 (2.45)	2.51	2.67

Lower values are specified for transformers, as can be seen in Table 3.1.4, where only the UHV side is presented.

Table 3.1.4 *Insulation level for transformers*

(kVpeak)	*Italy*	*Russia*	*Japan*	*China*
SIWV	1800	2100 (1800)	1425	1800
pu	2.10	2.14 (1.84)	1.59	2.00
LIWV	2250	2550 (2250)	1950	2250
pu	2.62	2.60 (2.30)	2.17	2.51

In countries such as Russia and China, the same SIWV is proposed for transformers and reactors as for other substation equipment, while in Japan the proposed SIWV requirements are roughly 10% lower in comparison to other equipment, and in Italy higher SIWV values are proposed. This is mainly due to the fact that Japan's UHV system has been optimised with respect to limiting the switching surges as much as possible. Furthermore, expressed in p.u., the SIWV requirements for both transformers and other equipment in Italy, Russia (with MOSAs) and China are relatively close to each other, but are much higher than those of Japan.

Also, with respect to the LIWV, Italy shows the same LIWV for transformers as for the other equipment. Japan requires LIWV values roughly 13% lower for transformers than for other equipment, and Russia/China roughly 6% lower values. Expressed in p.u., LIWV requirements for transformers in Italy, Russia (with MOSAs) and China are comparable. For other equipment, the proposed LIWV levels are fairly close.

For all equipment, Japan requires the lowest SIWV and LIWV at each level, as full advantage is taken of improved technologies to decrease the insulation levels. In figure 3.1.8, a comparison in p.u. is shown between the SIWV and LIWV applied in different countries.

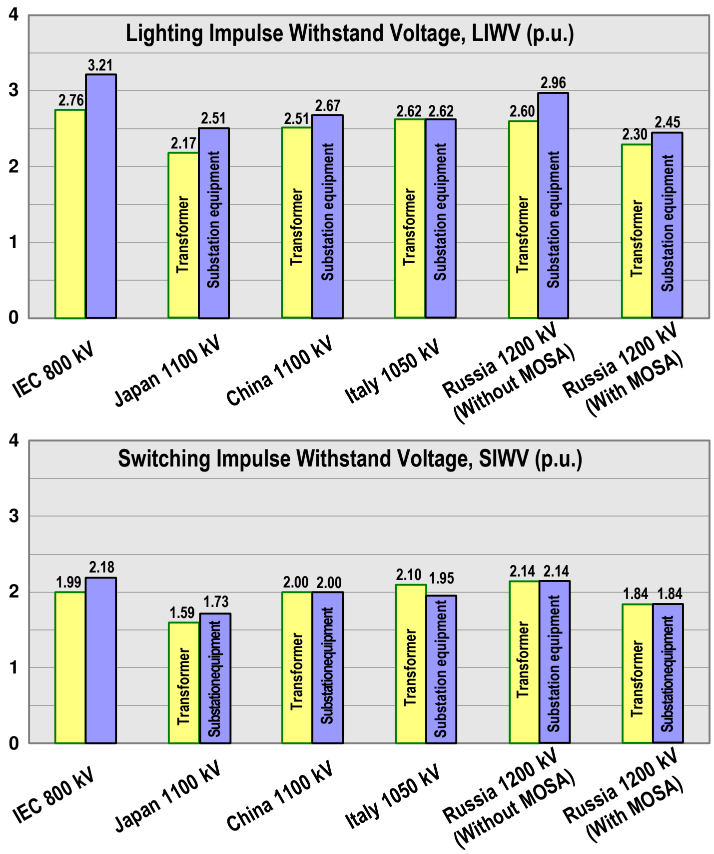


Fig. 3.1.8 *LIWV, SIWV*

Withstand voltage for UHV equipment were previously discussed within IEC TC 28 WG01. Through document IEC 28 (Secretariat) 81, a proposal for withstand voltages was made in 1987, but they were not standardized because there was no market relevance at that time. Table 3.1.5 compares the SIWV and LIWV of the document with that of China and Japan's recent projects. For SIWV, the values applied in Japan are well in line with the document, but the values applied in China are rather high. For LIWV, the values of China and Japan are in agreement. [14] The discussion will continue in IEC TC 28.

Table 3.1.5 *Comparison of LIWV and SIWV of IEC with China and Japan*

	IEC28 (Secr.)81	***China***	***Japan***
Highest voltage for equipment Um (kV)	1050-1100	1100	1100
Standard switching impulse withstand voltage phase-to-earth (kV)	1425 1550 1675	1800	1425 1550
Standard lightning impulse withstand voltage (kV)	1950 2100 2250 2400	2250 2400	1950 2250

In Ref. [15], the specifications for longitudinal withstand strength are given for China. The SIWV is 1675 + 900 kV and the LIWV is 2400 + 900 kV. Additional information is presented in Table 5.3.1.

3.1.5 Insulation levels and arrester protection levels

The information available covers gapped arresters applied in Russia and MOSAs applied in Italy, Japan and China. [12],[13] A comparison is shown in Table 3.1.6.

Table 3.1.6 *MOSA characteristics*

kV	Italy	Russia	Japan	China
Rated voltage (rms)	749	800	826	828
Peak at 10 kA			1550	1553
Peak at 14 kA		1850		
Peak at 20 kA	1800		1620	1620
LIPL (pu)	2.10	1.89	1.80	1.80
SIPL (pu)				1.62

In the figures 3.1.9 and 3.1.10 IEC insulation levels and commonly used protection levels are given for system voltages up to and including 800 kV. Insulation levels and arrester protection levels for the UHV projects in Italy, Russia (USSR), Japan and China have been added as well. As seen from the diagrams the trend in decreasing relative insulation levels continues. The very low relative arrester protection levels for the projects in Japan, China and Russia are also striking.

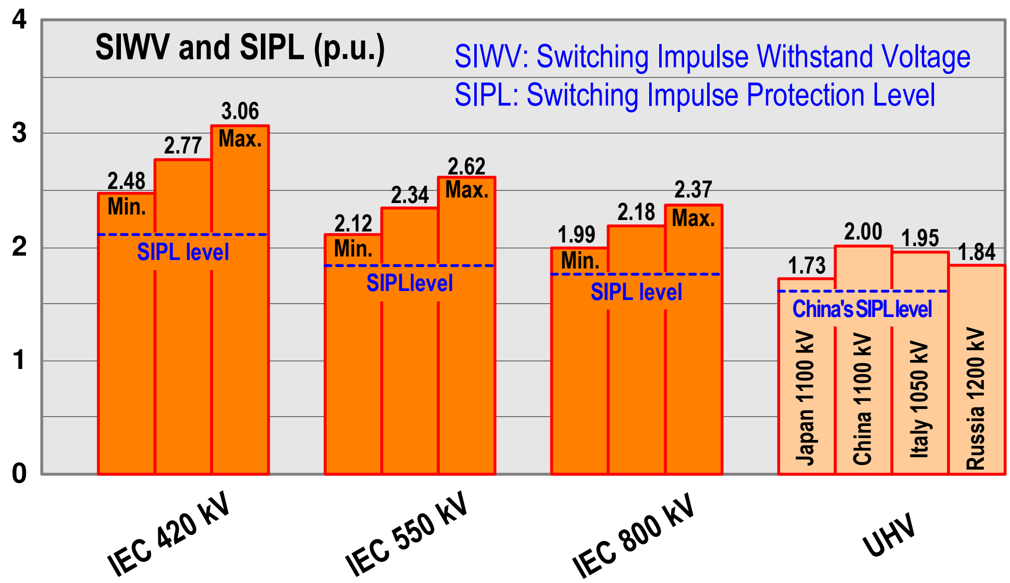


Fig. 3.1.9 *SIWV, SIPL*

Apart from Russia's use of conventional gap-type surge arresters (SiC, ZnO) as well as MOSAs for new applications, the following information can be given on Russian specifications. ZnO arresters used for SIPL of 1.8 p.u. have a maximum permissible operating voltage of 694 kV and permitted voltage of 760 kV for 20 minutes. The extinguishing voltage of the power frequency current, after a switching impulse current, is 1000 kV and after a lightning impulse current, 800 kV. The residual voltage at a switching impulse current of 1.5 kA (3/8 ms) is no more than 1760 kV and at a lightning impulse current of 14 kA (8 µs) is no more than 1940 kV.

MOSAs, used for SIPL of 1.6 p.u., have the same maximum permissible operating voltage and a permitted voltage of 765 kV for 60 minutes. Residual voltage at a switching impulse current of 2.8 kA (1.2/2.5 ms) is no more than 1570 kV, and at a lightning impulse current of 15 kA (8 µs), no more than 1760 kV.

3.1.6 Comparison with insulation withstand voltages calculated as per IEC procedure

The IEC procedure for insulation coordination is outlined in IEC 60071-1. [16] The application guide can be found in IEC 60071-2. [17] The procedure is applied here to an 1100 kV system, using arrester protection levels for fast- and slow-front overvoltages, i.e. LIPL and SIPL with values specified for the UHV systems in Japan and China. The calculation results such as for required withstand voltage could be compared with the selected insulation levels for existing and planned UHV systems.

3.1.6.1 Slow front overvoltages

Depending on the degree of limitation of slow-front overvoltage by arresters, the coordination factor K_{cd} shall be between 1 and 1.1 as per Ref. [17]. See Fig. 3.1.4.

The coordination withstand voltage, U_{cw}, is K_{cd} times the arrester protection level and thus shall be 1 to 1.1 times the SIPL.

To obtain the required withstand voltage, U_{rw}, the coordination withstand voltage shall be multiplied by the altitude correction factor, K_a, considering 1000 m and the safety factor, K_s.

The altitude correction factor, applied for external insulation only, is equal to $e^{m(H/8150)}$ where H is the altitude and m the factor according to the Figure 9 of Ref. [16]. For the coordination voltages expected for the 1100 kV system, the m-factor, for phase-to-earth insulation, is around 0.5, which results in $K_a = 1.06$.

The recommended safety factors as per IEC 60071-2 are as follows:

- For external insulation $K_s = 1.05$
- For internal insulation $K_s = 1.15$

Therefore, the required withstand voltage will be:

- For external insulation U_{rw} = 1.11 to 1.22 times SIPL
- For internal insulation U_{rw} = 1.15 to 1.27 times SIPL

With an SIPL of approximately 1.6 p.u.(1440 kV), U_{rw} will be:

- For external insulation 1598 to 1757 kV
- For internal insulation 1656 to 1829 kV

3.1.6.2 Fast front overvoltages

The coordination lightning impulse withstand voltage can be directly calculated by means of the simplified method in IEC 60071-2 using the following empirical formula:

U_{cw} = LIPL+ 2*S*L/c = LIPL + A/n*L/(Lsp+La), where

LIPL = Lightning impulse protection level of the arrester

La = Ra/Rkm line length with an outage rate equal to Ra (m)

Ra = Acceptable failure rate (1/year)

Rkm = Outage rate for lines connected to the station (1/(m*year)

S = 1/(Kco*(Lsp+La))

Kco = Corona damping factor (μs/(kV*m))

A = 2/(Kco*c)

c = Speed of light (300 m/μs)
Lsp = Span length (m)
L = Height of arrester + length of connection leads + distance to protected object (m)
n = Number of lines connected to the station

As an example, assuming the following:

- Ra: Acceptable failure rate 0.0025 (once in 400 years)
- Rkm: 0.00001 = One lightning fault per 100 km per year on the line in front of the station
- N: One or two lines to the station
- Lsp: Span length 500 m
- Kco = 0.4E-6 (for 6- or 8-conductor bundle)
- L = 30 m

This will result in the following coordination withstand voltage:

- For one line to the station U_{cw} = LIPL + 667 kV
- For two lines to the station U_{cw} = LIPL + 333 kV

To obtain the required withstand voltage, U_{rw}, the coordination withstand voltage shall be multiplied by the altitude correction factor, K_a, considering 1000 m and the safety factor, K_s.

The altitude correction factor, applied for external insulation only, is equal to $e^{(H/8150)}$ where H is the altitude (m-factor equals to 1). This gives $K_a = 1.13$.

The same safety factors as for slow-front overvoltage apply.

Therefore, the required withstand voltage, U_{rw}, will be:

- External insulation U_{rw} = 1.19*(LIPL+667) …… one line
- Internal insulation U_{rw} =1.15*(LIPL+667) …… one line
- External insulation U_{rw} =1.19*(LIPL+333) ……. two lines
- Internal insulation U_{rw} =1.15*(LIPL+333) ……. two lines

Finally, with an LIPL of 1620 kV (1.8 p.u.), U_{rw} will be:

- External insulation U_{rw} = 2721 kV …… one line
- Internal insulation U_{rw} = 2630 kV …… one line
- External insulation U_{rw} = 2324 kV ……. two lines
- Internal insulation U_{rw} = 2246 kV ……. two lines

The method described above was developed for AIS, but many of the UHV stations are GIS. However, it is stated in IEC 60071-2 that the procedure gives a conservative estimate for GIS even if a generally valid recommendation cannot be made on how conservative it is compared to AIS.

3.1.6.3 Comparison

For slow-front overvoltage, the selected SIWV for substation equipment in Japan is 1550 kV and in China 1800 kV. The procedure above indicates a required level for external equipment of 1598 to 1757 kV and for internal equipment 1656 to 1829 kV. China’s requirement is well within the calculated values, but Japan’s significantly lower level is considered sufficient.

For fast-front overvoltage, the selected LIWV for substation equipment in Japan is 2250 and in China 2400 kV. For transformers, the corresponding figures are 1950 and 2250 kV. The procedure above, considering two lines, gives 2324 kV for external equipment and 2246 kV for internal. For China, both substation equipment and transformer LIWV are above these values. In Japan, LIWV for the substation equipment is above, but LIWV for transformers is below. If only one line is considered, neither China nor Japan's LIWV values are above the calculated levels.

It must be pointed out that the IEC procedure is a simplification and, as mentioned above, not directly applicable to GIS. However, the procedure does reveal that the insulation coordination for fast-front overvoltages taking into account the preferred low insulation levels for UHV requires further detailed study.

3.1.7 Very fast transient overvoltage (VFTO)

Very fast transient overvoltage is generated by disconnectors within GIS installations. It can reach up to 2.6 p.u. or even more (in one specific case reported in Ref. [18], the VFTO reaches 3.05 p.u.), at frequencies in the MHz range. When PIR is used for these disconnectors at opening and closing, overvoltage can be limited to values such as 1.4 p.u. [19] At the UHV level, in order to prevent flashovers inside the GIS between conductor and tank, it is crucial to apply such PIR to the disconnectors. As reported in Ref. [18], in China's pilot project, PIR will not be installed for MTS (mixed technology switchgear or HGIS, hybrid GIS).

VFTO is discussed in further detail in Section 3.4.1.5.

3.1.8 Clearances

The required clearances between phase and ground, between phases, between different circuits and between phase and structure is dependent on altitude, prescribed wind velocity, safety requirements, risk of flashover, etc. But at the UHV level, it is obvious in all countries that the switching overvoltage is the most crucial stress factor for determining the required clearance. As climatic parameters and legal conditions are most dominant in OH lines, it does not make much sense to compare the clearances in OH lines between the UHV configurations in different countries. In substations, the conductor position is less influenced by climatic parameters and therefore clearances in substations are preferable for comparison.

The clearances between phase and ground, between phases and between phase and structure are given in Table 3.1.7. [2],[13]

Table 3.1.7 *Clearances of phase to ground, phases to phases, and phase to structure*

(m)	*Italy*	*Russia*	*Japan*	*China*
Phase to ground	8	12	8.5/10	
Phase to phase	12	11.4 -12.4	10.5 -11.5	11.3
Phase to structure	9.5	7.5 - 9.7	7.5 - 8.5	7.5

To clarify the necessary clearance at the entrance to UHV substations, [20] flashover tests were carried out using shielding rings under dry and wet (water spray) conditions. It was confirmed that flashover voltages decrease under wet conditions, as shown in Fig. 3.1.10, because water droplets on the shielding ring enhance the local electric field and lead to the occurrence of streamers. This means that with large shielding rings such as those for bushings, switching impulse voltages possibly increase under dry conditions, but decrease under wet. Accordingly, in Japan, the withstand voltage test of a bushing was performed under dry and wet conditions. In the test, waveforms of 250/2500 μs (standard) and 500/3000 μs were both applied taking into account that the critical front duration tends to be longer as the gap length tends to be larger.

Further information on clearances will be provided by CIGRE WG B3.22.

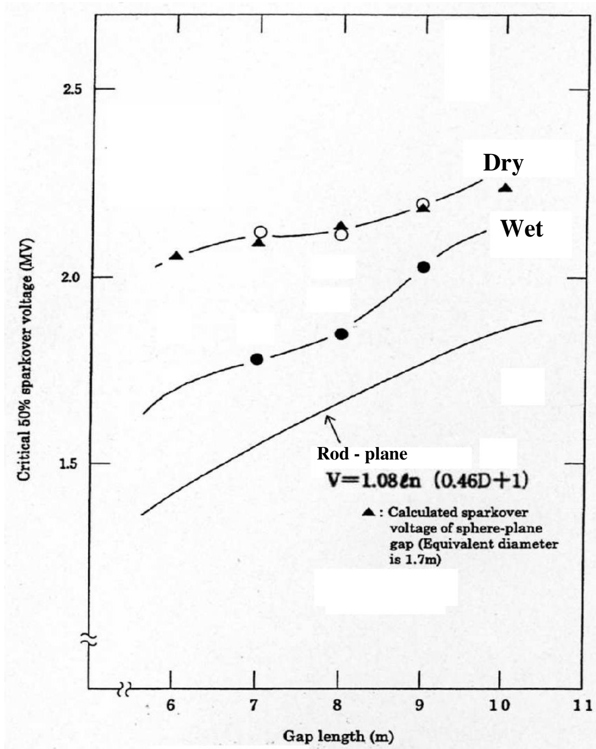


Figure 3.1.10 Critical 50% flashover characteristics (Phase to structure)

3.2 Transformers

3.2.1 Insulation level

The insulation level for power transformers should be specified based on insulation coordination with consideration for margin and the practise of utilities in terms of protection levels of different types of substations such as "AIS", "MTS", "GIS", etc., and arrangement/connection points in the substations for applied line arresters. For the 800 kV class system voltage, the insulation level for transformers should be selected or specified based on Tables 3.2.1 and 3.2.2, standardized in IEC and IEEE, respectively. The IEC and IEEE standards are lined up by multiple values of the insulation level for the 800 kV class, with discretion for the selection of insulation level by utility and taking into consideration the decision of rational specifications for power transformers.

Table 3.2.1 *Rated withstand voltages for transformer windings with Um=800 kV (IEC 60076-3 2000-03, Part 3 : Insulation levels, dielectric tests and external clearances in air)*

Um ; Highest voltage for equipment ($kV_{r.m.s}$)	Rated switching impulse withstand voltage phase-to-earth (kV_{peak})	Rated lightning impulse withstand voltage (kV_{peak})	Rated short-duration induced AC withstand voltage ($kV_{r.m.s}$)
800	1 300 1 425 1 550	1 550	630
		1 675	680
		1 800	N/A
		1 950	N/A
		2 100	N/A

Table 3.2.2 *Dielectric insulation levels for Class II power transformers (IEEE Std C57.12.00-2000 : IEEE Standard General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers)*

Nominal system voltage (kV)	Basic lightning impulse insulation level (kV crest)	Chopped wave level (kV crest)	Switching impulse level (kV crest)	Low frequency test levels	
				Induced-voltage test (phase to ground)	
				One hour level (kV rms)	Enhancement level (kV rms)
Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
765	1 800	1 980	1 500	690	800
	1 925	2 120	1 600	690	800
	2 050	2 255	1 700	690	800

On the 1100 kV class system voltage, the insulation levels are not specified in any international standards, and are presently decided by each utility according to individual 1100 kV transmission projects. Table 3.2.3 shows examples of insulation levels of 1100 kV project transformers that are actually in operation or are part of an ongoing project. The records for Russia are from the 1980s, and the insulation levels selected for China and Japan's projects involve the existence of high-performance zinc oxide arresters (protection level: 1620 kVpeak at 20 kA). However, as different insulations levels are decided, it is necessary to standardize them with a lineup of insulation levels due to the application of arresters with similar characteristics for both projects

Table 3.2.3 *Rated withstand voltage for UHV transformer windings*

Country	*Um ; Highest voltage for equipment $kV_{r.m.s}$*	*Rated switching impulse withstand voltage phase-to-earth kV_{peak}*	*Rated lightning impulse withstand voltage kV_{peak}*	*Rated short-duration induced AC withstand voltage $kV_{r.m.s}$*
Russia	1 200	2 100	2 550	1 100
China	1 100	1 800	2 250	1 100
Japan	1 100	1 425	1 950	1 100

3.2.2 Equivalent surge capacitance

As there is no official data on equivalent surge capacitance for UHV transformers, relevant research is underway. In the meantime, it is assumed that the values would be quite high compared with 500 kV class transformers because of the extremely large capacity of UHV transformers (the power supply of UHV transformers for China and Japan's projects is 1000 MVA per phase). There is an example value of approximately 10,000 pF per phase with single phase, core type and 1000 MVA per phase, but the value is for high voltage, large capacity and 6 legs in parallel connection per phase, so it would be changeable according to the type of transformer, core or shell, the arrangement of windings, and the provisions against surges in the high-voltage windings, etc. On the other hand, there are another available values that the equivalent surge capacitances are approximately 1,000-2,000pF per phase. Therefore, in the general calculations for insulation coordination, a wide range of values or large margin shall be considered for the equivalent surge capacitances ranging from 1,000 to 10,000pF per phase. Similarly, an example value of approximately 3000 pF per phase for equivalent surge capacitance for 800 kV class transformers requires the same considerations as for UHV transformers.

3.3 Circuit Breakers

3.3.1 TRV for terminal fault test duties

3.3.1.1 General

For rated voltages equal to or higher than 100 kV, the TRV for terminal fault test duties is described by two parameters (T10 and T30) or four parameters (T60 and T100).

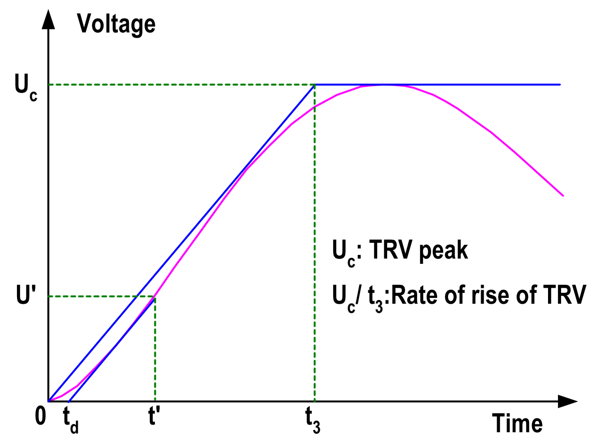


Fig. 3.3.1 *Representation of specified TRV by two-parameter reference line and delay line*

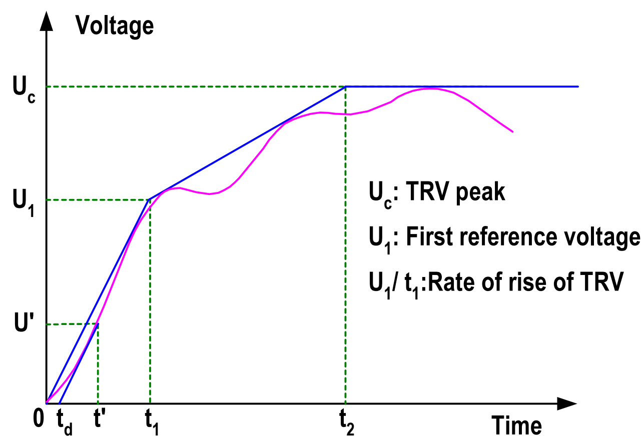


Fig. 3.3.2 *Representation of specified TRV by four-parameter reference line and delay line*

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

$$U_c = U_r \sqrt{\frac{2}{3}}\, k_{pp}\, k_{af} \qquad (1)$$

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, given by Equation (2), is a function only of the rated voltage and the first-pole-to-clear factor.

$$U = \frac{U_r \ k_{pp}}{\sqrt{3}} \qquad (2)$$

3.3.1.2 Inherent TRV calculated based on Japan's UHV system

Inherent TRVs for terminal fault duties on one side and those for Long Line Fault (LLF) on the other side were analysed using EMTP considering electromagnetically and electrostatically induced voltages under 3LG conditions in TEPCO's 1100 kV transmission systems without MOSAs, shown in Fig. 3.3.3. TRVs for transformer fed faults (Transformer Limited Fault: TLF) were also calculated for single-phase-to-ground fault (1LG) conditions in addition to three-phase-to-ground fault (3LG) conditions.

The calculated TRVs, summarized in Table 3.3.1, are classified as TLF, LLF, T60 and T100 duties. Figure 3.3.4 compares typical TRV waveforms with a TRV representation having TRV peak values twice that of existing 550 kV standards. Furthermore, TRV peak values and rates of rise are plotted as functions of the breaking currents in Fig. 3.3.5. Most of the calculated TRV values can be covered by a specified TRV with peak values twice that of existing 550 kV standards. However, rates of rise of TRV for TLF far exceeds the standard values due to higher TRV frequency around 5 kHz and therefore special measures might be required for circuit breakers.

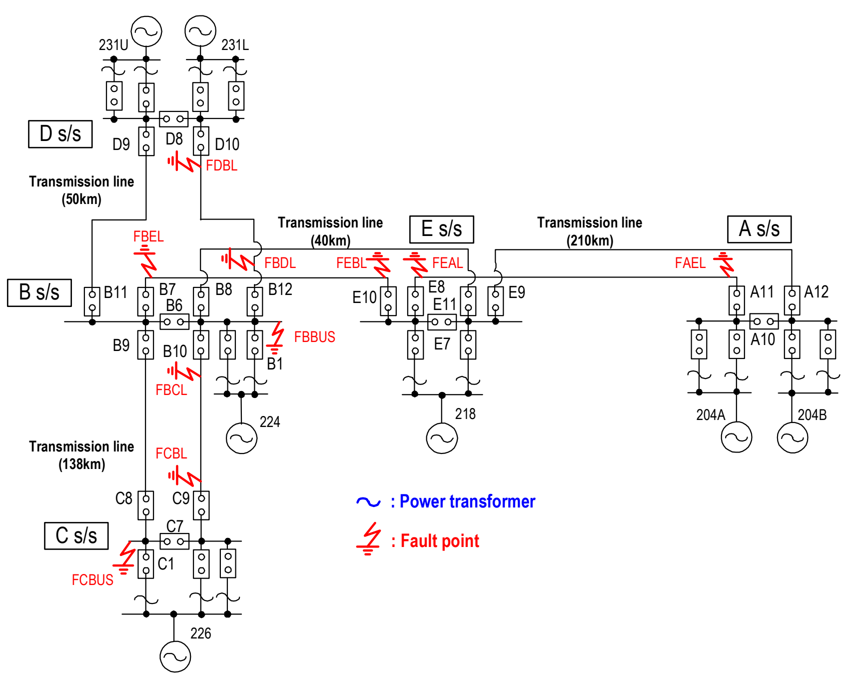


Fig. 3.3.3 *1100 kV system used for TRV analysis*

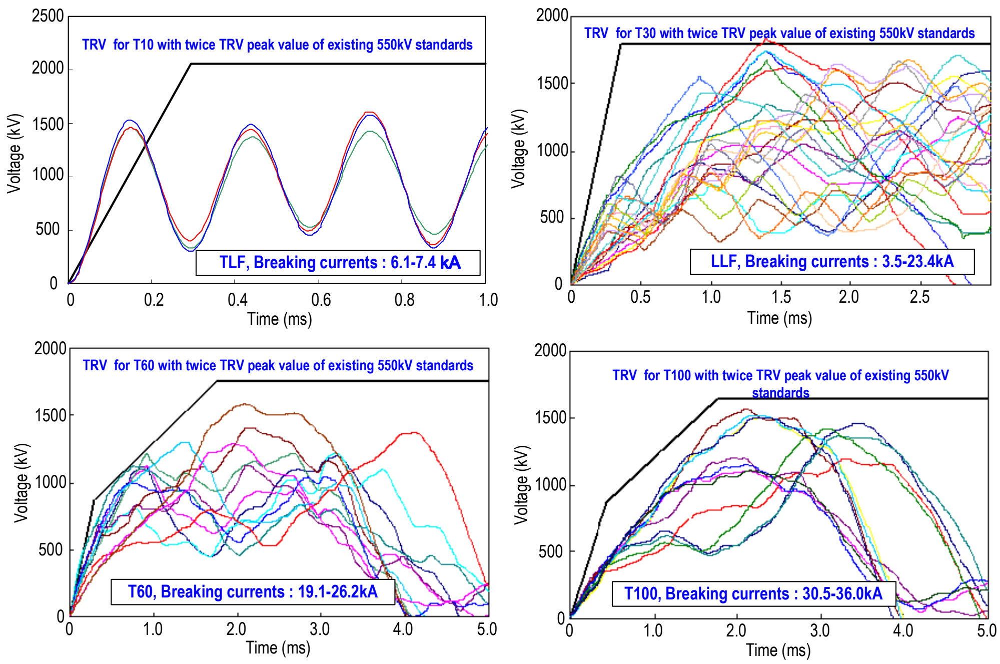


Fig. 3.3.4 *Comparisons of TRV waveforms with twice TRV peak values of existing 550 kV standard*

Table 3.3.1 *Inherent TRV for TEPCO 1100 kV system*

Duties	**Breaking currents (kA)**	**Rate of rise of TRV (kV/μsec)**	**TRV peak values (kV)**
TLF	6.1 (12)-7.5 (15%)	6.2-14.5	1046-1528
LLF	3.5 (7)-14.5(29%)	0.96-4.25	1049-1879
T60	19.1 (38)-27.2 (54%)	1.08-5.47	890-1586
T100	30.5 (61)-36.0 (72%)	0.84-1.38	927-1571

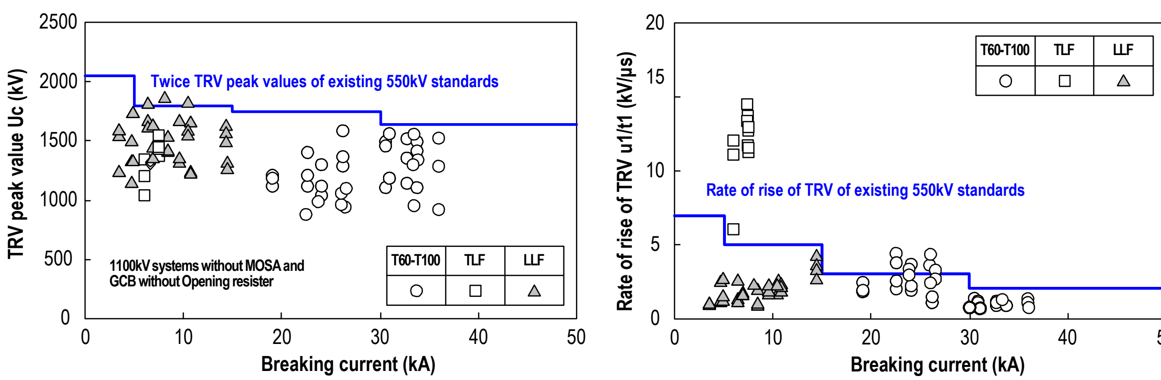


Fig. 3.3.5 *TRV peak values and rates of rise of TRV are plotted as functions of breaking currents*

Table 3.3.2 *Inherent TRV peak values of 1100 kV system for different FPCF*

Faults	***Test-duty***	k_{af}	U_c (kV) k_{pp}=1.3	U_c (kV) k_{pp}=1.2	U_c (kV) k_{pp}=1.1	90% value of TRV peak (kV)	Maximum TRV peak (kV)
TLF	***T10***	1.76	**2061**	**1903**	**1744**	**1514**	1528
LLF	***T10***	1.76	**2061**	**1903**	**1744**	**1746**	1747
LLF	***T30***	1.54	**1798**	**1660**	**1522**	**1685**	1879
BTF	***T60***	1.50	**1751**	**1617**	**1482**	**1405**	1586
BTF	***T100***	1.40	**1634**	**1509**	**1383**	**1512**	1571

Table 3.3.2 shows the 90% values of inherent TRV peaks calculated for TEPCO's 1100 kV transmission lines compared with inherent TRV peak values for different first-pole-to-clear factors. If the amplitude factor in IEC 62271-100 (with Amendment 3, that will be approved as edition 2.0) can be applied to the 1100 kV system, a first-pole-to-clear factor of 1.2 covers most of 90% inherent TRV peak values.

In conclusion, inherent TRVs of TEPCO's 1100 kV system can be covered by TRV peak values twice that of existing 550 kV standards except in the case of TLF. [21]

3.3.1.3 First pole-to-clear factor (k_{pp}) for terminal fault test duties

IEC 62271-100 specifies a first-pole-to-clear factor of 1.3 for effectively earthed neutral systems irrespective of the rated voltage. It is calculated from Equation (3) using the zero-sequence reactance X_0 and positive-sequence reactance X_1

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

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 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 factors in UHV systems generally have smaller values than those for the systems with lower voltages as described in the section 3.1.2.

Figure 3.3.6 shows the calculation results of the first-pole-to-clear factors for 245, 420, 550 and 1100 kV transmission lines in Japan [22] and the Netherlands. The first-pole-to-clear factor values investigated in recent 550 kV transmission systems are generally smaller than 1.2. For 1100 kV transmission systems, the known values of k_{pp} do not exceed 1.2.

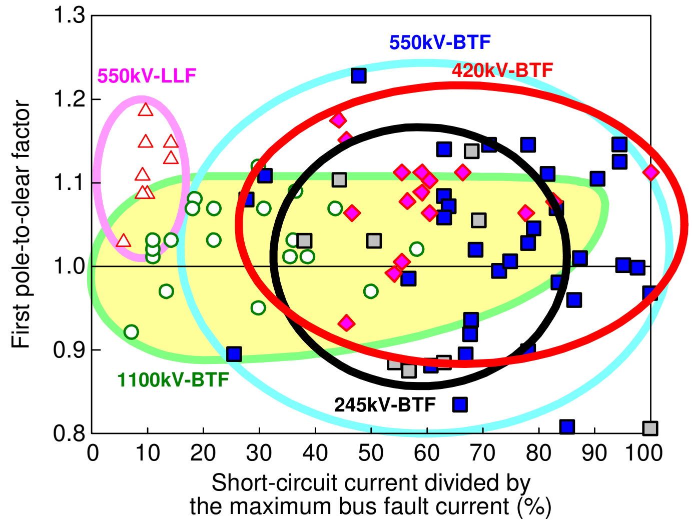


Fig. 3.3.6 *First pole-to-clear factors in 245-1100 kV systems*

The first-pole-to-clear factors were evaluated at four different stages of TEPCO's 1100 kV transmission lines including 550 kV systems shown in Fig. 3.3.7. Overvoltages of faulted and healthy phases in the case of 1LG and 2LG were investigated using EMTP.

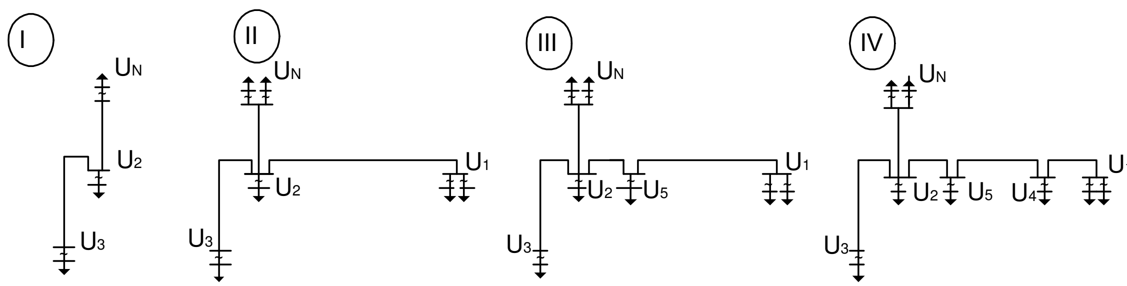
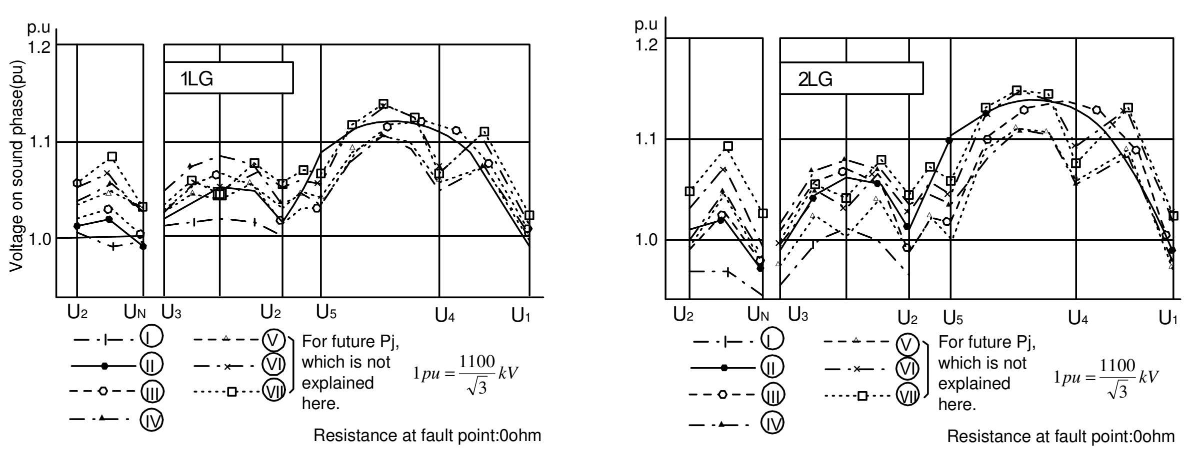


Fig. 3.3.7 *1100kV transmission network used for calculation*

Figures 3.3.8 summarize the calculated results of overvoltages in healthy phases during 1LG and 2LG. Overvoltages prevail between 0.95 and 1.1 p.u. at each substation. Therefore, the first-pole-to-clear factor of TRV duties was defined as 1.1 in Japan. [21]



Figs. 3.3.8 *(a) FPCF for Japanese UHV (1LG), (b) FPCF for Japanese UHV (2LG)*

In conclusion, the first-pole-to-clear factor for the rated voltage of 1000 kV and above could be reduced to less than the existing values of IEC standard for rated voltages up to 800 kV, even though the effect of the line length should be considered in detail.

3.3.1.4 Amplitude factor (k_{af}) for terminal fault test duties

The amplitude factor of inherent TRV in UHV systems tends to increase due to low losses of power transformers and transmission lines as well as low damping of travelling waves. For instance, TRV of test-duty T100 in Japan's future UHV system will show an amplitude factor k_{af} of 1.58 instead of the standard value of 1.4 based on k_{pp} of 1.1. Because of the low k_{pp}, TRV of the last pole shows the most severe peak value under certain conditions.

Table 3.3.3 gives the amplitude factors in IEC 62271-100 (including Amendment 3, at the final stage of approval as edition 2.0) for terminal fault interruption by circuit breakers with a rated voltage of 100 kV and above. The amplitude factor is 1.7×0.9 = 1.53 for test-duty T10 based on a first-pole-to-clear factor of 1.5 with voltage reduction of 0.9 across the transformer.

Table 3.3.3 *Amplitude factors for terminal fault test duties*

Test duty	Amplitude factor
T10	1.76
T30	1.54
T60	1.50
T100	1.40

TRV calculations performed for UHV networks in China and Japan indicate that the amplitude factors do not show much difference in those stipulated in IEC 62271-100 for networks with lower rated voltage than 1100 kV. Concerning TRVs for breaking current equal to 10% of the rated short-circuit current, it must be checked that it also covers cases of three-phase line faults with low short-circuit current and full short-circuit source power.

CIGRE WG A3.19 is currently studying such cases. Figure 3.3.9 is an example that shows the TRV calculated in the case of a three-phase line fault in Hydro-Québec's 765 kV network.

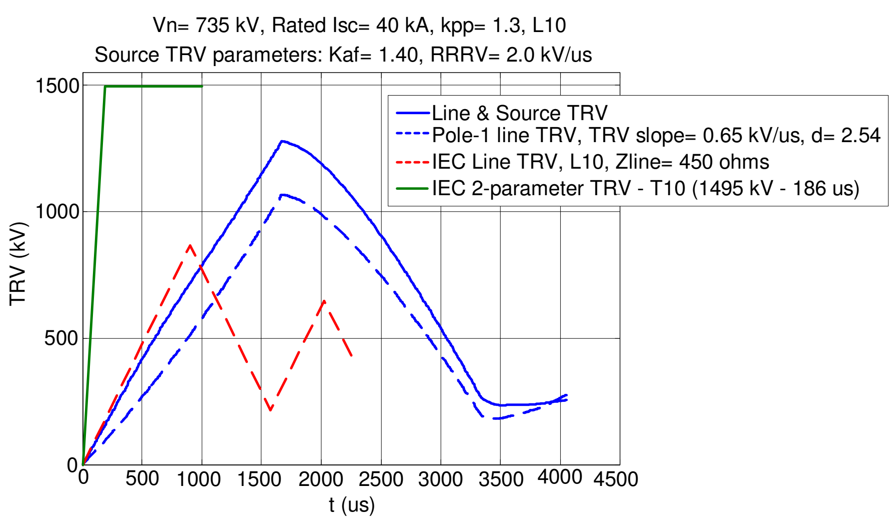


Figure 3.3.9 *Comparison of TRV and line-side voltage for a 3-phase line fault in Hydro-Québec's 765 kV network (Nominal voltage: 735 kV) with TRV envelopes for T10 duty of 800 kV as stipulated in IEC*

As shown in Figure 3.3.9, the TRV peak calculated based on the rated voltage of 735 kV in Hydro Québec is equal to 1279 kV. The corresponding TRV peak relative to 800 kV specifications is then,

$$1279 \times \frac{800}{735} \quad = \quad 1392\ kV \qquad (4)$$

Hydro Québec uses the value of the 800/735 ratios, when considering the specifications of 800 kV substation equipment, thus adding some additional margins.

In Edition 1.2 of IEC 62271-100 (dated 2006-10) [23], the specified value of the TRV peak for T10 duty is based on a first-pole-to-clear factor of 1.3 and is equal to

$$\text{Uc} = 800 \times \sqrt{\frac{2}{3}} \times 1.3 \times 0.9 \times 1.7 \quad = \quad 1299\ kV \qquad (5)$$

From (4) and (5), it appears that some long line faults, associated with low short-circuit currents, may not be covered by test duty T10 in IEC 62271-100. IEC SC17A has already taken this into account and has prepared an amendment that is in the final phase of approval (FDIS). In this Amendment 3 to IEC 62271-100, the first-pole-to-clear factor is raised to 1.5 and the amplitude factor remains at 0.9 × 1.7 so that the peak TRV is raised to Uc = 1499 kV, higher than the value in (4). From a design point of view, TRV peak should be lower than the SIWV value, except for LLF and out-of-phase. TRV peak for 1100 kV lines is discussed in the section 3.3.1.2 and the WG will be studied more in depth in the near future.

3.3.1.5 Rate of rise of recovery voltage (RRRV) for terminal fault test duties

Table 3.3.4 gives the RRRV values in IEC 62271-100 for terminal fault interruption by circuit breakers with a rated voltage of 100 kV and above.

Table 3.3.4 *RRRV for terminal fault test duties*

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

TRV calculations performed for UHV networks in China and Japan indicate that the values in Table 3.3.4 are applicable for networks with a rated voltage of 1100 kV, [21], [24] except in the case of TLF, which corresponds to test-duty T10. RRRV of TLF attains 14.5 kV/µs at maximum.

3.3.1.6 First reference voltage (U_1) for terminal fault test duties

The first reference voltage (U_1) represents the maximum voltage at which the RRRV is required to be withstood during test duties T60 and T100 (see Figure 3.3.2). In IEC 62271-100, this value is presently equal to

$$U_1 = 0.75 \times U_r \sqrt{\frac{2}{3}}\, k_{pp} \qquad (6)$$

CIGRE WG A3.19 has been discussing whether the Equation (6) is also applicable to EHV/UHV systems as it can allow covering cases of a line fault with 60% of the rated short-circuit current and whether it is also applicable for terminal fault test duty T100, as shown in the past by WG23 of IEC SC17A when Amendment 1 to IEC 62271-100 was prepared.

Table 3.3.5 shows the 90% values of the first reference voltages calculated for TEPCO’s 1100 kV transmission lines compared with U_1 values for different first-pole-to-clear factors. A first-pole-to-clear factor of 1.2 also covers the 90% values of the first reference voltage.

Table 3.3.5 *First reference voltages of 1100kV system for different FPCF*

Faults	Test-duty	U_1 (kV) k_{pp}=1.3	U_1 (kV) k_{pp}=1.2	U_1 (kV) k_{pp}=1.1	90% value of first reference voltage (kV)	Maximum first reference voltage (kV)
BTF	***T60***	**876**	**808**	**741**	**762.4**	843.5
BTF	***T100***	**876**	**808**	**741**	**440.7**	493.2

3.3.1.7 Effect of MOSAs with different characteristics on TRV

The influence of MOSAs on TRVs for terminal fault duties is analysed by EMTP using MOSAs with different characteristics, as shown in Table 3.3.6. The V-I characteristics of Type A are superior to that of Type B.

Figure 3.3.10 shows typical results of TRV waveforms with a TRV representation having peak values twice that of existing 550 kV standards. MOSA can effectively reduce the TRV peak values for terminal fault duties, so it should be noted that the TRV peak reduction does not show a significant difference for MOSAs with different characteristics, because the restriction voltages around 10–100 A determine the effect of TRV peak reduction and those values are similar for different MOSAs.

The application of MOSAs can reduce the amplitude factors of TRV for terminal faults, TLF (transformer limited or secondary faults) and out-of-phase. However, it may not lead to a reduction large enough for LLF (long line faults whose applicability to UHV systems remains to be established) where the TRV is generated at both the source and line sides of the breaker terminals. The phenomena are not observed in transmission systems up to 800 kV. Therefore, the effect should be considered when the TRVs for UHV are extrapolated and compared with the existing standards.

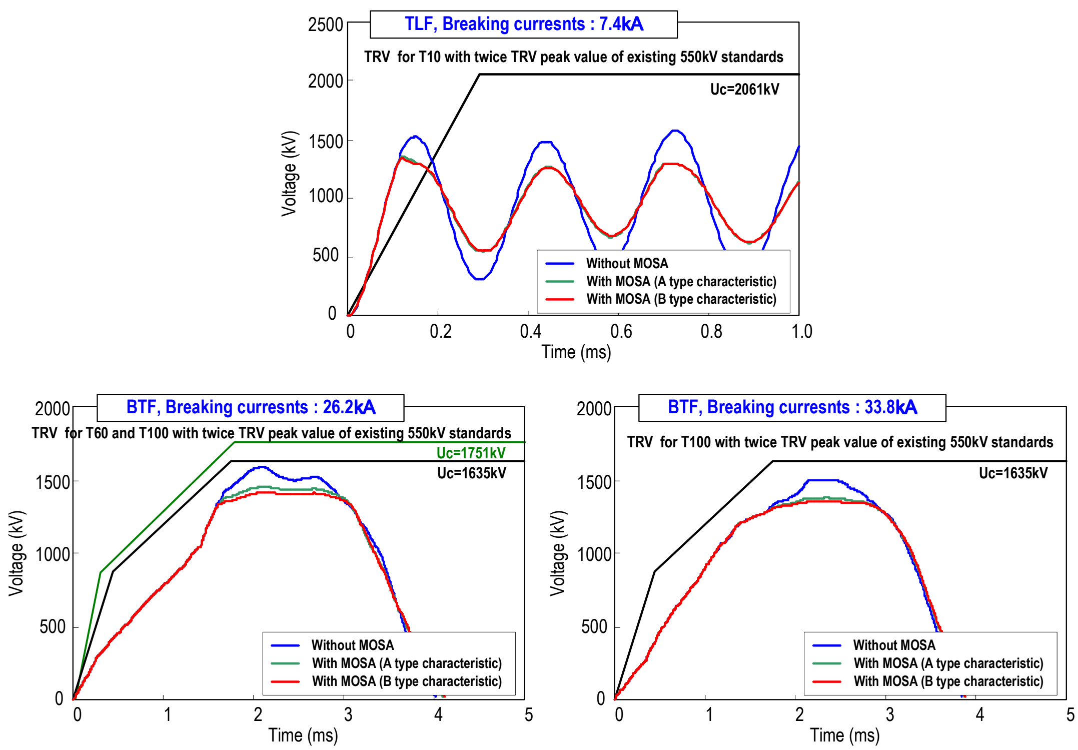


Figure 3.3.10 *Effect of MOSA with different characteristics on TRV*

Table 3.3.6 *V-I characteristic of different types of MOSAs*

Characteristic	1 mA	1 A	10 A	100 A	1 kA	10 kA	20 kA	50 kA
Type A (kV)	1080	1235	1285	1335	1435	1555	1620	1770
Type B (kV)	1160	1250	1305	1370	1510	1710	1800	1900

3.3.1.8 Calculation of TLF fault current

Severe TRV conditions may occur when there is a short circuit immediately after a transformer without any appreciable capacitance between the transformer and the circuit breaker. In such cases, the rate-of-rise of transient recovery voltage (RRRV) may exceed the values specified in the standards, due to the relatively small capacitance to earth of transformers, i.e. 3000 pF for 800 kV applications and up to 10,000 pF in UHV applications (transformers with six windings in parallel per phase). The corresponding natural frequency of the transformer leads to TRV having a rate of rise that is two or three times the value for a terminal fault with the same short-circuit current. RRRV of 14.5 kV/μs has been reported for the UHV system in Japan. [25]

The system TRV can be modified by capacitance or a resistor so that it is within the standard TRV capability envelope. As an alternative, a definite-purpose circuit breaker can be specified for fast transient recovery voltage rise times.

For circuit breakers with a rated voltage equal to or higher than 100 kV, TRVs specified for terminal fault test duties T30 and T10 cover most applications in this current range. In special cases where the connection between the circuit breaker and the transformer has a very low capacitance, a special test duty may be specified or capacitance could be added to allow the use of a standard circuit breaker. TRVs for these special cases will be covered in a revised IEEE C37.06-200x. [26]

Taking into account the actual characteristics of power transformers for rated voltages of 800 kV and higher, such as short-circuit reactance and power, the fault current for transformer-limited faults is usually between 10 and 16% of the rated short-circuit current of the circuit breaker (a typical value of 10 kA corresponds to 20% of the rated short-circuit current for a 50 kA circuit breaker and 16% for a 63 kA circuit breaker). However, a higher-value TLF current is possible such as in the case of AEP's 800 kV system in which the 765/500 kV transformers that connect the AEP system to neighbouring systems have impedance as low as 6.35%, leading to a fault current of up to 17.2 kA. On the opposite side, the maximum TLF current for Hydro-Québec's 735 kV systems is only 6 kA.

As the TLF current varies in a wide range depending on the characteristics of the transformer, it is suggested that a specific TLF breaking current be introduced, independently from the terminal fault breaking current, as already recommended in IEEE C37.016 for high-voltage circuit switchers.

3.3.2 TRV of compensated/uncompensated lines

3.3.2.1 Series compensated lines and their effect on circuit breakers recovery voltage and switching surges

As utilities face increasing opposition to adding new transmission lines to networks, application of series capacitors becomes an interesting alternative for enhancing transient and steady-state stability and improving loading between parallel lines.

Series capacitor banks (SCB) have already been put into use in EHV systems (Hydro-Québec, Turkey, BC Hydro, Venezuela, Chile, Sweden, etc.)

For UHV, where the power is generally transmitted over very long distances, the use of series-compensated lines would certainly be beneficial by improving the voltage control and the voltage and angle stability as well as increasing the maximum load for transmission.

3.3.2.2 Effects on the lines CB TRVs during line fault interruption

There are numerous published reports on the effects of series capacitors on line CB TRV severity when clearing faults on series-compensated lines. [27]-[31] Depending on the protection schemes used to set the bypass conditions for series capacitors, the line CBs can be exposed to severe TRV exceeding IEC standard values. This is a case where the line CBs must clear a line fault for which the series capacitor is not bypassed, resulting in a trapped charge on the series capacitor.

The following four types of SCB protection schemes are used:

- Slow re-insertion type: The bank is protected by a self-triggered gap and a bypass CB only. For this type of protection, the gap is usually set so that it will self-trigger for most faults on the line (internal faults) except for those with a relatively small fault current.
- Instantaneous re-insertion: The bank is protected by MOVs, forced-trigger spark gap and bypass CB (as seen in Fig. 3.3.11).
- Fast re-insertion type: The bank is protected by two self-triggered gaps, a low setting gap with a CB in series and a high setting gap with a bypass CB in parallel.
- Thyristor-controlled series capacitors (TCSC): As shown in Fig. 3.3.12, thyristors are used to bypass or insert modules of capacitance and inductance to rapidly modulate the line reactance. [32]

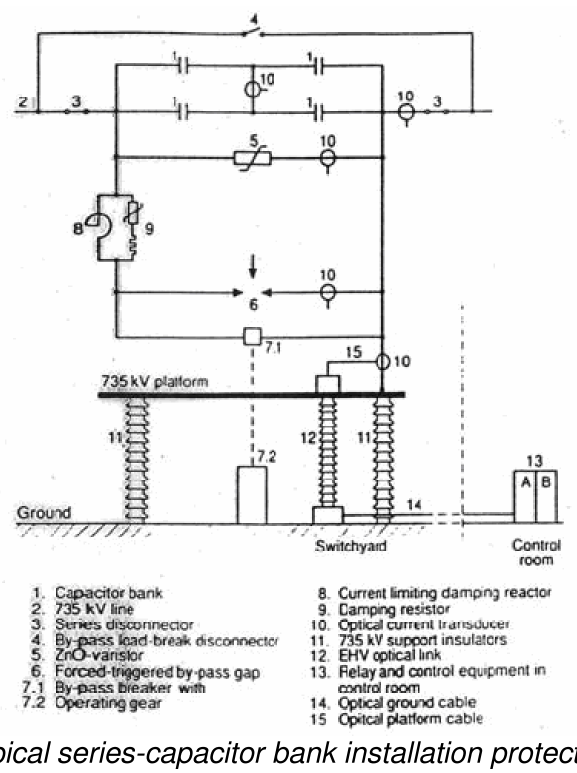


Fig. 3.3.11 *Typical series-capacitor bank installation protected by MOVs*

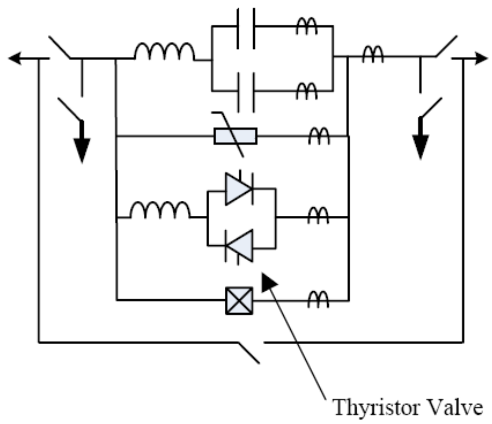


Fig. 3.3.12 *Thyristor-controlled series capacitor*

3.3.2.3 Turkey's network

Iliceto et al. studied the effect of series capacitors on TRV across line circuit breakers on Turkey's 420 kV grid. [28],[29] Techniques such as surge arresters, opening resistors on CBs, MOVs in parallel with CB contacts and fast bypassing of series capacitors were analysed. In the first installations on the Turkish network, series capacitors were protected by self-triggering spark gaps that would bypass the capacitors whenever a fault resulted in transient voltage across the capacitors higher than the gap withstand voltage. Therefore, the increased TRV across the CB would only be present for faults with a relatively small current so that the voltage across the capacitor is lower than the setting for the spark gap.

In more recent series capacitor installations on the 420 kV network, the capacitors are protected by MOVs across a circuit breaker terminal and therefore, the trapped charge is equal to the MOV protection level. This scheme can lead to higher TRVs than the self-triggered spark-gap-protected capacitor. For configuration where the series capacitors are located at an intermediate point of the line, the TRVs are even higher due to the trapped charge on each side of the CB.

Iliceto et al. performed TRV analysis for different fault locations on the line (three-phase to ground and three-phase isolated from ground). They showed that the highest TRV (4.11 p.u.) was obtained on the remote CB during a three-phase-to-ground fault located beyond the series capacitors. References [28] and [29] propose a list of mitigation measures for reducing the TRV across the CB. By using MOVs in parallel with the interrupting chambers of the CBs, it was possible to limit the TRV level to below 3.0 p.u. for CBs that are required to synchronize two islanded parts of the network, and 2.5 p.u. for other line CBs used on series-compensated lines. This value was deemed acceptable for Turkey's 420 kV network because the CBs composed of two breaking units could withstand the high TRV values exceeding IEC standard values.

3.3.2.4 Hydro-Québec experience

In the early 1990s, Hydro-Québec launched a vast program to fortify its 765 kV network. This program involved installing 37 series capacitor banks for a total of 15,000 Mvars. The protection scheme consisted of MOVs and a forced-triggered spark gap as described in Fig.3.3.11. The MCOV protection level is 2.5 p.u. in accordance with the rated voltage of the capacitor. Prior to this vast program, extensive studies were performed to evaluate the TRV level and switching surges, taking into account the series capacitors. The results are reported in Ref. [31].

The study took into consideration numerous parameters that could impact the TRV level, such as type, location and duration of fault as well as presence of SA, shunt reactor and opening resistors. The highest TRVs (around 4.0 per unit) were obtained during interruption (by remote CB) of ungrounded bi-phased faults near the capacitor bank. As reported by Iliceto et al., the fault currents are relatively low for cases of high TRV (< 25% of CB rating). These high TRV values were obtained when no shunt reactors or line surge arresters were connected to the network. Simulation studies showed that without series capacitors, the worst TRVs were around 3.0 p.u. during interruption of ungrounded faults.

Therefore, the study demonstrated that TRV values exceeded IEC standard values and some mitigation measures were necessary to limit the TRV values to the rating of the existing circuit breakers (2.8 p.u. based on 765 kV). Considering the use of 587 kV MOSAs at both ends of the lines, the probability of exceeding the CB TRV rating (2.8 p.u.) was calculated by means of statistical approach considering the fault type occurrence (three-phase grounded and ungrounded, bi-phased ungrounded, etc.). With the presence of MOSAs, the risk of exceeding the TRV withstand capabilities of the existing CB was then considered acceptable.

3.3.2.5 BC Hydro experience

BC Hydro has used series-compensated lines in its 500 kV grid since the early 1970s. The first installations were protected by self-triggered bypass spark gaps. At the beginning of the 2000s, new lines were constructed and the old series-compensation installations were refurbished by adopting MOV bypass protection rated at 2.2 p.u. The capacitor banks for the new line were installed in the middle of the line (330 km).

Extensive EMTP studies were performed to evaluate the level of TRV obtained under the worst conditions (clearing three-phase ungrounded and grounded faults) with and without line surge arresters and considering a protection level of 2.5 p.u. for the series capacitors. The detailed results are reported in Ref. [30]. From these results, the maximum TRV obtained was 1.6 p.u. on the source side. When faults were statistically applied exceeding the series capacitor banks, it resulted in TRVs up to 4.8 p.u. and 3.8 p.u., respectively, for three-phase ungrounded and three-phase grounded faults without line surge arresters. Considering the presence of surge arresters at both ends of the line, the maximum TRV reached about 3.2 p.u., which is similar to the values found by Hydro-Québec and Iliceto. Finally, line surge arresters with a 1.57 p.u. protection level were used to guarantee a maximum TRV of 3.2 p.u.

As for other TRV studies for series-compensated installations, the short-circuit current associated with the highest TRVs was relatively low (comparable to T10 and T30 test duties) and the time to peak was quite long.

3.3.2.6 Solutions to reduce TRVs

All TRV studies on series-compensated lines clearly show TRV values far exceeding IEC standard values when no mitigation measures are taken. Different solutions can be used to reduce TRV stress on series-compensated line CBs:

- Line surge arresters at both ends: This can reduce peak TRV to about 3.2 p.u. considering a 2.5 p.u. MCOV protection level for series capacitors and 1.7 p.u. for line surge arresters;
- MOVs in parallel with the interrupting units of CBs: This solution has been successfully applied on Turkey's 420 kV series-compensated network. The full simulation results are

presented in Ref. [29]. MOVs in parallel with circuit breaker chambers were applied for both protection schemes of series capacitors, i.e. spark gaps and MOVs.

- Opening resistors: This solution is efficient only if used on CBs at both ends of the line. With a resistor value of 800 ohm and insertion time of 16 ms, the maximum TRV obtained from simulations on Hydro-Québec's 765 kV network was reduced from 3.36 to 2.22 p.u. for three-phase ungrounded faults.[31]
- Fast protective device (FPD): Recent development of FPD for HV series capacitors has become very attractive for reducing TRV during line fault clearing. This new device is well documented in Refs. [33] and [34]. It was used for the first time on a pilot installation at Kamouraska series capacitors in Hydro-Québec's 315 kV network.

The FPD consists of a very fast switch and a fast mechanical switch that makes it possible to bypass the capacitor bank within 1 ms (Figs. 3.3.13 and 3.3.14). Due to the high closing speed of the FPD and its ability to be triggered for low series-capacitor voltages, it is possible to bypass the series capacitor well in advance of the line CBs opening. The TRVs of series-compensated line CBs are then comparable with the standard TRVs for uncompensated lines. This solution has been operated successfully on a 315 kV line at Hydro-Québec since October 2003. The FPD comprises a plasma switch in parallel with a very fast mechanical switch, as shown in Fig. 3.3.13.

A second installation is on the way for a 230 kV compensated line. It will also be considered for future installation on 765 kV lines following the positive field experience of the pilot project at 315 kV and after proving its performance and reliability via extensive laboratory tests for its application on the 765 kV network. [34]

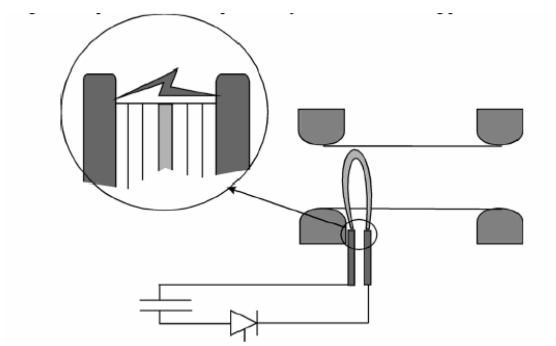


Fig. 3.3.13 *Fast protective device: plasma switch and fast mechanical switch*

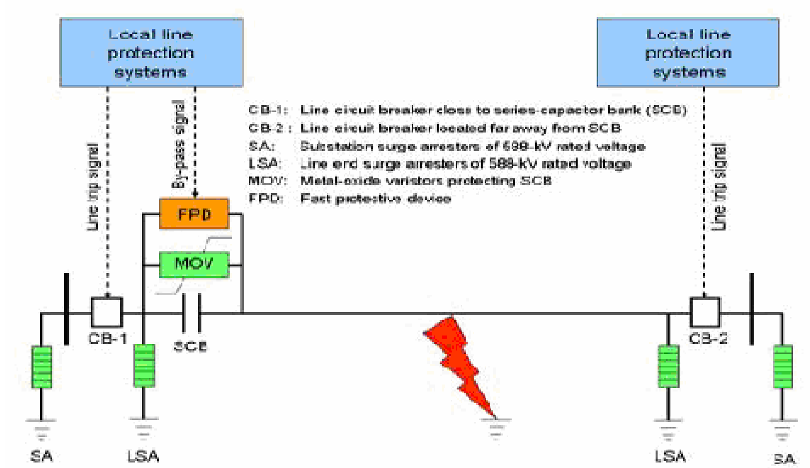


Fig. 3.3.14 *Fast protective device installation*

3.3.2.7 Effects on switching surges

The effect of series capacitors on switching surges is reported in Ref. [27] for a 345 kV series- and shunt-compensated network. During a reclosing sequence (after fault clearing), very high switching surges were observed due to the trapped charge on the capacitors (if the series capacitors are not bypassed during the reclosing sequence). The total switching overvoltage could reach 4.0 to 4.5 p.u., which is very severe even on a 345 kV system. At higher voltage levels, the relative switching surge withstand of the equipment is usually less compared to lower voltages.

If shunt reactors are connected on the line, there will be a reduction of the trapped voltage on the series capacitor due to oscillation between the shunt reactor and the series capacitor, although this reduction will not be so significant due to the usually high quality of the shunt reactor (low loss). However, since surge arresters normally protect the shunt reactors, the switching overvoltage would be limited to the protection level of the arresters. If shunt reactors are not used, it is highly recommended that surge arresters be installed on the line.

3.3.2.8 Shunt compensated lines and their effect on circuit breakers recovery voltage and switching surges

It is well known that long lines at EHV are usually shunt-compensated to compensate for the Mvars generated by the line under weak load conditions. Different approaches are used by utilities for the way in which they operate their shunt reactors. Shunt reactors are used in transmission OH lines for 2 main purposes:

- Switchable shunt reactors at busbars or tertiary windings of power transformers for steady-state voltage control issues;
- Fixed shunt reactors at the ends of OH lines to deal with switching transient overvoltage (TOV) requirements, related to line closing and/or opening operation (including fast auto-reclosing issues)

During a reclosing sequence on the line, shunt reactors have a positive effect in reducing the switching surges because the line charging will discharge through the shunt reactors before reclosing the circuit breaker. The trapped charge during reclosing of the line will depend on the fault location, the reclosing delay and the damping provided by the oscillating circuit (given by the shunt reactor Q factor).

Shunt reactors also help to reduce TRV across the line circuit breakers especially during interruption of non-earthed faults and during line charging current interruption because the line will again discharge through the shunt reactors, leaving a reduced trapped charge on the line side of the CB. Results from EMTP studies on Hydro-Québec's 735 kV system (series- and shunt-compensated lines) show an overvoltage reduction of about 10% during fault interruption when shunt reactors are connected to the line. [31]

3.3.3 Characteristics of short-line faults

3.3.3.1 General

In IEC 62271-100, L90 and L75 are the type test duties for short-line fault (SLF) conditions such as line faults that occur at a distance ranging from 100 m to several kilometres down the line. The fault current is equal to 90 and 75%, respectively, of the rated short-circuit breaking current.

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 Eqs. (7), (8) and (9), where Z_0 is the zero-sequence surge impedance and Z_1 is the positive-sequence surge impedance.

$$Z_{first\ pole} = \frac{3\, Z_1\, Z_0}{Z_1 + 2\, Z_0} \tag{7}$$

$$Z_{second\ pole} = \frac{Z_1\left(Z + 2\, Z_0\right)}{2\, Z_1 + Z_0} \tag{8}$$

$$Z_{third\ pole} = \frac{\left(2\, Z_1 + Z_0\right)}{3} \tag{9}$$

Various line surge impedance values for UHV systems are given in Table 3.3.7 as well as values for EHV systems. It should be noted that in the case of three-phase line faults, the surge impedance is highest for the third pole to clear.

3.3.3.2 Single-phase faults as the basis for rating

In IEC 62271-100, a single-phase test at phase-to-earth voltage is considered to cover all types of short-line faults. This is supported by the following considerations:

- Line surge impedance relative to the last pole to clear is highest in the case of a three-phase fault, and it is also the surge impedance for a single-phase fault. Therefore, the RRRV obtained during a single-phase fault interruption covers all SLF conditions;
- A single-phase short-line fault test demonstrates an arcing window of (180°−dα) that covers the requirements for all multi-phase fault cases in effectively-earthed and non-effectively-earthed systems;

These considerations could also apply in the case of UHV. However, CIGRE WG A3.19 has been discussing whether it is recommended that SLF test duties be performed as single-phase with line characteristics as defined hereafter for single-phase faults.

3.3.3.3 Line surge impedance and bundle contraction

IEC 62271-100 and IEEE C37.04 stipulate standard line surge impedance of 450 Ω, considering the completed bundle contraction of multi-bundle conductors due to magnetic attraction caused by a large fault current through the conductor, although the equivalent line surge impedance calculated without bundle contraction is less than 360 Ω (see IEEE C37.011-2005 and the values in Table 3 for system operating voltage of 500 and 765 kV).

Table 3.3.7 summarizes analytical line surge impedance under both normal conditions and completed bundle contraction for several transmission lines. The equivalent line surge impedance of multi-bundle conductors is calculated as 250–311 Ω for 4-8 bundle conductors under normal conditions without taking into account bundle contraction. These values are assessed based on the bundle and tower configurations illustrated in Fig. 3.3.15 with a constant parameter line model supported by EMTP. The line surge impedance tends to be larger if a transmission line is high from ground.

Table 3.3.7 *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)		
						1st pole	2nd pole	3rd 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

TRV frequency can be obtained in case of 800 kV South Africa project as follows.
Impedance at the source side: 800kV/√3/40kA/(2×3.14×50Hz)=36.78mH, Impedance at the line side: 36.78mH×1/9=4.09mH for L90, TRV frequency: 450 ohm/(4×4.09mH)=27.5kHz for L90

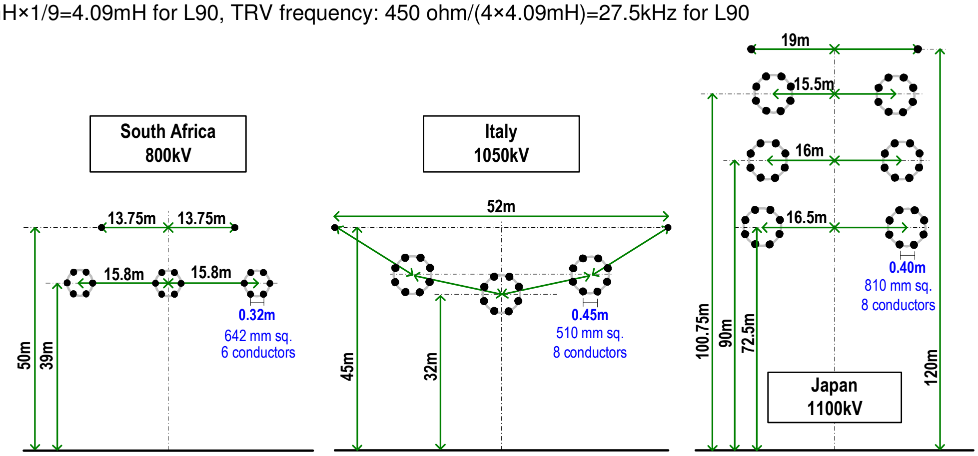


Fig.3.3.15 *Collision time of multi-bundle conductors*

Table 3.3.7 shows that line surge impedance for the third pole to clear increases several percentage points compared with the values for the first pole to clear. If bundle contraction is assumed, line surge impedance for the third pole to clear increases by 36-56% and approaches the standard value of 450 Ω. The change in line surge impedance depends on the multi-bundle conductor design (materials, cross section, spacer distance and spacer size) and the line tension in addition to the fault current. Several studies have reported the time required for bundle collision.

Table.3.3.8 *Collision time of multi-bundle conductors*

Country	Size (mm^2)	Number of Conductor	Span (m)	Sub-conductor distance (mm)	Initial tension (kN)	Breaking current (kA)	Time to bundle collision, Cal. (sec)	Time to bundle collision, Exp. (sec)
Italy	520	8	---	450	---	50.0	0.166	---
Japan	410	6	45	400	34	40.8	0.140	0.110
	410	6	45	400	34	53.2	0.106	0.080
Japan	810	4	45	550	49	40.8	0.148	0.124
	810	4	45	550	49	53.2	0.114	0.090

	810	8	50	400	53	50.0	0.202	---
	810	8	45	400	60	50.0	0.149	---

For example, CIGRE WG 13.01 [35] indicates that twin conductors, in a 686 mm^2 cross section carrying 40 kA, collided at 50 ms after a fault occurrence. Table 3.3.8 summarizes the collision times of various multi-bundle conductors surveyed in Japan, which collided at 100-200 ms when carrying 30-50 kA through the line.

The analytical times to bundle collision are in relatively good agreement with the experimental data. The analysis also provides the time to bundle collision in the case of 8 conductors, 810 mm^2, calculated at a breaking current of 50 kA with a DC time constant of 150 ms.

Figure 3.3.16 shows a typical result of a change in sub-conductor distance as well as line surge impedance of the third pole to clear. The results are calculated for 8 conductors, 810 mm^2, at a breaking current of 50 kA with a DC time constant of 150 ms. The electromagnetic force generated between sub-conductors increases with an increase in current and decrease in sub-conductor distance. The sub-conductors collided at 149 ms after the fault occurred. Line surge impedance of the third pole to clear increases and gradually approaches the standard value at the completed bundle contraction. However, impedance is estimated to be less than 350 Ω for about 5 cycles (100 ms) after the fault initiation.

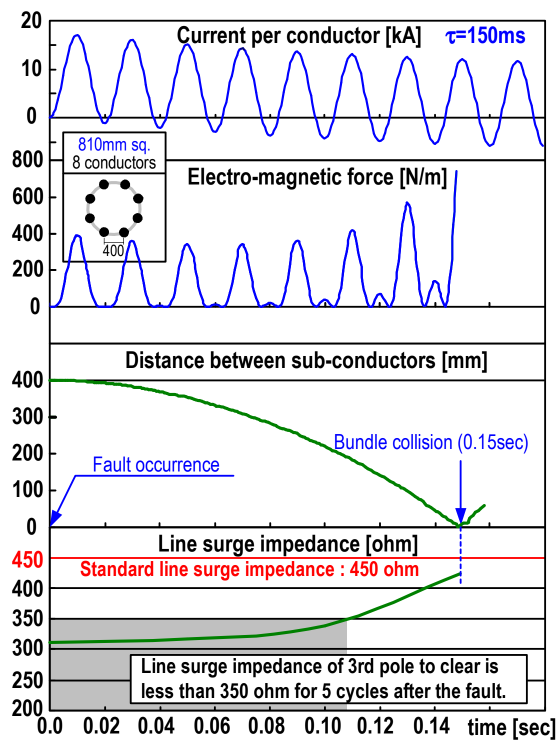


Fig.3.3.16 *Collision time of multi-bundle*

UHV transmission lines normally employ multi-bundle conductors with a larger cross section for reduced radio interference and corona noise, which results in a longer time required to obtain bundle collision. Since bundle contraction is not supposed to be completed at the time the fault current is interrupted (50–80 ms after fault initiation), line surge impedance for L90 and L75 duties could be reduced for rated voltages exceeding 800 kV.

3.3.3.4 Peak factor "k"

The line-side contribution to TRV is equal to the instantaneous value of the line-side voltage at current zero multiplied by the peak factor "k" ("d" in ANSI/IEEE standards).

The peak factor is defined in Table 4 of IEC 62271-100. Its value is independent of the rated voltage and is equal to 1.6. This value is also considered suitable for UHV applications, taking into account that the initial TRV peak is of secondary importance for SLF interruption, compared to the two more influential parameters: RRRV and di/dt. A conservative estimate of the peak factor is given by Equation (A-29) in IEEE C37.011-2005, shown below as Equation (10):

$$peak\ \ factor = 0.4 \times (2 + \frac{Z_0}{Z_1}) \qquad (10)$$

Using the values of Z_0 and Z_1 given in Table 3.3.9 for 1000 kV networks in Japan and Italy, and assuming that there is no bundle contraction, k is equal to 1.64 and 1.57, respectively. A peak factor of 1.6 can be recommended for UHV applications; however, WG A3.22 will investigate further whether the formula and the damping factor are applicable to UHV.

3.3.4 DC time constant

3.3.4.1 General

Large power generators 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 large-diameter conductors in order to reduce corona noise as well as increase transmission capacity. For example, UHV transmission lines use 8 conductors, 400–810 mm^2, depending on the allowable level of corona noise. The application of multi-bundle conductors also increases the DC time constant (τ = L/R) because the reduction in resistance (R) exceeds the reduction in inductance (L).

Table 3.3.9 summarizes analytical results of DC time constants calculated using various tower designs with different multi-bundle conductors used in different projects. The constants were obtained using the ratio of positive-sequence inductance to positive-sequence resistance of the lines. In IEC 62271-100, a special-case time constant was added to the standard value of 45 ms, based on a survey conducted by CIGRE WG 13.04. [35] The special-case time constant is 75 ms for a rated voltage of 550 kV and above, which corresponds to the medium value of constants surveyed for 800 kV lines.

Table 3.3.9 *DC time constants of short-circuit currents in EHV / UHV transmission line*

Maximum voltage	Conductors		DC time constant (ms)
	Size (mm^2)	Bundle	
765 kV (Canada)	686	4	75
800 kV (USA)	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

It is expected that the DC time constants for UHV systems will be higher than the standard values due to the use of multi-bundle conductors with larger diameter in addition to the existence of large power generators and large-capacity power transformers. The influence of the high DC component on test-duty T100a was evaluated by the energy of the last major loop before the interruption, slope of current at the time of interruption and TRV characteristics. The results do not show any significant difference when the constant exceeds about 120 ms. [36] Therefore, it is advisable to use a higher special-case time constant of about 120 ms for rated voltages exceeding 800 kV.

3.3.4.2 DC time constant in UHV system in Japan

Network losses are smaller in UHV systems compared to 800/550 kV or lower voltage systems, since multi-bundle conductors are frequently used for transmission lines. In addition, large power sources tend to be located close to UHV networks, and large-capacity transformer banks are connected to the networks. These characteristics lead to a higher X/R ratio and subsequently, a longer DC time constant in fault currents.

On the other hand, the influence on interruption performance saturates as the time constant becomes longer than about 100-120 ms. Figure 3.3.17 shows an example rate of decrease of interrupting performance [36] assuming that interrupting capability is determined by the rms value of the breaking current.

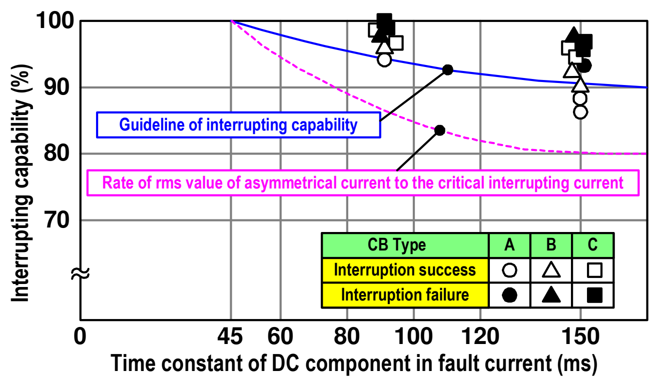


Fig.3.3.17 *Influence of time constants of DC component on interrupting capability*

In Japan, estimation was conducted using actual electric parameters of each network component. Table 3.3.10 shows typical values of electric parameters of each system component. DC time constant is estimated by the X/R separation method.

Table 3.3.10 *Typical values of each component for estimation of DC time constant*

Equipment	*Resistance R (%)*	*Reactance X (%)*	*Time constant X/R (ms)*	
Generator	**0.2-0.3**	**23**	**240 ~ 370**	Ta=L2/R=0.2-0.3s X2=Xd''=25%,Xd'=30% (at 1.3GVA)
500kV Transformer	**0.1-0l.3**	**8-15**	**150 ~ 240**	Xt=12-15%,R=0.2-0.3% (at 1.2-1.5GVA)
UHV Transformer	**0.067**	**6**	**260**	Xt=18%, R=0.2% (at 3.0GVA)
UHV Transmission Line ($810mm^2$, *8 bundle)	**0.0025**	**0.125**	**150**	
UHV Transmission Line ($610mm^2$ *8 bundle)	**0.0035**	**0.125**	**110**	
500kV Transmission Line	**0.0025**	**0.05**	**70**	$810mm^2$ *4 bundle

Note: Values are 1000MVA base

The 500 kV transmission lines that supply fault currents to the UHV system are shorter in length, and the DC time constant tends to be longer because they have the shortest time constant among those in the components considered in Table 3.3.10. Based on the estimation of a simple model network in which the DC time constant ranges from 100 to around 200 ms (as shown in Table 3.3.11), and the detailed analysis with actual UHV networks in the first and second stage in which the DC time constant ranges from 100 to around 150 ms (as shown in Table 3.3.12), therefore a specification of 150 ms was decided.

Table 3.3.11 *Estimation of simple model network (Short circuit current less than 40kA)*

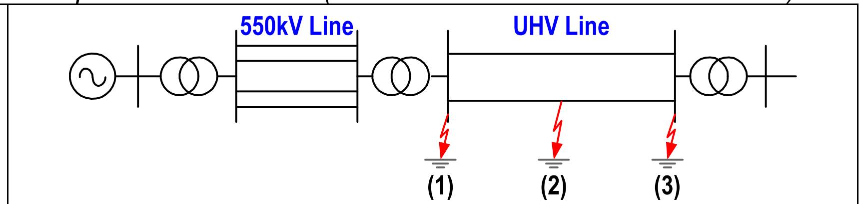
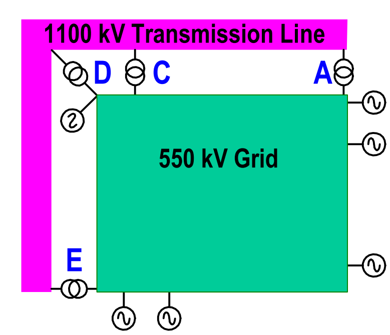
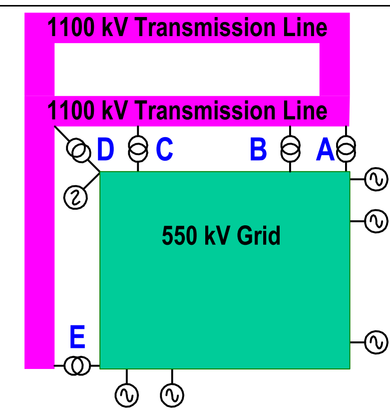
		
Model	***A*** *The influence of 500kV Transmission lines is comparatively small.*	***B*** *The influence of 500kV Transmission lines is comparatively large.*
Max. Short Circuit current (kA)	(1): 40, (2): 35, (3): 30	(1): 40, (2): 35, (3): 30
Conditions	Power source: 50 GVA 500kV Line: 20 km*5 route UHV Transformer: 60 GVA UHV Line: 40 km (810sq* 8bundle)	Power source: 100 GVA 500kV Line: 70 km*5 route UHV Transformer: 60 GVA UHV Line: 40 km (610sq* 8 bundle)
Reactance's (X)	(1): 1.41, (2): 1.66, (3): 1.91	(1): 1.42, (2): 1.67, (3): 1.92
Resistance's (R)	(1): 0.023, (2): 0.028, (3): 0.033	(1): 0.047, (2): 0.054, (3): 0.061
DC Time Constant=(X/R/(2*pai*f)	(1): 195 ms, (2): 189 ms, (3): 184 ms	(1): 96 ms, (2): 98 ms, (3): 100 ms

Table 3.3.12 *Estimation of time constant of DC component in actual UHV networks*

UHV Network in Japan*			
Stage		***First stage***	***Second stage***
Time constants of DC component in fault currents at different Substations (ms)	***A***	156	149-165
	B	-	117-144
	C	149	111-142
	D	153	111-145
	E	154	103-135

***** 500kV and lower network is also modeled.***

3.3.4.3 Time constant for T100a and UHV applications

Different time constants of DC decrement have been presented for UHV networks. For example, it is 124 ms in China and 150 ms in Japan. For the purpose of standardisation, a compromised solution should be recommended as the preferred or rated value. For this purpose, consideration must be given to the three parameters that influence the interruption of asymmetrical currents required in T100a test duty:

- Energy of the last major loop before interruption,
- Slope of current (di/dt) at the time of interruption,
- TRV characteristics (peak and rate-of-rise).

According to Edition 2.0 of IEC 62271-100 (see 6.102.10.2.1.2 in document 17A/768/CDV), it is possible to compare T100a breaking capabilities using different time constants if the duration and peak value of the major loop to be interrupted do not differ by more than 10%. In that case, the energy in the last major loop can be assumed to be proportional to the product of the peak current multiplied by the duration of the major loop considering a constant arc voltage, and equivalence between asymmetrical currents can be achieved as defined by IEC. [37]

In practical cases, it can be assumed that interruption occurs after the third major loop of a current established with 100% asymmetry. It can be seen in Fig. 3.3.18 and Tables 3.3.14 and 15 that when time constants of 120 and 150 ms are considered, both the loop duration and amplitude of the last loop of current before interruption differ by less than 10%. Therefore, the IEC law of equivalence can be applied and a test based on a time constant of 120 ms can be used to demonstrate breaking capability with a time constant of 150 ms.

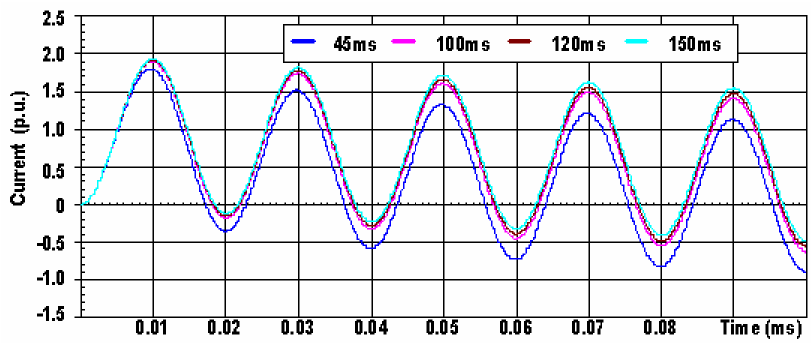


Figure 3.3.18 *Evolution of asymmetrical current in a network of time constants 45ms, 100 ms, 120 ms and 150 ms (f = 50 Hz)*

Table 3.3.14 *Duration of the third major loop as function of the time constant (f = 50 Hz)*

Time constant	*From (ms)*	*To (ms)*	*Duration*	*Relative value of loop duration*
45 ms	43.65	55.8	12.15	85.9%
100 ms	42.65	56.8	14.15	100%
120 ms	42.35	57.15	14.8	104.6%
150 ms	42.25	57.35	15.1	106.7%

Table 3.3.15 *Amplitude of the third major loop and product "Peak x loop duration" as function of the time constant of the network (f = 50 Hz)*

Time constant	*Third peak (p.u.)*	*Third peak (%)*	*Relative value of Peak x loop duration*
45 ms	1.33	82.6%	70.9%
100 ms	1.61	100%	100%
120 ms	1.66	103.3%	108.1%
150 ms	1.72	106.9%	114.1%

*** 1 p.u. = peak value of symmetrical current**

Taking into account the criteria introduced in Edition 2.0 of IEC 62271-100, a test performed with (and not less than during actual tests) the parameters of the major loop specified for L/R

=120 ms would be acceptable for demonstrating T100a with L/R = 150 ms. Alternatively, the r.m.s. value of the test current could be increased to meet the relative value of the peak current × loop duration specified for 150 ms.

It should also be noted that a test based on a time constant of 120 ms leads to di/dt at current interruption and TRV characteristics that are both more severe than those required for a time constant of 150 ms. Moreover, it must be taken into account that during testing in high-power laboratories, it may be difficult to meet the long duration of a major loop of current.

In view of these considerations, and taking into account that the three parameters for T100a interruption based on a time constant of 150 ms can be covered by the previously described test based on a time constant of 120 ms, it is recommended that 120 ms be selected as the time constant for networks with a rated voltage higher than 800 kV.

3.3.5 TRV with/without opening resistors

3.3.5.1 General

An opening resistor scheme can reduce the switching overvoltages and also have a considerable effect to mitigate the switching duties of a circuit breaker. In the UHV system in Japan, the opening resistor method with a 700 ohms resistance is used to realise a reduced insulation level and compact facilities. The effects of opening resistor on TRV include the following aspects.

a) Damping of transient oscillation of TRV amplitude

The opening resistor reduces the amplitude of TRV oscillations. It can considerably mitigate the TRV peak as well as the initial rate of rise of TRV for testing duties of a terminal fault, a short line fault, and capacitive current switching.

b) Phase angle shift of breaking current

The opening resistor is inserted into the original circuit, which causes the phase angle shift of the current though the resistor contacts. This phase shift can significantly reduce the severity of the switching duties for capacitive current switching and out-of-phase conditions. For example, the TRV for capacitive current switching approaches a sine waveform instead of (1-cosine) waveform. The TRV behaviour in out-of-phase condition is discussed in the clause 3.3.6 in detail.

3.3.5.2 Effect of opening resistors on TRV

The Effect of opening resistors on TRV in the Japan’s UHV system was calculated by EMTP. I-4 model and II-1 model (Simplified model) in Figure 3.3.19 (a) and (b) are used for analysis.

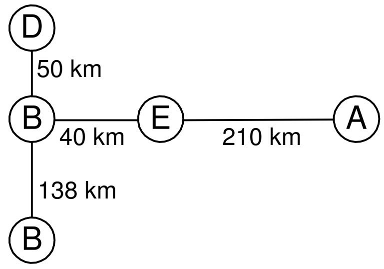


Figure 3.3.19 (a) *Model I-4*

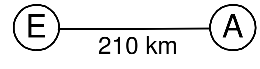


Figure 3.3.19 (b) *Model II-1*

The resistance value of 700 ohms for the closing and opening resistors was selected to suppress the switching surges as described in the section 2.9.1.2. Here, the resistance of the opening resistor value was changed from 500 to 750 ohms in order to study the effect on TRV reduction. A summary of this study is shown in Figure 3.3.20, and indicates that the effect of varying opening resistors in this range is quite small. The characteristics of the surge arresters are given in Table 3.3.6.

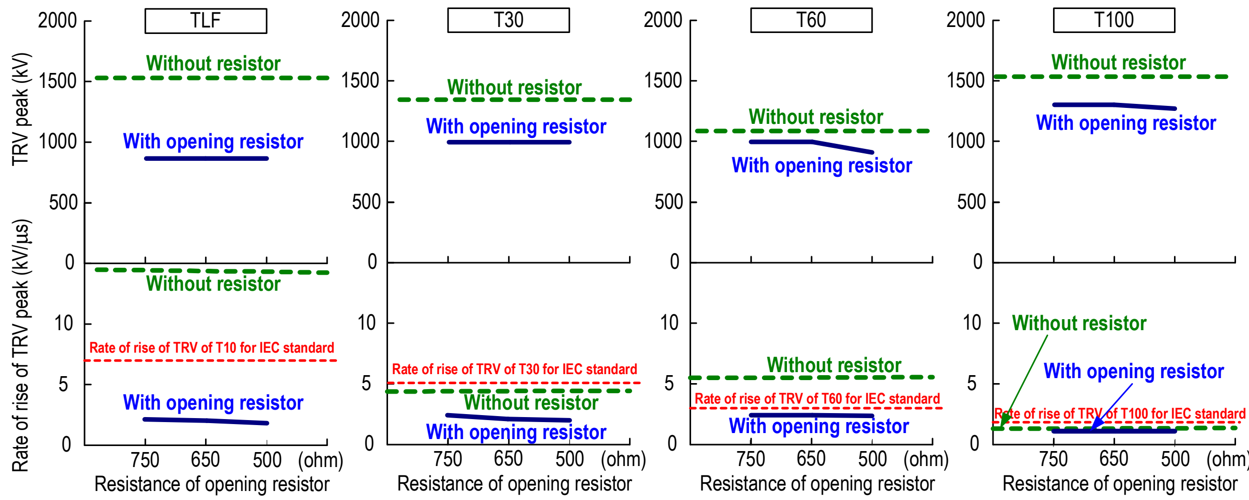


***Fig. 3.3.20** Effect of opening resistor value on TRV parameters*

3.3.5.3 Category of fault current and modes

Fault current values are categorized based on fault mode and reveal that the range of fault current depends on the fault mode. The results are shown in Fig. 3.3.21.

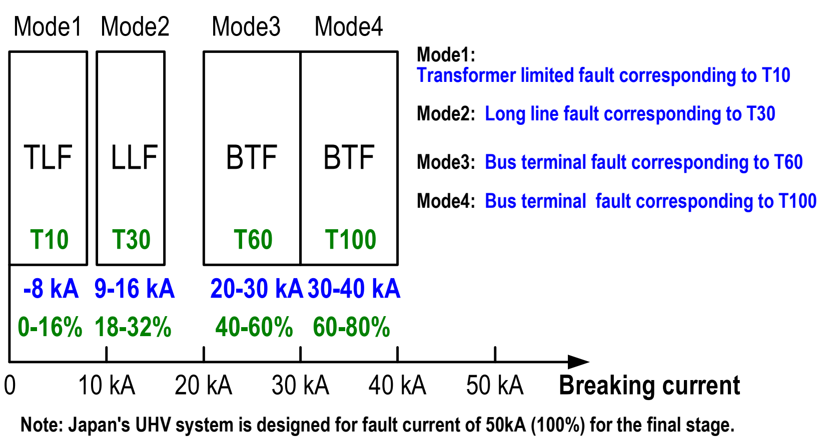


***Figure 3.3.21** Fault current and modes*

3.3.5.4 TRV for main interrupters with/without opening resistors

1) Terminal fault

In Japan's UHV system, the opening resistors as well as the surge arresters are considered in the early stage of the system study. The TRV specifications were determined based on the application of the opening resistors combined with the surge arresters. The TRV without opening resistors and with surge arresters in addition to the case without the opening resistors nor surge arresters are not officially considered. In these two cases, only the maximum values are indicated in parentheses for reference.

(A) U_1/t_1 (dv/dt); Various calculation results for fault clearing are shown in Fig. 3.3.22. The results include the following three cases: with opening resistors (R) and surge arresters (SA); without opening resistors and with surge arresters; and without opening resistors or surge arresters. The values are grouped in pairs. The first is with opening resistors and the other is without opening resistors. By adding opening resistors, the U_1/t_1 values are reduced, especially for regions with a smaller current.

The rate of rise is greatly reduced by opening resistors for all duties. Opening resistors are especially effective for smaller current values due to the suppression of transient phenomena. Table 3.3.16 shows the maximum calculated values (in parentheses) and the specified values for the case with opening resistors and surge arresters with U_1/t_1 values for Japan's UHV system. The results show that the values with opening resistors are lower than the extrapolated standard values for the reduction of the fault current by using resistors for the main interrupters.

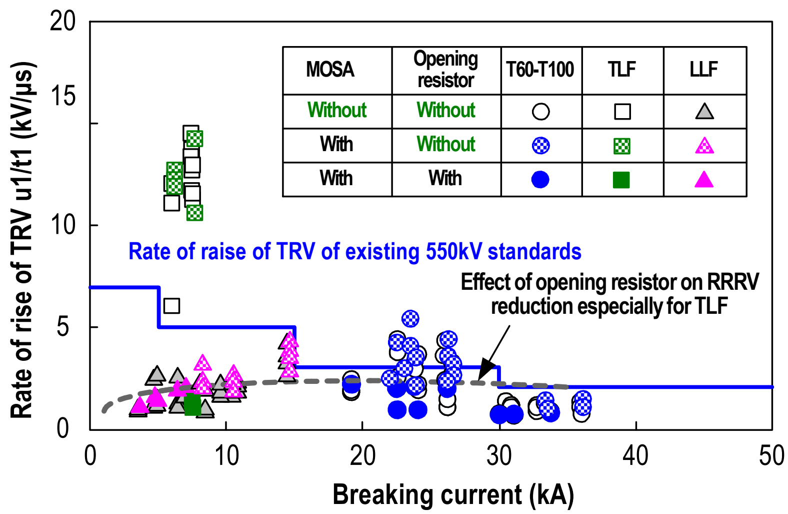


Figure 3.3.22 *Calculation results for U1/t1 of Japanese UHV system*

Table 3.3.16 *Specified and calculated values of U_1/t_1 of Japan's UHV system*

System condition	T10 (16%; 8 kA)	T30 (30%;15 kA)	T60 (60%; 30 kA)	T100 (80%; 40kA)
Without R and without SA	(14.5 kV/μs)	(4.3 kV/μs)	(5.5 kV/μs)	(1.4 kV/μs)
Without R and with SA	(15.5 kV/μs)	(4.3 kV/μs)	(5.5 kV/μs)	(1.4 kV/μs)
With R and With SA*	3 kV/μs (2.3 kV/μs)	3 kV/μs (2.5 kV/μs)	3 kV/μs (4.6 kV/us)	2 kV/μs (1.2 kV/μs)
Existing 550 kV standards	7 kV/μs	5 kV/μs	3 kV/μs	2 kV/μs

Note; * Maximum calculated values are indicated in ( ).

(B) U_1 (first peak voltage); Various calculation results for fault clearing are shown in Fig. 3.3.23. The majority of U_1 values are covered by the standard values extrapolated from IEC 62271-100 (2002) (1.3 × 1 p.u. = (√2 × 1100 kV / √3) = 1167 kV), but they are not covered by the latest standards in 2006 (1.3 × 1 p.u. × 0.75 = 876 kV). The values with opening resistors are lower than those without opening resistors, because t_1 (corresponding to U_1) is defined by the timing of the arrival of the reflection wave from the line end, which does not depend on whether there are opening resistors or not, but the U_1/t_1 value is reduced by the use of opening resistors.

Table 3.3.17 shows the maximum calculated values (in parentheses) and the specified values for U1, which are defined based on a first-pole-to-clear factor of 1.1 with the use of surge arresters.

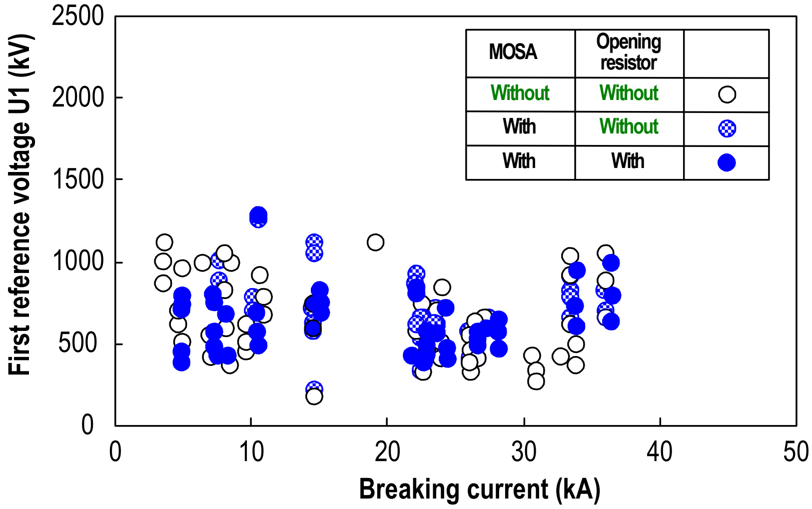


Figure 3.3.23 *Calculation results of U1 for Japanese UHV system*

Table 3.3.17 *Specified and calculated values of U1 of Japan's UHV system*

System condition	T30 (15kA)	T60 (30kA)	T100 (40kA)
Without R and without SA	(1278 kV)	(1110 kV)	(1047 kV)
Without R and with SA	(1278 kV)	(922 kV)	(830kV)
With R and with SA	988 kV (FPCF=1.1) (833kV)	988 kV (FPCF=1.1) (857 kV)	988kV (FPCF=1.1) (1012 kV)
IEC value (extrapolated)	---	876 kV(FPCF=1.3)	

Note: Extrapolated IEC value is estimated as 0.75x1.3x1p.u. (898kV)
Maximum calculated values are shown in parentheses

(C) Uc (TRV peak voltage); Various calculation results for fault clearing are shown in Fig. 3.3.24. The Uc is reduced by using opening resistors, especially in lower-current regions due to the high impedance ratio of transformers and suppression of transient phenomena by the resistors. The data with opening resistors is covered by the extrapolated IEC standard values even when the first-pole-to-clear factor is 1.1. In the case of LLF, Uc without opening resistors increases even with the use of surge arresters, because although surge arresters reduce the overvoltage to ground, the TRV between CBs results in a difference in voltage at both sides of the CB.

Table 3.3.18 shows the maximum calculated values (in parentheses) and the specified values for Uc. In the case without opening resistors (1st and 2nd rows), the Uc values are suppressed by surge arresters except for T30 duty, which corresponds to LLF conditions. In the case with opening resistors, Uc values are greatly reduced and specified values are expressed as 1385 kV (1.1×1.4) for all ranges from T10 to T100.

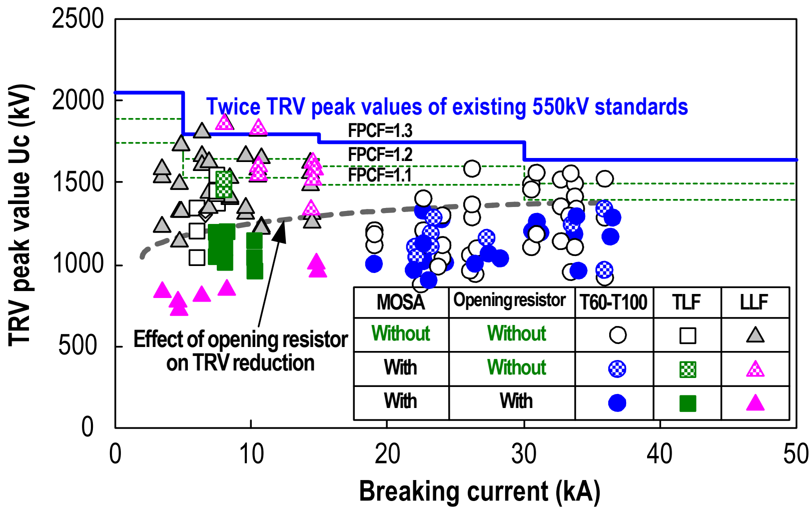


Figure 3.3.24 *Calculation results of Uc for Japan's UHV system*

Table 3.3.18 *Specified and calculated values of Uc of Japan's UHV system*

System condition	T10(8kA)	T30(15kA)	T60(30kA)	T100(40kA)
Without R and without SA	(1528 kV)	(1879 kV)	(1586 kV)	(1571 kV)
Without R and with SA	(1478 kV)	(1879 kV)	(1303 kV)	(1337 kV)
With R and with SA	1385 kV: 1.1x1.4 (890 kV)	1385 kV: 1.1x1.4 (1217 kV)	1385 kV: 1.1x1.4 (1157 kV)	1385 kV:1.1x1.4 (1309 kV)
IEC value (extrapolated)	1786 kV: 1.3x1.7x0.9	1752 kV (1.3x1.5)		1634 kV: 1.3x1.4

Note: The maximum calculated values are shown as ( ) for reference.

2) Short line fault (SLF) interruption

SLF interruption is a phenomenon where a high rate of rise of recovery voltage occurs at the initial stage of interruption. The initial rise of TRV is reduced by about 60% by opening resistor.

3) Capacitive current switching

Capacitive current switching duties become most severe with no load switching, but with opening resistors, the recovery voltages between the interrupters are divided by the ratio of resistance. This significantly mitigates the capacitive current switching duties.

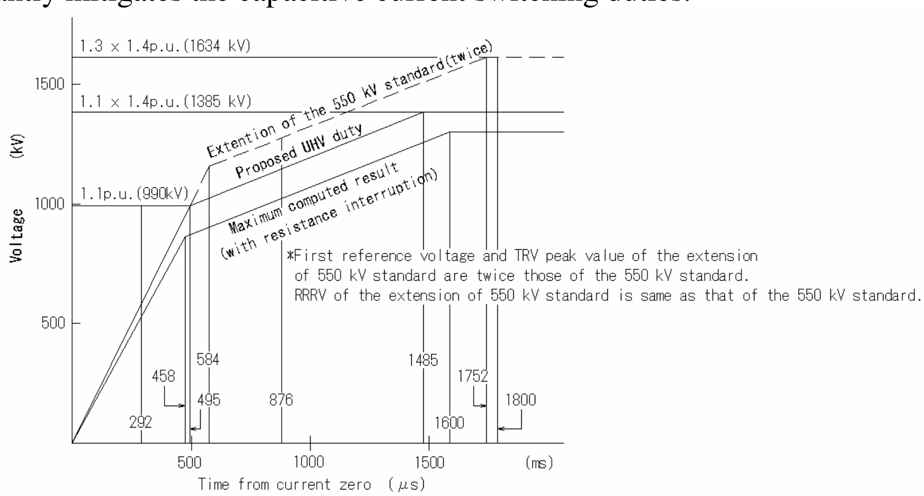


Fig.3.3.25 *TRV for small capacitive switching with/ without opening resistor*

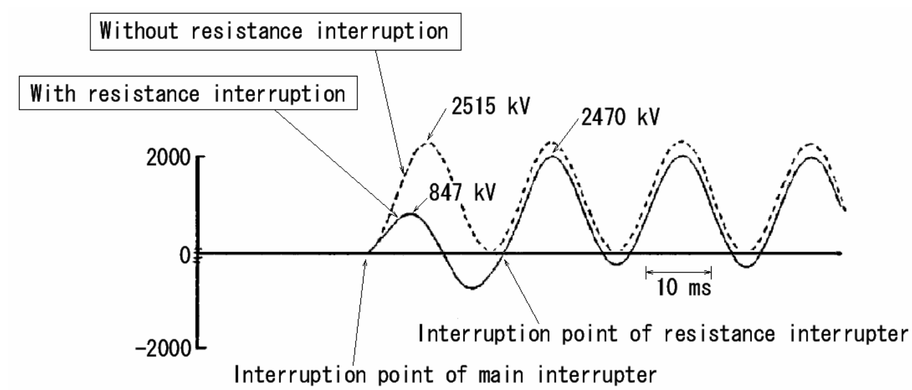


Fig.3.3.26 *TRV for small capacitive switching with/ without opening resistor*

3.3.5.5 TRV for resistor interrupter

1) Terminal fault

1. U_1/t_1(dv/dt): Figure 3.3.27 shows the TRV for the resistor contact of the interrupter, and the U_1/t_1 is determined by T10 duty. Table 3.3.19 summarizes the TRV duty for the resistor contact.

Table 3.3.19 *Summary of TRV condition for resistor contact*

Basic specification	Interrupting current	U_1	U_1/t_1	t_1	Uc	t_2
With opening resistor 750 ohms	1000A	250kV	2.3 kV/μs	109 μs	1200 kV	2200 μs

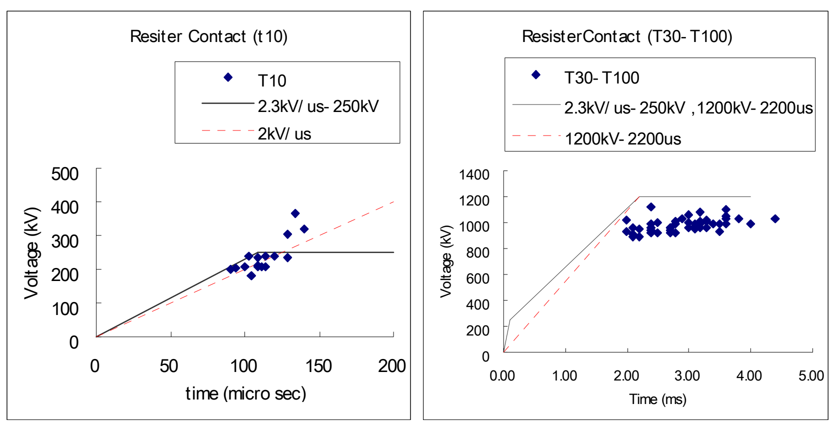


Fig. 3.3.27 *TRV shape of resistor contact with opening resistor*

2) Capacitive current switching

Because resistance is inserted in the circuit after the main circuit is interrupted, the TRV wave shape varies depending on the line length. In the case of a long line (210km), the TRV wave shape becomes [(cos θ-cos(ωt +θ), where θ =tan-1 ωCR).

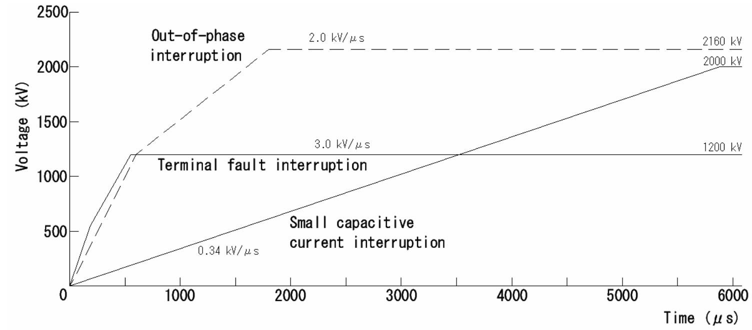


Figure 3.3.28 *Four TRV parameters for small capacitive switching duty for resistor interrupter*

The peak value decreases slightly compared to that of (1- cos ω t), however, the initial part of the rate of rise of TRV increases steeply (See Figure 3.3.29).

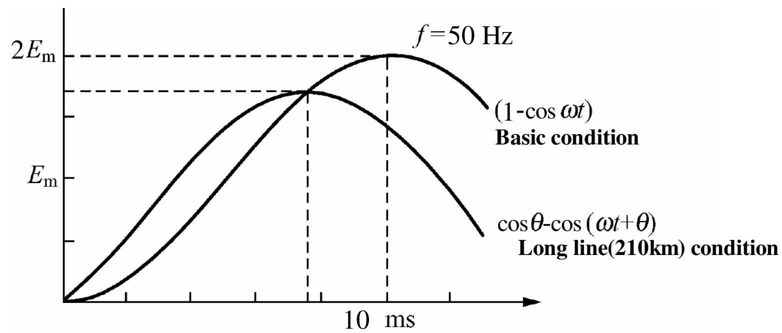


Figure 3.3.29 *TRV wave shape of line-charging switching for resistor interrupter*

3.3.5.6 Evaluation of switching duties with opening resistors

1) Switching duties of main interrupter with opening resistors

Theoretically, annex F of the IEC standards proposed the following approach to evaluate the switching duties for SLF and BTF. Let the inherent TRV be V(t).

V(t) = (u1/t1) ×t   (0<t<t1)   (11)

(Uc-u1)/(t2-t1)×(t-t1) + u1   (t1<t<t2)   (12)

Uc   (t2<t)   (13)

Next, the current will be expressed as;

I(t) = √ 2 ×I rated×sinωt   (13)

The network impedance without the opening resistors is given by;

Z(t) = V(t) / I(t)   (14)

The equivalent network impedance with the opening resistor will be theoretically given by;

Zr(t) = (R×Z(t))/ (R+Z(t))   (15)

Then the switching duty with the opening resistor will be theoretically as follows;

$$Vr = I(t)\times Zr(t) \quad (16)$$

2) Switching duties of resistor interrupter with opening resistors

The interrupting current for resistor interruption is different from that for the inherent one.

Let the inherent interrupting current be I(t), for example, then usually I(t)=E*sin(wt), where E(t) is the system operating voltage.

Assuming the network impedance at the circuit breaker before interruption is Zo(t)

$$Zo(t) = E(t) / I(t) \quad (17)$$

When the opening resistor is inserted into the network impedance, the new impedance Zrr will be,

$$Zrr(t) = R+Z(t) \quad (18)$$

Then the interrupting current through the resistor contacts will be,

$$Irr(t) = E(t) / Z(t) \quad (19)$$

Finally, the switching duty for the resistor unit will become,

$$Vrr(t)=Z(t) \times Irr(t) \quad (20)$$

3.3.6 Phenomena related to out-of-phase

3.3.6.1 General

Interconnections at the EHV level are increasingly used for multiple powerflows between regions and between countries. Such large powerflows require substantial phase shift (voltage angle) to transmit energy in an AC system. Even in a meshed network such as the interconnected European 420 kV system, substantial phase angles can occur between the northern and southern parts of the grid. Angles as large as 60º are no exception and the UCTE has taken the decision to install an online phasor measurement system to monitor stability limits within the European grid. In Brazil, the phasor angle difference along the 800 kV transmission system from Itaipu to Sao Paolo (triple circuit, ~1000 km, 60 Hz, series compensated) can reach values of 100º or more under full-power operation. When the systems with such large phasor angles are split up into two sections under stable conditions, the dynamic out-of-phase angles will inherently be large as well. Out-of-phase angles as large as 180º are therefore considered realistic. Generally utilities that exploit long-distance transmission systems specify out-of-phase angles as large as 120, 150 and 180º.

Similarly, it can be expected that UHV grids where regions with a large surplus of generated power are interconnected with regions with a large load demand, will show substantial angles between the voltages at both sides. Whether these angles will show up under circumstances of splitting up the system depends to a large extent on the number of parallel branches and the meshed structure of the UHV network. Although large out-of-phase angles may occur in the heavily meshed European network, the probability of out-of-phase conditions with a large angle is rather low. UHV networks, however, tend to be simple and far from meshed. Moreover, the length of OH lines is usually long, so that the probability of occurrence of large out-of-phase angles in general cannot be ignored.

Breaking the current under out-of-phase conditions with large out-of-phase angles (roughly more than 90º) deserves some attention, as the dielectric TRV stress may be beyond the capabilities of the involved circuit breakers. In the IEEE and IEC Standards that cover voltages up to and including 800 kV, specified recovery voltages under out-of-phase conditions are applicable for out-of-phase angles as large as 105º (see Clause 6.110.3 of IEC doc 17A/768/CDV). Looking at the peak values of the recovery voltage, it may be that only angles less than 105º are covered. Apart from circuit breakers, other equipment may be stressed by out-of-phase current that may be larger than the short-circuit current contribution of that specific branch in the network.

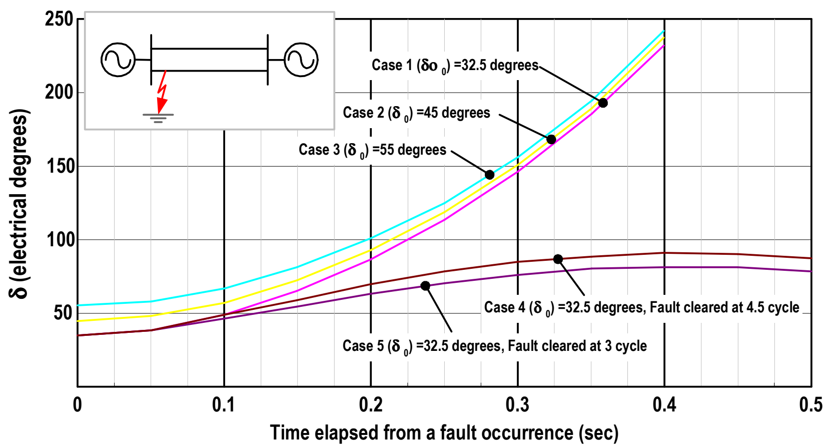
In order to prevent the occurrence of large out-of-phase angles and/or overstressing of the circuit breakers, utilities may apply special protection schemes. This is quite normal for large generating plants, but less common for interconnections at the transmission level. The most familiar protection systems are the power swing relay and the out-of-phase relay, which may be separate devices or may be functions in an advanced (digital) distance/zone protection relay. While the power swing relay detects certain slow changes in complex impedance as measured by the relay, the out-of-phase relay continuously monitors the voltage angle between the line's ends.

The power swing relay acts on large angle variations, but small angles, by giving a trip command (or an alarm, but then it acts as a monitor rather than a protection). The relay offers an alternative to block tripping for operating areas where there is some question as to whether tripping is necessary or where tripping must be prevented. The setting of the angle variation threshold for blocking is based on extensive computer simulations of the network under several dynamic loading conditions.

The out-of-phase relay blocks the tripping command of the conventional protection relay functions (distance/zone protection) when a certain threshold is passed by the out-of-phase angle. The block will last until the out-of-phase angle decreases to a value where the circuit breaker is able to clear the current.

Some utilities are in favor of such protection functions, but they are not unanimous about the settings of the devices. Other utilities feel that such functions interfere with the reliability of the main protection systems. Of course, network topology and the utility's experience with out-of-phase conditions play an important role in the implemented policy. For instance, Brazil's 800 kV system employs out-of-phase blocking relays, but Canada's system has no protection device to block the circuit breakers in the case of large out-of-phase angles. In India's extended 420 kV network, out-of-phase protection has not been applied nor is it foreseen for the emerging 800 kV network.

In Japan, the out-of-phase protection is performed by two stages. The first stage is to prevent the occurrence of out-of-phase conditions, which may result in large area blackouts. It caries out online forecast calculations of the phase angle difference between a generator internal voltage and the main system internal voltage; examples of two cases leading to stable conditions and three cases leading to unstable conditions after a fault occurrence are given in figure 3.3.30. When the predicted phase angle difference exceeds a pre-determined threshold value, due to an electrical disturbance such as a short-circuit, some generators are tripped so that the stability of the entire network is secured. About 200 to 300 ms before the phase angle reaches the threshold value, trip signals are sent out from a central system protection unit. By offline studies, the threshold values have been determined for each network condition (generally above 100°). The second stage is to split up the network in case the fore-mentioned protection system does not operate properly. Protection relays detect the out-of-phase condition by measuring the phase angle difference between the busbar voltages at both sides of a transmission line or a transformer. When the electrical centre of the out-of-phase condition is within this OH-line or this transformer, and the phase angle approaches and exceeds 180°, the relay will give a tripping command. (Much smaller phase angle differences than 180° could lead to unnecessary trips as the power swing may settle down to stable conditions; see figure 3.3.30.) The out-of-phase current is interrupted approximately 45 to 70 ms after the detection of phase opposition (180°). As the slip interval between the generators at both sides is about several hundreds to 2000 ms per turn, there is a certain possibility of interruption under a condition close to 180°.



Note: Curves of cases 1, 4 and 5 quoted from "Element of power system analysis, second edition", written by W. D. Stevenson. Jr., McGraw-Hill Book Company Inc.

Figure 3.3.30 *Example of power swing curves from [38] (cases 2 and 3 are added)*

Specifications for TRV at out-of-phase switching at the UHV level are compared in Ref. [39]. In Japan, Russia and China, a voltage factor of 2.0 is used, resulting in a recovery voltage of 2 p.u. This voltage factor is based on an out-of-phase angle of 180º, under conditions of a first-pole-to-clear factor close to one. In Italy, based on an out-of-phase angle of only 90º, the voltage factor is 1.4, probably with a low first-pole-to-clear factor as well. The applied voltage for making the out-of-phase current is 1.41 p.u. in Japan, Russia and China, suggesting an angle of 90º, while in Italy a voltage factor of 1.0 p.u. is used (60º). Peak TRV value is 2.5 p.u. in Japan and China, with an amplitude factor of 1.25, common to IEC. In Russia, the peak value is 3.0 p.u., suggesting an amplitude factor of 1.5. In Italy, the peak value is 2.21 p.u., which leads to an amplitude factor of 1.58. RRRV is specified as 1.54 kV/µs in China, as in the IEC Standard. In Italy, it is 3.0 kV/µs and in Japan, 6.0 kV/µs. [40]

The application of MOSAs can suppress the TRV peak values for terminal faults, resulting in reduction in the amplitude factor of TRV for terminal faults, TLF (transformer limited or secondary faults) and out-of-phase. However, it may not lead to sufficient reduction for LLF (long-line faults) where TRV is generated at both the source and line sides of the breaker terminals. In addition to MOSAs, the application of opening resistors will lead to considerably lower TRV peak values and RRRV values, as shown in Fig. 3.3.31.

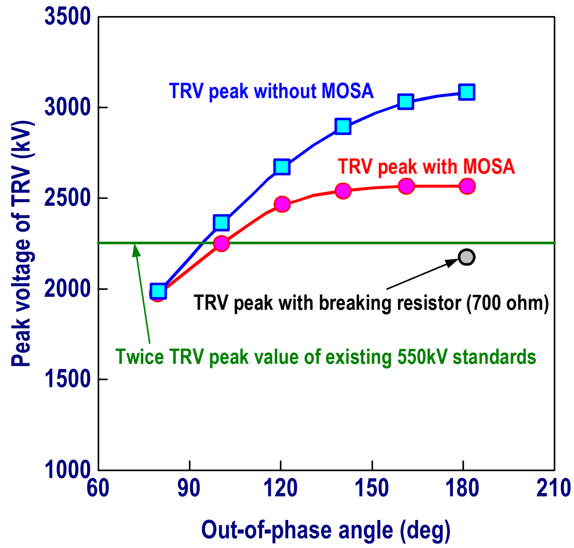


Fig. 3.3.31 *TRV out-of-phase switching vs out-of-phase angle*

The triangular waveforms of TRV in China's UHV network [41] as well as in the report [42] were observed in the case of out-of-phase conditions on a long OH line. The TRV at line-side can be calculated by the travellling time multiplied by the rate of rise of the recovery voltage, where RRRV = Zeq * di/dt and i is the peak value of IOP, the out-of-phase-current. Equivalent surge impedance Zeq is given by that for the first pole to clear (similarly to determine ITRV) but not for the last pole to clear (That is used to determine the RRRV of SLF interruption). The value ranges from 300 to 350 ohm. For 50 Hz, this leads to RRRV = 0.13 to 0.16 * IOP. [43]

When the busbar side of the circuit breaker is to be represented by another OH line, a triangular waveform will also appear at the source side, thus increasing the RRRV to, for instance, a double value, but with different reflection times, as shown in Ref. [41].

The amplitude of I_{OP} depends on the short-circuit power at the busbars at both line ends and the line impedance. The longer the line, the lower the amplitude on one hand, but the longer the reflection time on the other hand. The combination tends to produce slightly higher TRV peak values for longer lines. As long as the short-circuit power at the busbars is rather low or the out-of-phase angle rather small, the TRV peak value will be covered by 2.5 p.u. (product of an out-of-phase factor of 2.0 and an amplitude factor of 1.25), as specified in the present standards (for rated voltages up to and including 800 kV). However, at higher values of the short-circuit power or out-of-phase angle, peak values exceeding 2.5 p.u. will appear.

Figure 3.3.32 shows the TRV calculated in Ref. [41] under out-of-phase conditions in Jin-Nan and Nan-Jing lines in an 1100 kV network in China.

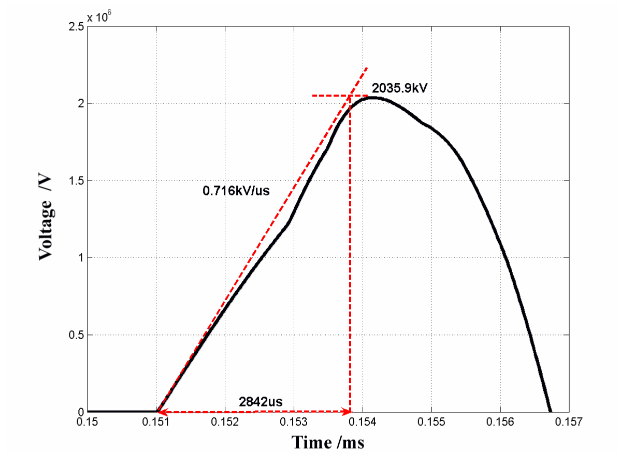


Figure 3.3.32 *TRV waveform of Nanyang CB during out-of-phase conditions while the oscillation centre is on the Jing-Nan line*

The out-of-phase angle and the short-circuit power at the busbar are not given in Ref. [41]. In this case with a rather low out-of-phase current, the peak value of the TRV and RRRV are covered by that as specified for the out-of-phase test duty. The peak of 2035.9 kV is also covered by the value calculated for terminal fault test duty T10 with a first-pole-to-clear factor of 1.3 (2055 kV); it would not be covered if a first-pole-to-clear factor of 1.2 is taken for T10. The 0.716 kV/μs rate of rise is sufficiently covered by the value for T10. It is required to investigate more detailed whether T10 (or T30) test duty generally can cover the requirements for out-of-phase duty for UHV systems.

For circuit breakers equipped with pre-insertion resistors, Ref. [41] shows that a much higher TRV peak value is applied to the auxiliary interrupter, compared with the main interrupter, and values exceeding 2.5 p.u. are already obtained at smaller out-of-phase angles. Also, simulation results from Japan show that the peak value of TRV across the auxiliary interrupter is higher than the TRV across the main interrupter (2.41 versus 2.28 p.u.). [21] The influence of PIR on the TRV waveform is explained in Section 3.3.6.2.

The effect of MOSAs on the TRV waveform can be understood from Refs. [42] and [25]. The use of special MOSAs with a very low SIPL can limit the TRV peak value to within 3.2 p.u., as shown in Fig. 3.3.30. MOV in parallel to the arcing chambers can limit the TRV peak value to 3.0 p.u., when the involved circuit breakers are required to synchronize the systems.

3.3.6.2 Effect of opening resistors under out-of-phase conditions

There is a report from China [41] indicating that TRV peak under out-of-phase condition with opening resistor scheme is higher than that without opening resistor, while similar study in Japan showed that TRV peak is reduced by applying the opening resistor method [21]. This section provides technical explanations for these conflicting results.

In general, the opening resistors can mitigate the TRV oscillation for terminal fault duties and reduce the RRRV and peak of TRV. In the case of out-of-phase conditions with or without opening resistors, TRV peak is affected following several parameters.

1) Frequency of line side oscillation
2) Whether the line side oscillation is at one side of CBs or both sides
3) Phase angle between two network under Out-of-phase condition

When the opening resistor is applied, two additional parameters affect the TRV.

4) Phase shift
5) Amplitude of line side oscillation (Before interruption)

3.3.6.2.1 *Phase shift*

The phase angle of the interrupting current is decided by the total impedance of the network and is normally delayed 90 degrees from the voltage if there is no opening resistor. In the case of opening resistor applications, the phase angle of the interrupting current is determined by not only the back (network) impedance but also the opening resistor. Considering the several hundred ohm of opening resistor and the back impedance corresponding to 50 to 63 kA short-circuit current in the network, the opening resistor will be dominant and the phase shift of interrupting current will be up to around 10 degrees. In the case of a network with small short-circuit current, the back impedance becomes large and comparable to the resistance value of the opening resistor. In such cases the phase shift will go to up to around 40 degrees. This phase shift influences the TRV peak value when the peak of the transient oscillation of the line side comes close to the peak of the power source voltage.

3.3.6.2.2 *Amplitude of line side oscillation*

Before the out-of-phase condition is interrupted, the voltage between two networks is distributed along the back (network) impedances and opening resistor. Voltage distribution on the back impedance will increase the amplitude of the transient oscillation at the line side. For networks with large short-circuit currents, voltages across the back impedance is small and around several to 10%. In the case of the networks with small short-circuit currents, the voltage on the back impedance becomes large and is up to 20% on one side.

3.3.6.2.3 *Other parameters*

1) Frequency of line side oscillation

Frequency of line side oscillation is roughly in proportion to the line length, but varies depending on the degree of shunt reactor compensation. If the degree of compensation increases, the frequency of line side oscillation goes lower, and when this frequency is close to power frequency, the peak of line side oscillation is likely to overlap the source voltage peak and cause a severe TRV peak.

2) Whether the line side oscillation is at one side of CBs or both sides

In the IEC standard, line side oscillation is assumed to be on one side of the CB. In the case of a switching station it is possible to have oscillations on both sides of the CB. If the line length of both sides is almost the same, the oscillation frequency is also same in opposite polarity and then severe TRV will appear.

3) Phase angle between two networks of Out-of-phase condition

Phase angle between two networks of Out-of-phase condition is also important as discussed in other section.

3.3.6.2.4 *Simplified calculation*

Simplified calculation is carried out assuming the UHV pilot plant in China as Network 1 and Japanese planned UHV network as Network 2 respectively. Parametric conditions for this study are shown in Table 3.3.20. NOTE: parameters of NETWORK1 and 2 are chosen only for this study and are NOT same with actual network parameters of neither Japan nor China. Generally there are surge arresters in actual UHV network in China and Japan, and the transient voltage to the ground is cut off at about 1300 kV by these arresters. However, no arresters are modelled in this study to grasp the effect by deference of network condition to TRV without non-linear elements.

Examples of voltage waveform of the line side voltage are shown in Fig. 3.3.33 and comparison of TRV voltage is shown in Table 3.3.21. Major points for affecting parameters to TRV peak are listed in Table 3.3.22. From Table 3.3.22 it is understood that, condition of Network 1 was of severe condition for out-of-phase TRVs with opening resistor and resulted in higher TRV peak than that of without opening resistor. More than 20% of voltage is distributed on back impedance and then, such level of amplitude of line side oscillation occurred. Frequency of line side oscillation is about 120 Hz. Phase shift of interrupting current is around 40 degrees. These parameters led the superimposing of side line oscillations peak to near peak of power frequency voltage with opening resistor. Adding to this, Network 1 is the case of switching station in the middle of 600 km length OH-line. This implies line side oscillations are applied to each side of terminals of Circuit breaker at reverse polarity.

3.3.6.2.5 Summary

TRV peak for out-of phase condition with opening resistor method is affected by the system configuration and network parameters, and vary. Attention shall be paid to these phenomena when applying the opening resistors.

***Table 3.3.20** Simplified network for study*

	NETWORK 1	NETWORK 2
System voltage	1100kV / root 3 (=635.1 kV rms)	1100kV / root 3 (=635.1 kV rms)
Back impedance	741 mH (SC current = 2.73 kArms)	162 mH (SC current = 12.5 kArms)
OH line capacitance	3 micro F (both sides) (0.01 micro F *300 km)	2.1 micro F (One side) (0.01 micro F *210 km)
Sh. reactor	1688.5 mH (100% compensation)	4825 mH (100% compensation)
Opening resistor	600 ohm	600 ohm
Phase difference	180 degree	180 degree
Frequency	50 Hz	50 Hz
Configuration	Switching station	Substation

NOTE: 1) Parameters of NETWORK1 and 2 are chosen only for this study and is NOT same with actual network parameters of Japan nor China, 2) No arresters are modelled in this study to grasp the effect by deference of network condition to TRV without non-linear elements.

***Table 3.3.21** Comparison of TRV peak voltage*
(TRV peak / peak voltage of line side to ground)

	NETWORK 1	NETWORK 2
Without resistor	100 % / 100 %	86 % / 130 %
With resistor	117 % / 116 %	80 % / 72 %

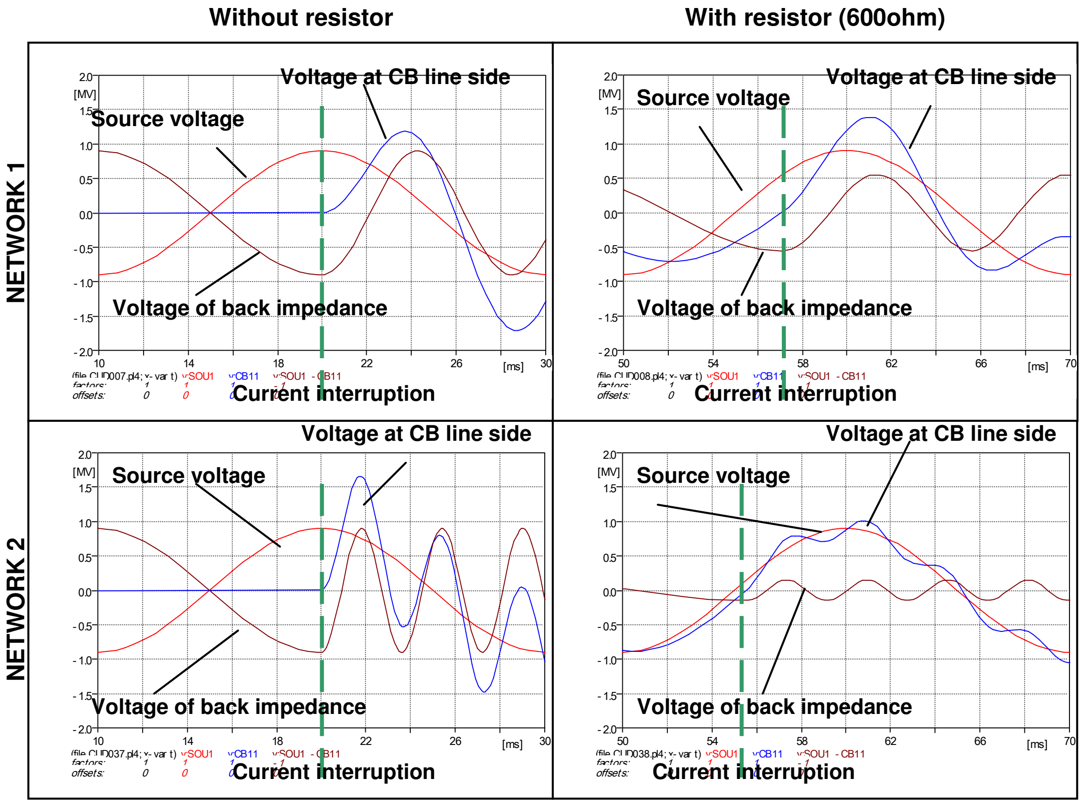


__Fig. 3.3.33__ Typical waveforms of line side TRV (__Red:__ Source voltage, __Brown:__Line side oscillation, __Blue:__Voltage at CB line side terminal)

Table 3.3.22 *Comparison of two network characteristics with opening resistor method*

	NETWORK 1	NETWORK 2
Phase shift (Angle from voltage zero to current zero point)	Large: Due to large back impedance	Small
TRV amplitude at line side	Large: Due to large back impedance	Small
TRV frequency at line side	Middle: Due to long line and compensation	High: Due to relatively short line
System configuration	Both sides are line (Switching station)	Normal: One side is line and another side is transformer

3.3.7 High frequency components imposed on fault currents

Fault currents are distorted by the superposition of high-frequency surge currents caused by sudden voltage change. Since an 1100 kV system has twice the operating voltage of a 550 kV system, and high-frequency surge currents attenuate slowly due to small transmission line resistance, the fault current distortion of the 1100 kV system becomes larger than that of the 550 kV systems. Interruption duty becomes 10% more severe due to current distortion. Figure 3.3.34 shows an example of the analysis waveform of a fault current.

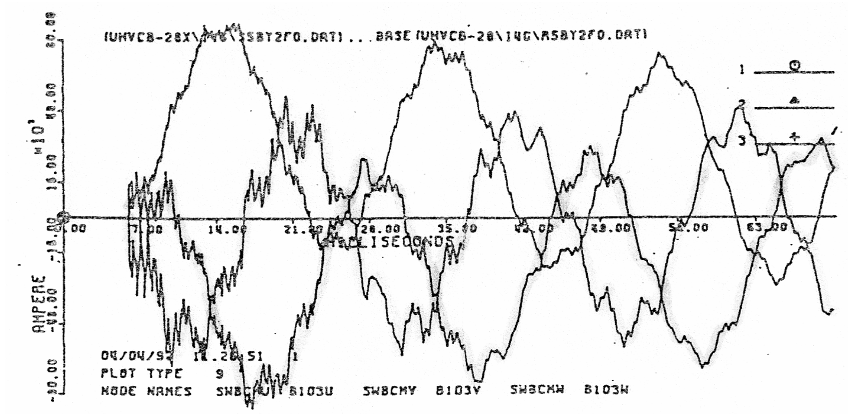


Fig.3.3.34*Analysis waveform of fault current (example)*

Figure 3.3.35 shows the fault current waveform of an 1100 kV transmission line having a present operational voltage of 550 kV. The fault current is about 2.1 kA and was caused by a two-phase short circuit. The fault occurred outside the protection range, and the fault current flows through this line.

Consequently, the current does not drop to zero after the fault is eliminated. High-frequency surge currents attenuate within about 1.5 cycles. To understand this phenomenon in more detail, it is necessary to accumulate additional data on fault currents.

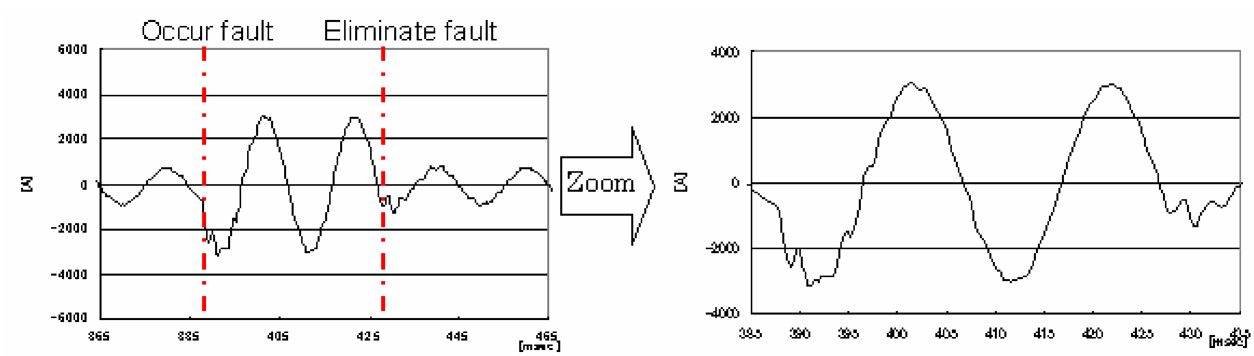


Fig. 3.3.35 *Double phase fault in 1100 kV line operated at 550 kV (Japan)*

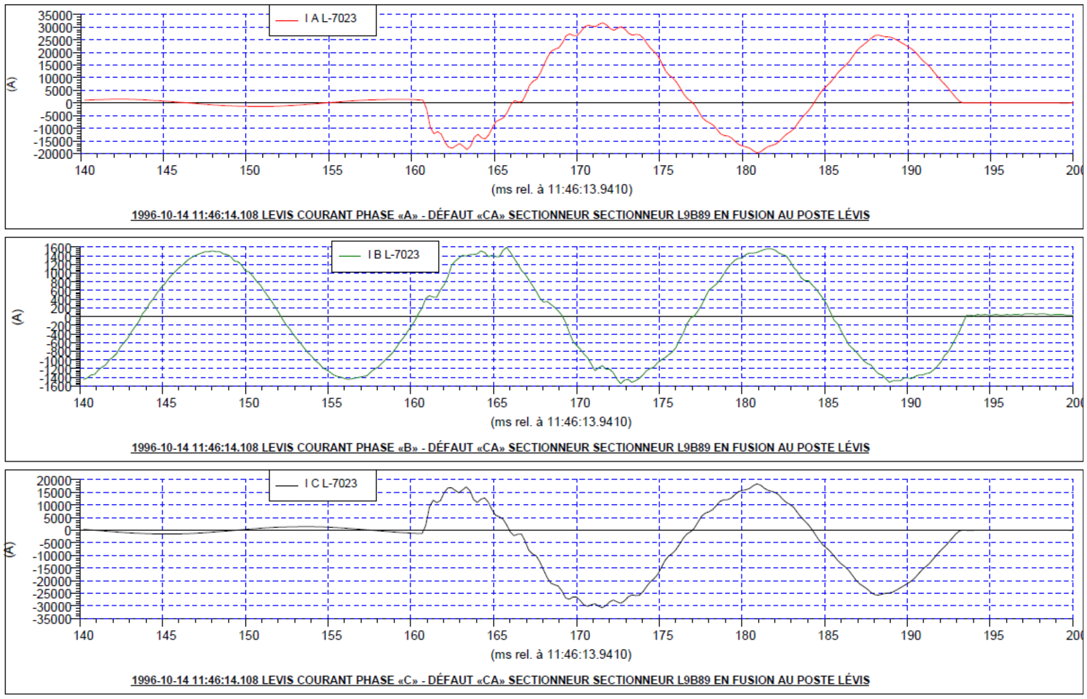


Fig. 3.3.36 *Double phase fault in 735 kV line (Hydro Québec, Canada)*

The majority of high-frequency-component fault currents in Canada's 735 kV transmission lines (686 mm^2 × 4 conductors) were attenuated within one cycle and no prominent oscillations were observed at the clearing instant, as can be seen from the actual case in Fig. 3.3.36.

3.3.8 Capacitive current

3.3.8.1 General

As capacitive current switching tests must be performed as single-phase for UHV applications, it is necessary to define the voltage factor (k) to be applied to the phase-to-earth voltage in order to reproduce the voltage stress of a three-phase breaking operation.

Figure 3.3.37 gives the recovery voltage on the first pole-to-clear as a function of C_1 *and* C_0.

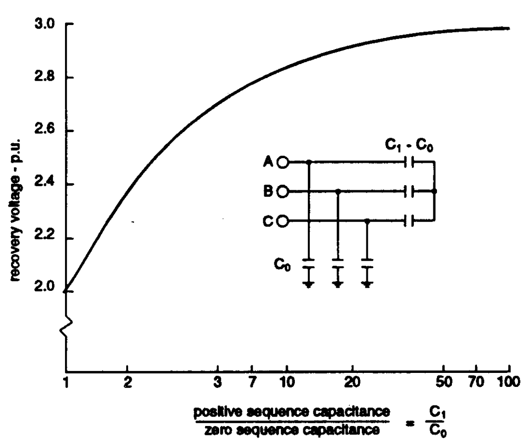


Fig. 3.3.37 *Recovery voltage as a function of* C_1 *and* C_0

Typical values for the ratio of C_1 / C_0 are between 1.5 and 2.0. For example, the calculated values for C_1 and C_0 for Eskom's 800 kV lines with single circuits and 6 × Tern ACSR conductors per bundle are as follows:

Horizontal configuration:	C_1 = 13.2 nF/km : C_0 = 8.9 nF/km	C_1 / C_0 = 1.48
Delta conductor configuration:	C_1 = 14.8 nF/km : C_0 = 7.6 nF/km	C_1 / C_0 = 1.95

3.3.8.2 Voltage factor for UHV

3.3.8.2.1 Switching overhead-lines under normal conditions

Depending on the ratio of C_1 and C_0, a voltage factor must be applied during the single-phase test in order to obtain the same TRV peak as during three-phase operation. Using the data from the previous example, the peak recovery voltage is 2.1 and 2.3, respectively, and the voltage factor for the single-phase test would then be 1.05 and 1.15, respectively.

However, when determining the voltage factor, it must be taken into account that restrike will not necessarily occur at the peak value of recovery voltage, but would more likely occur during the period between one-quarter and one-half cycle of the power frequency after current interruption.

For example, Fig. 3.3.38 shows that in the case of capacitor banks with ungrounded neutral, the peak recovery voltage on the first pole to clear can be obtained during a single-phase test using a voltage factor of 1.25, but in order to cover the recovery voltage during the first half-cycle, the voltage factor must be 1.4, as defined in IEC 62271-100 and ANSI/IEEE C37.04.

Based on the previous considerations, in the case of unloaded line switching for which the ratio C_1 / C_0 is between 1.5 and 2.0, a voltage factor of 1.2 is recommended for operations with no other phase faults.

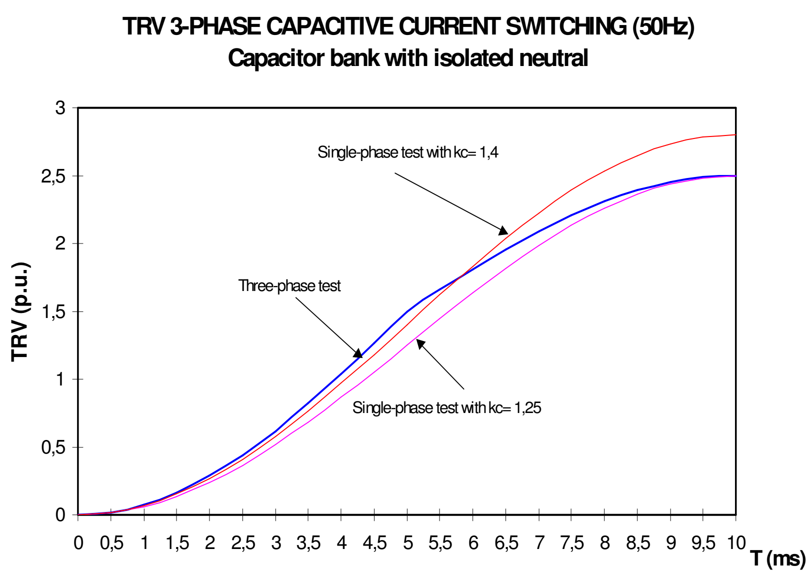


Figure 3.3.38 *Comparison of recovery voltages of three-phase and single-phase tests*

3.3.8.2.2 Switching overhead-lines under fault conditions

The voltages and currents in the case of a fault interruption in a transmission line, depend on the circuit parameters and the interrupting sequence. The highest voltage appears on the healthy phase, which is interrupted prior to the faulted phase. The highest current occurs on the last interrupted phase when the faulted phase is the first pole to be interrupted. [44]

The recovery voltage is typically 2.74 p.u., when switching off a healthy phase in a 550 kV network in the case of a phase-to-earthed fault. For phase-to-phase fault conditions, the recovery voltage and capacitive current are less severe than for phase-to-earthed fault conditions.

Based on the previous considerations, a voltage factor of 1.4 would be required where capacitive current switching must be verified in the presence of single- or two-phase earthed faults.

3.3.8.3 Shunt compensated lines

Shunt reactors, which are used to limit switching and temporary overvoltages at planned commutation and fault clearing, are placed on at least one end of the line, but usually on both ends of a UHV line that exceeds 100 km. In this case, switching-off of the line is accompanied on the line side by slowly attenuating low frequency, close to 50/60 Hz, so the resulting voltage across the circuit breaker is lower than in the case of uncompensated lines. This, however, requires the connection of shunt reactors to the OH line before de-energization of the line, which is common practise. But, in the case of transfer tripping in single- or three-phase mode (such as with three-phase high-speed auto-reclosing applications), it is possible for the OH line to be de-energized without shunt reactors connected to the heavily loaded line.

3.3.8.4 Current

An increase in the rated voltage of UHV lines having bundled phases results in a rise in specific line capacitance and a steep increase in the charging current per km. As the distance between UHV substations tends to increase with voltage, the charging current of UHV lines could be extremely large.

The capacitive current that must be interrupted varies widely depending on the length and type of line considered. For UHV systems, the value ranges from 1000 A (210 km line in Japan) to 2030 A (700 km line in Russia). Similar values are already required for capacitor banks in high-voltage systems, such as 1200 A as stipulated in the draft revision of IEEE C37.06/8.2-2007.

Compensated lines with shunt reactors have lower charging currents than uncompensated lines. The charging current of a compensated line is equal to the value for the uncompensated line multiplied by one, minus the ratio of reactor reactance and line capacitive reactance.

Interruption of such high capacitive currents is not necessarily difficult for high-voltage circuit breakers as the highest probability of restrike is usually met with short arcing times, i.e. with lower currents. Accordingly, test duty LC1 in IEC 62271-100 is required to be performed with a low percentage (10 to 40%) of the rated capacitive breaking current.

Adopting the lowest percentage (10%) for test duty 1 or even introducing a lower value such as 5%, while still performing test duty LC2 with 100% of the rated capacitive breaking current, would make it possible to test the circuit breakers in the most severe cases.

3.3.9 UHV reactor current switching

3.3.9.1 General considerations

Shunt reactor switching is addressed as an IEC standard. [45] Here, general considerations are reviewed briefly, followed by a more detailed description of UHV applications.

Shunt reactor switching is a unique and onerous duty for circuit breakers. At high voltages, the shunt reactor current is low (in the order of a few hundred amperes at most) and current interruption is readily achieved. However, due to the nature of the interaction between the breaker and the circuit, the current is forced to zero prior to the natural power-frequency zero-crossing, a phenomenon known as current chopping. Current chopping results in stored energy in the reactor and when that energy is converted to capacitively stored energy, chopping overvoltage occurs. This overvoltage is referred to as suppression peak overvoltage (Fig.3.3.39). The transient recovery voltage (TRV) across the breaker is then the difference between the source-side power frequency voltage and the suppression peak overvoltage.

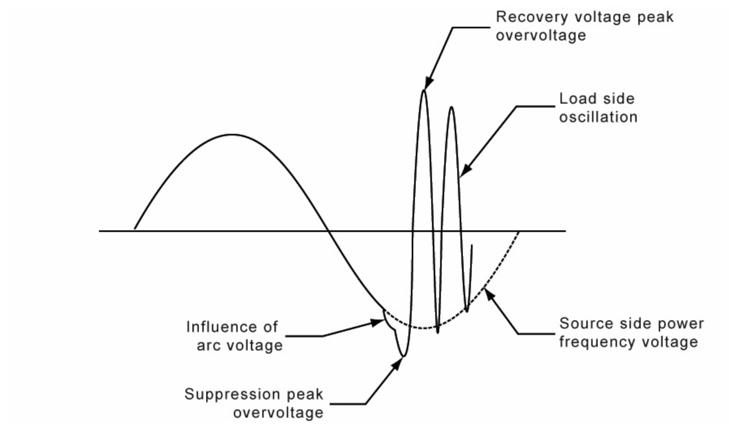


Fig. 3.3.39 *Suppression peak overvoltage*

The general case for shunt reactor switching is the four-legged scheme as shown in figure 3.3.40. The suppression peak overvoltage k_a in p.u. is given by:

$$k_a = (1+K)\sqrt{1+\frac{1}{(1+K)}\left(\frac{i_c}{u_o}\right)^2\left(\frac{L}{C_L}\right)} - K \qquad \ldots(21)$$

where K is the neutral shift in pu, i_c the chopped current level, u_o the peak voltage across the reactor at current chopping, L the inductance of the reactor and C_L the total load side capacitance.

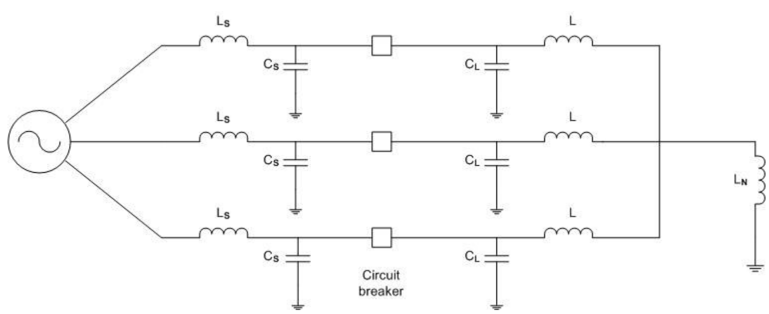


Fig. 3.3.40 *General four-legged shunt reactor switching case*

The peak value of the TRV across the breaker k_{rv} in pu is given by:

$$k_{rv} = 1 + 2K + k_a \qquad \ldots(22)$$

For four-legged reactor schemes at EHV, the neutral reactor is bypassed (neutral earthed) prior to switching the main reactor. The same procedure would apply at UHV and K can be set to zero in Equations (14) and (15) giving:

$$k_a = \sqrt{1 + \left(\frac{i_c}{u_o}\right)^2 \frac{L}{C_L}} \qquad \text{...(23)}$$

and

$$k_{rv} = 1 + k_a \qquad \text{...(24)}$$

The frequency of the suppression peak overvoltage is given by:

$$f = \frac{1}{2\pi\sqrt{LC_L}} \qquad \text{...(25)}$$

Using the chopping number approach, Eqn (16) can be written as [44]:

$$k_a = \sqrt{1 + \frac{1.5N\lambda^2}{\omega Q}\left(\frac{C_P}{C_L} + 1\right)} \qquad \text{...(26)}$$

where N is the number of interrupters in series in the breaker, λ is the chopping number in $AF^{-0.5}$, C_p is the grading capacitance across one interrupter, ω is the angular frequency and Q is the three-phase reactor rating in VA. Equation (26) assumes that $C_S >> C_L$.

As for EHV shunt reactor switching, UHV reactor switching will be treated on a single-phase basis including for type testing. Type testing is done on a unit basis and the test results are extended by calculation to the multiple interrupter cases. As the behaviour of multiple interrupter breakers for reactor switching is not fully understood, some caution should be exercised and appropriate TRV limitation measures should be provided.

Reignition overvoltages are generated by reignitions following an initial interruption. Reignitions are provoked when the voltage between the contacts exceeds the dielectric withstand of the contact gap. The rate of rise of a reignition overvoltage is between those observed during fast-front transients and those of lightning overvoltages, while that of a chopping overvoltage are similar to that of slow-front transients. [46], [47]

The amplitude of a reignition overvoltage sometimes becomes higher than that of a chopping overvoltage, when the reignition occurs near the crest of the load side oscillation voltage, therefore the destructive capability of a reignition overvoltage on the insulation of a reactor as well as a circuit breaker must also be considered. Reignition may occasionally be followed by high-frequency arc extinction that could trigger voltage escalation. In South Africa's 800 kV systems, the highest switching and reignition overvoltage in a full GIS system were measured as 1.6 p.u. and 1.8 p.u. respectively. In Japan, high frequency arc extinctions were occurred in actual 300kVGIS connected to a cable in the field. [48], [49]

3.3.9.2 TRV limitation

Due to the well-known effects of reignition on circuit breakers, [50] the intent of TRV limitation is to either significantly mitigate reignition, i.e. limit the voltage at which it occurs, or to avoid reignition altogether. Firstly, however, is the selection of breakers: from Equation (26), the breaker should have the lowest possible values for λ and C_p and the fewest number of interrupters N in series. Auxiliary measures for consideration are described in Table 3.3.23 below.

Table 3.3.23 *TRV limitation measures*

Measure	Advantage	Disadvantage
Opening resistor	Functions by phase shifting the current to an angle << 90° thereby reducing the value of k_a and k_{rv}	Increases the mechanical complexity of the circuit breaker by the addition of the resistor and associated switch
Metal oxide varistor	Limits the voltage across the circuit breaker to its protection level and thereby limiting k_{rv}	Adds to the complexity of the circuit breaker particularly if GIS; the varistor is exposed to repeated mechanical vibration each time breaker is operated
Controlled switching	Achieves a contact parting time such that current interruption is achieved at the first subsequent current zero, i.e. no reignitions	Assumes a suitable minimum arcing time in order to achieve the purpose; minimum sizing of reactors for UHV must be established to determine viability of this option

Note: *In Japan, installation of MOSAs to ground, between CB and reactor is more common practise to protect the chopping and reignition overvoltages in addition to lightning overvoltage.*

3.3.9.3 UHV shunt reactor switching circuit breaker requirements

In addition to all else, Equation (26) shows that shunt reactor switching circuit breakers can be rated based on minimum reactor switching. Such a minimum rating at UHV has yet to be established, so for demonstration purposes, this value is taken as 600 MVar based on Ref. [51]. Furthermore, it is assumed that the circuit breaker will have at least two interrupters in series (best-case assumption) and the chopping number of a single interrupter is estimated at 30×10^4 $AF^{-0.5}$. The value of k_a and k_{rv} can now be calculated:

$$k_a = \sqrt{1+\frac{1.5(2)\left(30\times10^4\right)^2}{314\left(600\times10^6\right)}} \qquad \ldots(27)$$

$$= 1.56 \text{ p.u.}$$

$$k_{rv} = 2.56 \text{ p.u.} \qquad \ldots(28)$$

This is a minimum value for the reason stated above and because C_P/C_L was taken as being negligible. For a C_L value of 3000 pF, the frequency of TRV will be 958 Hz.

The TRV for 1100 and 1200 kV systems is shown in Table 3.3.24. Prospective biased switching surge test values for live circuit breakers are also shown for comparison.

Table 3.3.24 *TRVs for 600 MVar shunt reactor switching*

System voltage (kV)	*TRV (kV peak)*	*Prospective biased switching surge total test voltages (kV peak)*
1100	2304	2556 - 2729
1200	2508	2636 - 2809

The aforementioned chopping number is applicable for circuit-breakers of the puffer technology. Circuit-breakers based on auto-blast technology will show a lower chopping number, for instance 10×10^4 $AF^{-0.5}$.

3.3.9.4 Discussion and conclusion

When a safety margin is applied to the TRV values in Table 3.3.24, the resulting withstand voltage will approach, or perhaps even exceed, open breaker withstand requirements. Reaction to this leads to the following considerations:

1. Voltage limitation by means of varistors across the breaker will most likely be required, particularly if the chopping number is as high as estimated and the actual reactor ratings are even lower than 600 MVar. In Japan, installation of MOSAs to ground, between CB and reactor is more common practise to protect the chopping and reignition overvoltages in addition to lightning overvoltage. WG A3.22 will study and compare these countermeasures more in depth based on the actual experience.
2. Controlled switching is obviously mandatory to avoid reignition. As noted earlier, such switching requires a suitable minimum arcing time. A single 500 kV interrupter breaker is reported to have a minimum arcing time of 9 ms at 50 Hz. [52] Assuming that the frequency of the load side is unchanged and that the amplitude of load-side oscillation at 1100 kV is twice that at 550 kV, the minimum arcing time for the single 550 kV interrupter and the two 1100 kV interrupter breakers should be almost the same. Controlled switching can thus be equally applied for the latter case.
3. Controlled switching on shunt reactors ideally requires a maximum arcing time without reignition smaller than half a cycle (9 ms at 50 Hz). However, even if the CB does not meet this requirement, it could still be acceptable by controlled switching techniques to limit the reignitions at small arcing times, which will not cause excessive reignitions overvoltages.

A first review of this subject concludes that, while much development work remains to be done, reactor-switching breakers may incorporate both voltage limitation and controlled switching.

3.3.10 Controlled switching

3.3.10.1 General

Controlled switching systems (CSS) have become an economical solution and are commonly used to reduce switching surges for various switching applications. Recent developments in transformer switching, taking into account residual flux, can realise effective mitigation of severe inrush current and temporary overvoltage that may lead to inadvertent operation of protective relays and degradation of power quality. CSSs combined with metal oxide surge arresters can reduce undesirable overvoltage caused by energization of long transmission lines to achieve insulation coordination. The limited number of applications for line switching may stem from initial difficulties caused by insufficient technical considerations including idle time compensation. The upcoming IEC62271-302 Technical Report ‘High voltage alternating current circuit breakers with intentionally non-simultaneous pole operation’ will standardize the testing procedures required for CSSs based on the recommended evaluation tests by CIGRE WG A3.07 [46][52]. The CIGRE guide emphasizes the importance of compensating for variations in operating time because CSSs require accurate operation consistency throughout the lifetime of the circuit breaker. Variations in operating time due to external variables such as ambient temperature, control voltage and mechanical energy of the drives can be compensated by the controller using the dependence of variations on the variables evaluated according to the testing requirements. Recent research indicates that the closing time for certain drives is delayed after a few hours of idle time. Accordingly, compensation is essential even for a daily-operated CSS if it demonstrates this dependence (especially in the case of hydraulic operating mechanisms).

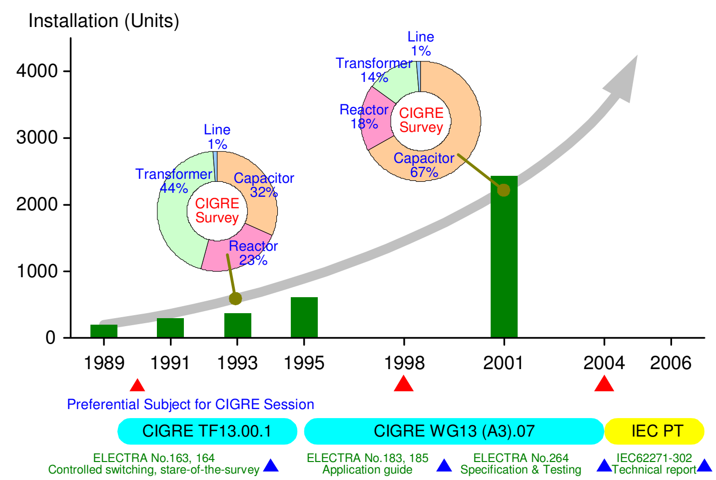


Fig.3.3.41 *CIGRE survey on worldwide installations of CSS*

Table 3.3.25 *Potential CSS applications to UHV systems*

Applications	Targets	Benefits
Capacitor energization Line energization	Voltage zero across CB	Elimination of closing resistor Reduction of overvoltage
Capacitor de-energization Line de-energization	Optimum arcing time	Minimization of restrike probability
Reactor de-energization	Optimum arcing time	Elimination of reignition probability Reduction of associated overvoltage
Transformer energization	Prospective core flux identical to the residual flux	Reduction of inrush current and associated overvoltage
Rapid auto-reclosing	Voltage zero across CB	Elimination of closing resistor Reduction of overvoltage

The number of CSS installations has increased rapidly since the late 1990s due to satisfactory service performance. CSSs are often specified for shunt capacitor and shunt reactor banks due to several economic benefits including elimination of closing resistors and extension of maintenance interval for nozzles and contacts. According to the CIGRE survey shown in Fig. 3.3.41, approximately 2,400 CSSs were supplied and installed around the world in 2001, and more than 4000 units are presently estimated to be in service. Before 1995, the number of installations was limited due to technological immaturity, but it increased rapidly when effective compensation algorithms were introduced using advanced sensors and reliable digital relay technologies. Today, 70% of the installations worldwide are applied to capacitor banks; however, CSSs are not used for shunt capacitors in Japan, as the amplitude of inrush currents is suppressed by fixed inductors, originally intended to reduce the 5th harmonics of the power frequency. In some applications, the use of a large series reactor may lead to severe TRV during fault clearing generated between the capacitor bank and the series reactor.

In response to the need for flexible operation and control of switching equipment in transmission and distribution systems, advanced controllers capable of controlled transformer energization taking into account the residual flux in the transformer core [53],[54] and also capable of controlled re-closing of uncompensated lines [55],[56] have been demonstrated to be effective in suppressing switching transients in the field. Further development efforts will increase the number of installations of CSS for these applications.

The installations include a wide range of rated voltages for gas circuit breakers (GCBs) of up to 550 kV for one break or 800 kV for two and four breaks. Hydro-Québec has extensive practical experience in controlled switching for 765 kV shunt reactors using air blast (8 breaks) and SF6 (4 breaks) technologies, since commissioned in 1992. Since 1100 kV GCBs are composed of two series 550 kV one-breaks, the effectiveness of the CSS can be visualized from the field experience with 550 kV GCBs.

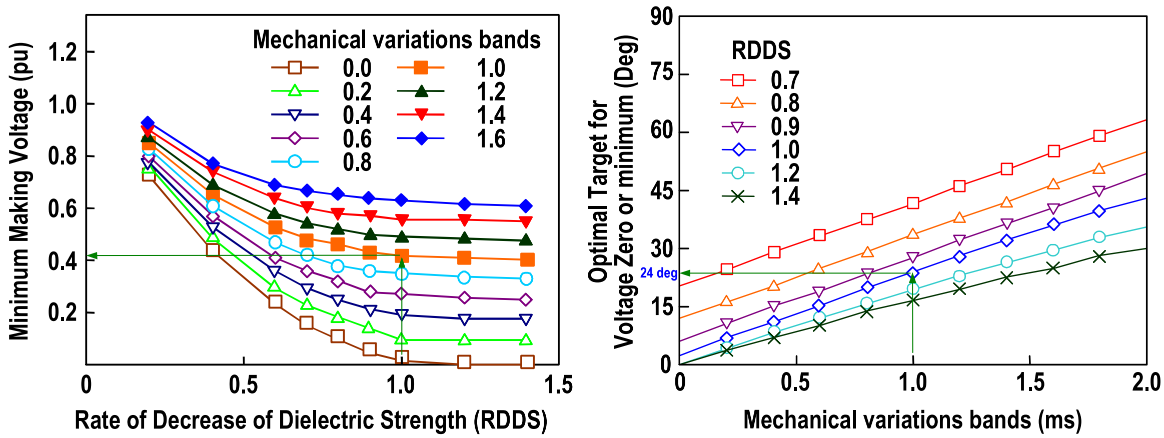


Fig. 3.3.42 *Minimum making voltage and optimal targets for voltage zero or voltage minimum as functions of the RDDS and mechanical variations bands of GCB*

Table 3.3.25 summarizes potential CSS applications for UHV systems, which include small capacitive current de-energization and energization, small inductive current de-energization [57], transformer energization and rapid auto-reclosing. Various technical and economical benefits include elimination of closing and opening resistors and reduction of switching overvoltage. The most beneficial application of CSSs at UHV would be for shunt reactor switching and transformer energization. Line switching would be more of a technical challenge, especially for shunt-compensated lines where the controller algorithm must determine the optimum energizing instant considering the oscillating trapped charge on the line.

1100 kV two-break GCB typically has a grading capacitor (C_1) with the values of 1000-2000 pF. The capacitance (C_2) of the middle part of two-break interrupter to the ground is estimated as 100-250 pF. Therefore the voltage distribution between breaks ranges 51-55%, which is given by $(C_1+C_2)/(C_1+C_1+ C_2)$. Assuming the voltage distribution factor of 1.1 (55:45), the RDDS requirement for making at the voltage minimum (RDDS=1, which corresponds to the maximum slope of the system voltage at zero crossing.) is calculated as 186 kV/ms at 60Hz, which is almost the same dielectric recovery performance requirement for 550 kV one-break GCB.

Figure 3.3.42 shows the dependence of the minimum making voltage on the RDDS and the mechanical variations bands. The correlation can be applied to all the ratings including UHV GCB. In case of RDDS=1, the minimum making voltage becomes around 0.4 p.u. using GCB with the mechanical variations bands of +/-1.0ms. The optimal targets for voltage minimum are also shown as functions of the RDDS and the mechanical variations bands.

3.3.10.2 Capacitive switching applications

The use of shunt capacitor banks in a UHV system is considered unlikely because the banks are generally located in close proximity to the load areas. However, CSSs are technically applicable for capacitive current switching, even though GCBs are required to possess high RDDS performance so as to close at the minimum voltage, in addition to the minimum mechanical variation bands. Modern GCBs generally provide a very low probability of restrike for capacitive current interruption. Nevertheless, the probability of restrike can be further reduced by means of the CSS, which ensures long arcing times especially effective for UHV GCBs after several fault current interruptions.

3.3.10.3 Reactor switching applications

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.

For application to UHV shunt reactor banks, GCBs are required to possess a certain arcing window to interrupt small inductive currents without reignition. Figure 3.3.43 shows the rate of rise of dielectric strength (RRDS) using 550 kV one-break GCBs, which corresponds to the characteristics for 1100 kV two-break GCBs. Tests were carried out at breaking currents of 315 A in accordance with test duty 1 stipulated in IEC62271-110.6.115.

Small inductive current interruption phenomena can be classified into three categories depending on the contact gap at the instant of current interruption: (a) Reignition-free as a result of successful interruption because the dielectric withstand between contacts always surpasses the transient recovery voltage after interruption; (b) Reignition as a result of dielectric breakdown; and (c) Thermal reignition as a result of thermal interruption failure. Thermal reignition, however, does not cause any prominent transients and can successfully interrupt the current at the next current-zero. Accordingly, the periods for a reignition-free window (a) combined with the thermal reignition window (c) can be chosen as the opening target. Controlled opening of shunt reactor banks can eliminate the reignition overvoltage, which can potentially induce GCB damage such as nozzle puncture. It also provides economic benefits such as reduced possibility of reactor damage and extension of the number of interruptions before the nozzle and contact need to be replaced, exceeding a factor of two relative to that required for any rating of GCB without CSS.

3.3.10.4 Unloaded transformer energization

Transformer energization can create high-amplitude magnetizing inrush current of up to several thousand amperes and may result in undesirable temporary overvoltages that cause inadvertent operation of protection relays due to saturation of the power transformer iron core. High inrush current also imposes severe mechanical stress on the transformer windings and may reduce the life expectancy of a transformer exposed to frequent energization; for example, step-up transformers in hydroelectric power plants are frequently switched to adapt to daily load variations. Considering the importance of securing long-term dielectric performance of UHV transformers, it is preferable to reduce the mechanical and electrical stress from energization.

Inrush current will depend on (a) magnetic characteristics of the transformer core; (b) processing instants of the circuit breaker; (c) electrical connections of the power transformer; (d) residual flux; and (e) electrical characteristics of the "source" system.

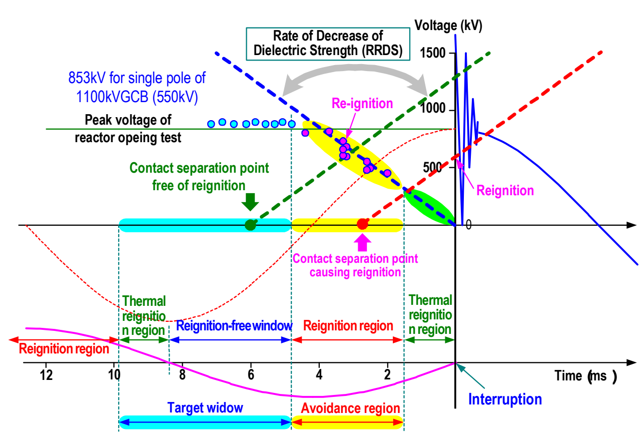


Fig.3.3.43 *RRDS characteristic for 550kV GCB*

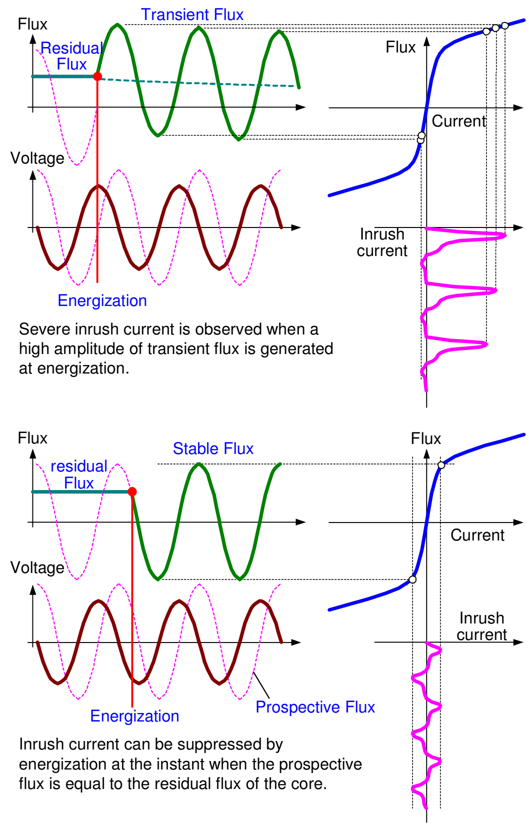


Fig.3.3.44 *Magnetizing flux in a core of a transformer and corresponding magnetizing current*

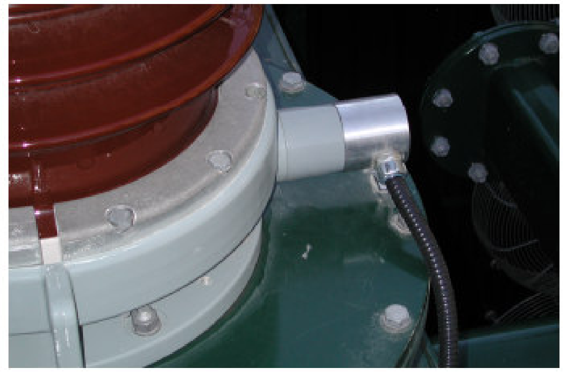


Fig. 3.3.45 *Transformer bushing voltage sensor*

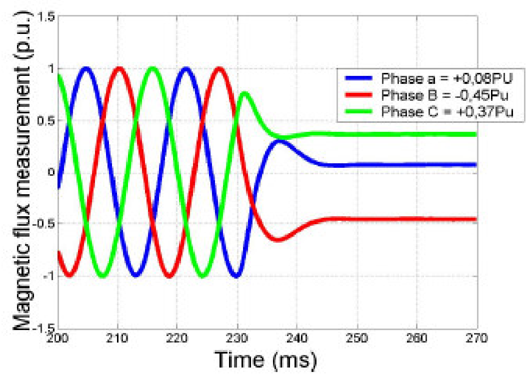


Fig 3.3.46 *Typical Measurement of the residual flux*

Figure 3.3.44 shows the dynamic magnetic flux and current behaviour when a transformer is energized. Energization of a transformer with no residual flux in the core at peak voltage will not cause any transients. However, the change in flux after energization depending on the residual flux and the energization instant will generate greater saturation of the magnetizing current. Therefore, the optimum targets should be adjusted taking into account the residual flux. The inrush current can only be 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 well as any CB operations in case of fault clearing connected to the system.

In 2001, Hydro Québec has installed two prototype systems to control the optimum instant for energizing high-voltage step-up transformers. Each system consists of a synchronous controlled switching system with the new residual magnetic flux measurement system [53]. The system uses the relationship 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. Measuring and integrating the voltage of each phase just before and during de-energization of the transformer in the steady state determines the residual flux, which is the end value of the integrated voltage. With this method, only a small number of cycles are used for integration to prevent that even a small offset error in the voltage measurement lead to a large error in the results. A novel transformer built-in voltage sensor also has been developed to measure each phase voltage of the transformer shown in Fig.3.3.45.

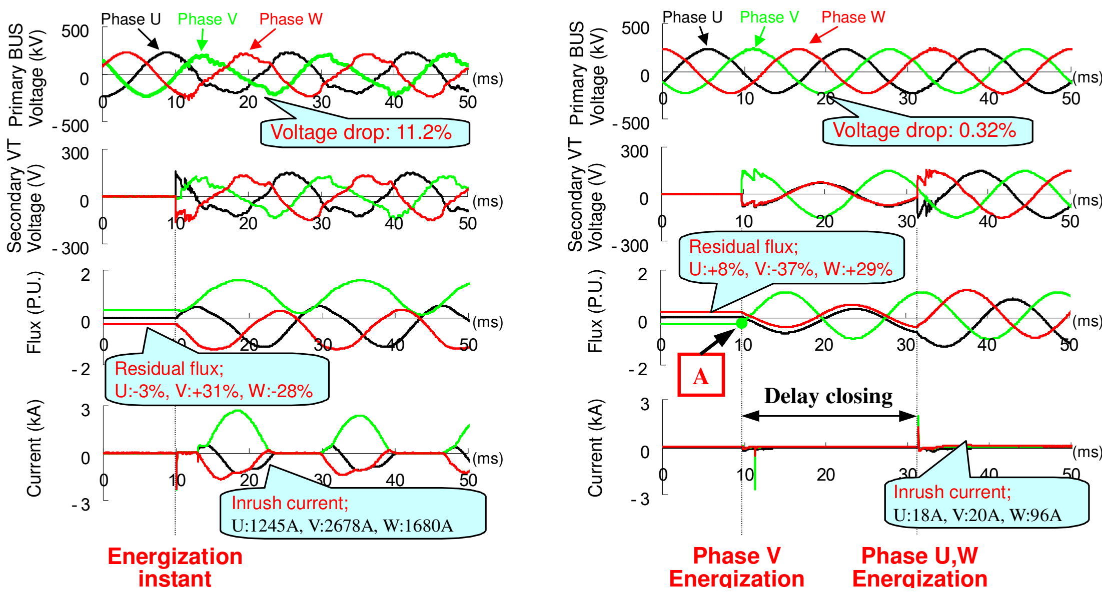


Fig. 3.3.47 *(a) 3-phase simultaneous energization and (b) Controlled energization taking into account residual flux*

Figure 3.3.46 shows a typical record of measured residual flux at the last opening, which is used for adjustment of breaker characteristics and issuing a closing order for each phase. The results show no inrush current or TOV on any phase. Figure 3.3.47 (a) shows a typical example of voltage, current and flux in the core calculated in the case of three-phase simultaneous energization. High inrush current ranging from 1245 to 2678 A is obtained due to magnetic saturation in the cores, causing a voltage drop of up to 11.2% in the primary bus terminal. On the other hand, figure 3.3.47 (b) shows a typical example of controlled transformer energization. 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 that the prospective normal core flux is identical to the residual flux. The second and third phases (U and W) are closed 1.5 cycles later around the voltage peak of the first phase. The inrush current is reduced to below 100 A and voltage disturbance is effectively suppressed. By choosing the phase with the maximum residual flux value as the first phase to be energized, both mechanical and electrical stress on the transformer can be greatly reduced.

Most power transformers at the UHV level may not be energized or de-energized frequently; however, the step-up power transformers in hydroelectric power plants can be switched often to adjust to daily load variation. Therefore, a controlled transformer switching system taking into account the residual flux can be used to effectively reduce the overvoltage caused by transformer energization.

Furthermore, the sympathetic interaction phenomenon related to no-load transformer energization sometimes appears when other power transformers are energized. The associated inrush current may cause complete saturation in the iron core of the energized power transformers. Depending on the severity of this phenomenon, the overcurrent protection relays or even the differential protection relays of such on-load power transformers may operate inadvertently, causing a complete shutdown of all transformers and subsequent system black-outs. [58], [59]

In the case of UHV-level power system expansion, performing no-load power transformer energization might increase these phenomena. As this issue is of significant concern, consideration should be given to the application of a CSS, which can greatly mitigate such transient phenomena in the presence of UHV transmission systems/links.

3.3.10.5 Uncompensated and compensated line switching

Energization and auto-reclosing of long transmissions lines can cause undesirable overvoltages in the transmission network so special overvoltage mitigation measures are employed to meet the insulation coordination. The most common practise has been metal-oxide surge arresters 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. Using MOSA at the middle of the line can reduce these overvoltages.

The CSS can potentially reduce the re-closing 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, GCB 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.

For UHV systems, the optimal resistance of closing resistors could vary depending on the length of transmission lines. Furthermore, the effectiveness of closing resistors in reducing the overvoltage may decrease in the case of very long lines, generally exceeding 200 km.

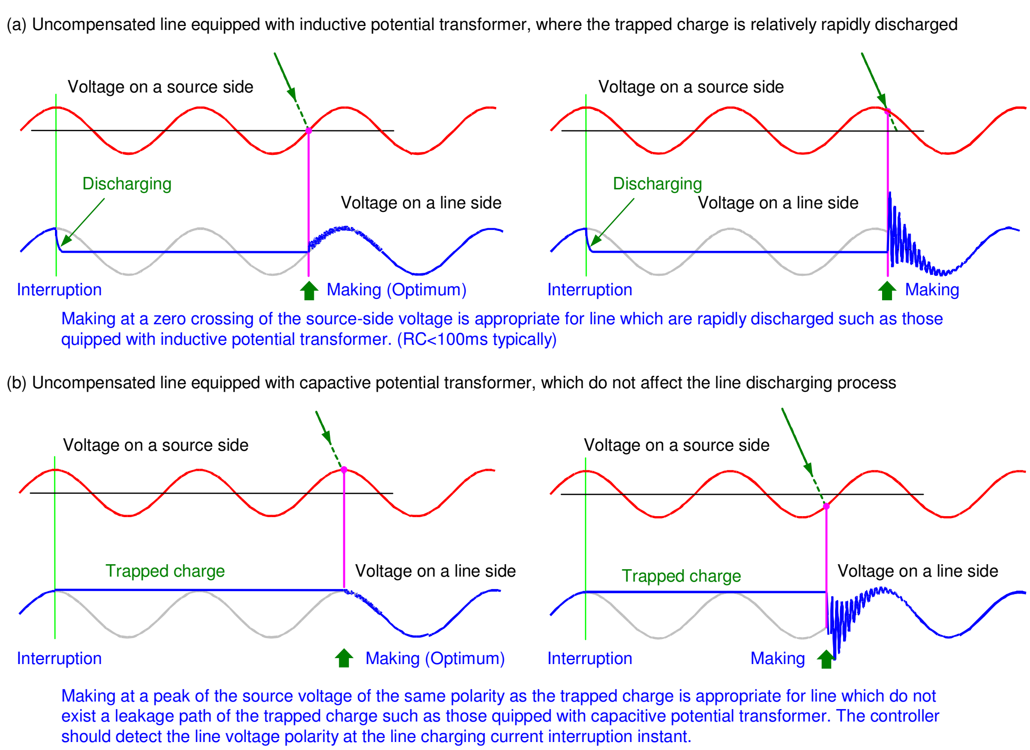


Fig.3.3.48 *Optimum making targets for uncompensated line switching*

Consequently, using the CSS combined with MOSAs could be a viable solution for a UHV transmission system with long lines.

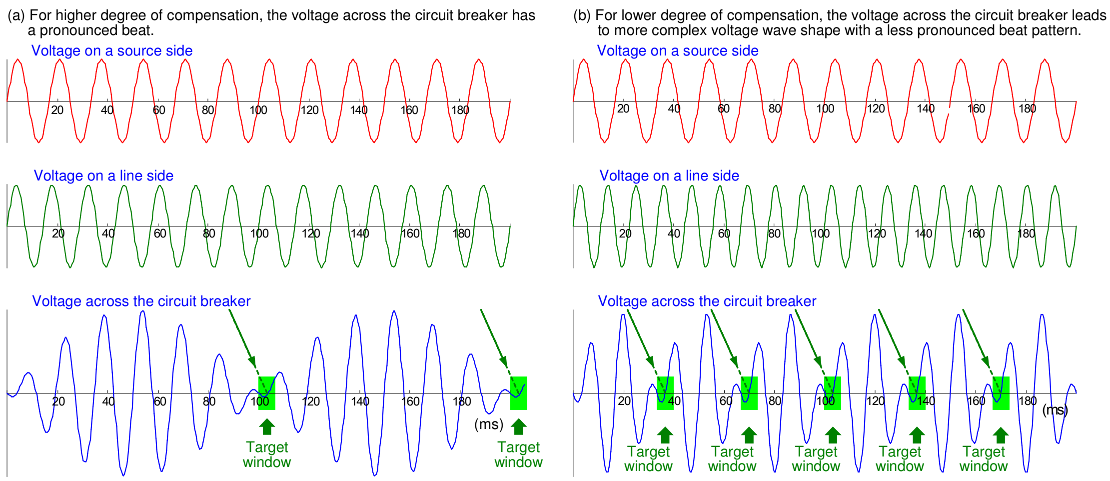


Fig.3.3.49 *Optimum making targets for compensated line switching*

Strategies for different line configurations are described below.

a) In the case of an uncompensated line with an inductive potential transformer, the controller can suppress the surge effectively (less than 1P.U.) by controlled closing at voltage-zero on the source-side because the trapped DC charge is rapidly discharged (typically less than 100ms). (See Figure 3.3.48)

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.

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 show a prominent beat especially for a high degree of compensation because the line oscillation frequency typically falls in the range 30-50Hz. The optimum instant is voltage minimum across the CB; preferably during a period of the minimum voltage beat [56] as shown in Figure 3.3.49.

British Columbia Hydro has 500kV transmission lines with a typically 300 km. Some systems are equipped with mid-line series capacitors providing 50%

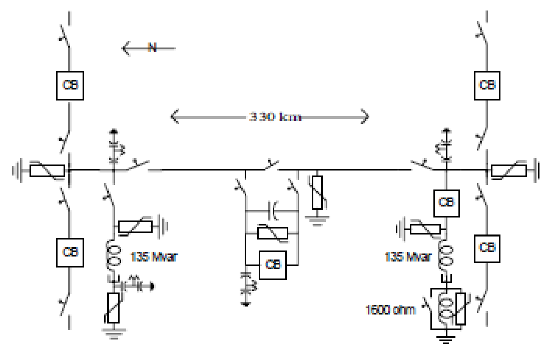


Fig. 3.3.50 *500 kV transmission line arrangement*

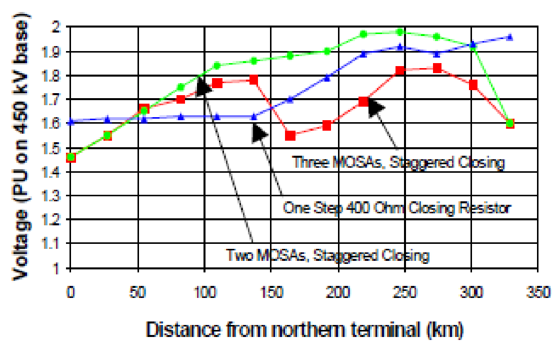


Fig. 3.3.51 *Voltage profiles with a closing resistor or two and three MOSAs*

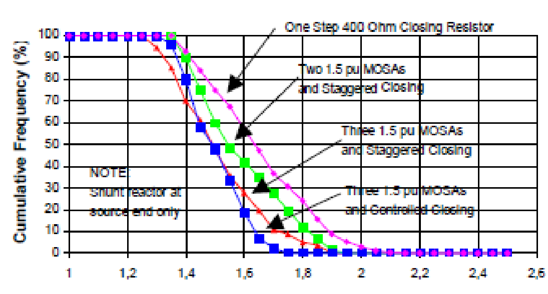
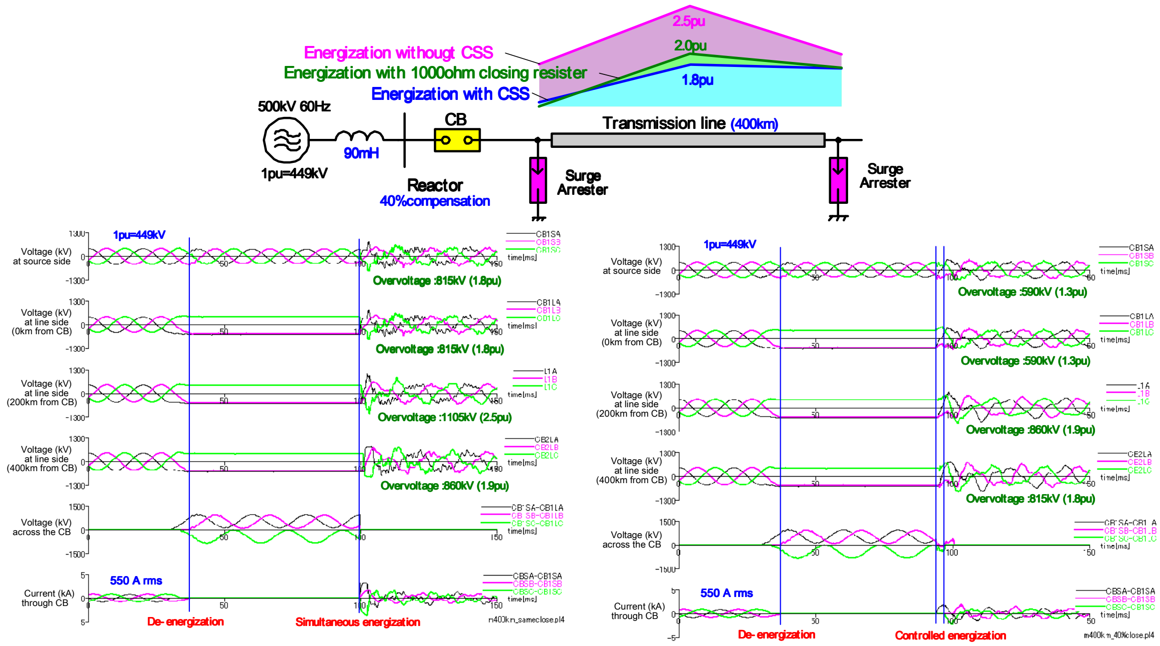


Fig. 3.3.52 *Three-phase reclosing overvoltage for various mitigation methods*



(a) Random energization *(b) controlled energization*

Fig.3.3.53 *Reduction of overvoltage in application of controlled line switching*

compensation. Economic constraints dictated that the bypass protection for this bank comprises a MOSA rated at 2.2 p.u., 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 a switchable reactor at the receiving end.

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 optimise the secondary arc control. Figure 3.3.50 indicates the line equipment arrangement [56].

Figure 3.3.51 compares the voltage profile along a line with conventional closing resistors to the use of two and three MOSAs with staggered closing. The effectiveness of overvoltage control due to the closing resistors 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 voltage exceeding the design target, even with the non-optimum times inherent in staggered closing.

Figure 3.3.52 indicates the improvement that can be achieved by using line-connected MOSAs. Two alternatives were considered: a MOSA at each line terminal and three MOSAs with the third connected at mid-line. Note that the objective of reducing the overvoltage to less than 1.7 p.u. can be achieved only with the use of three MOSAs plus controlled closing. Figure 3.3.53 shows typical analyses of overvoltage reduction of controlled uncompensated line energization.

In another example, Tables 3.3.2 and 3 present some statistical simulations from switching overvoltage studies on a 550 kV transmission line during the planning/design stage. This transmission line is part of an interconnection tie between the two major grids of Brazil from 10 years ago (south/southeastern and north/northeastern grids). These two tables present the analytical results of both phase-to-ground and also phase-to-phase transient overvoltage in the line-receiving end and in the middle of the lines. [60]

Table.3.3.2 *No-load line energization cases performed (550 kV Jaú→Miracema line)*

Cases	Switching overvoltage at ends (p.u. - ϕ-n/ϕ-ϕ)		Switching overvoltage in mid-point (p.u. - ϕ-n/ϕ-ϕ)		MOSA Energy in line receiving end (p.u.)	
	Maximum	Average	Maximum	Average	Maximum	Average
MOSA at both line ends	1.95/2.25	1.91/2.15	2.50/2.40	2.18/2.14	0.48	0.25
PIR plus MOSA at both line ends	1.90/1.90	1.66/1.65	1.95/1.85	1.63/1.59	0.10	0.01
CSS plus MOSA at both line ends	1.90/1.95	1.83/1.88	2.05/2.15	1.87/1.83	0.15	0.04

Table.3.3.3 *Automatic tripolar auto-reclosing cases performed (550 kV Jaú→Miracema line)*

Cases	Switching overvoltage at ends (p.u. - ϕ-n/ϕ-ϕ)		Switching overvoltage in mid-point (p.u. - ϕ-n/ϕ-ϕ)		MOSA Energy in line receiving end (p.u.)	
	Maximum	Average	Maximum	Average	Maximum	Average
MOSA at both line ends	2.05/2.30	1.92/2.14	2.95/2.65	2.26/2.19	1.30	0.40
PIR plus MOSA at both line ends	1.90/1.95	1.69/1.61	2.00/1.90	1.70/1.56	0.10	0.01
CSS plus MOSA at both line ends	1.90/2.00	1.81/1.85	1.95/2.00	1.83/1.84	0.05	0.02

The results reveal that the general performance of the CSS is similar to PIR application, either controlling phase-to-ground or phase-to-phase switching transient overvoltages, at both the receiving end and middle of the line. A comparison of cases with/without CSS shows that switching overvoltage can be mitigated at a considerable level in the middle of the line. It is also obvious that the potential for 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 the reduction of mechanical structural dimensions and weight. MOSAs and CSS all together can potentially allow transmitting large amounts of powers perspective considering recent increasing economic and environmental constraints.

3.3.10.6 Summary

The rapid increase of CSS application is ascribed to several factors including successful field experience using the system with an effective compensation algorithm, the CIGRE proposal for type testing recommendations and versatile operation and control of transmission systems due to global changes in the electrical industry. Since CSSs can provide significant technical and economic benefits including enhanced power quality and operation flexibility, they could be incorporated into circuit-breaker control systems as a standard specification in the near future.

The advantages of CSSs will be more extensive for UHV systems, where experts place emphasis on reducing switching overvoltage as much as possible, as insulation coordination is mainly based on slow-front overvoltage and its cost consequences are considerable. Based on the aforementioned considerations, there is no reason why CSSs cannot be applied at the UHV level, as the behaviour of 1100 kV two-break circuit breakers can be directly extrapolated from single-break 550 kV circuit breakers.

CSSs will provide many economic benefits when applied to shunt reactor banks and transformer energization in the UHV system. In the case of processing at the voltage minimum, RDDS of at least 186 kV/ms at 60 Hz (155 kV/ms at 50 Hz) is required for 1100 kV two-break GCBs, which corresponds to RDDS = 1.

Step-up UHV transformers in hydroelectric power plants are frequently switched to cope with daily load variations. Controlled transformer switching taking into account the residual flux is a viable scheme for effectively reducing overvoltage caused by transformer energization. Since the effectiveness of closing resistors in reducing overvoltage may decrease in the case of very long lines typically exceeding 200 km, CSS combined with MOSAs could be one solution for long UHV transmission lines.

The possibility of greater compactness related to the design of transmission towers and lines, given by the application of CSS on UHV OH line circuit breakers, associated with shunt reactors and MOA applications for TOV mitigation, should be thoroughly investigated during the planning or engineering design stage of UHV systems.

As information technologies progress, it may become possible to use CSSs for fault current interruption, uprating of modern and aged circuit breakers and compensated line auto-reclosing with a minimum of surge arresters. Furthermore, various monitoring results of GCBs recorded in the controller can be used for remote diagnostics and condition-based maintenance in order to improve equipment reliability further and optimise maintenance practise.

3.4 DS, ES

3.4.1 DS capacitive switching

3.4.1.1 Introduction

Disconnecting switches normally have a capacitive current interrupting capability, however, there are no standardized interrupting ratings for the capacitive current. For air-insulated disconnectors, the interrupting current does not exceeded 2 A for the system operating voltages up to 800 kV. For GIS disconnectors, the interrupting current ranges from 0.1 A at 72.5 kV and up to 0.8 A at 800 kV according to IEC 62271-102 [61]. Maintenance Team 42 (MT42) within IEC is investigating this capability with particular reference to air-insulated disconnectors and how type testing should be performed [62].

A very fast transient overvoltage (VFTO) is generated by disconnector (DS) operations during switching of small capacitive currents due to the repetition of restriking between the disconnector contacts, because the operating speed of DS is relatively slow (2-3m/s even in case of GIS DS) compared with a circuit breaker. The maximum overvoltage is up to 3 p.u.

3.4.1.2 General considerations

The basic circuit for capacitive current switching is shown in Fig. 3.4.1. Recent research of capacitive current interruption in atmospheric air has shown that capacitive current switching using disconnectors is more complex than previously envisaged [63]. Successful current interruption is dependent on the magnitude of the current (as determined by the value of the load side capacitance CL) and on the ratio of the source side capacitance CS to CL. For high values of CS/CL (CS/CL > 1), recovery after current interruption is mainly a dielectric event with shorter arcing times and lower overvoltages. For low values of CS/CL (CS/CL < 1), recovery is a thermal event due to restriking injected energy with longer arcing times and higher overvoltages. The longer arcing times in the latter case means longer arc lengths that promote partial arc collapses and even longer arcing times.

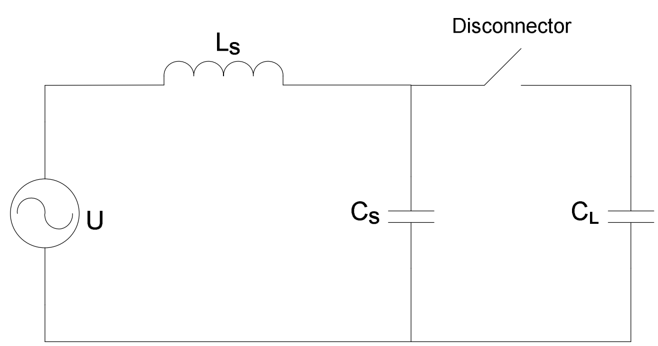


***Fig. 3.4.1** Basic capacitive current switching circuit*

The influence of the CS/CL ratio can be understood by reference to Figures 3.4.2 and 3.4.3. When a restrike occurs, the voltages on the source and load sides of the disconnector will equalize at the equalization voltage. At $C_S/C_L > 1$, the equalization voltage is close to the source side voltage (A in Fig. 3.4.2) and at $C_S/C_L < 1$ is closer to load side voltage (B in Fig. 3.4.2). The energy injected during equalization is not significant but that due to recovery to the source voltage can be significant. The greater the difference between the equalization voltage and the source voltage, the greater the energy injected to sustain the arc as shown in A and B in Fig. 3.4.4.

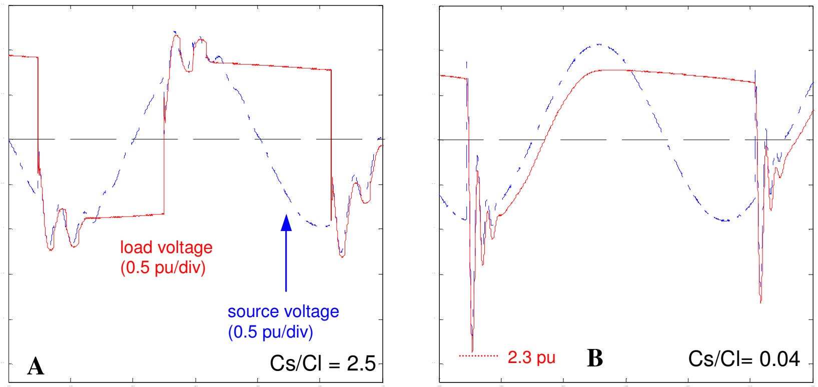


Fig. 3.4.2 *Restriking process without overvoltages (A) and with overvoltages (B) at interruption of 2 A capacitive current with disconnector. Load side voltage (solid lines) and source side voltage (dashed lines) are shown. Time: 5 ms/div. 1 p.u. = 245 kV (Traces courtesy of KEMA)*

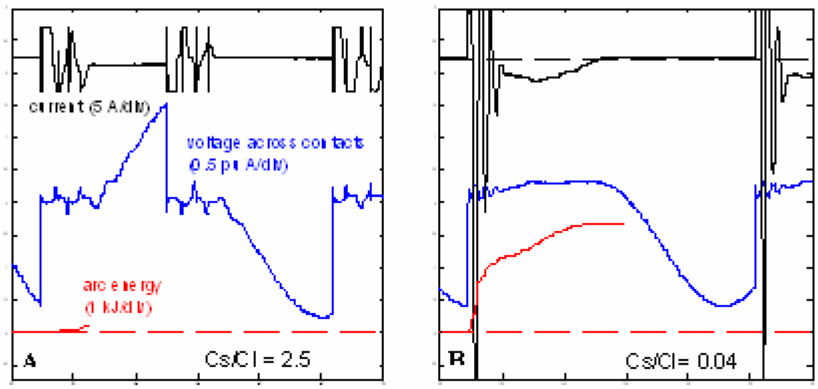


Fig. 3.4.3 *Restriking process without overvoltages (A) and with overvoltages (B) at interruption of 2 A capacitive current with disconnector. Load side voltage (solid lines) and source side voltage (dashed lines) are shown. Time: 5 ms/div. 1 pu = 245 kV (Traces courtesy of KEMA)*

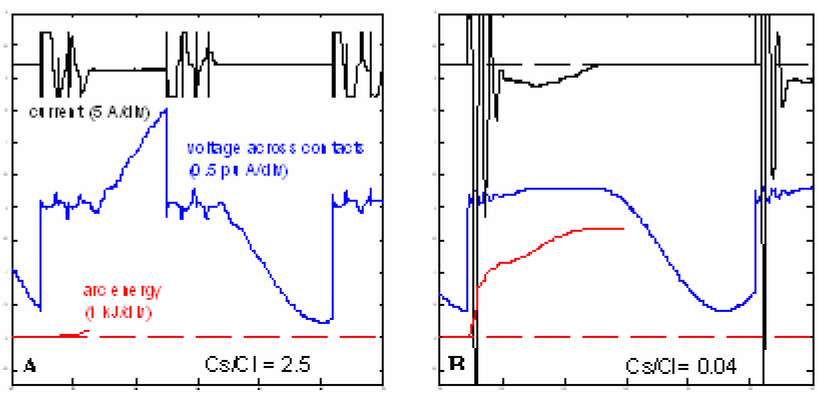


Fig. 3.4.4 *Restrikes in disconnector arc. Current: 2 A capacitive. 1 pu = 245 kV. A: CS/CL = 2.5; B: CS/CL = 0.04. Upper trace: arc current; middle: voltage across disconnector blades; lower: energy in the restrike. Time: 5 ms/div (Traces courtesy of KEMA)*

Analysis of the restriking event shows that the equalization voltage UE is given by:

$$U_E = U_S - \frac{U_D}{1 + C_S/C_L} \qquad \text{...(29)}$$

where US is the source side voltage at restriking and UD is the voltage across the disconnector prior to restriking. The maximum overvoltage on the load side UL is given by:

$$U_L = U_S + \beta\left(\frac{U_D}{1 + C_S/C_L}\right) \qquad \text{...(30)}$$

where β is a damping factor of value less than 2.

The maximum current peak IL through the load is given by:

$$I_L = U_R\sqrt{\frac{C_L}{L_S}\left(\frac{1}{1 + C_S/C_L}\right)} \qquad \text{...(31)}$$

where U_R is the difference between U_S and U_E. Equations (29), (30) and (31) clearly show the interactive nature of capacitive current switching. Equation (31) in particular shows that the source impedance needs to be accurately represented to demonstrate disconnector performance in a type test.

In the case of GIS disconnectors, a slightly complicated circuit should be considered for capacitive current switching. First, Ls is divided into Lss and $Ls_{\text{-GIS}}$, and Cs into Css and $Cs_{\text{-GIS}}$ as shown in Fig. 3.4.5. Here, $Ls_{\text{-GIS}}$ and $Cs_{\text{-GIS}}$ are inductive and capacitive impedance within the GIS. However, $Cs_{\text{-GIS}}$ is quite small and then, the modified basic circuit for a full GIS will be as shown in Fig. 3.4.6. In this basic capacitive current switching circuit, Css is usually much larger than C_L and then higher surge is generated. The $Ls_{\text{-GIS}}$ is also small because it is an impedance within the GIS and, the restriking surge is of high frequency. Another point to be considered is that the interrupting ability of GIS disconnecter is so high that the current is immediately interrupted after a re-strike. A current that continues to flow for half cycle as shown in Fig. 3.4.2 (B) is seldom observed.

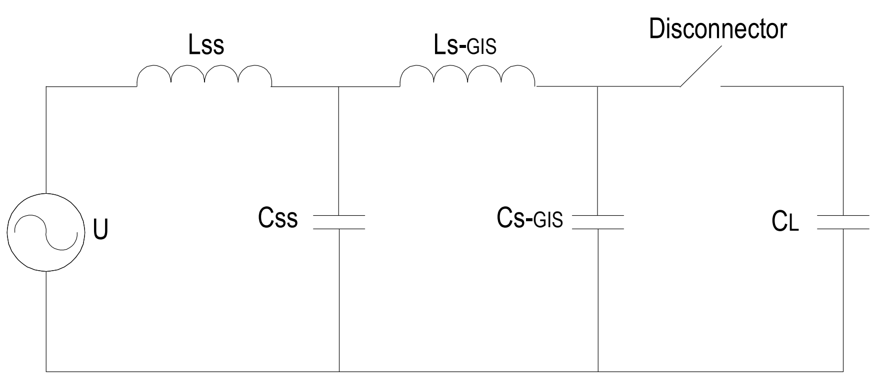


Fig. 3.4.5 *Theoretical capacitive current switching circuit*

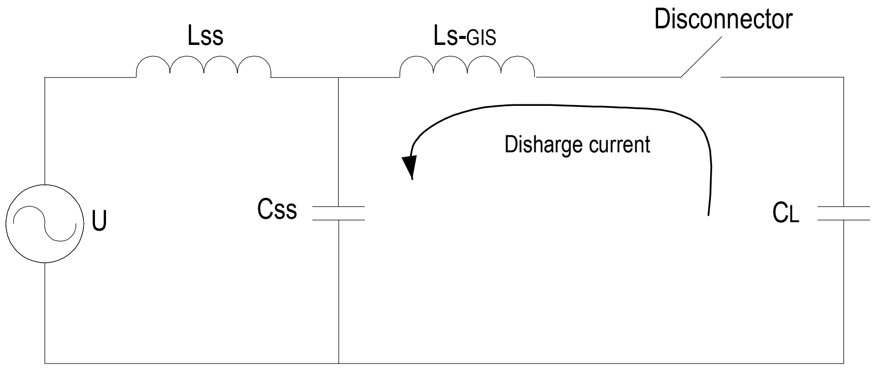


***Fig. 3.4.6** Basic capacitive current switching circuit*

3.4.1.3 UHV air-insulated disconnectors

The required withstand voltages (Urw) for the air-break DS in 1200 kV systems calculated in accordance with the IEC 62271-1 practises are shown in Table 3.4.1. [64]

***Table 3.4.1** Required withstand voltages for 1200 kV air-insulated disconnectors**

Lightning impulse (kV peak)		***Switching impulse (kV peak)***	
Phase-to-earth	Across isolating distance	Phase-to-earth	Across isolating distance
2400	2400 (+980)	1800	1800 (+685)

**** Note that actual rated voltages will be higher than these values.***

The isolating distance across the open disconnector will probably exceed 10 m based on the above withstand requirements. Quite apart from the obvious mechanical design constraints in dealing with the associated blade lengths, in order to achieve the necessary blade speed to reach the minimum contact gap for current interruption, as soon as possible, UHV disconnectors will likely consist of two breaks in series.

The bus-work within UHV air-insulated stations will be the flexible (bundled) type and is expected to have a charging current of about 0.002 A/m. Instrument transformers will be of the optical type and will not contribute to the capacitive load. The current to be interrupted is therefore unlikely to exceed 0.5 A, which corresponds to a bus length of 250 m. At such current levels, current interruption tends to be a dielectric event. The arc will usually be of a “dancing” nature, i.e. each restrike will be in a new location rather than in the previous arc channel, and interruption is dependent on achieving a minimum contact gap capable of withstanding the recovery voltage. The minimum contact gap is estimated to be at least 4 m.

3.4.1.4 UHV GIS disconnectors

Extrapolation of the test duty 3 specified bus-charging current in Annex F of reference [61] suggest that the required bus-charging current switching capability of GIS DSs at UHV is in the range 1 to 1.2 A. However, this remains to be confirmed once actual UHV GIS parameters become known. A factor that will influence the DS interrupting capability is the perceived need for opening resistors in order to limit the magnitude of the very fast transients (VFTs) generated by restriking [65].

The information available is on GIS type DSs applied in Japan and China [66],[67]. A summary of the bus-charging current switching duty for 1100kV DS in Japan is as follows,

a) Recovery voltage

The recovery voltage of bus-charging current switching for 1100kV DS is specified to be the rated phase to earth voltage 635kV (=1100/ $\sqrt{3}$ kV) due to the same principle for 550kV equipment in JEC-2310-2003 “AC disconnectors”.

b) Switching current

The switching current (I), which corresponds to the bus-charging current, is specified to be 0.5 A derived from the following equation,

$$I = \omega CV \qquad (32)$$

Where C is the load side capacitance, and is assumed to be 2000 pC, which is the maximum value estimated by the actual UHV layout.

3.4.1.5 VFTO and its countermeasure

Very Fast Transient Overvoltages (VFTO) up to 2.8 p.u. were generated due to reignition during the closing and opening operation of a disconnector switches (DS). A VFTO with high frequency components may cause severe dielectric stresses to the substation equipment, especially the windings of power transformers and potential transformers, because of its steep rate of change of voltage. It will propagate through the GIS enclosure and raise the grounding potential of the equipment to the earth. If a trapped charge remains on the grading capacitors of GCB, the amplitude of the VFTO will increase due to the offset of the transient voltages, which may also cause severe mechanical stresses to the substation equipment.

A switching resistor either in parallel or in series is often employed to reduce the amplitude of VFTOs generated by DS switching. A DS with a switching resistor is normally required for extended mechanical endurance performance due to frequent operations.

For 550kV systems, VFTOs are covered by the lightning impulse withstand level (LIWV). However the VFTO for an 1100kV disconnector has to be studied and the proper countermeasure here to be taken because the VFTO could be beyond LIWV, whose value has been determined from the total insulation coordination study for 1100kV systems.

An introduction to the bus-charging current switching duty for the 1100kV disconnectors used in Japan and China, the calculation results of VFTO analysis to estimate the effect of disconnector with switching resistors fitted and the required specifications of the switching resistor on the disconnector are described below.

3.4.1.6 Analysis of VFTO in full GIS

To confirm the effect of the switching resistor and to determine its value, the VFTO analysis was carried out in Japan for the following substation arrangement and employed DSs with and without switching resistors. The substation has a double-busbar scheme and consist of a GIS with four feeder bays and four transformer bays. The switching condition of DS is the occurrence of restriking with the remaining voltage of 2 p.u. between the disconnector contacts. There are five types of DSs, a line-side DS, a bus-bar side DS with line feeder, a bus-tie DS, a bus-bar side DS for the transformer bay and a bus-section DS. The resistor value for the DSs was varied to a maximum 1000 ohms and the calculation for a disconnector without a switching resistor (2 ohms of arc resistance), was also carried out for reference.

Figure 3.4.6 shows the single line diagram used for the VFTO calculation. Table.3.4.2 shows the specific constant values used for the calculation. Fig.3.4.7 shows the calculation results.

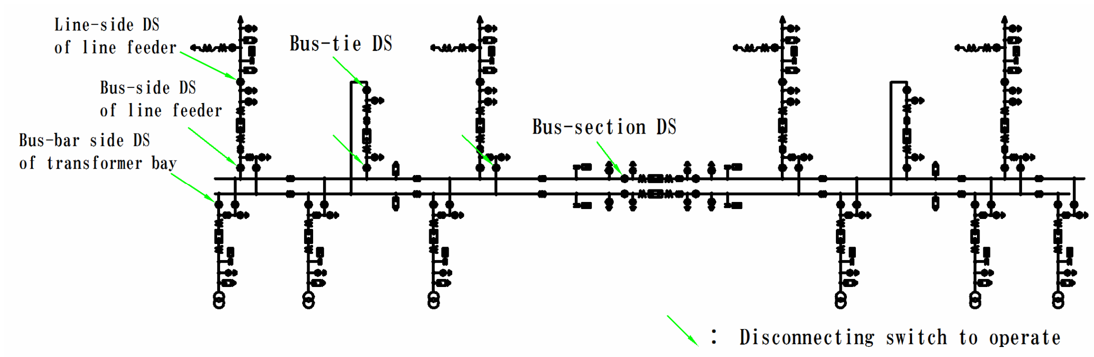


Fig. 3.4.6 *Single line diagram for calculation*

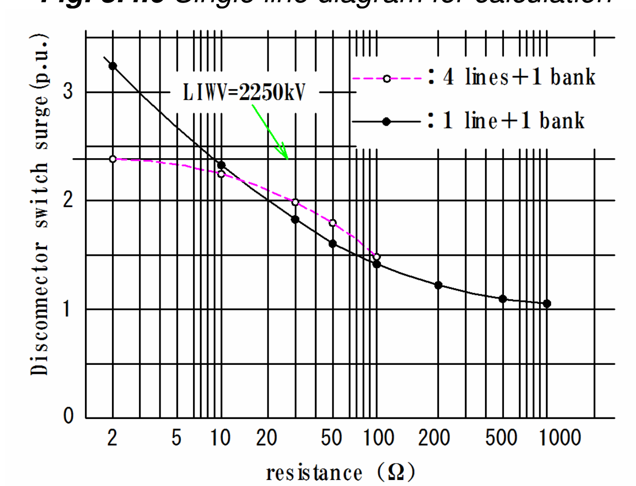
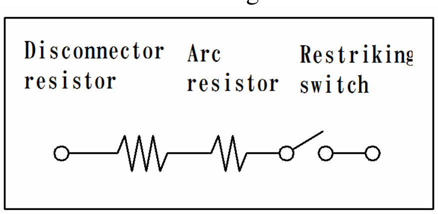


Fig. 3.4.7 *Calculation results (without switching resistor)*

Table.3.4.2 *Specific constant values for calculation*

Items			VALUE
GIS busbar	Surge impedance		90 ohm
	Propagation velocity		270 m/us
Transformer	Capacitance		4600 pF
Lightning arrester	Simulate as the minimum residual voltage		V_{10kA}=1555 kV
Disconnector	Simulation for restriking arc 	Switching resistor	0 - 1000 ohm
		Arc resistance	2 ohm
		Restriking condition	Source side :+1p.u. Load side :-1p.u.
Transmission line	Surge Impedance		230 ohm

From Fig. 3.4.7, it is understood that a maximum overvoltage of 3.25 p.u. occurred and the overvoltage exceed LIWV when using a disconnector without a switching resistor on the one-feeder bay plus (+) one-transformer bay condition. The overvoltage value goes on decreasing as the resistance of the switching resistor increases, then saturates at approximately 1 p.u.

It is confirmed that the overvoltage value can be suppressed by using a switching resistor, for example 1.13 p.u. (1015 kV) with a 500 ohm resistance and 1.07 p.u. (=961 kV) with 1000 ohms Additionally, using the switching resistor is effective in increasing the overall reliability of the dielectric capability by decreasing the induced voltage to the sheath and the control circuit. On the other hand, increasing the resistance increases the voltage applied to the resistor, then increase the resistor and increase the overall size of disconnector. The resistance of the switching resistor is determined to be 500 ohms, which is effective for decreasing the overvoltage to 1.2 p.u. within the saturated region.

In Japan, field verification tests have been carried out where facilities are connected to a 550 kV commercial network through the transformer. The disconnector surge tests were performed with four different circuit configurations. Figure 3.4.8 shows an example of the VFTO generated by disconnector operation [68]. It was confirmed that the maximum VFTO level could be suppressed to less than 1.2 p.u. in the field. From the electromagnetic immunity (EMI) viewpoint, the potential rise at the GIS tank was measured. It was confirmed to be no more than 10 kVp, and there was no malfunction in the control and protection systems.

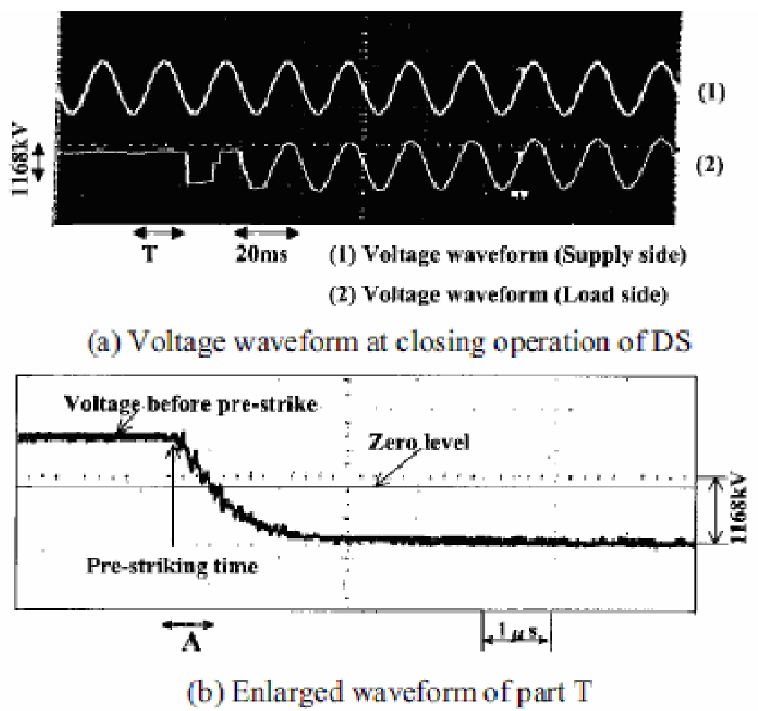


Fig.3.4.8 *Example of waveform*

The VFTO generated in 550 kV systems was evaluated and the results showed that it will not exceed 2.8 p.u. The insulation coordination in the 1100 kV systems ensures that the VFTO level due to disconnector switching will not exceed the LIWV level. A resistive making and breaking method with a 500 ohm resistor was employed to reduce this VFTO level. The VFTO can effectively be reduced to less than 1.3 p.u. due to the switching resistor [66]. The VFTO can be successfully suppressed in 1100 kV systems by using DS equipped with a switching resistor. This insulation coordination policy secures the VFTO less than the LIWV level of the substation equipment.

3.4.1.7 Analysis of VFTO in hybrid GIS

VFTOs up to 2.8 p.u. were generated due to reignition during the closing and opening operation of a disconnector switches (DS). A switching resistor either in parallel or in series is often employed to reduce the amplitude of VFTO generated by DS switching.

Figure 3.4.9 shows a single line diagram for an1100 kV hybrid GIS planned in China [68], which employs a one and half GCB arrangement for the first and future stages of the substation layout. In EMTP analysis, the resistance of the GIS conductors and overhead lines were assumed to be proportional to the square root of the dominant frequency of the surges considering the skin effect under high frequency.

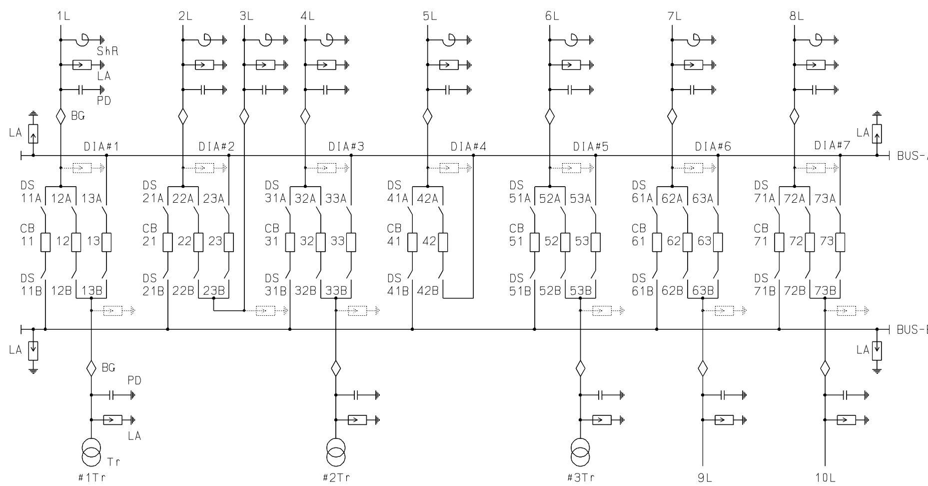
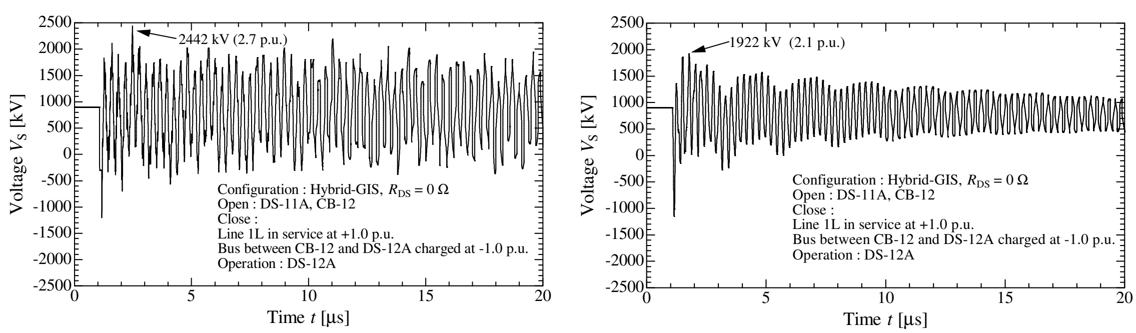


Fig.3.4.9 *Single line diagram of 1100 kV Hybrid GIS planned in China*



(a) Full-GIS ***(b) Hybrid-GIS***

Fig. 3.4.10 Typical analysis of VFTO due to DS operation without a closing resistor

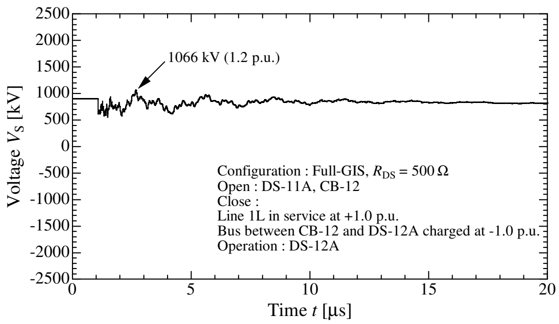
Fig. 3.4.10 shows typical results of VFTO analysis for DS operations without a switching resistor. The maximum value of the VFTO is 2.7 p.u. (2442 kV) for a full GIS and 2.1 p.u. (1922 kV) for a hybrid GIS. Since the results indicate that the VFTO may exceed the insulation level (LIWV) of 2400 kV for a full GIS, a solution is required. Figure 3.4.11 shows typical results of VFTO for DS operations with a switching resistor (500 ohms), which can reduce the VFTO to less than 1.2 p.u.

Table 3.4.2 (a) *VFTO peak after DS open without a closing resistor*

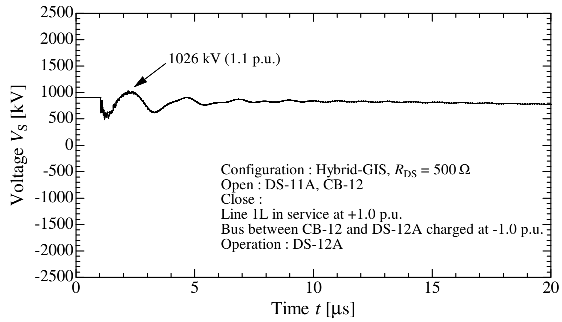
Operation mode	Maximum overvoltage (peak , kV) of measured point						
	1	2	3	4	5	6	7
1	1602	1721	1351	0	0	0	0
2	1473	1574	1273	1556	1359	1309	1372
3	0	1390	1792	1791	2111	0	0
4	1411	1317	1668	1652	1434	1434	1338
5	0	0	0	2260	1861	1800	1427

Fig. 3.4.2 (b). *VFTO peak after DS open with a parallel resistor*

Operation mode	Resistor connected in parallel (Ω)	Maximum overvoltage (peak , kV) of measured point							
		2	3	4	5	6	7	11	12
3	500	913	903	1144	1064	0	0	898	934
3	600	900	878	1104	1039	0	0	898	924
3	700	886	849	1073	1019	0	0	898	914
5	500	0	0	1050	1051	925	927	930	954



(a) Full-GIS



(b) Hybrid-GIS

Fig. 3.4.11 *Typical analysis of VFTO due to DS operation with a parallel resistor*

In China, the VFTO was evaluated at the 1100 kV Jindongnan GIS substation. In this system configuration, the maximum VFTO attains 2.51 p.u. (2260 kV) after the DS operation without a switching resistor as shown in Table 3.4.2. A DS equipped with an appropriate resistor can successfully suppress the VFTO less than 1.27 p.u. (1144 kV). The optimal resistance is estimated as 500-700 ohms in parallel [69].

The VFTO generated in 550 kV systems was evaluated in Japan, and the results showed that it will not exceed 2.8 p.u. The insulation coordination in the 1100 kV systems ensures that the VFTO level due to disconnector switching will not exceed the LIWV level. A resistor making and breaking method with a 500 ohms resistor was employed to reduce this VFTO level. The VFTO can effectively be reduced to less than 1.3 p.u. due to the switching resistor [68].

Field verification tests have been carried out in facilities connected to the 550 kV commercial network through the secondary side of the transformer since May 1996. The total energized hours reached more than 58,000 by the end of March 2007. Disconnector surge tests were performed with four different circuit configurations. It was confirmed that the maximum VFTO level, could be suppressed to less than 1.2 p.u. in the field. The potential rise at the GIS tank was measured from the electromagnetic immunity (EMI) viewpoint. It was confirmed to be no more than 10 kVp, and there was no malfunction occurred in the control and protection systems.

In conclusion, the VFTO can be successfully suppressed in 1100 kV by using a DS equipped with a switching resistor. The insulation coordination policy ensures a VFTO less than the LIWV level of the substation equipment.

3.4.1.8 Requirement for the switching resistor of DS

The resistor for DS switching needs special duties on its dielectrics and thermally.

a) Dielectric capability

Fig.3.4.12 shows the calculation results of the voltage applied to the switching resistor. From the results, dielectric capability of 1700 kV is sufficient, because the maximum voltage occurred by restriking at +1p.u. of the source voltage and -1p.u. of the remain voltage on the load side for the four line feeder and the four transformer feeder substation.

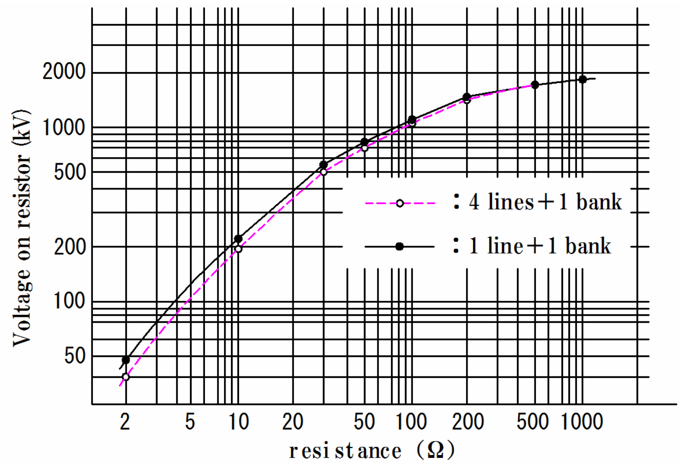


Fig.3.4.12 *Calculation results (with switching resistor)*

b) Thermal capability

The thermal capability of switching resistor should withstand the thermal stress of one CO operation because the possibility of more than one CO operation within a few minutes, which corresponds to the radiation time constant of the switching resistor, is estimated to be small.

3.4.1.9 Considerations for structure with switching resistor

An example of a GIS disconnector structure fitted with a resistor is shown in Fig.3.4.13. In the Fig.3.4.14, when the movable and stationary electrodes start to separate, the charging current is interrupted once because the current is small. However, a restriking arc generates because insulation recovery characteristics is not sufficient (Step 1). As the distance between the two electrodes increases, the restriking arc moves to the part between the resistor shield and the moveable electrode (Step 2). The restriking repeats and current is completely interrupted when the sufficient insulating distance is provided (Step 3). Inserting the resistor into a discharge path, where the gap between electrodes is long and discharge voltage is high, is the principle to suppress the overvoltage.

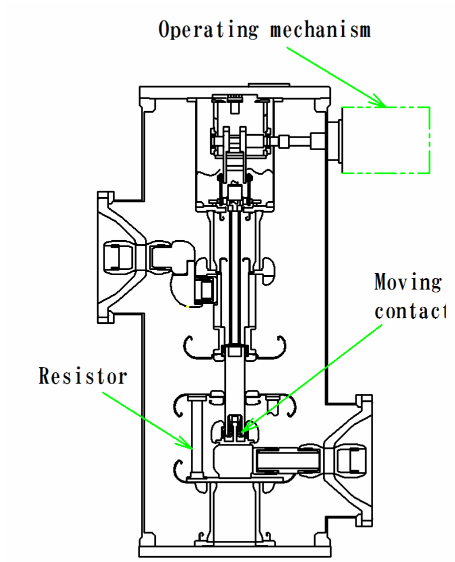


Fig 3.4.13 *DS structure*

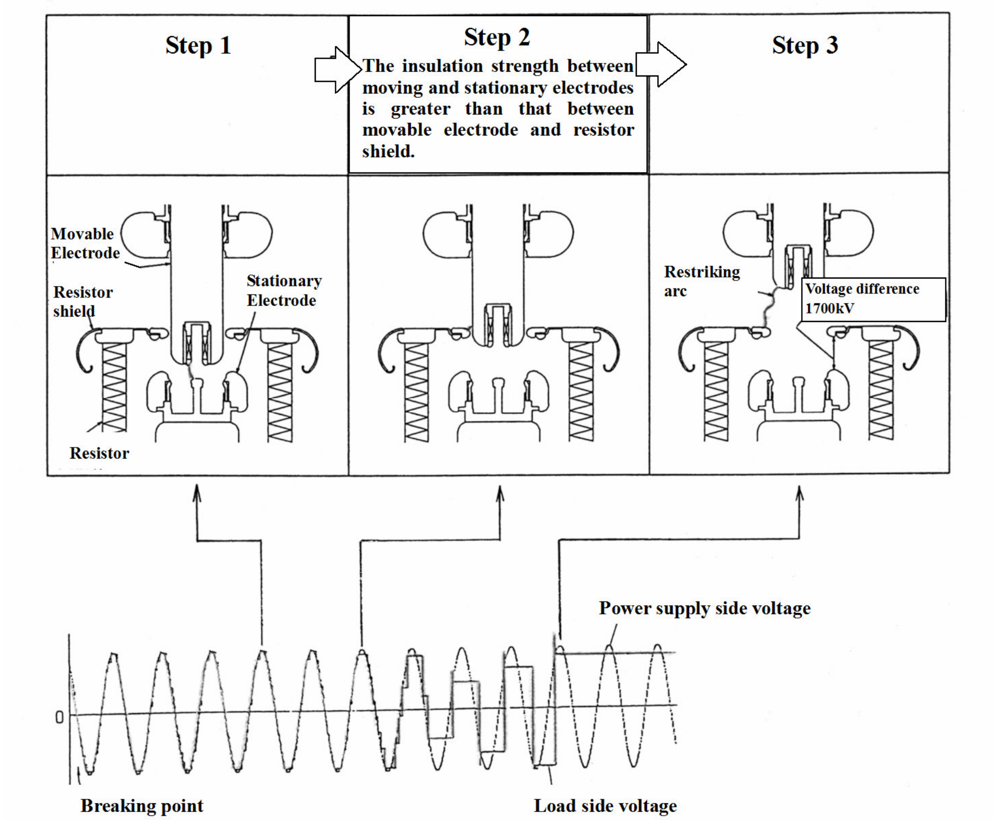


Fig. 3.4.14 *Surge suppressing concepts in switching process of 1100kV DS*

3.4.1.10 Discussion

UHV capacitive current switching with DSs will require further review when MT42 completes its task in late 2008 or early 2009. Of particular interest is how to address the influence of C_S/C_L in type testing.

3.4.2 Bus transfer current switching

3.4.2.1 Introduction

Disconnector bus-transfer current switching ratings are stated in Annex B of reference [61]. The rated bus-transfer current for both air-insulated and gas-insulated DSs is 80% of rated normal current and normally not expected to exceed 1600 A. The rated bus-transfer voltages for DSs at 245 kV and above are shown in Table 3.4.3:

***Table 3.4.3** Rated bus-transfer voltages for DS*

Rated voltage (kV)	Air-insulated disconnectors (Vrms)	Gas-insulated disconnectors (Vrms)
245	200	20
300	200	20
362	200	20
420	300	20
550	300	40
800	300	40

Corresponding loop impedances are simply the bus-transfer voltage divided by the bus-transfer current. Air-insulated DSs commonly include commutating contacts to achieve this capability.

3.4.2.2 General considerations

Bus-transfer switching known as loop switching, is the commutation of current from one circuit to a parallel circuit. With reference to the circuit shown in Fig. 3.4.15, as the disconnector opens, the arc voltage builds forcing more and more of the current i_s into the parallel path. The recovery voltage for this case is the power frequency open circuit voltage across the disconnector after the current has transferred to the parallel path. The parameters to be considered in analyzing the circuit in Fig. 3.4.15 are as follows:

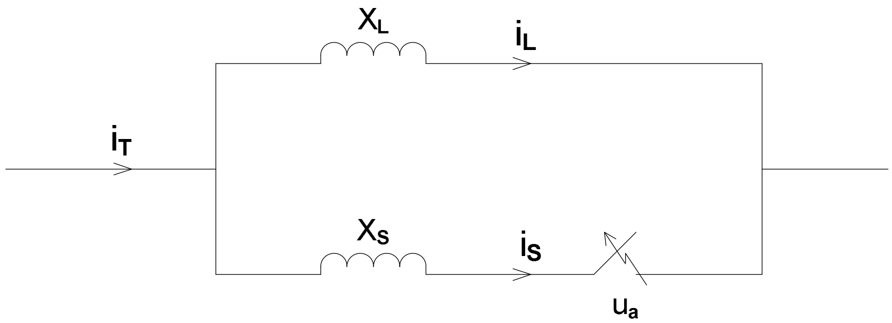


***Fig. 3.4.15** Equivalent circuit for bus-transfer switching*

- Initial current before the disconnector is opened I_S;
- Switch current i_S as the disconnector is opening;
- Total current I_T through both the disconnector and the parallel path; I_T is a constant.
- Series and parallel impedances X_S and X_L; $X_S + X_L$ = loop impedance X_{LOOP};
- Arc voltage u_a;
- Open circuit voltage UOC across the disconnector as given by XLIT.
- Switching event is non-linear because u_a is a non-linear quantity. We can write:

$$L_L \frac{di_L}{dt} = L_S \frac{di_S}{dt} + u_a \qquad \text{…(33)}$$

and

$$i_T = I_T \sin \omega t$$

$$= i_S + i_L \qquad \ldots(34)$$

,where $L_L = X_L/\omega$ and $L_S = X_S/\omega$.

Equation (25) then becomes:

$$\frac{X_L}{\omega}\frac{d(i_T - i_S)}{dt} = \frac{X_S}{\omega}\frac{di_S}{dt} + u_a \qquad \ldots(35)$$

and differentiating the left term

$$X_L I_T \cos \omega t = \frac{1}{\omega}(X_S + X_L)\frac{di_S}{dt} + u_a \qquad \ldots(36)$$

Equation (26) is the basic equation that describes loop switching. Under initial steady state conditions, the switch is closed and $u_a = 0$:

$$X_L I_T \cos \omega t = \frac{1}{\omega}(X_S + X_L)\frac{d}{dt}(I_S \sin \omega t) + 0$$

$$= (X_S + X_L) I_S \cos \omega t \qquad \ldots(37)$$

giving

$$X_L (I_T - I_S) = X_S I_S \qquad \ldots(38)$$

Under final steady state conditions, the switch is open and $I_S = 0$:

$$X_L I_T \cos \omega t = 0 + u_a \qquad \ldots(39)$$

i.e. the arc voltage equals the open circuit voltage across the switch. The condition to be met is therefore that the arc voltage must rise to a value equal to the open circuit voltage across the switch in order to totally transfer the current to the parallel path. The arc will actually become unstable at an arc voltage lower than that given by Equation (39) and dependent on the power input to the arc. The arc collapses and the arc voltage across the disconnect switch then jumps to the open circuit value [62].

Equation (39) is also significant in that the circuit shown in Fig.3.4.16 can represent it. The circuits shown in Figs. 1 and 2 are electrically equivalent and either one can be used for calculation or test purposes. The circuit in Fig. 3.4.16 is that specified in reference [61].

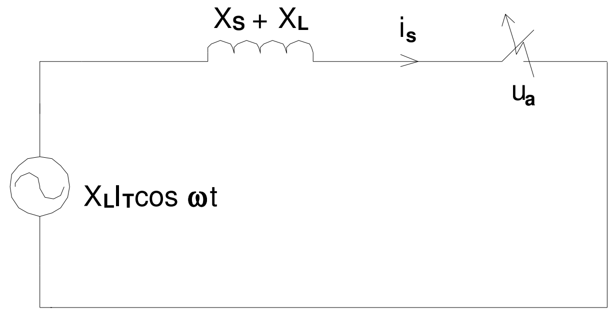


Fig.3.4.16 *Bus-transfer switching circuit based on Equation (26)*

The recovery voltage across the disconnector is the power frequency open circuit voltage and is not a transient recovery voltage as implied in reference [61]. Once a current transfer has occurred, the reverse is not possible by "reignition" or "restrike" since this would mean transfer to an infinite impedance circuit.

3.4.2.3 Discussion

In the past loop switching with DSs has tended to be used in double-busbar layout schemes. Also, there is some indication that UHV transmission systems may operate on a constant power flow basis and the present upper limit of 1600 A bus-transfer current will need to be reviewed. Likewise upper bus-transfer voltages of 300 V and 40 V air-insulated and gas-insulated DSs, should also be reviewed based on the actual circuit layout dimensions. One example, however, is that discussed in the appendix below for the Japanese UHV Project. That application is probably unique to utilities in Japan and requires a bus-transfer voltage (recovery voltage) for 1000 kV GIS of 300 V (margin included) at 8000 A. The corresponding TRV has a minimum rate of rise of 400 V/μs again with a margin included.

3.4.2.4 Bus-transfer switching in Japanese UHV Project

A GIS double busbar configuration is used in the UHV project in Japan [66] and the bus-transfer switching duty for 1100kV DS was determined by the following considerations.

1) Loop current

The rated loop current of an 1100kV DS is determined to be 8000A, which corresponds to the rated current of the GIS. In Japan, it is general practise that the maximum loop current corresponds to the rated current of the DS.

2) Recovery voltage

The recovery voltage (or bus-transfer voltage) of 1100kV DS (V) is derived from the following simple equation:

$V=\omega L*d*I$, where

L: inductance of the GIS busbar = 0.3μH/m
d: maximum loop length of circuit = 250m
I: loop current = 8000A (correspond to the rated current)

The rated recovery voltage is determined to be 300 V with allowance for a margin, which is the same value as required for 550kV DSs in Japan.

3) TRV

The TRV of an 1100kV DS is derived from the following equation:

$Vp=\sqrt{2}\,\omega ZI$, where

Z: surge impedance = 90ohm
I: loop current = 8000A

The rated TRV is determined to be 400V/μs again with allowance for margin.

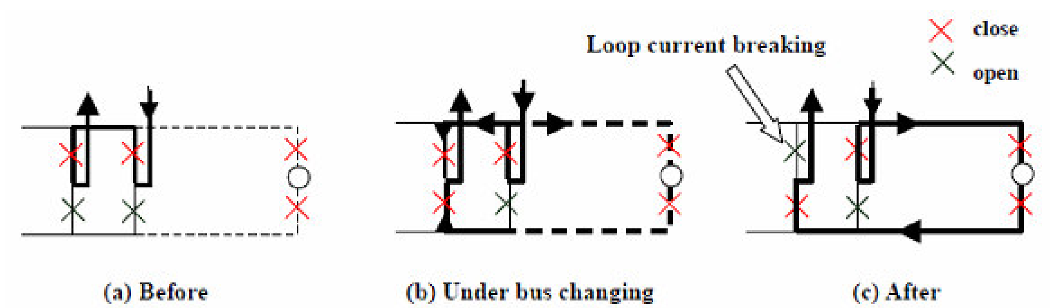


***Fig.3.4.17** Bus-transfer operation in double busbar four bus-tie system*

3.4.3 Induced current switching for earthing switches (ES)

3.4.3.1 General

For earthing switches (ES) which are used in circuits with transmission line in parallel with the energized other transmission line, a switching capability is required for the electromagnetically induced current and the electrostatically induced current. (refer to Fig.3.4.18).

In Annex C of reference [61] an electromagnetic and electrostatic induced current and voltage are standardized for 550 kV and 800 kV ES 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). See Table 3.4.4.

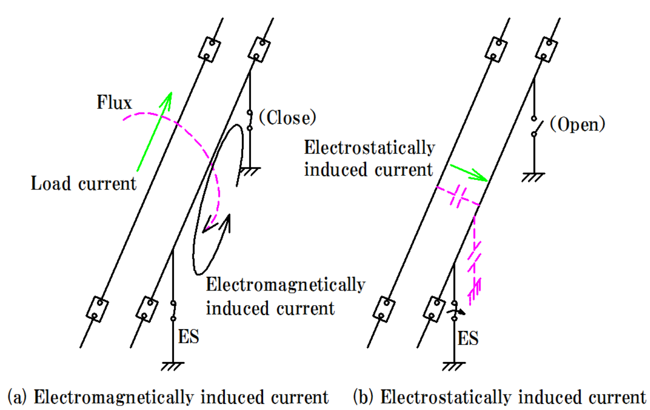


***Fig.3.4.18** Electromagnetically and electrostatically induced current switching*

Table 3.4.4 *Induced current and voltage for 550kV and 800kV earthing switches (class B)*

Rated voltage (kV)	Electromagnetic coupling		Electrostatic coupling	
	Rated induced current (A rms)	Rated induced voltage (kVrms)	Rated induced current (A rms)	Rated induced voltage (kVrms)
550	160	20	25	25
800	160	20	25	32

For the 1100kV ES, the characteristics of the induced current should be estimated individually because of the difference in the conditions, such as the rated current, the configuration of the transmission towers and the length of the parallel transmission lines.

3.4.3.2 Duty for 1100kV Earthing switch (ES)

An 1100kV earthing switch (ES) is used for earthing the main circuit of feeders or main busbars under de-energized condition. For actual operations, an induced current switching capability is also requested for the earthing switch because some currents are induced from the adjacent transmission line which is under operation. (refer to Fig. 3.4.18) The rated induced current switching condition is determined from the analyses of the electromagnetically and electrostatically induced current for various switching conditions of the earthing switch under the single line operation of a double transmission line configuration.

1) Rated induced current switching condition

The rated induced current switching condition (Table 3.4.5) is determined from the analysis of the electromagnetically and electrostatically induced current switching taking account of the actual length of the 1100kV transmission line and the load current, and selected the severest duty among the electromagnetically induced current.

Table 3.4.5 *Rated induced current switching condition*

Items			Condition
Application of induced current switching duty			Line feeder ES (Not applicable for main busbar, Tr feeder and maintenance ES
Switching condition	Induced current	Switching current	1000 A
		Recovery voltage	70 kVrms
		TRV	160 V/us
	Electrostatic induced current	Switching current	40 A
		Recovery voltage	50 kVrms
Switching operation cycles			100 times

a) Electromagnetically induced current switching

The calculation was carried out by assuming a 200 km length transmission line and a load current of 8000 A for one operating line with a double transmission line configuration and the other in a de-energized condition. The well-known Carson-Pollaczek method was used for calculation and the other detailed conditions are as follows,

The configuration of the conductors of the transmission line and towers are shown in Fig.3.4.19 and Table 3.4.6. The maximum current obtained from the calculation is shown in Table 3.4.8 together with the calculation results of a length of 250 km.

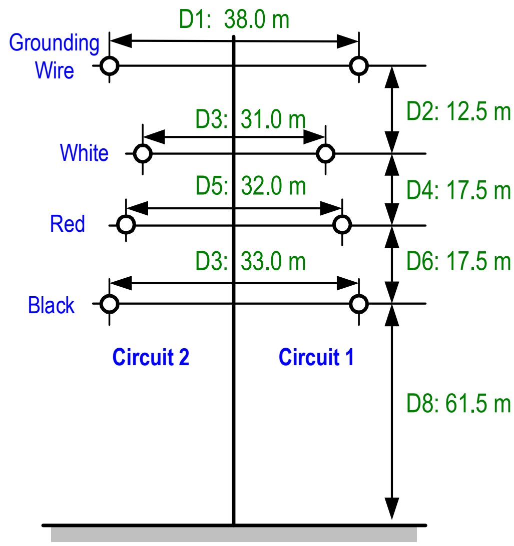


Fig.3.4.19 *Analysis model of the tower*

Table 3.4.6 *configuration of conductors of transmission line for calculation*

	Overhead grounding wire	Overhead Power line
Type and size of lines	OPGW, 500 mm^2 x 2 wires	ACSR, 810 mm^2 x 8 wires
Resistance of conductor	0.103 ohm/km	0.05 ohm/km (per wire)
Relative permittivity	5.0	1.0
Rated voltage	1100 kV	
Current for energized line	8000 A	
Transmission line length	200 km (250 km for reference calculation)	

Table 3.4.7 *Switching condition for ES (for Electromagnetic induced current)*

Case No.	Condition of objective ES on de-energized line			Condition of remote end ES on de-energized line
	A phase	B phase	C phase	
Case 1	close	close	close	Closed condition for all 3 phases
Case 2	open	close	close	
Case 3	close	open	close	
Case 4	close	close	open	
Case 5	open	open	close	
Case 6	open	close	open	
Case 7	close	open	open	
Case 8	open	open	open	

Table 3.4.8 *Results of electromagnetically induced current switching for 1100 kV ES*

	Line length: 200 km	Line length: 250 km
Current for energized line	8000 A	8000 A
Switching current	810 A	810 A
Recovery voltage	65.0 kV	81.3 kV
TRV	162 V/µs	162 V/µs

From the above results and the comparison with the standard value for a 550 kV ES (rated current of 8000 A and line length of 200 km) in JEC 2310-2003 “AC Disconnectors”, the values of switching a 1000 A current and 70 kV recovery voltage which were the same values for the 550 kV ES, were selected as the switching duty. For the TRV value, 160V/µs which was obtained from the calculation results and was more severe than the standard value for a 550 kV ES was selected. The calculation results of the 200 km line length were chosen because the length of 250 km line was too severe for taking into account of actual system condition.

b) Electrostatically induced current switching

The calculation for electrostatically induced current switching was carried out under the same conditions as the electromagnetically induced current switching except for the following remote end ES condition. For the switching conditions of the ES, the remote end ES on the de-energized line was open condition for all three phases though it was closed for electromagnetically induced current switching.

Table 3.4.9 *Switching condition for ES <for Electrostatic induced current>*

Case No.	Condition of objective ES on de-energized line			Condition of remote end ES on de-energized line
	A phase	B phase	C phase	
Case 1	close	close	close	Opened condition for all 3 phases
Case 2	open	close	close	
Case 3	close	open	close	
Case 4	close	close	open	
Case 5	open	open	close	
Case 6	open	close	open	
Case 7	close	open	open	
Case 8	open	open	open	

The calculations were carried out under above conditions shown in Table 3.4.9 and the maximum current obtained from the calculation is indicated in Table 3.4.10 together with the calculation results of 250 km of length. From the results, the values of switching current 40 A and recovery voltage 50 kV, which were obtained from the results for 200 km line length and 8000 A rated current, have been selected as the switching duty.

Table 3.4.10 *Results of electrostatically induced current switching for 1100 kV ES*

	Line length: 200 km	Line length: 250 km
Current for energized line	8000 A	8000 A
Switching current	31.8 A	40 A
Recovery voltage	45.4 kV	45.4 kV

c) Test duty of induced current switching

Because 100 times make-break operating cycles is specified for induced current switching in JEC-2310-2003 “AC Disconnectors” [70], the same make-break operating cycles (100 times) was adopted to 1100 kV ES.

3.5 Secondary arc current extinction, single-phase auto reclosing

3.5.1 General

Secondary arc induced by sound lines with the system voltage is observed when a single phase grounding fault is generated. A single phase or multi-phase auto reclosing can be completed successfully after the secondary arc extinction. System voltage, line configuration and length as well as wind speed affect the secondary arc extinction time. The secondary arc generated in 345-765 kV (EHV) OH-lines will not generally exceed 100 A and the arc is generally self-extinguished within one second if the current is smaller than 40 A. However, secondary arcs with higher current generated in UHV OH-lines are supposed not to self-extinguish.

In very long arcs typical for EHV/UHV insulation the non-uniformity along the arc length and internal exchange of energy between parts of arc channel play more important role in secondary arc extinguishing than its elongation, creating intermittent character of arc [69]. As the insulation length is usually designed to be directly proportional to maximum operating voltage, and the non-uniformity in longer arcs is more pronounced, the extinction of secondary current arcs in tests on 1000-1200 kV lines happened faster and at higher currents in comparison with observed in operation of 330-750 kV lines [39].

Figure 3.5.1 shows motions of primary and secondary arc. Secondary arc ignites after primary arc extinction by clearing the fault, and extends by elevation of itself and influence of wind and post arc gas of primary arc. Existing conductive gas or atmosphere after arc extinction, it takes certain time to recover insulation strength to withstand reclosing surge voltage.

The reclosing process is illustrated in Fig. 3.5.2. When secondary arc does not ignite or extinguishes instantly, the time for reclosing is evaluated by only the recovery characteristic of after primary arc extinction. The time for reclosing is evaluated by the longer one of recovery time after primary arc or sum of secondary arc extinction time and recovery time.

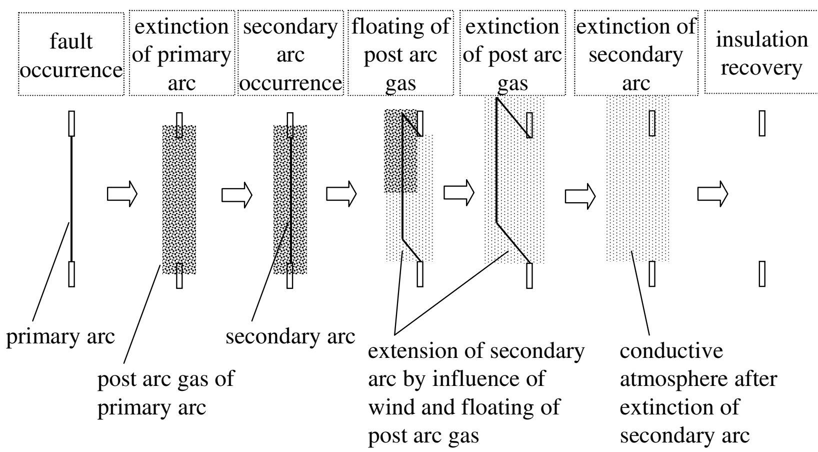


Figure 3.5.1 *Primary and secondary arc motion*

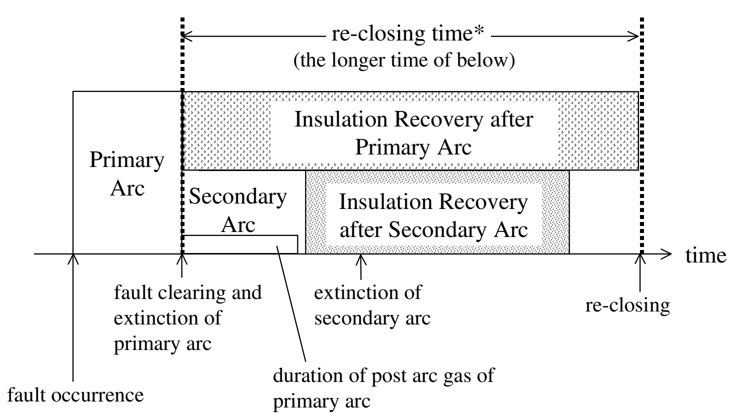


Figure 3.5.2 *Reclosing process after fault occurrence*
*(*The definition of reclosing time generally includes the time after fault detection.)*

Fig. 3.5.3 shows the primary arc (10 kA peak) followed by the secondary arc from a staged fault test on the BC Hydro 500 kV system. The initial intensity of the secondary arc immediately after primary arc extinction and the gradual recovery is clearly evident. The primary and secondary arc currents were measured by means of an optical current transformer and a typical trace is shown in Fig. 3.5.4.

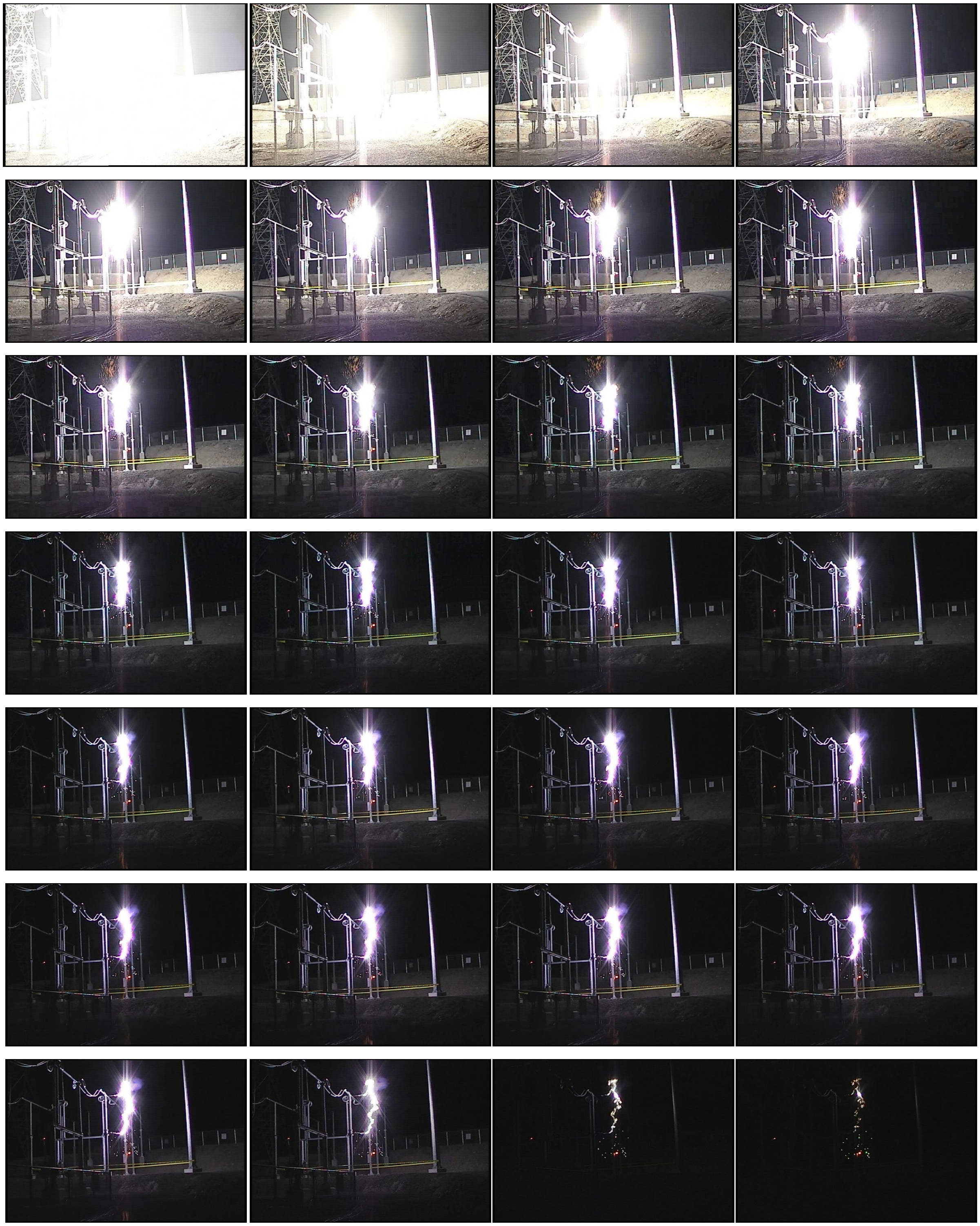


Fig.3.5.3 *Secondary arc current behaviour (Courtesy of BC Hydro)*

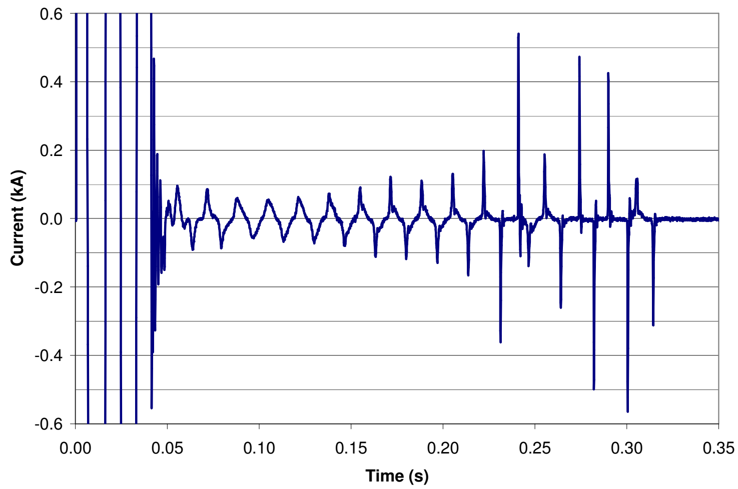


Fig. 3.5.4 *Primary and secondary arc currents (Trace courtesy of BC Hydro and NxtPhase Corporation)*

Figure 3.5.5 summarizes the results of secondary arc tests including arc extinction time and recovery peak voltage investigated in 330-1200 kV lines.

The arc extinction time of the secondary arc (with a current of 150 A and a peak recovery voltage of 140 kV) is about 4 seconds for 1100 kV double-circuit lines of 210 km-length in Japan. Russian experience showed that the 90 % values of the extinction times were evaluated as 0.7 s at 40 A peak, 1.2 s at 60 A peak and 2.6 s at 90 A peak. The secondary current peak of Russian 1200kV compensated lines may exceed 150A and the correlation of arc extinction time was given [71]. A limited number of a single grounding fault tests conducted on the Russian 1200 kV lines showed shorter arcing times as compared with those of 787 kV lines.

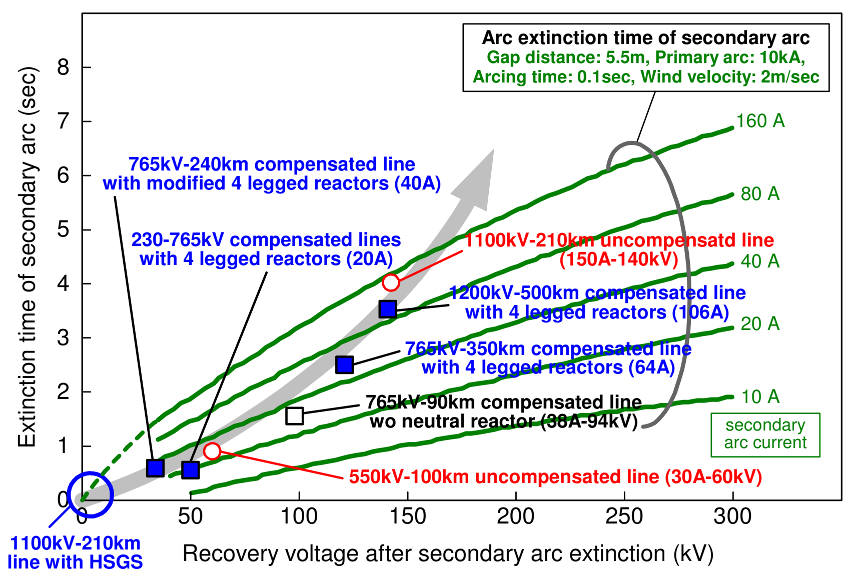


Fig.3.5.5 *Arc extinction time of secondary arc*

A four-legged shunt reactor equipped with an appropriate reactance at neutral point is often used for shunt compensated EHV and UHV transmission lines. The arc extinction time of the secondary arc with the current of 38 A and the peak recovery voltage of 94 kV is about 1.7 seconds for the Canadian 765 kV transmission lines without a four-legged shunt reactor, however, it is reduced to less than 0.5 seconds with the application of 1500 ohm reactance at the neutral point, resulting in a secondary arc current of 20 A. In Russia, the secondary current had to be limited to below 90 A for 787 kV lines in order to limit the maximum dead time of single-phase auto-reclosing (SPAR) less than 3.0-3.5 s.

In transposed lines a 4-legged reactor might present a simple solution to secondary arc suppression. Its application either uses the existing insulation of the neutral point of shunt reactor or requires its moderate increase. In Russian practise the insulation of 750 kV shunt reactor neutral has class 35 kV (1-min withstand voltage 85 kV). To exclude permanent flow of possible unbalance current through neutral reactor it is normally shunted by a circuit-breaker; and to limit overvoltages on the neutral reactor it is equipped with a MOV.

The use of high speed grounding switches (HSGS) is one of the solutions, which immediately extinguishes the secondary arc of the faulted phase grounded by closing operation of HSGS. For UHV transmission lines, rapid auto reclosing operation within one second can be realised by synchronized operations between HSGS and GCB. In general, HSGS will be applied because of the following reasons:

- HSGS extinguishes considerably large secondary arc current due to the same phase double-circuit grounding fault in the double-circuit 800 kV or UHV transmission lines, which can not be extinguished in a second with four-legged reactor. Especially, for the long untransposed transmission lines, it is difficult to reduce secondary arc current to 40 A or smaller by four-legged reactors.
- In the short UHV lines of 100-200 km, it is not necessary to apply shunt reactors to transmission lines to compensate reactive power. Applications of HSGS instead of a four legged shunt reactor will be economically affordable in such short UHV lines,

HSGS have not been standardized yet. It is often customized to cope with longer arcing times based on circuit breaker interrupter design although the TRV peak value is relatively lower. Arc extension up to 80 ms has been developed.

3.5.1 Operating shunt reactors, four-legged shunt reactors

Utilities operate their shunt reactors in several ways, as they may be permanently connected to one line’s end, may be connected in a switchable way to the line, or both fixed and switchable at either end, or even connected to the substation rather than the line.

The usual way of operating the shunt reactors is to connect them before energization of the OH-line in order to avoid too high power frequency voltages due to the Ferranti-effect (TOV). After loading the line beyond a certain level, some or all shunt reactors are switched off. When the loading drops under this level one or more shunt reactors are switched in again. During normal system conditions, connecting or disconnecting shunt-reactors is based on the voltage profile. Before unloading the line the shunt reactors are connected and may stay connected after de-energization until the next energization.

In case of faults or problems in the system, the protection and/or transfer tripping will interfere. Utilities that apply SPAR (single phase rapid auto-reclosing) will allow the faulty phase to be tripped without the shunt reactor(s) connected, as the voltage on that phase is low anyway. Before reclosing they automatically will connect the shunt-reactors to all phases. In this way, they are prepared for the three-phase tripping if the SPAR was unsuccessful. Care has to be taken for single phase ferroresonance, due to the capacitive coupling between the switched off phase with its capacitance to earth in parallel to the shunt reactor (after arc extinction) and the healthy phases. Among other solutions, a mitigation is to disconnect the shunt reactor temporary and connect it after reclosing [3].

Utilities that apply TPAR (three-phase rapid auto-reclosing), have often a permanently connected shunt reactor at least at one side. Anyway some utilities will delay the tripping until the shunt reactors are connected, while others specify their circuit-breakers to clear healthy phase capacitive currents under Ferranti-conditions. In Russia the air-blast circuit-breakers, used to switch the EHV and UHV shunt reactors, are equipped with arc gaps across a part of the interrupting chambers, so that at higher system voltages they are connected instantaneously. Before three-phase reclosing the utilities connect their shunt reactors to the line.

Examples of the policies of several utilities are as follows:

HQ: both line ends switchable SRs (controlled switching; PIR on air-blast technology and MOSA in combination with modern technology CB). At faults TPAR, but no guarantee that SRs are connected -> CBs capable to switch out uncompensated lines (Ferranti-effect).

AEP: prefer PIR above MOSA. For SPAR, AEP uses a special scheme to switch the shunt reactors in order to extinguish the secondary arc current, as shown in the following figure.

BC Hydro: one line end a fixed SR, other end switchable SR with fast insertion CBs capable to switch out uncompensated lines.

Russia: either instantaneous insertion of SR through spark gaps or delay of healthy phase switching until SRs are connected. Normal operation: connect SRs before switching off. Automatic insertion in all phases of SR at an overvoltage for a certain period SPAR with 3-phase insertion of SR before reclosing. Automatic insertion in all phases of SR at a single pole or there-pole opening command to a line circuit-breaker.

India: SRs fixed to the lines switchable SR at the busbars.

Turkey: all SR switchable (controlled switching, MOSA). Automatic insertion of SR at higher operating voltage (within 1.5 s). SPAR, even with single phase disconnection of SR when ferroresonance due to coupling to healthy phases may occur.

A modified reactor schemes has been applied to some 765 kV transmission lines in the US. Field tests demonstrated a successful single phase reclosing. Field tests demonstrated a successful single phase reclosing that if the secondary arc current were limited to less than 40 A rms, it extinguished within 0.5 second as shown in Fig. 2.2.1

3.5.2 HSGS

3.5.2.1 Developments of HSGS for UHV system in Japan

A fast multi-phase reclosing system was employed to avoid loss of a double-circuit line. Because of the large charging MVA of a UHV line, the electro-static induction from sound phases may keep the secondary arc current in such a long period that the reclosing in a second will be impossible.

The duration of the secondary arc in different fault conditions on six phases of a double-circuit line was evaluated, and a reclosing system featured HSGS within one-second was developed by TEPCO. With the connection of four-legged shunt reactors, reclosing within one-second is difficult to realise for all the cases of faults of double-circuit lines.

The UHV experimental characteristics of insulation recovery after primary arc (4 kA, 0.1 sec) interruption are shown in Fig.3.5.6. This data were carried out outdoors when the wind velocity was generally lower than 2.5m/s, which corresponds to the wind velocity parameter on this study. It takes around 0.6~0.9 sec for recovering insulation strength enough to withstand 1.6 p.u. On this studying condition, possible surge voltage at reclosing is lesser than 1.6 p.u. Arcing on surface of suspension insulator, which is a rare phenomenon, causes recovery time to be longer.

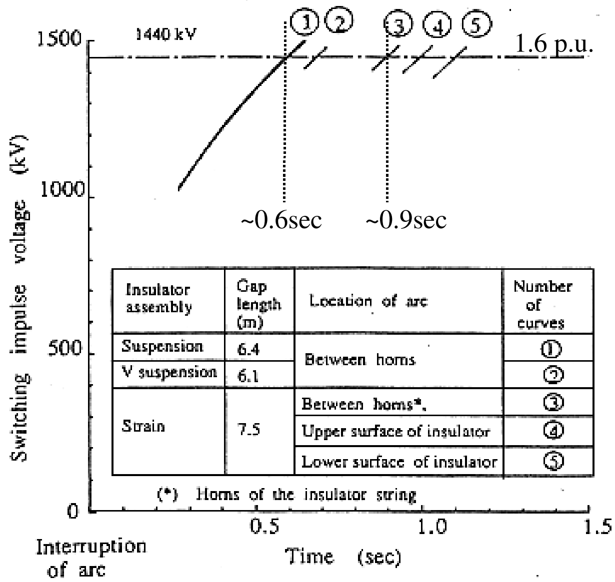


Figure 3.5.6 *Recovery characteristic after primary arc extinction [72]*

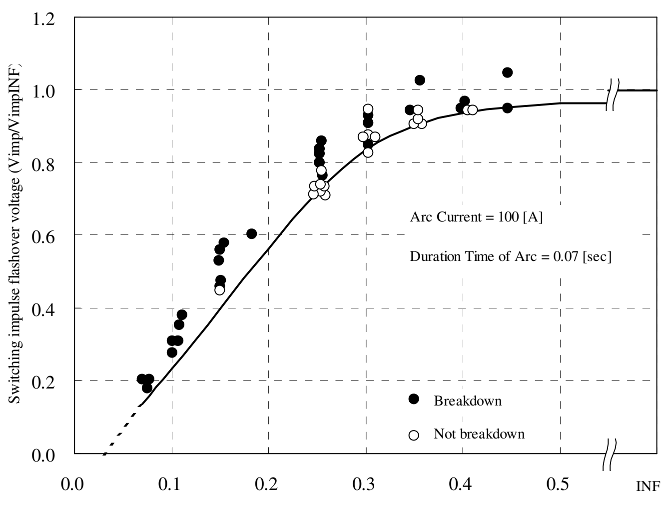


Figure 3.5.7 *Recovery characteristics after secondary arc extinction [73]*

When secondary arc at fault point would be persisted for some duration, there is an insulation recovery characteristic after secondary arc extinction. The UHV experimental characteristic of insulation recovery after arcing (100A, 0.07 sec) is shown in Figure 3.5.7 carried out outdoors when the wind velocity was generally lower than 2.0m/s, which corresponds to the wind velocity on this study. It takes around 0.5 sec for recovering the insulation strength before the fault.

Taking the above mentioned insulation recovery characteristics into consideration, operating sequence of HSGS as shown in Fig. 3.5.8 will be applied in the UHV system of TEPCO.

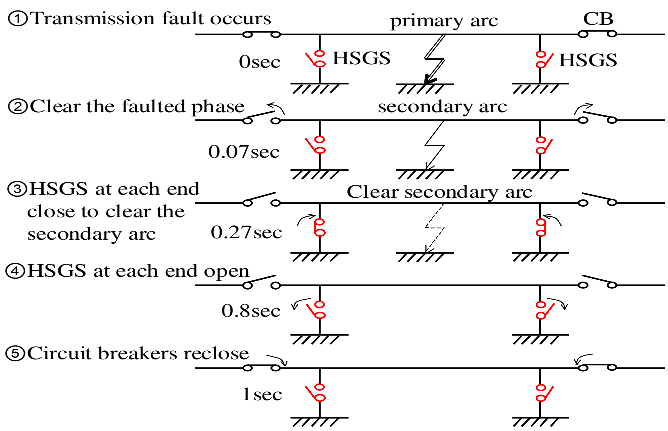


Fig. 3.5.8 *Fast reclosing using High Speed Grounding Switches (HSGS)*

3.5.2.2 Delayed zero phenomena caused by successive faults

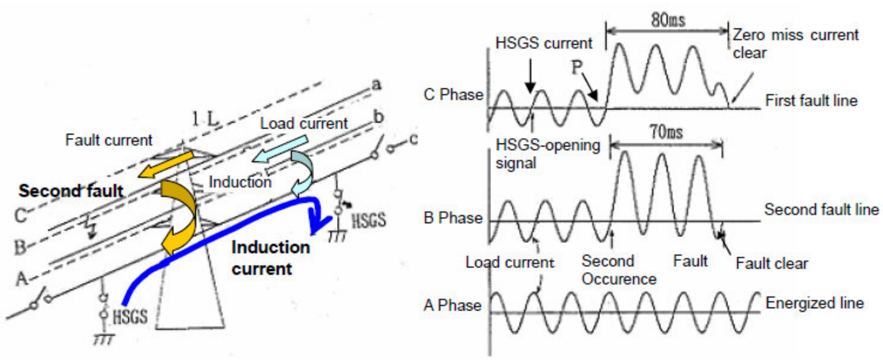
In addition to the ordinary induced current interruption, a delayed current zero phenomenon caused by multiple lightning strikes (and therefore successive fault) was specified as a special duty for TEPCO system as shown in Table 3.5.1. Although the probability of the occurrence of this phenomenon would be very low, it was determined to achieve high reliability of the UHV system. The phenomenon is explained as shown in Fig. 3.5.9.

The phenomenon considers a successive ground fault due to multiple lightning strikes or another (second) phase ground fault is caused during an HSGS operation to interrupt the first ground fault, At this instant, a larger current is induced by the second fault current and this additional induced current may offsets the AC component of the originally flowing current (induced by healthy phase) in the first phase, resulting in a delayed current zero. This condition continues until the circuit breaker of the second faulted phase interrupts the ground fault current. Then the HSGS should withstand a long arcing time up to 80 ms without a current zero.

Table 3.5.1 Specifications for HSGS (Delayed current Zero Condition)

Condition	OHL length	Interrupting Current	Recovery voltage	Rate of Rise
Electromagnetically induced	200 km	3500 A mean	170 kV peak	0.26 kV/μs
	40 km	7830 A mean	65 kV peak	0.46 kV/μs
Electrostatically induced	200 km	5800 A mean	570 kV*	-
	40 km	7000 A mean	390 kV*	-
Arcing time: 80 ms + minimum arcing time (with current zero missing)				

** (1- cos) waveform*



The severest case for HSGS in which a second fault follows just before HSGS breaks the electromagnetic induction current at point P.

Fig. 3.5.9 *Delayed current zero phenomena in HSGS*

3.5.2.3 Field experiences of HSGS in KEPCO 765kV systems

In Korea, the 765 kV transmission system is to transport large capacity of electric power generated in the east and west coasts to the Kyungin area and it is estimated that the normal power will be several million kW. However, the system is using double-circuit steel tower in order to save the land space and adopted the high speed multi-phase reclosing system for preventing loss of the double circuits.

In the power system above 550 kV, the secondary arc does not extinguish in a short time induced electro-statically from other phase or other circuit. Especially in double-circuit transmission lines such as 765 kV transmission in KEPCO, it is desirable to install HSGS, since such conditions as the capacitances between each phase of healthy phase and healthy circuit become very complicated to be compensated and it is not only difficult but also not economic to apply the four-legged reactors.

Figure 3.5.10 shows the KEPCO 765 kV transmission grid and locations of HSGS installations.

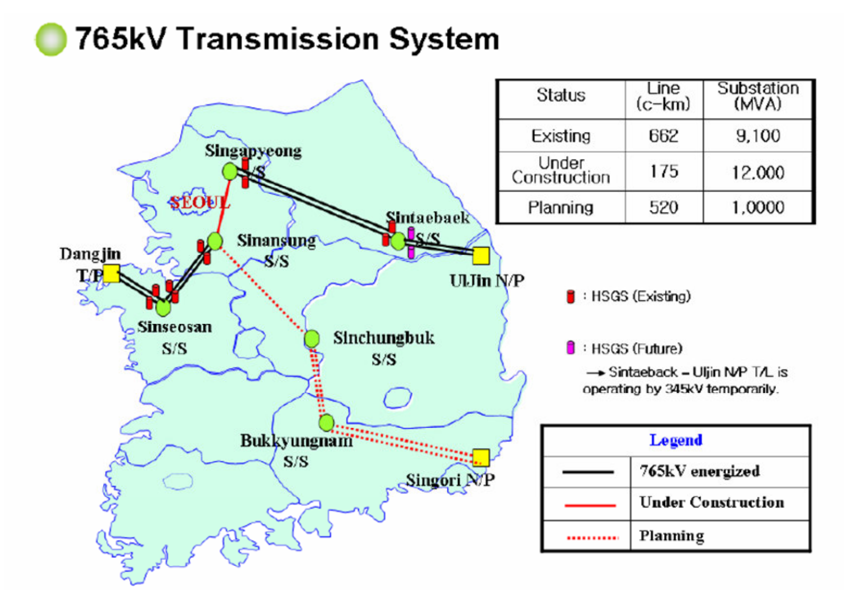


Figure 3.5.10 *765kV Transmission Grid in KEPCO and HSGS applications*

In the short 765 kV transmission lines less than 80 km, an HSGS installed at single end of the transmission line can extinguish secondary arc current in 750 ms. Therefore, HSGS is installed at both ends of the 765 kV transmission lines 80km or more and at a single end of those shorter than 80km.

Table 3.5.2 shows the operation experiences of HSGS in KEPCO. HSGS was operated at two or three times per year per line. KEPCO have not experienced any miss-operations and malfunctions.

Table 3.5.2 Operation experiences of HSGS in KEPCO

Substation / Year	Sinseosan ~Sinansung (double circuit transmission line)	Sintaebaek ~ Singapyeong (double circuit transmission line)
2003	12	
2004	-	2
2005	2	8
2006	2	6
2007	6	6
Sum	22	22

3.6 Surge Arrester

3.6.1 Continuous operating voltage Uc, rated voltage Ur and TOV capability

The selection of a suitable surge arrester first comprises the selection of continuous operation voltage, Uc, and rated voltage, Ur.

Uc is determined from actual service voltage across the arrester, which for normal phase-ground installation is equal to $Um/\sqrt{3}$. Ur is selected based on amplitude and duration of temporary overvoltages. Normally arresters are not used to limit temporary overvoltages (TOV) since this would in general result in enormous arrester energies. During TOV conditions therefore, in general, the voltage across the arresters is assumed to be unaffected by the arrester.

Applying the same ratio Ur/Um as for 800 kV, i.e. 588/800= 0.735, rated voltages of 809 and 882 would be required for 1100 and 1200 kV systems respectively.

With the same relative protection levels as for the 800 kV arresters this would give minimum LIPL and SIPL as per Table 3.6.1.

***Table 3.6.1** Arrester data extrapolated from 800 kV*

Maximum system voltage	Extrapolated Rated voltage	Extrapolated LIPL	Extrapolated SIPL
1100 kV	809 kV	1940 kV	1569 kV
1200 kV	882 kV	2115 kV	1710 kV

Furthermore, applying the same protective ratios LIWV/LIPL and SIWV/SIPL as used for 800 kV result in insulation levels as per Table 3.6.2

***Table 3.6.2** LIWV and SIWV of equipment calculated from protective ratios applied on 800 kV systems multiplied with arrester protection levels extrapolated from 800 kV*

Maximum system voltage	Extrapolated LIWV of equipment	Extrapolated SIWV of equipment
1100 kV	2677-2891 kV	1961-2134 kV

1200 kV	2919-3151 kV	2138-2326 kV

Extrapolation from 800 kV equipment thus results in much higher insulation levels than applied for the UHV systems in Italy, Russia, Japan and China.

Limitation of TOV is vital to obtain an optimal protection by arresters. A lower TOV directly affects possible protection levels since a lower arrester rated voltage could be selected. If a lower arrester rated voltage is possible to use the protection level is improved correspondingly. To improve it by adding more parallel block columns is less efficient.

As an example, for an arrester with multiple columns giving a protection level at 2 kA of 1.7 p.u. doubling of the number of columns would give a reduction in protection level of only 2-3 %. On the other hand if the rated voltage could be decreased by 10% the protection level also is reduced by 10 %.

This is valid until the continuous operating voltage set a limit. Historically the factor Uc/Ur has not been higher than 0.8 i.e. an Uc of 80 % of the "knee-point" on the voltage-current characteristics has as maximum been applied for commonly used arresters. Actual ratio is in most cases less since consideration of temporary overvoltages has required a higher rated voltage. The maximum possible ratio Uc/Ur to use is mainly determined by the thermal performance of the arrester housing and power losses of the metal-oxide blocks. (In the past also possible ageing of the metal-oxide blocks was an issue as well.) The criteria for a maximum Uc are set in the standards [74]. Energized at Uc and at maximum ambient temperature of 40 ºC (as per IEC) the average temperature of the arrester shall not exceed 60 ºC if existing arrester standard [74] would be applicable. Furthermore, thermal stability at Uc must exist after absorbing maximum decisive energy followed by rated voltage as verified by operating duty tests according to the standard.

If the thermal performance of the arresters could be improved or metal-oxide blocks with lower power losses used a higher ratio Uc/Ur would be possible. If temporary overvoltages are not decisive an increased relative Uc would then be possible to make use of to obtain a lower protection level.

However, the existing standard is here a hindrance to development. In the conditioning part of the operating duty tests a power-frequency voltage not less than 1.2 times Uc shall be applied. Practically this voltage must be below the "knee-point" otherwise the test is not possible to perform since the test samples will be damaged by the power-frequency voltage.

Maximum TOV of 1.4 p.u. with duration 0.4 to 0.5 s is indicated for the 1100 kV UHV system in China [75], [76] on the line side of the breakers and for this an arrester rated voltage of 828 kV preliminary has been specified. However, to withstand this TOV a lower rated voltage is possible, in the range of 740 to 775 kV. This will require a ratio Uc/Ur of 0.82 to 0.86 which also may be possible to achieve depending on the thermal performance of the arrester design and power losses of the metal-oxide blocks. At an initial stage in the design like for the current UHV systems it is therefore unnecessary and even incorrect to specify the rated voltage of the arresters. To obtain an optimum arrester only the stresses should be given as well as desirable protection levels. The selection of a suitable rating thereafter should be left to the manufacturer.

In Japan sound phase overvoltage (TOV) of UHV system at one line grounding fault is expected around 1.1 p.u. of maximum line to ground voltage. However, for the rated voltage of UHV arresters in Japan, overvoltage factor of 1.3 p.u. was adopted considering the rare TOV, and in line with effectively-grounded systems such as 550 kV, and then Ur was decided as 826 kV ($=1100/\sqrt{3}\times 1.3$).

Figure 3.6.1 shows the lightning surge operating duty test sequence according to Japanese standard (**JEC-217**-1984). The rated voltage of surge arrester corresponds to applicable power frequency voltage that an arrester can deal with lightning surges under the application of the rated voltage without thermal runaway.

On the other hand, the maximum TOV duties exceeding the rated voltage, is caused by various supposing factors, such as system conditions, generator constants and generator control systems, and failure modes considered. Therefore, durability capability of surge arrester for the maximum TOV is evaluated by the step 4 of stability evaluation test in **JEC217**-1984 standard as shown Figure 3.6.2.

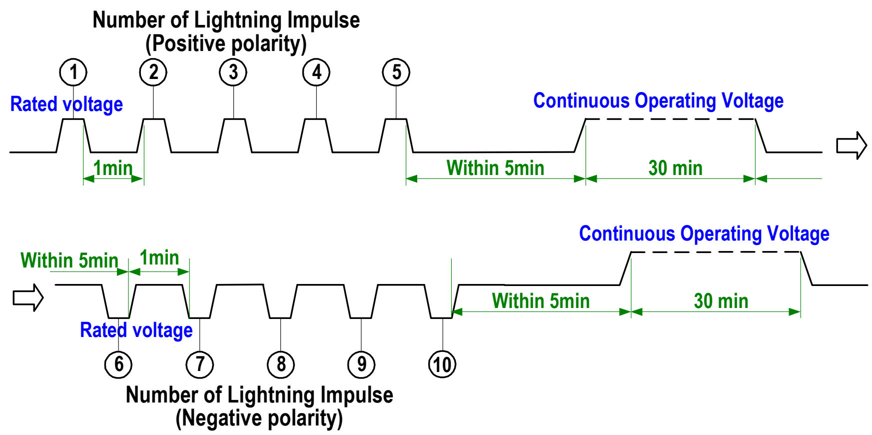


Fig.3.6.1 *Lightning surge operating duty test*

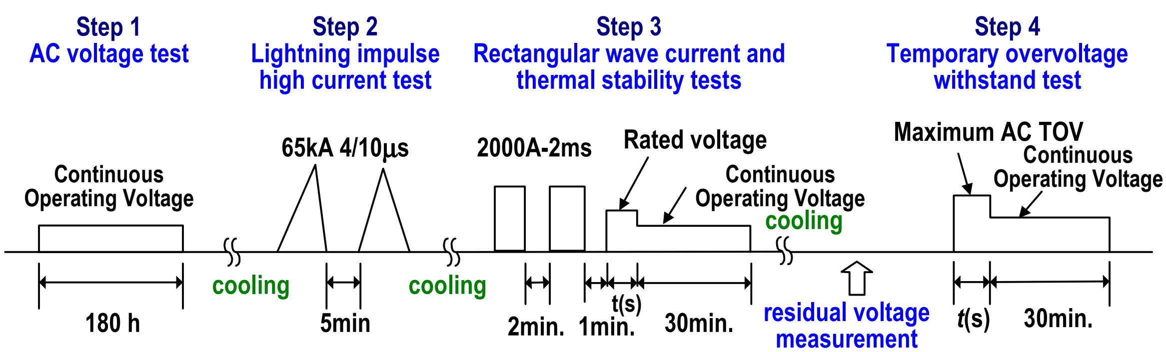


Fig.3.6.2 *Stability Evaluation Test according to JEC-217 1984*

3.6.2 Residual voltages

Insulation levels selected for UHV systems are well below the levels in Table 3.6.2. Surge arresters with improved protection characteristics and/or selected with lower relative rated voltage with respect to the system voltage than for 800 kV therefore are needed. The number and location of arresters in the substations must also be considered as well as other measures to limit amplitudes and, in particular, steepness of incoming surges to the stations.

The arresters of the highest class as per the IEC standard are in the switching surge operating duty test [74] subjected to a conditioning test with a first part comprising 20 8/20 current impulses with peak value equal to the nominal discharge current i.e. 20 kA followed by 2 high current impulses 100 kA 4/10. The large clearances on the UHV transmission lines to ensure necessary switching surge withstand voltage may lead to that a higher nominal current than 20 kA should be introduced. For typically clearances in the towers of 6 to 7.3 m [75], [76] [77] the withstand voltage for negative standard lightning impulse is approximately 3.6 to 4.5 MV. Assuming a shielding failure at critical current a fast front surge with this amplitude will travel towards the UHV station. Approximately the current through an arrester with protection level of 1620 kV (selected for 1100 kV systems in Japan and China) and furthermore assuming a surge impedance of the line of 275 ohm will be 20 to 27 kA.

However, due to the design of the shielding of the line the probability of shielding failures may be ignored.

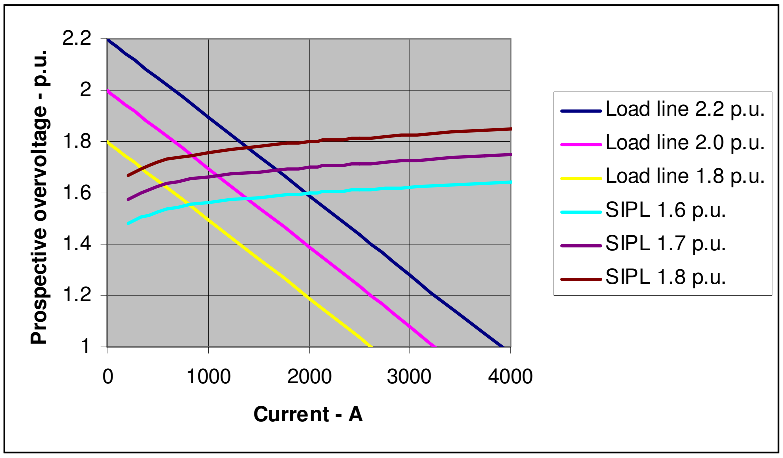


Fig.3.6.3 *Load diagram for the range of prospective overvoltages 1.8 to 2.2 p.u. and U-I arrester characteristics for SIPL 1.6 to 1.8 p.u.*

Regarding suitable current amplitude to define the arrester protection level for switching surges 2 kA seems to be sufficient also for UHV applications. From Figure 3.6.3, arrester discharge currents for prospective overvoltages of 1.8 to 2.2 p.u. and for voltage-current characteristics with SIPL at 2 kA of 1.6 to 1.8 p.u. could be estimated. For e.g. a SIPL of 1.6 p.u. the discharge currents range from 0.8 to 2 kA. Taking into account that prospective overvoltages most probably will be controlled below 2 p.u. 2 kA as coordinating current will be sufficiently high.

In Japan, nominal discharge current for UHV Arresters has been determined to 20 kA from the simple calculation formula, using spark-over voltage of air gap of transmission line which gap length is about 6 m and surge arrester V-I characteristics. In addition to this, among the lightning overvoltages analysis by EMTP program using the surge arrester V-I characteristics as shown in Figure 3.1.1 and V_{20kA}=1.8 p.u. (1620 kV), maximum discharge current was nearly 20 kA.

Switching impulse discharge current was 1kA or below from the result of switching surge analysis.

These current values can be categorized as the current values of class 5 surge arresters specified in Table 3.6.3 taken from [74] (20 kA for lightning and 2 kA for switching).

The lightning and switching insulation withstand test values are generally determined from basic and simplified formula to multiply levels (LIPL and SIPL) with some factors which is very convenient for general and relative evaluation methods of systems.

However, in order to decide the lightning and switching insulation withstand test values of UHV systems, where high reliability and efficiency were considered as essential, detailed overvoltage analyses have been used in Japan.

Table 3.6.3 *Peak currents for switching impulse residual voltage test as per IEC 60099-4*

Arrester classification	Peak currents (A)
20 000 A, line discharge Classes 4 and 5	500 and 2 000
10 000 A, line discharge Class 3	250 and 1 000
10 000 A, line discharge Class 1 and 2	125 and 500

3.6.3 Long duration current impulse withstand

The line discharge test as per IEC [74] is used to verify energy capability of 10 and 20 kA arresters. The highest class, i.e. class 5, is considered to cover line lengths up to 480 km. For a 588 kV arrester on an 800 kV system the test simulates the discharge of a 480 km line with surge impedance 294 ohm charged to 2.16 p.u.. For commonly used protection levels the test results in arrester energies of 5 to 7.5 kJ/kV rated voltage.

Transmission lines for UHV systems may be considerably longer than 480 km and thus prospective arrester energies much higher. On the other hand it is vital at UHV to keep the switching overvoltages as low as possible. Single-phase reclosure is e.g. considered as well as preinsertion resistors and controlled switching which will reduce arrester discharge duties as well.

In Figure 3.6.4 arrester energies as function of prospective overvoltage i.e. the charging voltage of the transmission line are given with the arrester protection level at 2 kA (SIPL) as parameter for an 1100kV/1000 km line. The surge impedance of the line is assumed to 275 ohm. The arrester discharge energy is significantly reduced if the prospective overvoltage without arrester is limited.

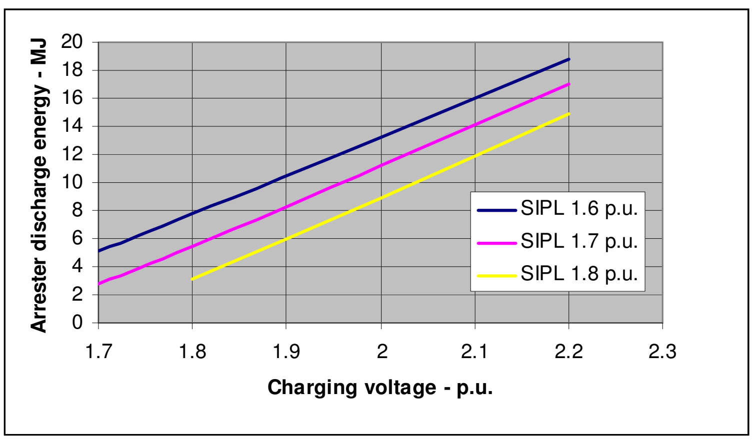


Fig.3.6.4 *Arrester discharge energy for 1000 km transmission line as function of overvoltage factor (charging voltage). Arrester protection level at 2kA switching impulse (SIPL) as parameter*

1100 kV GIS-arresters in Japan have been confirmed to have the surge suppressing, energy absorption and thermal stability capabilities by switching surge duty test according to Japanese standard (**JEC-217**-1984). The concept of this test was introduced considering that surge arresters have to suppress various surge voltages and absorb their energies to protect the other equipments, even if the other surge suppressing equipments and device do not work well. The test sequence and test circuit are shown in Figure 3.6.5.

The primary purpose of switching surge duty test is to evaluate thermal stability of surge arrester at Uc after absorbing the switching surge energy. Switching surge duty test supposes the duty of the GIS-arrester at the receiving end of line, by resistor-closing failure of the circuit breaker. A circuit breaker connects between peak voltage of rated voltage of arresters on the line and rising voltage of reversed polarity of power source, and evaluates the thermal stability of arresters. That is, without resistors, considering the most severe cases. Figure 3.6.6 shows an example of the successful test record of this switching surge duty test.

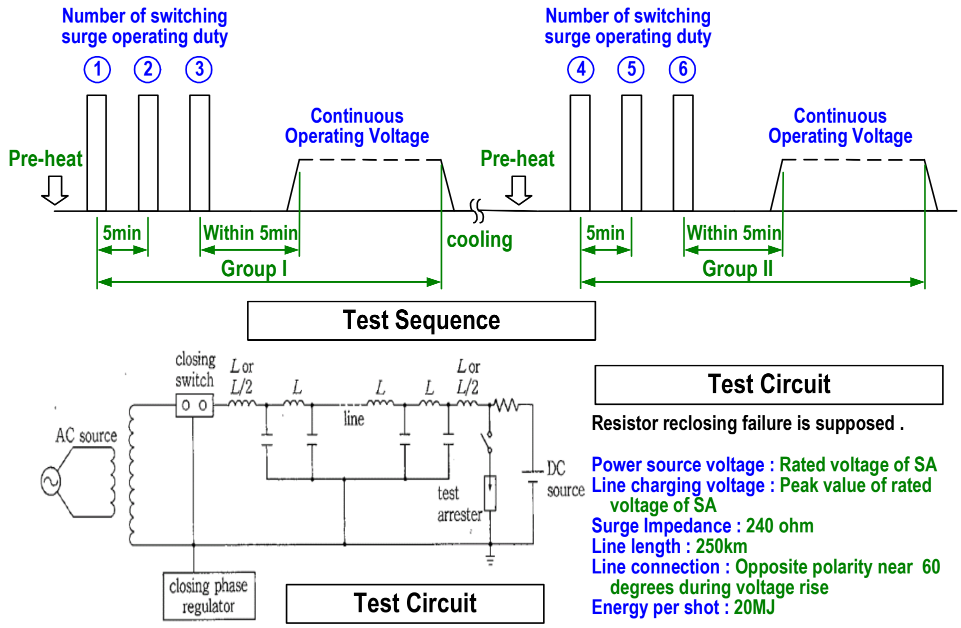


Fig. 3.6.5 *Switching Surge Duty Test according to Japanese Standards (JEC-217-1984)*

The above duties, tested in Japan, are considered as very severe. Besides, the existent test condition according to IEC [74] as shown in Table 3.6.4 seems necessary to be revised, because for the surge arrester of UHV system, the test conditions are more severe, considering the system characteristics such as low surge impedance and line lengths as also discussed earlier.

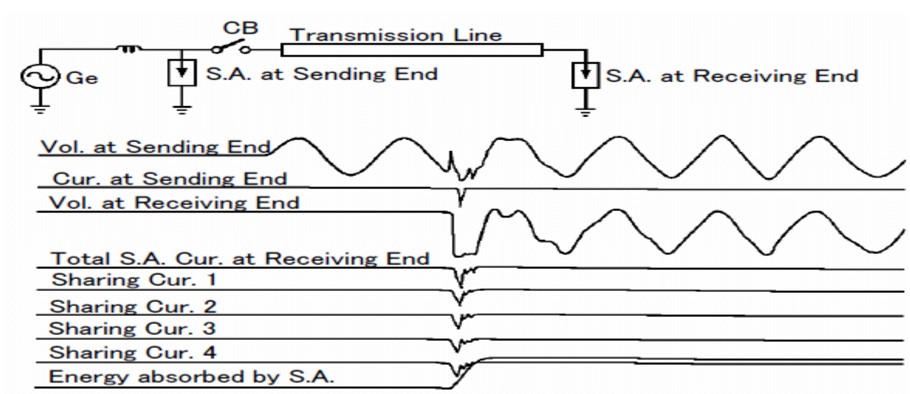


Fig. 3.6.6 *Typical Oscillograms of Switching Surge Duty Test*

Table 3.6.4 *Parameters for the line discharge test on 20000 A and 10000 A arresters (as per IEC 60099-4, [74])*

Arrester classification	Line discharge class	Surge impedance of the line Z (Ω)	Virtual duration of peak T (μs)	Charging voltage U_L (kv d.c.)
10 000 A	1	4,9 U_r	2 000	3,2 U_r
10 000 A	2	2,4 U_r	2 000	3,2 U_r
10 000 A	3	1,3 U_r	2 400	2,8 U_r
20 000 A	4	0,8 U_r	2 800	2,6 U_r
20 000 A	5	0,5 U_r	3 200	2,4 U_r

3.6.4 Lightning impulse discharge capability

The arrester energy from lightning may not be negligible either due to the high insulation strength of the transmission line connected to the substation. Taking the example above with a 4.5 MV full lightning surge with time to half-value on the tail equal to the median value for first negative stroke current of 77.5 µs this results in a discharge energy of approximately 2.4 MJ for an arrester with protection level of 1620 kV at 20 kA.

3.6.5 High current impulse withstand capability

The conditioning test in the standard with high current impulse of 100 kA 4/10 is more seen as a check of the insulation strength of the metal-oxide blocks and not as realistic current due to e.g. a close lightning stroke to the station. Such events must anyhow be avoided by proper shielding. Therefore, it is no need to introduce even higher current impulses for UHV applications than the existing 100 kA.

3.7 Radio Interference, Corona Losses

3.7.1 General Aspects

Radio-Interference (RI) and corona Audible-Noise (AN) are decisive factors for the design of the measures to suppress corona discharges. The practise for corona noise reduction is basically the same between each country; some differences of the conductor design of the line comes from:

- Target levels of RI and AN
- Location of evaluating point of RI and AN
- Required transmission capacity

Requirements for corona effects are mainly achieved by the configuration and design of multi-bundle conductors used in EHV and UHV systems. In fact, the corona noise will be reduced with an increase of the distance among phases, but it will be constrained by a limit for the OH line compaction degree.

In the following, some aspects concerning the evaluation of the parameters related with the corona effects (which includes 'radio interference', 'corona losses' and 'audible noise') are presented.

The **radio-interference-RI** field values can be assessed by empirical relationships with the main parameters of the installation, calibrated on the basis of the results of measurements performed on existing installations. As an example, the following expressions developed by CIGRE-IEEE (and then adopted by IEC-CISPR) can be used for pre-determining the RI field in the area surrounding the line:

$$\mathbf{E = -30 + 3.5\,E_{max} + 12\,r - 33\log D/20 + 5\,[1 - 2(\log 10\,f)^2] + h/300} \qquad (40)$$

Where,

E = RI field (dB/1µV/m)
E_{max} = electric field – max. value (kV/cm)
r = radius of the sub-conductor (cm)

D = distance from the line conductor (m)
f = frequency of the measurement (MHz)
h = height on the sea level (m)

Table 3.7.1 *RI levels calculated at the frequency of 0,5 MHz and at 15 m from the projection to ground of the lateral conductor bundle*

Line features			*RIV levels (dB/1µV/m)*		
Umax (kV)	***kV/cm***	***Conductor n/d/s***	***Dry***	***Light rainy***	***Heavy rainy***
765	14.9 (l) 16.1 (c)	6/31,5/450	43	60	67
1050	15.1 (l) 16.1 (c)	8/31,5/450	45	61	65

"l" = lateral phase; "c" = central phase; n = number of sub-conductors of the line bundle
d = conductor diameter (mm); s = sub-conductor section (mm^2)

The generation of RI noise is strongly affected by the atmospheric conditions, the geometric characteristics and the superficial conditions of the line conductors. Table 3.7.1 gives an example of the different RI values achievable under different weather conditions for different line geometries and maximum electric field E_{max} on the conductor surface.

The definition of the RIV limits to ensure the protection of the radio-TV broadcasts is covered by CISPR standards. In order to identify the limits the minimum signal level to protect is considered.

The definition of such a level falls under the competence of the national Authorities, depending on the characteristics of the installations and the environmental conditions of the involved regions. To this respect, the International Telecommunication Union - ITU has subdivided the world territory according to three regions (1, 2, 3) and each region under three climatic zones (A, B, C). For each of these zones the maximum level of noise naturally produced by the environment has been identified.

Corona losses in HV installations due to corona effect depend mainly on the characteristics of the conductor and on the electric field at its surface. Corona losses of a transmission line vary with the atmospheric conditions, ranging from about 0.5 to 1.0 kW/km for clean and dry conductors and some tens kW/km under heavy rain, snow or ice; under light rain, fog, dew condition intermediate values result. Considering that the atmospheric conditions triggering high losses levels generally exist for relatively short time periods, the corona losses of a line are on average low, one order lower than the ohmic ones. The highest values of the corona losses is anyhow an aspect to keep under control considering that corona losses in conjunction with the maximum line load require an additional availability of energy to supply.

Audible noise from corona effect is usually noticeable for electrical installations rated above 700 kV. The line conductors give a higher contribution compared of that of the substations where the design criteria of bus-bars and electrical components may keep the corona effect under control. The climatic and environmental conditions of the area crossed by the line may strongly affect the noise generated.

The highest audible noise levels are produced during heavy rain but in practise such a condition is not considered the most crucial as the noise resulting from the rain itself may generally prevail on the corona noise. As a consequence, the "wet" condition, i.e. during light rain, after rain, fog or dew, is considered the condition likely to produce the most disturbance.

Usually, measurements are performed in broad band employing the filter type "A" and the values are expressed in dB(A). Recommendations on how to evaluate the corona acoustic noise are given in ISO 1996-1, ISO 1996-2. [77],[78] Maximum tolerability levels of the acoustic noise are identified depending on the characteristics of the concerned area and the use of it.

Example of the different selected areas and the relevant Leq_{max} is given in Table 3.7.2. L_{eq} is increased by a 10 dB (A) when referred to the night time (from 10 p.m. to 7a.m.) in order to consider the higher physiological sensitivity people have in this time interval.

***Table 3.7.2** Maximum acoustic noise value allowed* for different areas of concern

Area classification	***Leq_{max} (dB(A))***	
	Daytime	Night
I - protected	40	50
II - residential	45	55
III - mixed	50	60
IV - human activity	55	65
V - mainly industrial	60	70
VI - exclusively industrial	70	70

3.7.2 Eskom 765 kV transmission line and impact of RIV, CL and AN on the conductor bundle design

Initial design studies in the early stages of the first Eskom 800 kV project (1979-80) indicated that because the lines will be located at altitudes greater than 1500 m above sea level, a 6 conductor bundle will have to be considered to limit corona effects, i.e. RIV, AN and corona losses CL.

Due to the uncertainties about air density correction factors to be applied to the AN, RIV and CL generated by line bundle conductors at this voltage level, Eskom built a high altitude corona cage to perform actual measurements relating to the mentioned corona parameters under dry and wet conditions. [79]

For AN, a design target of 53 dBA (L50 wet) at 800 kV at the servitude boundary and mid-span was selected. For RIV, experience based on the performance of 400 kV lines indicated that the design limit for 800 kV should be 72 dB at 0.5 MHz for the L_{50} wet condition.

Corona losses of a few tens kilowatts per phase were predicted for wet conditions.

The optimization studies for the selection of the conductor bundle were done for a horizontal line configuration and the following two possible bundles were considered.

6 x 400 mm^2 (conductor diameter = 28.81 mm)
4 x 800 mm^2 (conductor diameter = 38.1 mm)

The AN & RIV lateral distance profiles presented in Fig. 3.7.3 clearly show the better performance of the 6 x conductor bundle over the 4 x conductor bundle and confirm by measurement the validity of the initial design studies.

Corona Losses for centre phase, L_{50} under wet condition:

4 x Conductor = 70 kW/km/ph
6 x Conductor < 10 kW/km/ph

The final 6 conductor bundle used on both the first 436 km lines energized in 1987 was ZEBRA ACSR with diameter of 28.6 mm arranged in a bundle with diameter 640 mm.

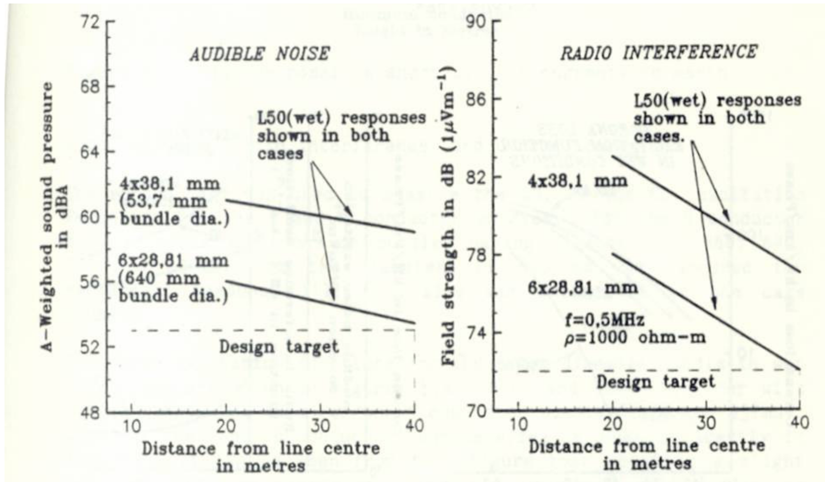


Fig. 3.7.3 *AN and RI lateral distance profile for a 765 line*

3.7.3 Italy's 1050 kV experience

3.7.3.1 Radio Interference

In the following, some results achieved on the 1000 kV line of Italy's Pilot Plant are presented.

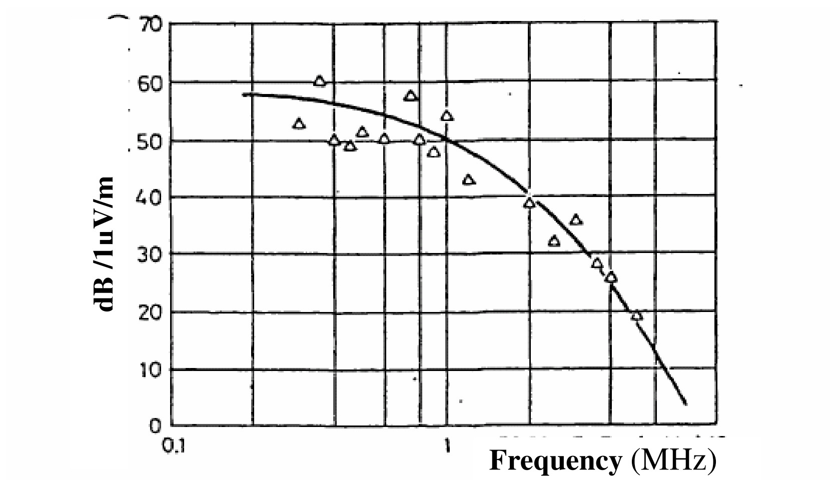


Fig. 3.7.4 *Frequency spectrum of the 1000 kV line – Italian Pilot Plant*
sub-conductor distance = 31.5 mm, Emax = 17.8 kV/cm *[80]*

Fig.3.7.4 shows the frequency spectrum measured at 20 m from the external phase. Fig. 3.7.5 shows the statistical distribution of the corona losses experienced under "dry" and rainy" weather, respectively. Fig. 3.7.6 shows the mean value of the corona losses versus the rain intensity, for the conductors bundle supplied at 730 kVrms and for two configurations, namely "symmetric" and "asymmetric" ($k_{asym.}$=1.5). The better behaviour of the asymmetric configuration finds justification considering that under rain conditions with it may be convenient to bring the lower sub-conductors nearer in order to reduce the electric field on their surface where the water drops more easily locate.

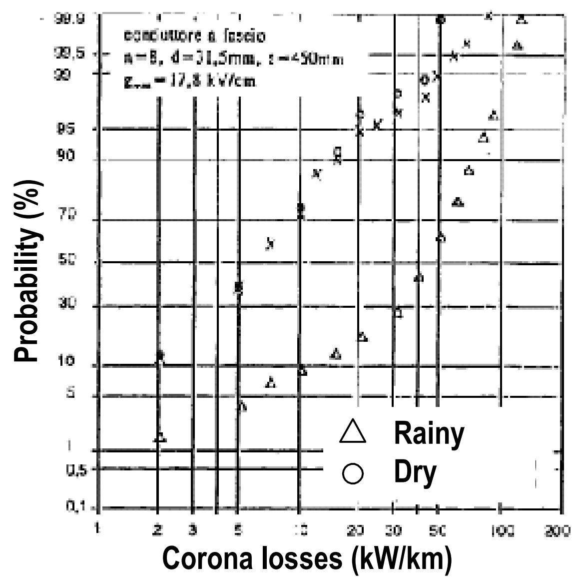


Fig. 3.7.5 *Corona losses for a bundle of 8 sub-conductors, d=31.5mm, s=450mm, E_{max}=17.8kV/m*

Fig. 3.7.7 shows the variation of the corona losses value as a function of maximum electric field on the conductor, under light ($\leq$ 0.03 mm/min) and heavy ($\geq$ 1mm/min) rain condition.

Fig. 3.7.8 shows the mean value of the "specific" corona losses, i.e. the losses (kW/km) referred to the squared value of the radius of the sub-conductors (cm^2) as a function of the mean value of the electric field. The curve of Fig. 3.7.8 was developed by ENEL on the basis of the results of several experimental investigations on the corona effects worldwide performed. It can be applied for an estimation of the losses in the limit of the electric field values of practical concern.

To the purpose of providing examples of applicable formula in the following the relationship developed by ENEL in the occasion of the research on the 1000 kV line for the Italian Pilot Plant and validated by the comparison with the results of measurement is presented. The losses Po (kW/km) can be evaluated according to the following formula a) or b) for the heavy rain conditions (value 95% of the distribution for the rainy time) or light rain (50%), respectively:

$\log P_o = 1.52 - 30 / E_{max} + 1{,}37 \log n + 2.3 \log d$ **a)** (41)

$\log P_o = 1.04 - 41 / E_{max} + 1{,}13 \log n + 3.8 \log d$ **b)** (42) where E_{max} = average of the maximum values of the electric field of the sub-conductors (kV/cm),

n = number of sub conductors, and d = diameter of the sub-conductor (cm)

3.7.3.2 Audible noise

In the following information is provided concerning:

The relationship of the corona audible noise versus the maximum electric field and the geometric characteristics of the bundle under light and heavy rain conditions. (Fig. 3.7.9)

The change of the audible noise amplitude versus rainfall for the conductors bundle in its symmetric and asymmetric (k=1.5) configuration. (Fig. 3.7.10)

Still, it should be considered that asymmetric conductors bundle or tubular conductors, even if good solutions in reducing audible corona noise, may present, in the UHV range, practical problems of realization (mechanical, related to vibrations, thermal).

Analytic formula for the audible noise have been identified on the basis of different experimental investigations. As an example of calculation shown in the note, the audible noise at 15m from the

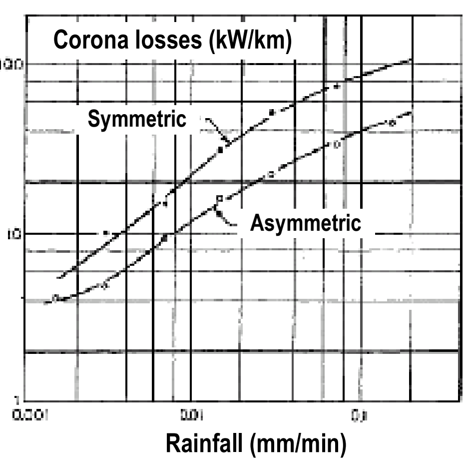


Fig. 3.7.6 *Corona losses vs rainfall intensity*

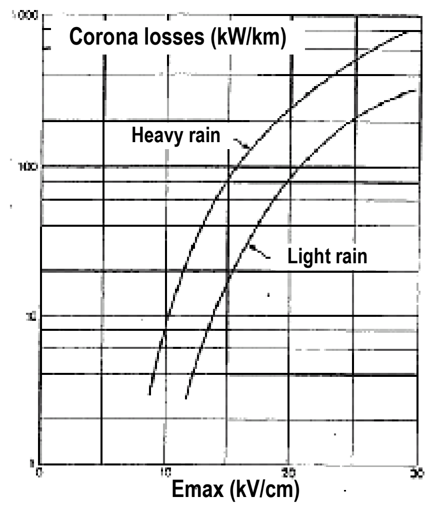


Fig. 3.7.7 *Corona losses vs max. electric field*

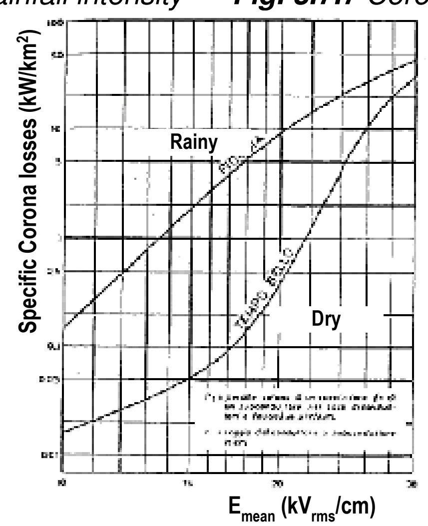
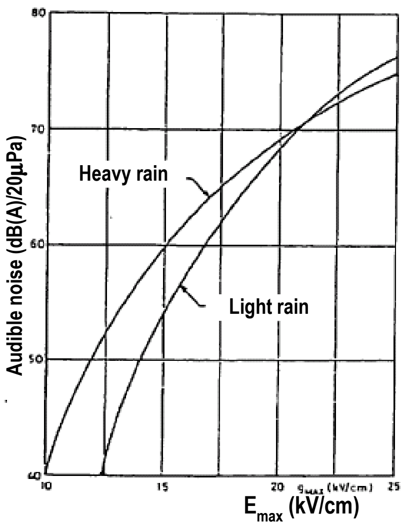


Fig. 3.7.8 *Specific corona losses vs the electric field on the conductor surface*

projection to ground of the lateral phase of the 1000 kV 8 bundle Dia.31.5 mm/450 mm conductors bundle submitted to an electric field of 17.76 kV/cm results as follows:

under light rain condition ($L_{50\%}$ value of the statistical distribution) = 54 dB(A)

under heavy rain condition ($L_{95\%}$ value of the statistical distribution) = 58 dB(A).



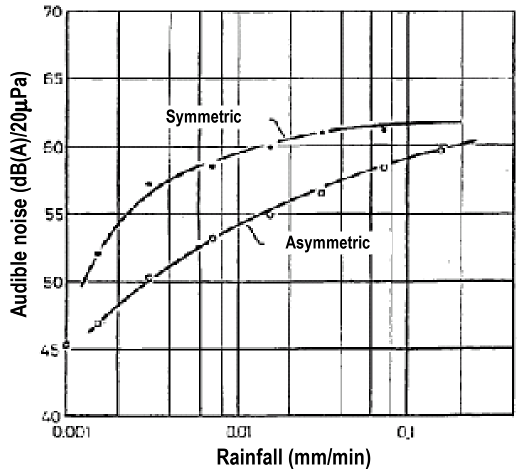


Fig. 3.7.9 *Audible noise versus rainfall*

Fig.3.7.10 *Audio noise rainfall*

Note: The empirical expressions for the acoustical noise (A), developed by ENEL during the investigations on the Italian 1000 kV Pilot Plant. The expressions are valid for lines featured by V ≥700 kV, n≥6, d=2 to 5 and installed at sea level; an increase of 3dB(A) should be considered each 1000m rise.

Heavy rain: $A=23-576/g_{max}+37\log(d)+10\log(n)$ (43)

Light rain: $A=30-863/g_{max}+57\log(d)+7\log(n)$ (44)

where:

g_{max} = mean value of the maximum electric field of the bundle conductors (kV_{rms}/cm)
n, d = number and diameter (cm) of the bundle conductors, respectively
D = distance of the measurement from the conductor (m)

3.7.4 TEPCO 1100 kV experience

3.7.4.1 Basic concept of corona noise reduction

The measure to reduce corona noise is one of the important design issues for UHV substations, especially AIS. Corona noise has two subjects. One is radio-interference (RI), which causes radio disturbance, and the other is corona audible-noise (AN).

In Japan, the regulation for RI in AM radio broadcasting band (526.5kHz–1606.5kHz) is relatively severe, and the government guideline requires to take some measures in case that the audience suffer with a SN ratio (Signal to Noise ratio) of less than 20dB(µV/m). Therefore, the design of transmission lines has been based on the SN ratio of 20dB(µV/m) or above.

On the other hand, the radio noise generated in a substation is not only emitted to its surrounding, but also propagates through the transmission line and then be emitted from the line. Accordingly, the countermeasure for corona noise of substations focused on RI, and its suppressed level is coordinated with that of transmission lines.

The design concept of UHV substations will be same as that of 550kV substations, which have a lot of AIS and have many field experiences of corona noise reduction.

3.7.4.2 550kV substation

The radio-interference electric field intensity right below the 550kV double-circuit transmission line (4-bundle conductors with ACSR410mm^2) in rain condition is around 60 dB (μV/m). Accordingly, the allowable RI level of substations has been set for 60 dB (μV/m).

With regard to the AN of substations, disturbances have not been caused up to now because corona discharges are suppressed from the RI requirement, and no special considerations have been taken.

3.7.4.3 UHV (1100kV) substation

Since UHV substations adopt fill-GIS, the countermeasure will be limited to the entrance of transmission lines. The RI level of UHV transmission lines are around 60 dB (μV/m), thus 60 dB (μV/m) will be adopted as the allowable RI level of UHV substations same as the 550 kV. The entrance of UHV Test station (Fig.3.7.11) was designed to satisfy this level.

With regard to AN, it was observed in the UHV Test Station as shown Fig.3.7.12, and considered in the conductor design of transmission lines as followings. However, no special considerations in substations will be taken because the noise from transformers caused by magnetic vibration of iron core is predominant.

Fig.3.7.11 *Entrance of UHV Test station*

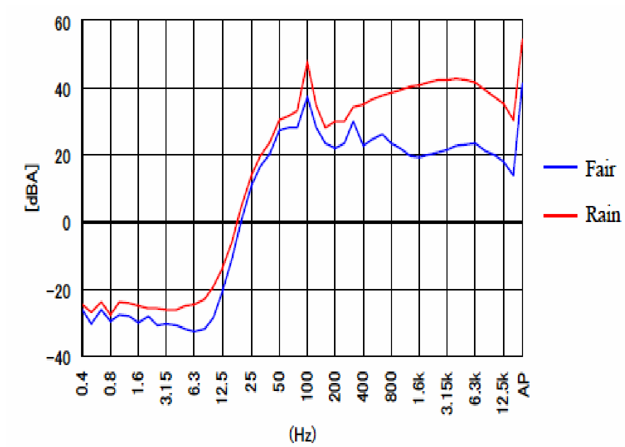


Fig.3.7.12 *Frequency analysis result of audible-noise measured at the entrance of UHV Test Station* ***(Applied voltage is 664kV=1100kV/$\sqrt{3}$ x 1.046)***

3.7.4.3.1 Conductor design of UHV transmission line

For UHV transmission lines, 8-bundle conductors with 810 mm^2 ACSR have been adopted (partially 8-bundle conductors with 610mm^2 are adopted in mountainous area).

These designs were determined taking into consideration not only RI but also AN, because they become a predominant factor of corona disturbances when the system voltage increases.

The AN of 550 kV transmission lines which have long-term operating experiences is around 50 dB (A), and problems have not been caused. On the other hand, complaints have been generated in overseas transmission lines with about 55 dB (A).

Therefore the allowable level for UHV transmission lines was determined to be 50 dB (A) or below in light rain condition in the vicinity right under the transmission lines.

Although random-noise is predominant in AN, corona-hum-noise (pure sound; with power frequency component and even-number multiple component of power frequency) was also reduced as much as possible, because such noises often cause discomfort once it is perceived.

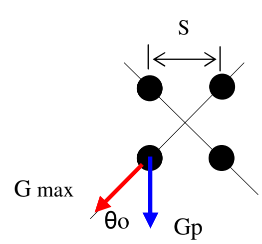
***Table 3.7.3** Estimated values of corona noise of UHV and EHV transmission line*

		550 kV	1100 kV	Reference
Circuit		Double-circuit	Double-circuit	Sub-conductor distance; 40 cm, symmetric configuration
Conductor		410 mm^2x4	810 mm^2x8	
G_{max}		15.5 kV_{rms}/cm	14.2 kV_{rms}/cm	At 1.0E (maximum voltage/$\sqrt{3}$)
G_p		14.9 kV_{rms}/cm	14.0 kV_{rms}/cm	
RI		61 dB (μV/m)	60 dB (μV/m)	Under heavy rain condition
AN	Random-noise	48 dB (A)	45 dB (A) [49 dB (A)]	Under light rain condition (L_{50} value of the statistical distribution, rainfall; 0.5 mm /hour)
	Corona-hum-noise	-	34 dB (A) [38 dB (A)]	

Note: G_{max} is the maximum electric field on conductor surface, and G_p is that in the bottom of conductor where water droplets are formed at rain condition and from which corona is mainly generated. These values show roughly calculated ones from the following approximate equations that assume complete three-phase transposition.

$$G_{max} = \frac{V\left\{1+\frac{r}{S}\cdot 2(n-1)\cdot \sin\frac{\pi}{n}\right\}}{n\cdot r\cdot \ln\left(\frac{D}{r_e}\right)} \quad ....(45)$$

$$G_p = \frac{V\left\{1+\frac{r}{S}\cdot 2(n-1)\cdot \sin\frac{\pi}{n}\cdot \cos\theta_0\right\}}{n\cdot r\cdot \ln\left(\frac{D}{r_e}\right)} \quad ....(46)$$



where,

V: Applied voltage to earth, n: Number of sub-conductors of the bundle,
S: Sub-conductor distance, D: Phase to phase distance,
r: Radius of sub-conductor, r_e: Equivalent radius of the bundle

$$r_e = \sqrt[n]{n\cdot r\cdot \left\{\frac{S}{2\cdot \sin\left(\frac{\pi}{n}\right)}\right\}^{n-1}} \quad .... (47)$$

Even under the same electric field, as the diameter and number of conductor increase, corona discharge tends to extend more easily, thus both RI and AN will also increase.

AN values are estimated ones based on actual measurement data obtained from a corona cage in the Central Research Institute of Electric Power Industry (CRIEPI) in Japan. The values enclosed in parentheses refer to noise values when spiral wires are wound around those conductors to prevent wind noise. [81]

3.7.4.3.2 *Practical design of substation equipment*

For bus-bar designs, minimum conductor size and number of conductors are determined to meet the RI level of 60 dB (μV/m) under rain condition. Regarding substation equipments and insulators, to suppress corona noise below that of busbar by an appropriate arrangement of shielding-rings is a fundamental practise. In actual design, corona noise level varies depending on the structure of connections with conductors. Therefore, the corona tests as shown in Table 3.7.4 are often performed though it is not standardized in Japan. [82]

The equipments of UHV Test Station such as gas bushing, V-shaped suspension insulator were designed to satisfy the corona test's requirement and verified at manufacturer's test site before shipment.

Table 3.7.4 *Typical procedures of corona test for substation equipment*

Test item	Condition	Test voltage	Allowable level
Visual corona test	Dry	1.2E (to earth)	There should be no apparent visual corona or audible-noise
RIV (Radio-Interference - Voltage) measurement test	Wet	1.0E (to earth)	RIV: 90 dB (μV) or below

**** 1.0E = Maximum voltage/$\sqrt{3}$***
***** RIV is measured by the following circuit.***

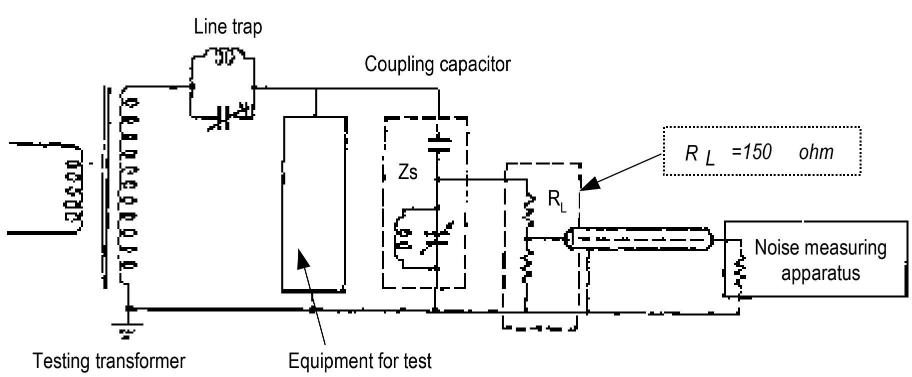


Fig.3.7.5 *Basic circuit of RIV (Radio-Interference-Voltage) measurement (NEMA Standard [80])*

Note

[1] Test voltage

Test voltage of the visual corona test is set to be 1.2 E, considering,

(1) Single phase test is conducted, and as the result, potential gradient on the conductor surface considered to be less than that of 3-phase arrangement

(2) Actual operating conditions (effect of relative air density, etc.)

The radio-interference voltage measurement test is carried out under wet conditions.

Since 1.2 E is too-strict requirement, 1.0 E is adopted. This level was determined through experiences considering that it would be appropriate to comprehensively evaluate by both test of visual corona and radio-interference.

[2] Allowable level of RIV (Radio-Interference-Voltage)

The RI level of transmission lines is expressed by radio-interference electric field intensity dB (μV/m). On the other hand, RIV is measured in dB (μV) for substation equipment usually. The difference between radio-interference electric field intensity and RIV is approximately 30dB from various test data on transmission lines. Consequently, the allowable level for RIV can be determined to be 90 dB (μV) by adding 30 dB to 60 dB (μV/m) that is above-mentioned RI level.

3.7.5 BPA 1200 kV experience

At the end of the seventies (1977-1978) BPA performed long-term measurements in the 10 km joint right-of-way of the three-phase 8x41 mm 1200 kV prototype line and the single-phase 2x41 mm 500 kV line running parallel, with the aim, among others, of assessing the long-term electrical and corona performance of UHV transmission systems and comparing the performance of the two line configurations at the RI, AN and television interference in roughly the same weather and over the same time period.

Table 3.7.5 gives a synthesis of the major values achieved (with all levels corrected to single circuit).

For further comparison, estimated values for two other single-circuits BPA-500 kV line configurations are given. The ozone concentration was measured. No increase was detected that could be attributed to the corona on the conductors.

Table 3.7.5 *Corona effects quantification*

System voltage (kV)	1200	500		
Operating voltage (kV)	1150	525		
Sub-cond. bundle n, Φ (mm)	4 x 41	2 x 41	1 x 63.5	3 x 33.1
Electric field[I] (kV/m)	7.3	7.3	6.7	8.5
RI (dB /1μV/m) [II]				
dry	46	52.5	61	46
rainy	65	70	81	68
AN dB(A) [III]	53	56.5	62,5	46
TV interf. (dB /1μV/m) [IV]	13	7.3	6.7	8.5

I max. value at midspan
II quasi-peak L50 level measured 15m from outside phase, CISPR Meter, 0.5 MHz
III weighted L50 levels measured respectively at 15m from outside phase
IV quasi-peak L50 level measured 40m from outside phase, CISPR Meter, 75 MHz

Additional specific remarks are as follows.

3.7.5.1 Radio Interference

With the line energized at 1200 kV the values were 48 dB and 67 dB under dry and rainy condition, respectively.

At the operating voltage of 1150 kV and 525 kV the 8x41mm line produced the same RI levels as the 3x33.1mm 500 kV configurations, and is about 6 dB and 15 dB quieter than the 2x41mm and 1x63.5mm configuration, respectively.

3.7.5.2 Audible noise

With the line energized at 1200 kV under rainy weather the levels measured at 15 m and 150 m from the lateral phase were 55 dB and 47 dB, respectively.

The level at 1100 kV was 4.5 dB lower than that at 1200 kV.

Under rainy weather, the level of the1200 kV line operating at its full voltage was 5 dB quieter than the twin 2x41mm 500 kV line operating at 540 kV.

The single 1x63.5 mm and 3x33.1 mm 500 kV lines operating at 525 kV were 7.5 dB noisier and 9dB quieter, respectively, than the 1200 kV line operating at its full voltage.

At 1150 kV, the 1200 kV 8x41 mm line was 7 dB noisier, 3.5 dB quieter and 9.5 dB quieter than the 3x33.1 mm, 2x41mm and 1x63.5mm 500 kV lines, respectively, operating at 525 kV.

3.7.5.3 Electric Field

With the 1200 kV line energized at its full voltage, the maximum electric field measured 1m above ground at mid-span was 7.6 kV/m for a line clearance of about 24.4 m.

Electric field strengths and associated effects (such as short-circuit currents on vehicles and fences) were nearly the same as those found under 500 kV lines with equivalent electric fields.

Due to increased clearances required for 1200 kV to keep the same maximum electric field from 500 kV lines, the attenuation rate for the 1200 kV line must be less than 500 kV lines.

3.7.5.4 TV interference

With the line energized at 1200 kV under rainy weather and the antenna at 40 m from the outside phase the L50 TVI levels at 75 MHz for Peak, Quasi-peak and Field Intensity measurements were 28 dB, 15 dB and –2 dB, respectively.

Under rainy weather the 1200 kV line was 13 dB, 19 dB and 9 dB quieter than the twin 2x41mm, the single 1x63.5mm and the single 1x33.3 mm 500 kV line, respectively.

3.7.6 Russian 1150 kV experience

Designing the 750 and 1150 kV lines was preceded by measurements of corona losses and TV-, radio- and audible noises on experimental short prototype lines and then was followed by field measurements on erected lines in operation. [71] The maximum gradient on conductor surface in 1150 kV bundle has not to exceed 90% of starting gradient of total corona, thus providing some margin for possible voltage increase over rated one, lower position of the conductors in the mid-span and reduced air density on altitudes up to 500 m. Radio noise at 100 m from the line was prescribed in levels of 48-30 dB for frequencies, respectively, from 0.15 MHz going up to 1000 MHz. Acoustic noise at distance 300 m has not to exceed 55 dB (A) during daytime and 45 dB (A) at night.

On bundled phases of 750 and especially 1150 kV lines corona losses in bad weather could be very high. As an effective measure to reduce them a temporary reduction of operating voltage was recommended. As an adviser to Interconnected pool dispatchers a system of on-line monitoring corona losses was developed and put in operation on several 750 kV lines.

References

[1] J. Takami, S. Okabo, “Observational Results of Lightning Current in Transmission, Towers”, IEEE-PD, Vol.22, No.1, Jan ’07, pp. 547-556

[2] Gu Dingxie, et al., “Study on Overvoltage and Insulation Coordination for 1000 kV AC Transmission System”, International Conference of UHV Transmission Technology 2006, Beijing, ACTECH037

[3] CIGRÉ Technical Brochure 336, December 2007, “Changing Network Conditions and System Requirements, Part II The impact of long distance transmission”, CIGRE WG A3.13

[4] A. Mercier, et al., “Transformer Controlled Switching taking into account the Core Residual Flux”, CIGRÉ SC 13 Session 2002, Report 13-201

[5] A.K. Lohkanin, V.S. Rashkes, et al., “Temporary Overvoltages and their Influence upon the Insulation Level of Equipment”, CIGRÉ SC 33 Session 1990, Report 33-209

[6] “Electric power transmission at voltages of 1000 kV AC or ± 600 kV Dc and above”, Électra 122, pp. 41-75,

[7] Lin Jiming, et al., “Limitation of overvoltages in 1000 kV pilot project in China”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-1-3

[8] A.L.J. Janssen, et al., “Changing Network Conditions and System Requirements – Studies performed by CIGRÉ WG A3.13”, CIGRE SC A3 Colloquium 2007, Rio de Janeiro, Report PS 2-1

[9] E. Zaima, et al., “System Aspects of 1100 kV AC Transmission Technologies in Japan: Solutions for Network Problems Specific to UHV AC Transmission System and Insulation Coordination”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-1-2

[10] C. Neumann, C. Weck , “Planning of UHV systems with respect to insulation coordination based on CIGRE experience”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-1-1

[11] E, Zaima, et al., “System Design and Insulation Coordination for UHV Transmission System in TEPCO”, International Conference of UHV Transmission Technology 2006, Beijing, ACTECH006

[12] Du Shuchun, et al., “Study on Insulation Coordination for 1000 kV UHV AC Transmission System”, International Conference of UHV Transmission Technology 2006, Beijing, ACTECH007

[13] CIGRÉ Technical Brochure 85 (1994), “UHV Technology”

[14] K.-H. Weck, “Standardization of insulation withstand levels for UHV systems in IEC TC 28, Insulation coordination”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 5-4

[15] Bao-jiu Li, et al., “Study on main design principles for 1000 kV AC substation”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-3-1

[16] IEC Standard 60071-1 Insulation Coordination, Part 1: definitions, principles, rules

[17] IEC Standard 60071-2 Insulation Coordination, Part 2: application guide

[18] Liangeng Ban, "Estimation of VFTO for GIS and HGIS of China 1100 kV UHV pilot project and suppressing countermeasures", IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-3-4

[19] R. Hemmi, et al., "Evaluation of VFTO and Its Reduction…", International Conference of UHV Transmission Technology 2006, Beijing, ACMAN008

[20] Y. Yamagata, et al., "Phase-to-Ground and Phase-to-Phase Sparkover Characteristics of Insulation at the Entrance of UHV Substation" IEEE Transaction Power Delivery, Vol.17, No.1 (2001)

[21] Y. Yamagata et al., "Development of 1100 kV gas circuit breakers and their verification tests", IEC/CIGRE UHV Symposium 2007, Report 2-4-3

[22] H. Hamada et al., "Severe duties on high-voltage circuit breakers observed in recent power systems", CIGRE Session 2002, 13-103

[23] IEC 62271-100 "High-voltage switchgear and controlgear – Part 100: High-voltage alternating-current circuit-breakers", Edition 1.2, October 2006

[24] Lin Jiming,et al., "The Transient Characteristics of 1100 kV Circuit Breakers", IEC/CIGRE UHV Symposium Beijing July 2007, 2-4-4

[25] CIGRE WG A3.22, "Technical Requirements for Substation Equipment exceeding 800kV", CIGRE Session 2008, A3-211 (to be published)

[26] IEEE C37-06-200x, Draft: Standard AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis - Preferred Ratings and Related Required Capabilities for Voltages above 1000 Volts (under discussing)

[27] D. D. Wilson, "Series compensated lines-voltages across the circuit breakers and terminals caused by switching", IEEE Transactions on Power Apparatus and Systems, Vol. PAS-73, pp. 1050-56, May-June 1973.

[28] F. ILICETO et al., "TRVs across Circuit breakers of series compensated line. Status with present technology and analysis for the Turkish 420 kV grid", IEEE Transactions on Power delivery, Vol. 7, No. 2, April 1992

[29] F. ILICETO et al., "TRVs across Circuit breakers of series compensated lines. Analysis, design and operation experience in the 420 kV Turkish Grid", CIGRE Session 2002, 13-109

[30] B.L. Avent et al., "Application of 500 kV circuit breakers on transmission line with MOV protected series capacitor banks", CIGRE Session 2002, 13-107

[31] Khodabachian et al., "TRV and the non-zero phenomenon in Hydro-Québec's projected series-compensated system" CIGRE Session 1992, 13-303

[32] Holmberg et al., "The Stöde Thyristor Controlled Series Capacitors", CIGRE Session 1998, 14-105

[33] J. Redlund et al., "A new fast protective device for high voltage series capacitors", IEEE No 1, pp.4244-0493, 2006

[34] Bui Van et al., "Control of switching Overvoltages and Transient Recovery Voltages for Hydro-Québec 735 kV Series compensated Transmission System", IPST'07, June 4-7, 2007

[35] WG 13.01, “Surge impedance of overhead lines with bundle conductors during short-line faults”, ELECTRA 17, April 1971

[36] T. Shimato et al., “Evaluation of interruption capability of gas circuit breakers on large time constants of DC component of fault current”, CIGRE session 2002, 13-104

[37] CIGRE Technical brochure No.304, Guide for application of IEC 62271-100 and IEC 62271-1, October 2006

[38] William D. Stevenson, Jr., “Elements of Power System Analysis”, 2nd edition, McGraw-Hill Book Company, Inc.

[39] CIGRE WG A3.22, IEC/CIGRE UHV Symposium 2007, Beijing, Report 4-1

[40] E. Colombo, et al., “Testing Challenges for UHV equipment”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 4-1

[41] Lin Jiming, et al., “The Transient Characteristics of 1100 kV Circuit Breakers”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-4-4

[42] A.L.J. Janssen et al., “Changing Network Conditions and System Requirements – Studies performed by CIGRÉ WG A3.13”, CIGRE SC A3 Colloquium 2007, Rio de Janeiro, Report PS 2-1

[43] CIGRE WG A3.13, “Changing Network Conditions and System Requirements, Part II The impact of long distance transmission”, CIGRÉ Technical Brochure 336, December 2007

[44] CIGRE Technical Brochure 305 “Guide for application of IEC 62271-100 and IEC 62271-1 – Part 2 : Making and breaking tests”. October 2006.

[45] IEC 62271-110, Edition 1: High-voltage switchgear and controlgear – Part 110: Inductive Load Switching, 2005

[46] CIGRE WG13.07, “Controlled Switching of HVAC Circuit Breakers: Guide for Application”, Part 1: ELECTRA No.183, pp.43-73, Part 2: ELECTRA No.185, pp.37-57, 1999

[47] IEC 62271-110, High-voltage alternating current circuit-breakers - Inductive load switching

[48] E. Zaima et al., “Reignition surges at reactor current interruption in cable-system GIS”, IEEE Tr .on Power Delivery Vol.5, No.2, pp.947-, 1990

[49] C. V. D. Merwe., “On site switching test conducted in a 765kV GIS”, Six international symposium on high voltage engineering, New Orleans LA, USA 32-28, 1989

[50] J.A. Bachiller, et al., "The Operation of Shunt Reactors in the Spanish 400 kV Network - Study of the Suitability of Different Circuit Breakers and Possible Solution to Observed Problems", CIGRE Session 1994, 23-106

[51] Gu Dingxie, et al., "Study on Overvoltage and Insulation Coordination for 1000 kV AC Transmission System", International Conference of UHV Power Transmission Technology, 2006

[52] CIGRE WG13.07, “Controlled Switching of HVAC Circuit Breakers: Planning, Specification and Testing of controlled switching systems”, ELECTRA, No.197, pp.23-733, 2001

[53] A. Mercier, et al., CIGRE 2002 Session 13-201, “Transformer Controlled Switching Taking into Account the Residual Flux”

[54] H. Ito, et al., CIGRE 2005 Colloquium A3&B3-209, “Application of Controlled Switching System for Transformer Energization taking into account a Residual Flux in Transformer Core”

[55] Fröhlich, et al., “Controlled closing on shunt reactor compensated transmission lines”, Power Delivery, IEEE Transactions on Volume 12, April 1997, pp.734–740

[56] B. L. Avent, et al., CIGRE 2002 Session 13-107, “Application of 500kV Circuit Breakers on Transmission Line with MOV Protected Series Capacitor Bank”

[57] T. Kobayashi, et al., "Application of Controlled Switching to 500 kV Shunt Reactor Current Interruption", IEEE Transactions on Power Delivery, Vol. 18, No. 2, April 2003

[58] Hayward, C. D., "Prolonged inrush currents with parallel transformers affect differential relaying", AIEE Trans., Vol. 60, pp. 1096-1101, Jan. 1941

[59] Bronzeado, H. S. and Yacamini, R., “Phenomenon of sympathetic interaction between transformers caused by inrush current”, IEE Proc. Science, Measurements and Technologies, Vol. 142, No. 4, July 1995

[60] P. Fernandez, et al., CIGRE 2005 Tokyo Colloquium A3&B3-208 “Use of controlled switching system in power system to mitigate transients. Brazilian experience”

[61] IEC 62271-102: High-voltage switchgear and controlgear - Part 102 Alternating current disconnectors and earthing switches

[62] IEC 62271-xxx, TR (future publication): Capacitive current switching capability of disconnectors

[63] D.F. Peelo, R.P.P. Smeets, S. Kuivenhoven and J. Krone, “Capacitive Current Interruption in Atmospheric Air.” Paper No. 106, CIGRE SC A3 and B3 Joint Colloquium, Tokyo 2005

[64] L. Stenström, “Calculation of required insulation withstand voltages for UHV systems per IEC procedure.” IWD A3-07 (WG22) 132

[65] G. Dingxie, Z. Peihong, X. Muhong, W. Sen, D. Min and L. Ying, “Study on Overvoltage and Insulation Coordination for 1000 kV AC Transmission System.” International Conference of UHV Power Transmission Technology, 2006

[66] T. Kobayashi, et al, Basic design/specifications of GIS for UHV AC and its verification test at site, IEC/CIGRE UHV Symposium Beijing 18-21 July 2007, Session 2-3-3

[67] Y. Yamagata, et al, “Field test of 1000kV gas insulated switchgear”, CIGRE Session 2000, 13-209

[68] R. Hemmi, et al, Evaluation of VFTO and its reduction by parallel resistor during switching operation of disconnecting switch in future UHV gas insulated substation, UHV seminar, pp. 460-466, China 2006

[69] Ban Liangeng, et al, Research on VFTO for 1000 kV UHV GIS of China, UHV seminar, pp. 250-257, China 2006

[70] JEC 2310-2003: AC Disconnectors

[71] N.N. Belyakov, et. al., “Application of single-phase auto-reclosing in a complex EHV network containing 1200 kV transmission lines”, CIGRE Session 1990, Paper 34-207

[72] Y. Goda et al., “Insulation Recovery Time after Fault Arc Interruption for Rapid Auto-reclosing on UHV (1000kV Class) Transmission Lines,” IEEE Transactions on Power Delivery, Vol. 10, No. 2, April 1995

[73] K. Sunabe and T. Inaba, “Recovery Characteristics after the Interruption of Fault Arcs in UHV-DC Transmission Lines”, T. IEE Japan, Vol. 110-B, No.2, p.138-146, 1990

[74] IEC 60099-4, Edition 2.1, 2006-07 “Metal-oxide surge arresters without gaps for a.c. systems”

[75] China 2006, ACTECH006, ”Study on Insulation Coordination in 1000kV UHV AC Transmission Project”

[76] China 2006, ACTECH007, ”Study on Overvoltage and Insulation Coordination for 1000 kV AC Transmission System”

[77] ISO1996-1, 2003 Acoustics – Description, measurement and assessment of environmental noise – Part 1: Basic quantities and assessment procedures

[78] ISO 1996-2, 2007 Acoustics – Description, measurement and assessment of environmental noise – Part 2: Determination of environmental noise levels

[79] AC Britten et al, “Radio interference, Corona losses, Audible noise and Power Frequency Electric Fields as factors in the design of Escom’s 765 kV lines”, CIGRE Open Conference on EHV Transmission Systems, October 1987, South Africa, No 3

[80] NEMA, “Method of Measurement of Radio Influence Voltage [RIV] of High-Voltage Apparatus”

[81] Y.Sawada, et al., “Akagi 1000kV project in CRIEPI – Corona test facilities and results up to 1983” CIGRE Session 1984, 36-05

[82] M.Isozaki et al., “Special design and arrangements on UHV AC conductors and subconductors taking reduction of environmental impact into consideration”, IEC/CIGRE UHV Symposium 2007, Beijing, Report 2-2-4

4 Technical Specifications of 800 kV Substation Equipment

4.1 800 kV Power Transformers

The 800 kV transmission systems have been adopted in several countries including Canada, the United States, Brazil, Venezuela, South Africa, Korea, China and India. Table 4.1.1 lists the main specifications for 800 kV class power transformers that have been investigated to date through ongoing surveys.

Table 4.1.1 *Major items for 800 kV power transformers (for substation)*

Item	Specification
Country	Canada, USA, Brazil, Venezuela, Korea, China, India, etc.
Utility	HQ, AEP, NPA, FURNAS, EDELCA, KEPCO, SGCC, PG, etc.
Type	Auto-transformer
Phase	Single
Rated Voltage (kV)	$735/\sqrt{3}$, $765/\sqrt{3}$, etc.
Insulation strength: BIL (kV)	1950, 2050
Rated Power (MVA)	1000/3, 1500/3, 1650/3, 2000/3, etc.
Short circuit impedance (%)	10.6, 14, 15, 18, etc
Cooling	OFAF, ODAF, etc
Sound level dB (A)	80, 83, 85, 91, etc

Additional information is given in Table 4.1.2, which lists detailed specifications for a KEPCO project as an example

Table 4.1.2 *Detail specification of power transformers in KEPCO project*

<table>
<tr><th colspan="2">Classification</th><th colspan="3">765 kV Transformers</th></tr>
<tr><td colspan="2">Type</td><td colspan="3">Single phase auto-transformer (2 divided tanks)</td></tr>
<tr><td colspan="2">Rated voltage</td><td colspan="3">$765/\sqrt{3}$ / $345/\sqrt{3}$ / 23kV</td></tr>
<tr><td rowspan="2">Rated capacity</td><td>Single phase</td><td>400 (200x2)</td><td>520 (260x2)</td><td>666.7 (333.35x2)</td></tr>
<tr><td>Three phases</td><td>1,200</td><td>1,560</td><td>2,000</td></tr>
<tr><td colspan="2">Cooling method</td><td>FOA1</td><td>FOA2</td><td>FOA3</td></tr>
<tr><td colspan="2">Cooling system</td><td colspan="3">Cooler type
(self-cooling function : no)</td></tr>
<tr><td colspan="2">Insulation strength (BIL)
(BSL)</td><td colspan="3">2,050 kV
1,500 kV</td></tr>
<tr><td colspan="2">Short circuit impedance</td><td colspan="3">18 percents</td></tr>
<tr><td rowspan="4">OLTC</td><td>Amplitude of voltage regulating</td><td colspan="3">+-7 percents</td></tr>
<tr><td>Voltage regulating type</td><td colspan="3">OLTC (VFVV type)</td></tr>
<tr><td>Tap position</td><td colspan="3">Common winding (neutral point side)</td></tr>
<tr><td>Number of tap</td><td colspan="3">23 (including rated voltage tap)</td></tr>
<tr><td colspan="2">Bushing type (BIL)</td><td colspan="3">Oil-Gas bushing
(Enclosed type) (2,050 kV)</td></tr>
<tr><td colspan="2">Connection of equipment</td><td colspan="3">GIB</td></tr>
<tr><td colspan="2">Noise level</td><td colspan="3">85 dB</td></tr>
<tr><td colspan="2">Preventive diagnosis system</td><td colspan="3">Yes</td></tr>
</table>

The main points obtained from the survey results are as follows: The transformers range from 1000 to 2000 MVA in bank capacity, which is very large compared with that for 500 kV class transformers. The main type of cooling applied is either OFAF (forced) or ODAF (direct), and is a major characteristic of large-capacity transformers. Although not indicated in the table, some transformers are equipped with an on-load tap changer on the neutral-point side of the windings. So, another feature of very high voltage transformers is on-load tap changers.

4.2 800 kV Voltage Transformers (VT), Current Transformers (CT)

4.2.1 800 kV VTs

Table 4.2.1 lists the technical specifications of 800 kV class voltage transformers adopted in South Africa, Canada, Russia, Korea and China, obtained from the world survey conducted by CIGRE WG A3.22. Inductive- and capacitive-type VTs are applied to 800 kV systems. VT specifications are unique compared to those for other equipment because they include rated secondary voltage, accuracy, and burden. Secondary voltage ranges from 110/$\sqrt{3}$ to 100 V, similar to that in the 500 kV specifications. Accuracy ranges from 0.2 to 1.2% for measuring applications and 3 to 6% for protection applications.

Table 4.2.1 *Specifications for 800 kV VT*

Country (Nominal voltage)	South Africa (765kV)	Canada (735kV)	Russia (750kV)	Korea (765kV)	China (765kV)
Classification	Conventional ITs	Conventional ITs	Conventional ITs	Conventional ITs	Conventional ITs
Type	Inductive type	Capacitive type *In case of large network automatism, inductive type is required*	Inductive type	Inductive type	Inductive type
Standard	BS3941 (1975)	CSA CAN3-C13.1	Russian standard	IEC186 (1996)	IEC60044-2
Lightning impulse voltage	2100kV	2100 kV, 2310 kV for chopped wave	2100kV with GSOA, 1950kV with MOV	2250kV	2100kV
Switching impulse voltage	NA	1550 kV	1550kV with GSOA, 1425kV with MOV	1425kV	1550kV
Power-frequency voltage	960kV	830 kV	950kV with GSOA, 830kV with MOV	975kV	975kV
Rated primary voltage	$765kV/\sqrt{3}$	$765kV/\sqrt{3}$	$750kV/\sqrt{3}$	$765kV/\sqrt{3}$	$765kV/\sqrt{3}$
Rated secondary voltage	$110kV/\sqrt{3}$	$120kV/\sqrt{3}$	100V	115-$115kV/\sqrt{3}$	$100kV/\sqrt{3}$, 100V
Rated burden	50/50VA	200 VA	300VA/200VA/1000VA	200/200VA	50/50/50VA
Accuracy class	0.2/0.2	0.6 WXY 1.2Z (for measuring), 3PZ (for protection purpose 5 to 120%), 6PZ for U >150%	0.5% / 0.2% / 3%	1.0/3P	0.2/0.5&3P/3P
Temperature characteristics	NA	-50 to 40 degree Celsius ambient temperature	NA	NA	NA
Voltage Factor	1.2/Continuous	-	-	1.2/Continuous, 1.5/30S	1.5/30S
Service Experience (including on-site experience)	23 years	40 years	-	5 years	Manufactured in 2007

4.2.2 800 kV CTs

Table 4.2.2 lists the technical specifications of 800 kV class current transformers in South Africa, Canada, Russia and Korea. All CTs are the iron core type. CT specifications are unique compared to those for other equipment because they include rated secondary current, accuracy, burden, excitation characteristics and transient characteristics. The rated secondary current is generally specified as 1 A. Accuracy ranges from 0.2 to 1.2% for measuring applications and 1% for protection applications. CTs used for protection applications are classified into two types with specified excitation characteristics or specified transient characteristics. The rated short-circuit current is 40 to 50 kA.

Table 4.2.2 *Specifications for 800 kV CT*

Country (Nominal voltage)	South Africa (765 kV)	Canada (765 kV)	Russia (750kV)	Korea (765 kV)
Classification	Conventional ITs	Conventional ITs	Conventional ITs	Conventional ITs
Type	Iron core type (Except for Line Protection)	Iron core (hair pin type) - oil type	Iron core type	Iron core (ring) type
Standard	BS3938 (1973)	CSA CAN13-C13	Russian standard	IEC185 (1996), JEC 1201
Lightning impulse voltage	NA	2100 kV, 2310 kV for chopped wave	2100kV with GSOA, 1950kV with MOV	NA (2250kV)
Switching impulse voltage	NA	1550 kV	1550kV with GSOA, 1425kV (with MOV)	NA (1425kV)
Power-frequency voltage	NA	830 kV	950kV with GSOA, 830kV with MOV	NA (830kV)
Rated primary current	(1) 4800/3200A, (2) 2400A, (3) 4800/3200/1600A	(1) 2000/ (2) 4000:1A, (4 secondary windings)	1000-4000A	(1) 8000/6000/4000/3000/ (2) 2000A
Rated secondary current	1A	1/1/1/1/5A	1A	1A
Rated burden	(1) NA, (2) NA, (3) 15VA	(1) 15 VA for protection, (2) 30 VA for measuring	-	(1) 25VA for protection, (2) 30VA for measuring
Accuracy class	(1) class X, (2) class X, (3) 0.2 (at 1600A tap)	(1) 10 TPY for 1 A for protection (2) 5 TPY for 5A for measuring	(1) 1% (4 relay outputs), (2) 0.5% (one measuring outputs)	(1) 1T for protection, (2) 1.2 (at 2000A tap) for measuring
Secondary winding resistance	(1) 9.6ohm (at 4800A tap) (2) 5.0ohm, (3) NA	-	-	(1) 32.8ohm (at 8000A tap) (2) NA
Knee-point e.m.f	(1) 4800V (at 4800A tap) (2) 550V, (3) NA	-	-	(1) 9050V (at 8000A tap) (2) NA
Maximum exciting current at knee-point e.m.f	(1) 0.042A (at 4800A tap) (2) 0.05A, (3) NA	-	-	(1) 0.08A (at 8000A tap) (2) NA
Continuous secondary current	(1) 2A, (2) 2.1A, (3) 2A	1 A and 5A for protection	-	(1) 2A, (2) 2A
Rated primary short-circuit current	50kA	40kA	-	50kA
Primary time constant Permissible time to accuracy limit	NA	150 ms	-	180ms
Service Experience (including on-site experience)	23 years	40 years	-	5 years

4.3 Circuit Breakers

4.3.1 Dielectric requirements

A comparison of dielectric requirements for the circuit breakers of existing 800 kV systems shows that the basic values are well in line with IEC 60694, and correspond to revised version IEC 62271-1 to be published soon. The requirements are listed in Table 4.3.1.

***Tab.4.3.1** Specifications of dielectric requirements for 800 kV circuit breakers in comparison with IEC*

		IEC 60694 Draft 62271-1	Canada HQ 765 kV	Brazil Furnas 765 kV	S. Africa ESKOM 800 kV	Russia 750 kV	China 800 kV	USA AEP 800 kV
Rated Voltage	kV	800	800	765	800	750	800	800
					GIS / AIS	GSOA / - MOV		
Lightning impulse withstand voltage								
Phase-to-earth and between phases	kV	2100	2100	2100	2100 / 2100	2100 / 1800	2100	2050
across open switching device	kV	2100 + 455	2100 + 455	2100 + 650			2100 + 455	2255
Switching impulse withstand voltage								
Phase-to-earth and across open switching device	kV	1425 (Draft 1550)	1425	1550	1550 / 1425	1550 / 1425	1425	1425 / 1600 dry
Between phases	kV	2420					2420	
across open switching device	kV	1100 + 650	1175 + 650	1300 + 650			1100 + 650	1550 / 1870 dry
Power-frequency withstand voltage								
Phase-to-Earth	kV	830	830	870	960	950 / 830	830	960
across open switching device	kV	1150	1300			1400	1150	960
Additional remarks								
Closing resistors		- - -	325 ohm or line surge arresters	400 to 600 ohm	450 ohm			300 ohm of two duty cycle rating

In particular, the LIWV (BIL: basic insulation level) of 2100 kV is nearly the same for all specifications. The AEP requirement is slightly less at 2050 kV due to the application of ANSI/IEEE standards that generally uses different values. Russia used a reduced LIWV of 1800 kV when using metal oxide arresters (MOV), which may have been overly optimistic when it was specified such a long time ago. The GSOA (gap silicium oxide arresters) specification is in line with IEC and the other utilities.

The 1425 kV switching impulse voltage to earth in the current standard is not followed by all of the utilities. Some require the next higher level of 1550 kV. The need for an increased level has been taken into account in the revised standard

The withstand capability across open circuit breakers must be tested using a combined voltage test, impulse voltage against power frequency voltage, according to IEC test procedures. ANSI/IEEE specifications did not use the combined voltage test and therefore the voltage requirements of AEP cannot be directly compared with the others.

Concerning the lightning impulse test, the power frequency fraction of the test voltage according to IEC is only 70% of the peak line-to-earth value (450 kV). The background to this is the low occurrence probability of the highest impulse value together with the short time period of power-frequency peak value with opposite polarity. The exception is Brazil, where a 100% peak value of 650 kV is used, presumably because of the extremely high rate of lightning flashes.

For the combined voltage test with switching impulse, all the utilities follow the IEC procedure for using the full power-frequency peak value against a reduced switching impulse voltage. The different switching impulse values are in line with the line-to-ground requirements. An explanation for the reduced impulse level in this test is given in CIGRE Guide TB 304.

The requirements for the power-frequency withstand voltage to earth differ widely. The minimum is 830 kV (IEC value, corresponding to 1.8 p.u.) and the maximum is 960 kV (nearly

2.1 p.u.). Since the high values cannot be related to service circumstances, they may be proof of a special high withstand capability as a quality control measure. The power frequency requirements across open circuit breakers are also extremely high in some cases. Hydro-Québec stipulates a value of 1300 kV (exceeding the IEC value) to be consistent with the 1829 kV (1293 kV rms value) specified for line charging current interruption. The reason for Russia's use of 1400 kV is not known.

IEC recommends 2.5 p.u., with the maximum requirement exceeding 3.0 p.u. for 1400 kV. The ANSI/IEEE recommends 960 kV (2 p.u.), the same withstand voltage level as to ground.

For the limitation of switching overvoltage, closing resistors were commonly used on old-type circuit breakers. Today, many utilities are using MOAs to reduce switching overvoltage. The specified resistance varies between 300 and 600 ohm. Opening resistors are specified only by Furnas for application to circuit breakers to switch shunt reactors (1000–4000 ohm).

4.3.2 Making, breaking and switching test requirements

Tables 4.3.2 and 3 show a comparison of circuit-breaker specifications related to 800 kV for terminal fault test duties for short-line faults, out-of-phase and capacitive current switching tests. Hydro-Québec stipulates a special class of circuit breakers for series-compensated lines. The requirements are also defined in the two tables.

4.3.2.1 TRV for terminal faults

The majority of specifications closely follow the requirements of IEC 62271-100 [1],[2] with the exception of those from Furnas (Brazil) and AEP (United States), which stipulate higher values for the first-pole-to-clear factor (k_{pp}).

A first-pole-to-clear factor of 1.3 is specified in IEC 62271-100 for terminal fault test duty T100 as it covers the values that can be obtained in the case of three-phase to ground faults in 800 kV networks that have effectively earthed systems (see the chapter on TRV for terminal faults).

The same k_{pp} value is required for T60 and T30, but Amendment 3 to the IEC standards will require a factor of 1.5 for T10 in order to cover TRV obtained during three-phase long-line faults. The corresponding peak value of TRV at T10 will be 1499 kV, based on an amplitude factor of 1.7×0.9 with k_{pp} = 1.5 or 1.76 with k_{pp} = 1.3, and will be close to the value currently specified by Furnas. The amendment prepared by IEC is in accordance with the present recommendations of CIGRE WG A3-19, which has studied the implications of three-phase line faults and determined that TRV in this current range would be covered if an amplitude factor of 1.76 is adopted.

The requirements for Furnas' 800 kV networks were defined in the early 1980s, including a first-pole-to clear factor of 1.5 for terminal faults. At that time, Brazil's network consisted of several weakly connected subnetworks. Although each subnetwork could be considered as solidly earthed, the network as a whole could not. Furthermore, the 800 kV network would not be a meshed network but rather a radial one, consisting of 3 parallel circuits, each 895 km long, and 4 substations. Thus, the planning engineers at that time, in consideration of such an unfamiliar high voltage level in Brazil, decided to adopt conservative requirements derived from system simulations under severe operation and emergency conditions.

AEP's specification is based on ANSI/IEEE C37-09-1979 [3],[4],[5], which has a first-pole-to-clear factor of 1.5 in order to also cover three-phase ungrounded faults. It should be noted that when this standard was revised in 1999, k_{pp} of 1.3 was specified for this rated voltage, as in IEC

62271-100. The present revision prepared by IEEE proposes a choice between 1.5 and 1.3, intended to cover or not cover, respectively, the case of three-phase ungrounded faults. In the case of T10, the same TRV peak value introduced by IEC in Amendment 3 to 62271-100 would also appear in the revised IEEE standard, with an alternative value retained at the draft stage with a higher peak of 1610 kV (corresponding to an amplitude factor of 1.64 with k_{pp} = 1.5 or 1.89 with k_{pp} =1.3) that is close to the 1649 kV specified by AEP corresponding to an amplitude factor of 1.68 with k_{pp} = 1.5 (the possibility of having three-phase ungrounded faults must be assumed to have this TRV peak).

In spite of the existing differences in TRV peak at T10, there is agreement between all specifications on the rate of rise of recovery voltage, which is approximately equal to 7 kV/µs.

4.3.2.2 DC time constant

The standard time constant of 45 ms for the DC component is specified in China, while higher values ranging from 67 to 88 ms are specified for other networks. These last values are comparable to the 75 ms given in IEC 62271-100 for special cases and rated voltages equal or higher than 550 kV.

4.3.2.3 Single-phase fault tests

Only Eskom specifies IEC 62271-100 requirements for single-phase faults. Double-earth fault tests are not applicable in effectively earthed systems.

4.3.2.4 Short-line-fault

The values in all specifications are covered by the requirements in IEC 62271-100.

4.3.2.5 Out-of-phase

The specifications require an out-of-phase factor of 2.0 and a TRV peak as stipulated in IEC, with the exception of Brazil, where a significant TRV peak is required, considering that the voltage can be phase-separated by 180°.

For series-compensated lines in the case of system separation (extreme contingencies), Hydro-Québec specifies that a circuit breaker that may be exposed to severe out-of-phase stress: (3.3 × 1.0 × peak system voltage) = 2000 kV, interrupted current = 5 kA, industrial frequency recovery voltage = 1400 kV.

4.3.2.6 Capacitive current switching

A voltage factor of 1.4 covers the specified values given in Table 4.3.2, with the exception of a factor of 1.5 specified in Russia. The same factor was previously stipulated in ANSI/IEEE, but has since been lowered to 1.4 [6] taking into account the actual synchronism of modern circuit breakers. A line-charging current of 900 A is generally adopted in the specifications, with the exception of Furnas and AEP specifying 1500 and 1800 A, respectively.

Hydro-Québec specifies the restrike probability class: C2 for a maximum line length of 310 km and overvoltage on non-faulted phases of 1869 kV (2.8 p.u.). In the case of system separation (extreme contingencies), Hydro-Québec stipulates a recovery voltage of 2200 kV and a restrike probability corresponding to C1 class for this special duty.

Table 4.3.2 *Specifications for terminal fault of 800 kV circuit breakers compared with IEC*

		IEC 62271-100	Canada HQ 765 kV special class for series-compensated lines	Brazil Furnas 765 kV	South Africa ESKOM 800 kV	Russia 750 kV	China 800 kV	USA AEP 800 kV
Transient Recovery Voltage of Terminal fault								
First-pole-to-clear-factor: k_{pp}	p.u.	1,3	1,3	1,5	1,3	1.4 at T100 1.5 at T30	1,3	
T10								
Amplitude factor: k_{af}	p.u.	1,53	1,53		IEC		1,53	
TRV peak value: uc	kV	1299	1299	1464	IEC		1299	1649
Time: t2 or t3	µs	186	186	t3 = 280	IEC		186	t3 = 230
Rate-of-rise: u1/t1 or uc/t3	kV/µs	7	7		IEC		7	7,17
T30								
Amplitude factor: kaf	p.u.	1,54	1,54		IEC		1,53	
TRV peak value: uc	kV	1308	1308		IEC		1299	1589
Time: t2 or t3	µs	262			IEC		260	t3 = 310
Rate-of-rise: u1/t1 or uc/t3	kV/µs	5	5		IEC		5	
T60								
Amplitude factor: kaf	p.u.	1,5	1,5		IEC		1,5	
First reference voltage: u1	kV	637	637	983	IEC		637	
Time: t1	µs	212	212	470	IEC		212	
TRV peak value: uc	kV	1274	1274	1464	IEC		1274	1508
Time: t2 or t3	µs	1272	1272	t2 = 2800	IEC		1272	t2 = 735
Rate-of-rise: u1/t1 or uc/t3	kV/µs	3	3		IEC		3	
T100								
Amplitude factor: kaf	p.u.	1,4	1,4/(1,81)		IEC		1,4	
First reference voltage: u1	kV	637	637	983	IEC		637	
Time: t1	µs	318	318/(640)	940	IEC		318	
TRV peak value: uc	kV	1189	1189/(1920)	1380	IEC	1221	1189	1408
Time: t2 or t3	µs	1272	1272(960)	t2 = 2800	IEC		1272	t2 = 1470
Rate-of-rise: u1/t1 or uc/t3	kV/µs	2	2		IEC	2,8	2	
DC time constant	ms	45	75	88	67		45	
Special time constant	ms	75						
Auto-reclose time	s	0,3	0,3	0,3	0,3	0,3	0,3	
Making current peak 50Hz / 60Hz	p.u.	2,5 / 2,6	2,7	2,75	GIS: 2,5 (100kA)/ AIS: 2,5 (125 kA)		2,5	
Making current peak at special time constant	p.u.	2,7	2,7				2,7 at 120 ms	
Additional remarks			bundle of 4 x 686 mm2 conductors Note (1)	Only three phase auto-reclosing	Single and three phase auro-reclosing			

Note : *Special breaking test sequences are requested by HQ for series-compensated line CB.*
Terminal fault with current of 15 kA (37% of rated capability of CB), peak TRV is 2040 kV and RRRV is 2 kV/µs.
Test with delayed zero current crossing, peak TRV is 1800 kV with RRRV of 2 kV/µs. Interrupted current ≈ 1 500 A.

***Table 4.3.3** Specifications for short-line fault, out-of-phase and capacitive current switching tests of 800 kV circuit breakers compared with IEC*

		IEC 62271-100	**Canada HQ 765 kV** *Special class for series-compensated lines*	**Brazil Furnas 765 kV**	**South Africa ESKOM 800 kV**	**Russia 750 kV**	**China 800 kV**	**USA AEP 800 kV**
Short-line fault tests								
Z	Ω	450	450	450	IEC		450	
AF		1,6	1,4	1,6			1,6	
t dl	µs	0,5	0,5				0,5	
Out-of-phase making and breaking tests								
Voltage factor	p.u.	2,0	2,0 /(2,45)		IEC		2,0	2,0
U1	kV		980	1307			980	
t1	µs		636	1880			636	
Uc	kV	1633	1633 /(2000)	2144		1992	1633	
AF	p.u.	1,25	1,25	2,0			1,25	
t2	µs		1272/ (1559)	11000			1,54	
u1/t1	kV/µs	1,54	1,54			2,25		
Breaking current	x I_{rated}	0,25	0,25/(5 kA)	0,25			0,25	
Capacitive current switching tests								
Voltage factor	p.u.	1.2 1.4 / 1,7	1,4	1,4	GIS: 1,2 AIS: 1,4	1,5	1,2 or 1,4	1,4
Capacitive current	A	900	900	1500	900	540 - 990	900	1800
Recovery Voltage	kV		1829 /(2200)					
Restrike probability class		C1 or C2	C2/ (C1)					
Frequency	Hz			66				
Line length	km		max 310			300-550		

4.3.3 Requirements for Inductive Load switching

Hydro-Québec stipulates special tests to verify the suitability of CBs for controlled switching applications. The test results are also used to set controller parameters, including minimum arcing time to avoid restrike, statistical scatter, operating time variations with ambient temperature, control voltage, idle time, mechanical wear, etc.) [7]

***Table 4.3.4** Specifications concerning inductive load switching in comparison with IEC*

		IEC 62271-110	**Canada HQ 765 kV**	**South Africa 800 kV**
TRV peak voltage	kV	1241	1241	IEC
Time to peak (t_3) for Load Circuit 1/ Load Circuit 2	µs	296/525	208/294	
Test conditions		Rated pressure except for test duty No 4	Rated and minimum pressure	
Mechanical endurance class		M1 or M2	M2	
Controlled switching			Yes (opening and closing)	

4.4 DS, ES

The WG A3.22 cannot collect sufficient technical specifications on the 800 kV DS and ES. However, there are no specific subjects for 800 kV DS and ES to be discussed within the WG.

4.5 High-Speed Grounding Switch (HSGS)

4.5.1 General

Korea's 765 kV transmission system delivers large amounts of electric power from generation facilities on the east and west coasts to the Kyungin area. Normal power is estimated at several million kW. The system employs double-circuit transmission towers in order to reduce land use and adopts a high-speed multi-phase reclosing system to prevent a route failure from causing further outage.

However, in power systems exceeding 500 kV, when an arc earthing fault occurs the faulty phase is separated by the CB, and the secondary arc induced by electrostatic and electromagnetic induction from other phases or the other circuit (because of double circuits) does not disappear in a short time, high-speed reclosing (within 1 second) cannot always be achieved. In this case, it is necessary to ensure quick reclosing after extinguishing the secondary arc by means of installing a proper suppression device to avoid the risk of system separation accident due to decreased stability. Especially in 2-circuit transmission lines, it is desirable to install a high-speed grounding switch (HSGS), since conditions such as those related to reactance capacity between each healthy phase and healthy circuit become very complex and it is not only difficult but also costly to apply the square shunt reactor.

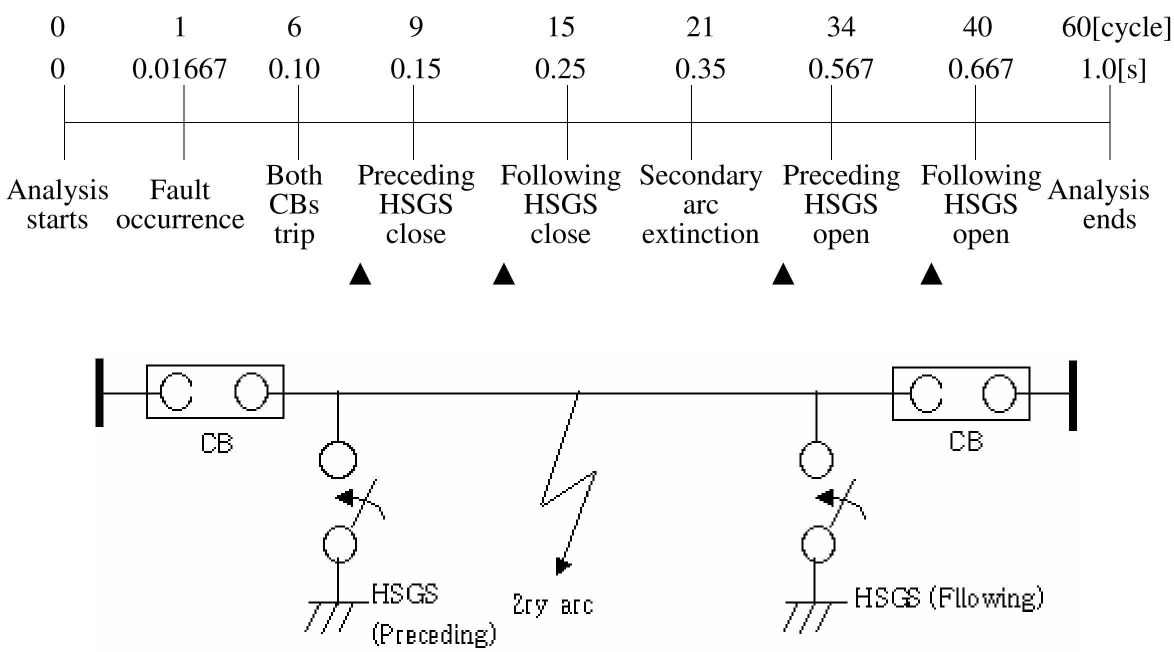


Fig. 4.5.1 *Schematic sequence of HSGS operation after a fault occurrence*

4.5.2 Design considerations of HSGS

A. Review of probability of multiple lightning occurrences

The LPATS calculated value of probability of multiple failures on a 765 kV transmission line is one (1) time/147 years based on the measurement status during a 2-year period. The value is one (1) time/91 years (per 100 km) in the case of applying a correction coefficient using measurement data from Japan.

B. Review of forest fires

According to data from the Forestry Office, the height of flames at the occurrence of a forest fire in Korea is 20–30 m. The height of 765 kV transmission lines from the ground is as shown in Table 4.5.1.

Table 4.5.1 *Height of 765 kV transmission line from ground*

Classification	Normal (m)	Lowest (m)	Type of steel tower
Upper arm	63 - 68	60 - 65	Suspension, strain
Middle arm	46.5 - 49	43.5 - 46	"
Lower arm	30	27	"

It is therefore estimated that a fault (following fault) at the occurrence of a forest fire may arise at 2 phases of the lowest arm (each phase at the lowest arm of 2 circuits) of both sides of the tower. Accordingly, in 765 kV transmission lines, a 2-phase ground fault of the lowest arm has the highest probability of occurrence during a forest fire and requires a review

Table 4.5.2 *Specifications of HSGS duties*

Utility	Consideration	Specification			Remark
		Rated voltage [kV]	Breaking current by electromagnetic induction	Transient recovery voltage	
BPA	Not considered	550	700	78 kV rms	Under operation
TEPCO	Considered	1,100	7,000	900 kV peak	Under verification
KEPCO	Considered	800	8,000	700 kV peak 1.3 kV/μs (rrrV)	Under operation

4.6 Surge Arresters

The survey on 800 kV equipment shows that arresters are specified for a rated voltage of 588 kV with only a few exceptions. With a normal power frequency overvoltage capability for metal oxide arresters of at least 1.1 times the rated voltage for 1 s, this further implies that the arresters are selected to withstand a temporary overvoltage of at least 1.4 p.u.

Furthermore, most of the utilities appear to have adopted the IEC philosophy for specifying the continuous operating voltage, Uc, according to the actual service voltage and not as a factor of the rated voltage. However, there are some exceptions such as a required Uc of 490 kV, which would indicate a system voltage as high as 849 kV. A nominal discharge current of 20 kA and line discharge class (LDC) 5 as per IEC [8] are also common requirements.

With the protection levels generally required for the 800 kV arresters, LDC 5 results in an energy requirement of approximately 5-7.5 kJ per kV rated voltage per single impulse. As stipulated in the IEC standards, two impulses must also be thermally withstood, which thus gives 10-15 kJ/kV as rated voltage. However, several utilities specify even higher energy requirements of up to 13 kJ per kV rated voltage for single impulse capability and thus 26 kJ per kV thermally. LDC 5 requirements are normally met by arresters in a single block column. However, such a high requirement as 26 kJ/kV rated voltage thermally requires a design with multiple columns of metal oxide blocks.

The required protection levels given at the nominal lightning impulse current of 20 kA with waveform 8/20 µs and at switching impulse current of 2 kA with waveform 30/60 µs vary somewhat between different utilities, as shown in Figs. 4.6.1 and 4.6.2.

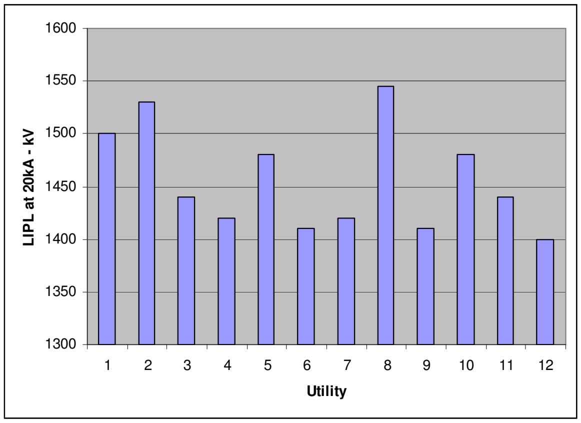


Fig. 4.6.1 *Range of required lightning surge protection levels (LIPL) at 20kA for 800kV arrester*

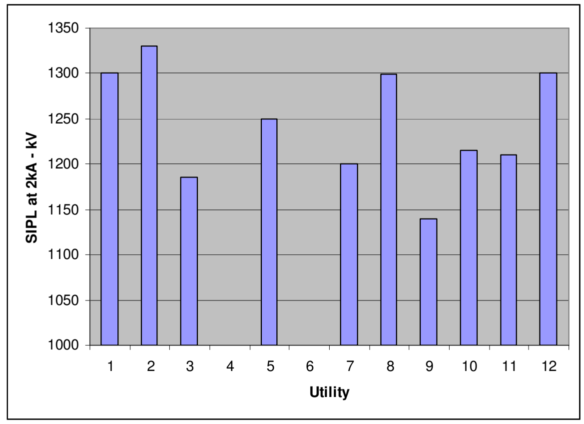


Fig. 4.6.2 *Range of required switching surge protection levels (SIPL) at 2kA for 800kV arrester*

The standard insulation level for 800 kV equipment is 1675-2100 kV for lightning and 1300-1550 kV for switching impulses. The survey shows that the requirements for external insulation strength of the arrester are at the upper range of these insulation levels. In addition, the arrester standard stipulates that the external insulation shall have an LIWV of at least 1.3 times the residual voltage at a nominal discharge current of 20 kA and an SIWV of at least 1.25 times the residual voltage at 2 kA switching impulse. These factors include an altitude correction factor of 1.13, valid for 1000 m above sea level. As shown in Figs. 4.6.3 and 4.6.4, the requirement for lightning is fulfilled in all cases, but for switching surges, a factor as low as 1.1 is used. This may be due to the arresters, in the particular case, being installed at low altitudes and therefore an atmospheric correction factor was not considered necessary.

The insulation level for most 800 kV equipment is LIWV of 1950 or 2100 kV and SIWV of 1425 or 1550 kV. Taking the lowest protection levels for any of the 800 kV arresters, this gives a protection ratio of 1.38-1.49 for lightning and 1.25-1.36 for switching surges.

Pollution performance of metal oxide surge arresters does not appear to be of great concern for most utilities. Only the creepage distance is specified, and pollution tests are generally not required.

Service experience appears to be excellent. Failure of an 800 kV arrester is a very rare case.

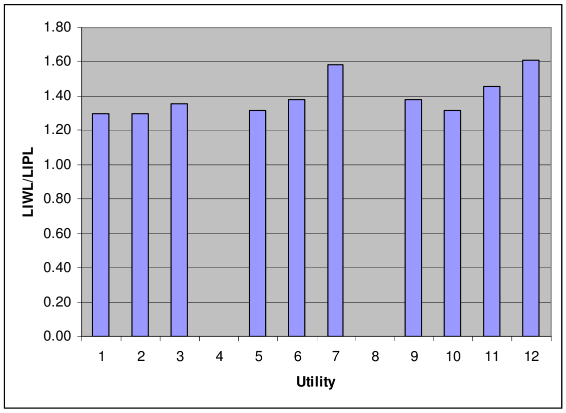


Fig. 4.6.3 *Range of ratios external insulation strength for lightning surge (LIWV) to protection level (LIPL) for 800kV arrester*

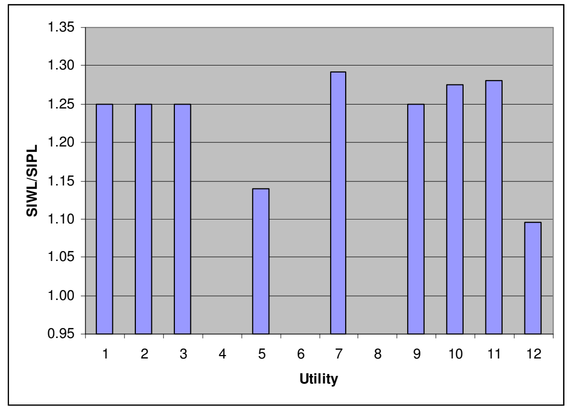


Fig. 4.6.4 *Range of ratios external insulation strength for switching surge (SIWV) to protection level (SIPL) for 800kV arrester*

4.7 Shunt Reactors

4.7.1 General

Table 4.7.1 lists the main technical specifications for shunt reactors (SRs) presently in use by utilities on EHV power systems. Members of CIGRE Working Group A3.22 collected the data contained in this table.

The primary reason for applying shunt reactors to EHV power systems is the need to absorb line charging MVar and consequently reduce the Ferranti effect. Different approaches are used by utilities in terms of reactive power compensation. Some utilities use permanently connected SRs to compensate for reactive power supplied by the line and the switchable SRs directly at the substation busbars for voltage control. This is the case in India's power grid. Most utilities that have contributed to the survey use shunt reactors at both ends of the line, except for BC Hydro, which may use a shunt reactor at one end only for shorter lines. Three-phase reactor banks range from 133 to 330 MVar for power systems of 550 to 800 kV.

SRs are used in transmission OH lines for two main purposes: (a) switchable SR at busbars or tertiary windings of power transformers for steady-state voltage control issues; and (b) fixed SR at OH line ends to deal with switching transient overvoltage (TOV) requirements, related to line closing and/or opening operation (including fast auto-reclosing issues).

Utilities in Russia also use SRs to reduce switching and lightning surges. To ensure that the SR is always connected when the line is switched, utilities in Russia use a spark gap in parallel with the breaking chambers. In addition to the spark gap, there is also a system-wide fast switching automatism to switch on the SRs. Hydro-Québec also uses a system-wide automatic scheme to switch the shunt reactors to control the voltage in the case of significant system disturbances.

Most utilities that responded to the survey are using a single-phase reclosing scheme (SPR), except for Hydro-Québec, which is using three-phase reclosing only on its 735 kV lines. For utilities using SPR, a neutral reactor at the shunt reactor bank is always used to extinguish the secondary arc within an acceptable delay. In cases where the lines are not transposed, a special 4-legged reactor bank is used by AEP (USA), as described in Section 3.5.2, to provide secondary arc suppression. For utilities applying SPR, there is of course a need to properly isolate the neutral of the reactor bank. The insulation levels are given in Table 4.7.1.

Table 4.7.1 *Main characteristics of UHV shunt reactors*

Country/utility	Canada/ Hydro-Quebec	Russia	Canada/BC-Hydro	USA/AEP	Brazil/Furnas	South Africa /ESKOM	India/Power Grid
Nominal/Maximum operating voltage(kV)	735/765	787	550	765/811 kV	765kV/800kV	765	800
Capacity of 3-phase group, (Mvar)	Type 1 : 155 Type 2: 330	330	135	Type 1 : 150 Type 2: 300	R1: 330 MVAr/800kV R2: 150 MVAr/800kV R3: 180 MVAr/69kV connected to 800kV Tr tertiary winding	133	240
Positioned on line ends	At both ends	Yes	One or both ends dependent on line length	None, or one at each line terminals, dependent on line length	One or both ends dependent on line length (please refer to the brazilian projects in Chapter 2)	Both ends	At both ends
Switchable	All switchable with CB equipped with controlled switching device (CSS)	Yes	Some fixed (switched with the line) and remainder switchable with CB equipped with CSS	Some are fixed (switched with the line) and some are switchable.	Bus Reactor switchable. Line reactors are permanently connected. Tertiary winding reactors are switchable.	Yes	Bus Reactor switchable. Line reactors are permanently connected
Automation for fast switching	Yes	Yes (spark gaps plus automation	No	No	No		No
Application of 4-legged reactor	No	Yes	Yes	Yes, on some lines.	No		Three single phase reactors, NGR provided on neutral
Permissible TOVs, L-G, p.u.	1.33 p.u. for 10s	1.30 p.u for 20 s., 1.88 p.u for 1 s-	1.25 p.u. for 10s	Line trips for over 1.06 pu/ 5 minutes	1.30 p.u. in less than 10 sec (for power frequency TOV)	1,25 p.u for 60 s 1,75 p.u. for 1 s	?
Level of switching surges on line end, L-G, p.u.	1.8 p.u.	2.1 (1.8)*	2 p.u. on older lines and 1.7 p.u on lines built after 1990.	2.0 pu	2.0 pu referred to 765 kV·sqrt(2)/sqrt(3) basis		1550 (reactor insulation level)
Power frequency 1 min withstand test voltage, L-G, for line side, (kV rms)	Specified only for bushings :880 kV (2 p.u.)	900 (750)*	Specified only for bushings: 620 kV	1.6 pu	920 kV (Specified only for bushings)		
Same for the neutral	34 kV	85	185 kV	550 kV LIWV	Not available at the moment (I will try to find some information on this issue)	550 kV LIWV	
Power frequency 1-hr withstand test voltage, L-G, for line side, kV	Specified only for windings: 750 kV, 1 hour. (1,7 p.u.)	635	Actual test sequence: 540 kV (1.7 p.u.) for 7200 cycles followed by one (1) hour at 476 kV (1.5 p.u.) all with partial measurements.	690 kV 1-hr 800 kV Enhanced (Applied Voltage: ANSI C57.21)	Not available (I will try to find some information on this issue)		
Switching surge withstand test voltage, L-G, kVp	1550 kV	1675 kV (1425)*	1175 kV	1700 kV	SIWV: 1550kV AC voltage: 870 kV (1.88E) Combined test for switching impluse power frequency: 1300+650kV	1425 kV	
Lightning impulse withstand test voltage for internal insulation, L-G, on full wave	1950 kV	2250 kV (1950)*	1550 kV	2050 kV	LIWV: 2100kV Combined test for lightning impulse plus power frequency: 2100+455kV	1950 kV	
Same on chopped wave (kV)	2145 kV	2400 kV (2100)*	Not required	2255 kV	Not available at the moment (I will try to find some information on this issue)		

Note: * *Values not within parentheses are for Russian equipment developed prior to 1985, protected by zinc oxide gapped arresters and actually installed on 1150 kV transmission lines; Values within parentheses are for equipment newly developed and protected with MOVs.*

4.7.2 Additional information related to Russia's 787-1200 kV shunt reactors

The common practise in Russia is to place shunt reactors on 787 kV line ends (usually on both ends). All reactors are switchable. Their circuit breakers are equipped with specially designed air gaps in parallel to arc quenching chambers, which ensures extremely fast (of the order of microseconds) connection of the reactor to the line upon detection of switching or lightning overvoltage, if the reactor was switched off in the previous operational mode. Flashover voltages of these gaps are coordinated with the insulation level of the equipment protected. In addition, there is an automation that commands switching-on of all three poles of the shunt reactor circuit breaker:

- Immediately, if reactor current is detected in even one of the poles;
- Immediately, if a command is issued to open the line circuit breakers, be it one-pole or three-pole line operation;
- If a relay overvoltage protection device detects the appearance of TOV, with a time delay corresponding to the value of increased voltage.

Shunt reactors on the line ends, air gaps on the shunt reactor circuit breakers and the abovementioned automatics and relay protection are mandatory elements of overvoltage protection in Russia's 787 kV transmission system. It should be noted here that the air gaps provide line connection not only for the shunt reactor, but also for the shunt reactor arresters, thus reducing not only TOVs, but also lightning and switching overvoltages. The system was such a success for 787 kV transmission that it was transferred to 1200 kV transmission.

References

[1] IEC 62271-100 High-voltage switchgear and controlgear - Part 100: High-voltage alternating-current circuit-breakers (October 2006)

[2] IEC 17A/768/CDV - Draft amendment 3 to IEC 62271-100 (November 2006)

[3] ANSI/IEEE C37.09-1979 - Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (October 1979)

[4] IEEE Std C37.09-1999 - Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis (June 1999)

[5] IEEE PC37.06 -D8.2 Draft: Standard AC High-Voltage Circuit Breakers. Rated on a Symmetrical Current Basis – Preferred Ratings and Related Required Capabilities for Voltages above 1000 Volts (April 2006)

[6] IEEE Std C37.09a – IEEE Standard Test Procedure for AC High-Voltage Circuit Breakers Rated on a Symmetrical Basis – Amendment 1 : Capacitance Current Switching September 2005).

[7] IEC 60694 – Common specifications for high-voltage switchgear and controlgear standards (January 2002)

[8] IEC 60099-4, Edition 2.1, 2006-07 “Metal-oxide surge arresters without gaps for a.c. systems”

5 Technical Specifications of Substation Equipment 1000 kV and above

5.1 UHV Power Transformers

Russia has been operating its 1200 kV transmission system since the 1980s, and China and Japan have been engaged in ongoing projects related to 1100 kV transmission systems. Table 5.1.1 lists the major specifications for the UHV transformers used in these projects. The main points determined from the survey are as follows: The transformers range from 2000 to 3000 MVA in bank capacity, which is much greater than that for 800 kV transformers. Transportation restrictions can greatly influence decisions on structure, transportation weight and size of UHV transformers. Cooling-type transformers, either OFAF or ODAF, are also applied as a major characteristic of large-capacity transformers. Although not indicated in the table, some transformers are equipped with an on-load tap changer on the neutral-point side of the windings to regulate the high-voltage-side windings. So, another feature of very high voltage transformers is on-load tap changers.

India is planning future projects related to a 1200 kV transmission system. This survey would be applied to consider the detailed specifications.

Table 5.1.1 *Major items for UHV power transformers (for substation)*

Item	*Specifications*			
Country	*Russia*	*Italian*	*China*	*Japan*
Utility	-	-	*SGCC*	*TEPCO*
Type	Auto-transformer			
Phase	Single			
Um (kV)	1200	1050	1100	1100
Rated Voltage (kV)	$1150/\sqrt{3}$	$1000/\sqrt{3}$	$1050/\sqrt{3}$	$1050/\sqrt{3}$
BIL (kV)	2550 (2250)	2250	2250	1950
Rated Power (MVA)	2000/3	1200/3	3000/3	3000/3
Short circuit impedance	12.5 percents	15 percents	18 percents	18 percents
Cooling	-	-	OFAF	ODAF
Sound level dB(A)	-	-	75	65

Additional information is provided in Tables 5.1.2 and 5.1.3, which list detailed specifications for Italy and Japan's individual projects.

Table 5.1.2 *Detail specification of power transformers in Italy's project*

Auto-transformers	
Rated voltage (kV)	$1000/\sqrt{3}$ / $400/\sqrt{3}$ / 12.2
Rated power (MVA)	400/400 (single-phase unit)
Rated LIWV (kVp)	2250/1300/95
Rated SIWV (kVp)	1800/consequent
Short circuit voltage (percent)	15

Table 5.1.3 *Detail specification of power transformers in TEPCO project*

Item			Specifications
Rated voltage	Primary		$1050/\sqrt{3}$ kV
	Secondary		$525/\sqrt{3}$ kV
	Tertiary		147 kV
Rated capacity			3000 MVA/3×3
Tertiary capacity			1200 MVA/3×3
Primary tapping range			± 7% (27 taps)
Impedance			18 %
Test voltage	LIWV	Primary	1950 kV
	AC	Primary and Secondary	1.5E (1 hour) - $\sqrt{3}$ E (5 min) - 1.5E (1 hour)

5.2 UHV Voltage Transformers (VT), Current Transformers (CT)

5.2.1 UHV VTs

Table 5.2.1 lists the technical specifications for UHV voltage transformers in Japan, Italy and Russia, obtained from the world survey conducted by CIGRE WG A3.22. UHV transmission systems utilize optical- or capacitive-type VTs, which have secondary voltage ranging from $110/\sqrt{3}$ to 100 V, similar to that specified for 800 kV VTs. Accuracy ranges from 0.2 to 1% for measuring applications and 1 to 3% for protection applications. Reported applications for optical-type VTs include photoelectric sensors and electronic circuits in UHV systems. Their temperature and frequency characteristics are summarized in the table.

Table 5.2.1 Specifications for UHV VT

Country (Highest voltage)	Japan (1100 kV)	Italy (1050 kV)	Russia (1200 kV)
Classification	Non conventional ITs	Non conventional ITs	Conventional ITs
Type	Capacitive and Optical type	Capacitive type with secondary amplification: Two secondary taps: one for measurement and one for protection	Capacitive type
Standard	-	-	Temporary Russian specification
Lightning impulse voltage	2250kV	2250 kV	2900kV with GSOA, 2400kV with MOV
Switching impulse voltage	NA	1675 kV	2100kV with GSOA, 1800kV with MOV
Power-frequency voltage	1.5E(30min.)- $\sqrt{3}E$ (1min.) -1.5E(30min.)	910 kV (1 min)	1150kV (1min with GSOA), 1100kV (1min with MOV)
Rated primary voltage	$1100kV/\sqrt{3}$	$1050kV/\sqrt{3}$	$1150kV/\sqrt{3}$
Rated secondary voltage	$110V/\sqrt{3}$	$100kV/\sqrt{3}$	100V
Rated burden	1VA	30 VA	300/600VA
Accuracy class	1T	class 0.2 for measuring (better than) 3P for protection	0.5% / 3%
Temperature characteristics	±0.2% (Summer: +20~+40º C) ±0.5% (-20~+40º C)	-	-
Frequency characteristics	±5% at fifth harmonics ±10%at seventh harmonics	-	-
Service Experience (including on-site experience)	10 years as a field test	3 years	At full voltage about 3 years

5.2.2 UHV CTs

Table 5.2.2 lists the technical specifications for UHV current transformers in Japan, Italy and Russia. UHV CTs have either an iron core or an air core. The type with an air core is employed in order to avoid iron core saturation caused by increased short-circuit current with large DC time constant. CTs with an iron core have a rated secondary current of 1 A. Secondary voltage of 20 V is specified for CTs with an air core because they have a voltage output, in principle. Accuracy ranges from 0.2 to 1% for measuring applications and 1% for protection applications. CTs with specified transient characteristics are used for protection applications where the rated short-circuit current is 50 kA.

Table 5.2.2 *Specifications for UHV CT*

Country (Highest voltage)	*Japan (1100 kV)*		*Italy (1050 kV)*	*Russia (1200 kV)*
Classification	Conventional ITs	Non conventional ITs	Conventional ITs	Conventional ITs
Type	Iron core (ring) type	Air core (ring) type	bus-bar side: 3-iron core (protection) core 1: TPY core 2, 3: TPX line-side: 2-iron core (1meas.+1prot.) core 1: TPX	Iron core type (3-step cascade)
Standard	JEC-1201	-	-	Temporary Russian specification
Lightning impulse voltage	NA	NA	2250 kV	2900kV with GSOA, 2400kV with MOV
Switching impulse voltage	NA	NA	1675 kV	2100kV with GSOA, 1800kV with MOV
Power-frequency voltage	NA	NA	910 kV (1 min)	1150kV (1min with GSOA), 1100kV (1min with MOV)
Rated primary current	(1) 8000A for line protection, (2) 8000A for measuring, (3) 4000A for TR protection	8000A for busbar protection	bus-bar side: 1250 A line-side: core 1: 1250 A core 2: 1200 A	2000-4000A
Rated secondary current /voltage	1A	20V	1A	1A
Rated burden	(1) 60VA for line protection, (2) 25VA for measuring, (3) 25VA for TR protection	2 ~ 6k Ω	bus-bar side: core 1: 5 VA core 2,3: 30 VA 5P30 line-side: core 1: 30 VA 5P30 core 2: 20 VA	(1) 40VA for protection (2) 20VA for measuring
Accuracy class	1.0	±1.0% (at 400 ~ 8000A)	bus: 5P(1) 5P30(2,3) line: 5P30(1) 0.2(2)	1% (4 relay outputs) 0.5% (one measuring outputs)
Secondary winding resistance	(1)(2) less than 40Ω (3) less than 20Ω	less than 10Ω	-	-
Secondary winding reactance	NA	less than 10Ω	-	-
Rated primary short-circuit current	50kA	50kA	-	-
Primary time constant/ Permissible time to accuracy limit	(1) 100msec/1.5cycle, 30msec/∞ (3) 100msec/6cycle	100msec/ 1.5cycle	-	-
Service Experience (including on-site experience)	10 years as a field test	10 years as a field test	3 years	At full voltage about 3 years

5.3 Circuit Breakers

Considerable research on UHV systems is carried out in Russia, Italy, USA, Japan, China, and India. A commercial UHV network is presently operating in Russia and one is planned in China for the near future and in Japan and India in the foreseeable future.

CIGRE WG A3.22 conducted a world survey on the specifications adopted for UHV substation equipment. Basic specifications for circuit breakers in Russia, Italy, Japan, and China's UHV projects are listed in Table 5.3.1. Each project's TRV duties without opening resistors are shown in Table 5.3.2, and those with opening resistors are shown in Table 5.3.3. TRV duties without opening resistors are not specified in Japan's projects.

***Table 5.3.1** Basic Specifications for circuit breakers of UHV projects*

Country	Russia	Italy (Pilot Plant)	Japan	China (Pilot Plant)
Highest voltage for equipment (kV_{rms})	1200	1050	1100	1100
Rated short circuit current (kA)		63 kA	50 kA	50 kA
Rated nominal current (A)		8000 (bus bar) 6000 (line bay equipment)	8000	
LIWV (kV)	2900 (with GSOA), 2400 (with MOV)	2250+600	2250 $2250{+}1100\sqrt{2}/\sqrt{3}$	2250+900, 2400+900
SIWV (kV)	2100 (with GSOA), 1800 (with MOV)	1675+600	1550	1675+900, 1800+900
PFWL (kVrms)	1150 (1min with GSOA), 1100 (1min with MOV) 2000 (between opened contact)	910kVrms	1.5E (30min.)- $\sqrt{3}$ E(1min.)- 1.5E(30min.)	1.5pu(30min)+ $\sqrt{3}$ pu(1min)+ 1.5pu(30min)
Closing/Opening resistor	NA	Closing/opening resistor 500 ohm	Closing/opening resistor 700 ohm Insertion time= 10ms for making, 35ms for breaking	
Operating sequence		3-phase: O-0,3s-CO-60s-CO; 1-phase: O-1s-CO-60s-CO	Auto-reclose time: 0.3sec	Auto-reclose time: 0.3sec
Making current peak		Short-time withstand current: 158kAp	2.5 p.u.	2.7 p.u. (50Hz)
FPCF	1.5 at T30	1.3	1.1	1.3
DC time constant (ms)			150ms (DC component at opening=80% , di/dt at breaking =28A/μs (equivalent to 63kA)	45ms Special time constant:120ms
Service experience			10 years as a filed test	

Table 5.3.2 *TRV Duties for circuit breakers of UHV projects (without resistor)*

Country	***Russia***	***Italy (Pilot Plant)***	***China** (Pilot Plant)***
TRV for BTF without breaking resistor	**T100s**: Uc=1518kV, u1/t1=2.8kV/µs	**T10**: Uc=1790kV, tp=200ms, Uc/t1=9,0kV/µs **T60**: Uc=1520kV, tc=800µs, u1/t1=3,3kV/µs **T100s**: Uc=1370kV, tc=1000µs, u1/t1=3,3kV/µs **T100a**: Uc=998kV, tc=1045µs, u1/t1=2,7kV/µs	**T10**: Uc=1786kV (AF=1.53), Uc/t3=7kV/µs, t3=255µs **T30**: Uc=1786kV (AF=1.53), Uc/t3=5kV/µs, t3=357µs **T60**: Uc=1751kV (AF=1.5), u1/t1=3kV/µs, t2=1752µs u1=876kV, t1=292µs **T100s**: Uc=1635kV (AF=1.4), u1/t1=2kV/µs, t2=1752µs, U1=876kV, t1=438µs **T100a**:Uc-=0.98p.u, Uc+=0.55p.u, t1=438µs, U1-=0.74p.u, U1+=0.76p.u, t2=1752µs, u1/t1=1.48kV/µs (minor loop), u1/t1=1.52kV/µs (major loop)
TRV dutiy for SLF without breaking resistor		**(Source-side)** u1=943kV t1=285µs, Uc=1370kV, tc=1000µs, u1/t1=3,3kV/µs **(Line-side)** **L60**: u0=378kV, ul=604kV, tl=120µs, ul/tl=5,0kV/µs **L75**: u0=236kV, ul=377kV, tl= 60µs, ul/tl=6,3kV/µs **L90**: u0= 94kV, ul=151kV, tl= 20µs, ul/tl=7,6kV/µs	
Out-of-phase without breaking resistor	TRV: Uc=2841kV, u1/t1=2.25kV/µs	Uc=1890kV, tp=150µs, Uc/t1=12,6kV/µs Breaking current: 16kA	Amplitude factor: 2.0 TRV: Uc=2245kV, u1/t1=1.54kV/µs, t2=1750-3500µs , Breaking current: 12.5kA
Capacitive current switching	voltage factor: 1.5 Capacitive current:1160-2030A (line= 400-700km)	Breaking current=900A u1=198kV t1=200µs Uc=1614kV tc=8ms u1/t1=1kV/µs	Voltage factor: 1.4 Capacitive current:1200A

***** TRV duty of China's project needs to be reviewed within the WG.***

Table 5.3.3 *TRV Duties for circuit breakers of UHV projects with opening resistor*

Country	***Italy (Pilot Plant)***	***Japan***
TRV for BTF with breaking resistor	**Breaking Unit-with resistor** **T10**: Uc=798kV, tp=565µs, Uc/t1=1,4kV/µs **T60**: Uc=1261kV, tc=3150µs, u1/t1=2,5kV/µs **T100s**: Uc=1232kV, tc=1025µs, u1/t1=3,1kV/µs **T100a**: Uc=860kV, tc=1045µs, u1/t1=2,2kV/µs	**Main contact :T16(8kA):**Uc=1385kV, t2=461µs, Uc/t1=3kV/µs , **T30 –T100:**Uc=1385kV, u1=990kV,u1/t1=3kV/µs, t2=1485µs **Resistor contact:** Uc=1200kV, u1=550kV, u1/t1=3kV/µs, t2=550µs
TRV dutiy for SLF with breaking resistor	**Main Breaking Unit with R** **(Source-side)** u1=756kV, t1=274µs, Uc=1192kV, tc=1010µs, u1/t1=2,7kV/µs **(Line-side)** **L60**: u0=378kV, ul=378kV*, tl=120µs,ul/tl=3,2kV/µs **L75**: u0=236kV, ul=236kV*, tl= 60µs, ul/tl=3,9kV/µs **L90**: u0= 94kV, ul=94kV*, tl= 20µs, ul/tl=4,7kV/µs	**Main contact :** Z=450 ohm, AF=1.4 (Conductor: 810mm sq. 8-conductors) Power Source side: T100*0.9
Out-of-phase with breaking resistor	**with resistor:** Uc= 942kVb (TRV critically damped), tp=500µs, Uc/t1= 1,9kV/µs **Auxiliary BU:** u1=732kV t1=150µs, Uc=1197kV, tc=2700µs u1/t1=4,9kV/µs, **Operating sequence**: CO	**Main contact ,** Breaking current=12.5kA u1=1200kV, Uc=2160kV, u1/t1=2kV/µs, t2=1800µs **Resistor contact :** Breaking current=2kA, u1=1750kV, Uc=2160kV, u1/t1=2kV/µs, t2=1800µs
Capacitive current switching		**Main contact** Breaking current=1kA**,** TRV peak=900kV **Resistor contact :** **Condition 1**: Breaking current=1kA, TRV peak=2515kV（1.4pu）,Waveform: (1-cos) **Condition 2**: Breaking current=0.1kA, TRV peak=2100kV（1.17pu）, Waveform: (1-cos) **Condition 3**:Breaking current=0.6kA, TRV peak=2000kV（1.11pu）, Waveform: sin rrrV=0.34kV/µs

5.4 DS, ES

Table 5.4.1 lists the disconnector specifications adopted in Russia, Italy, Japan, and China, as indicated in the world survey conducted by CIGRE WG A3.22.

***Table 5.4.1** Specifications for disconnectors of Russia, Italy, Japan, and China*

Country	Russia	Italy (Pilot Plant)	Japan	China (Pilot Plant)
Um ; Highest voltage for equipment (kV)	1200	1050	1100	1100
Rated short circuit current kA		63	50	50
LIWV (kV)	2900 (with GSOA) 2400 (with MOV)		2250 between contacts: $2250+1100\sqrt{2}/\sqrt{3}$	2400+900
SIWV (kV)	2100 (with GSOA), 1800 (with MOV)		$\sqrt{3}$	1800kV, 1675+900kV
PFWL (kVrms)	1150 (1min with GSOA) 1100 (1min with MOV)		1.5E (30min.)- $\sqrt{3}$ E(1min.)- 1.5E(30min.) AC voltage for between contacts : 1265kV rms (1min.)	1100 1100+635
Closing/Opening Resistor				
Bus-transfer current switching tests			Test voltage: 300Vrms rrrV = 400V/μsv Test current: 8000A	Test voltage: 400V Test current: 1600A
Bus-charging switching tests			Test voltage: 635kV Current: 0.5A (Load side capacitance : 2000pF)	Test voltage: 635kV Current: 0.5A
Withstand voltage and energy tests of closing/opening resistor			Opening and closing resistor = 500ohmv, Operation = CO Voltage across resistor for thermal capacity : 1700kV(Lightning impulse) Energy Absorption: 25kJ	

5.5 High-Speed Grounding Switches (HSGS)

Table 5.5.1 lists the specifications for UHV high-speed grounding switches (HSGSs) in Japan.

***Table 5.5.1** Specifications for HSGS of Japan*

Country	Japan
Induced current switching tests	***Electromagnetic induced*** current=5800 Arms, TRV=640 kVp, Uc/t3 = 0.79 kV/μs, (OHL length=70-200 km) current=7000 Arms, TRV=410 kVp, Uc/t3 = 1.15 kV/μs, (OHL length=40-70 km) ***Electrostatic induced*** Current=1200 Ap, TRV=900 kV (1-cos) , (OHL length =70-200 km) Current= 520 Ap, TRV=700 kV (1-cos) , (OHL length =40-70 km) Operating sequence =C-(θ) O (θ= 0.5s)
Induced current switching tests for Delayed current Zero phenomena	HSGS shall have a interruption window more than 80ms for Delayed current Zero phenomena. ***TRV: Electromagnetic induced*** current=3500 Amean, TRV=170 kVp, Uc/t3 = 0.26 kV/μs, (OHL length= 200 km) current=7830 Amean, TRV= 65 kVp, Uc/t3 = 0.46 kV/μs, (OHL length= 40 km) ***Electrostatic induced*** Current=3500 Amean, TRV=570 kV (1-cos) , (OHL length =200 km) Current=7830 Amean, TRV=390 kV (1-cos) , (OHL length =40 km) ***Long arcing time***: 80 ms with current zero missing (special case)

5.6 Surge Arresters

A survey on arrester requirements for the UHV pilots and projects in Japan, China, Italy and Russia provided general information on such issues as rated and continuous operating voltage, protection levels and energy requirements. However, many important arrester parameters are not completely addressed in available papers.

5.6.1 Continuous operating voltage, Uc, rated voltage, Ur, and TOV capability

Continuous operating voltage is generally specified as Um/√3, which follows IEC procedures. Rated voltages are given in Table 5.6.1.

Table 5.6.1 *Um and arrester rated voltages for UHV pilots and projects*

UHV project in	Russia	Italy	Japan	China
Um –kV	1200	1050	1100	1100
Rated voltage (Ur) - kV	800	750	826	828

In China's projects, the specified maximum temporary overvoltage is 1.4 p.u. with a duration of 0.4-0.5 s on the line side of the breakers. [1], [2] In Japan, arresters are designed for a TOV durability test with 1.55 p.u. for 0.17 s. [3] However, normal TOV of 1.1 p.u. is expected at a single line-to-ground fault, and 1.3 p.u. is considered rare. In Russia, the maximum phase-to-ground voltage at a ground fault reaches 1.4 p.u. With the given TOV values, it should be possible to select a lower rated voltage for the UHV system in China and Russia. A rated voltage of 740-775 kV would be possible in a case such as Italy's pilot plant.

5.6.2 External insulation strength

LIWV of 2250 kV is specified for the GIS arresters in Japan, [3] which is the same as for the GIS, but no specific requirements are found for arresters used in other cases. Presumably, the arrester insulation requirements are the same as for other equipment. Strictly following the existing IEC standard [4] for 10 and 20 kA arresters with a rated voltage of 200 kV and above, the lightning impulse withstand voltage shall be ≥1.3 times the lightning impulse protection level, and the switching impulse withstand voltage shall be ≥1.25 times the switching impulse protection level. These factors include an altitude correction factor, K_a, of 1.13 that takes into account an altitude of 1000 m and is calculated from the formula $K_a = e^{m(H/8150)}$ setting the m-factor equal to 1.

For UHV arresters, the factor for switching impulse withstand voltage should be reconsidered since the m-factor significantly reduces the withstand voltage levels in the UHV range. Otherwise, the requirement for arrester insulation will be higher than that for other equipment for which an m-factor is considered.

5.6.3 Residual voltages and classifying currents

For lightning protection in Japan, China and Italy's systems, characteristic value at 20 kA is selected as the coordinating current. In Russia, the value at 15 kA is specified. LIPL of 1.8 p.u. is commonly used except in Italy's pilot project, where a protection level of 2.1 was applied. This most likely reflects the state of surge arrester technology at the time. The actual protection level of the delivered arrester was 2.0 p.u. [5] In Russia, higher values were used at an earlier stage when only SiC gapped surge arresters were available. In Japan, 4 parallel columns with high-performance ZnO elements, which have seen extensive field use as 550 kV GIS arresters, have achieved the low LIPL. The V-I characteristics of the 1100 kV arrester are shown in Fig. 3.1.1 of the chapter 3.

The switching surge protection level is around 1.6 p.u., except for Italy where 1.69 p.u. is adopted. Coordinating currents are specified as 2–3 kA. For Japan's project, the current for switching surge protection is not officially specified at present. However, the actual protection level of the arrester at 2–3 kA would be around 1.6 p.u.

5.6.4 Energy requirements

The required energy capability for arresters in Italy's project is specified as only 3–4 kJ/kV. [6] However, the actual capability of the arrester is 17 MJ, [7] presumably due to the use of a multiple-column arrester to obtain as low a protection level as possible. High energy capability is then automatically obtained.

In both Japan and China, TOV is mentioned as the deciding factor in energy requirements. This is obvious in Japan's case with a TOV of 1.55 p.u. with a duration of 0.17 s considering the arrester characteristics specified. [3] However, for China, the calculated arrester energy at 1.4 p.u. of 0.4 s with approximately the same arrester characteristics as in Japan is reported to be 8.6 MJ, [2] which seems very high.

Energy resulting from switching surges is calculated as only 3.26 MJ. Based on simulations, 20 MJ is specified in China and 55 MJ in Japan. In China, thermal stability after two energy discharges of 20 MJ is required. The required test procedure used to verify thermal stability for Japan's GIS arrester is shown in Fig. 5.6.1.

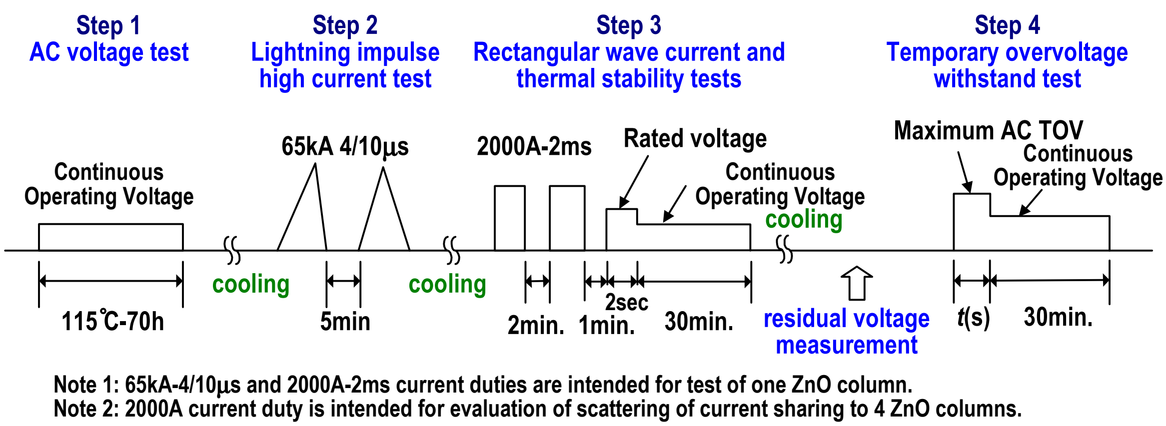


Fig. 5.6.1 *Stability Evaluation Test according to JEC-217 1984*

5.6.5 Lightning impulse discharge capability

Discharge duties relevant to lightning were not addressed. The reason for this may be that lightning is considered negligible compared with the anticipated stress from TOV and switching. However, the high insulation strength of the transmission lines may give significant arrester energy in the case of shielding failure. [5].

5.6.6 High current impulse withstand capability

In the IEC standards, the conditioning test in the switching surge operating duty test comprises 2 high-current impulses with an amplitude of 100 kA and waveform of 4/10 µs.

Japan's UHV arresters have been tested using high-current impulses of 65 kA, the same as Japan's standard value for 10 kA arresters considering the current to be reduced by the 4×parallel-column arrangement; however, for China and Italy's projects, 100 kA is specified. This most likely reflects the higher applicability of the standards compared to prospective arrester stress.

5.6.7 Pollution performance

Pollution does not pose a threat to GIS arresters. However, such risks as external flashover, partial heating of the active part and internal partial discharge tend to increase for AIS arresters. A certain creepage length on the insulators is normally specified for AIS arresters. In Russia, 21600 mm is specified and in China around 25 mm per kV (system voltage). Specific tests for verifying AIS arresters under polluted conditions are not covered in available papers.

5.6.8 Mechanical strength

Information on mechanical strength is not presently available. However, due to the size of UHV arresters, AIS in particular, the mechanical requirements are demanding. Different solutions comprising high-strength fiberglass tubes with external silicone rubber insulation for pedestal mounting or molded designs with silicone rubber insulation for suspended mounting have been suggested [5].

5.6.9 Short-circuit rating

Italy's project is the only one for which a short-circuit current rating of 63 kA is specified. The other projects also have requirements on short-circuit performance, but they have not yet been published in available papers. Considering the huge size of UHV arresters and possible severe consequences of an arrester exploding due to overload, performance under short-circuit conditions is an important issue. Furthermore, AIS arresters are most probably located very close to other equipment in order to achieve the desirable protection, which of course makes it even more important that a possible arrester failure occurs in a "controlled" way.

5.7 Shunt Reactor

EHV/UHV shunt reactors have retained their position as a reliable, less expensive source of consumption of excessive reactive power from transmission lines. In comparison with shunt reactors connected to the tertiary winding of an EHV/UHV transformer, the EHV/UHV shunt reactor provides two important benefits: it is more effective because it is not placed beneath the reactance of the transformer, and it can limit TOV when connected to the line end. Practically, connecting EHV/UHV shunt reactors to the line is necessary if the line length exceeds approximately 300 km at 750 kV or 200 km at 1000–1200 kV. Such shunt reactors must be switchable, and proper automation or spark gaps (used in Russia) are needed to ensure fast connection to the line for limiting switching overvoltage and TOV at possible line faults or switching errors. In combination with FACTS technology, EHV/UHV shunt reactors provide good control of planned and fault regimes. Last year, magnetic-controlled shunt reactors appeared on the market, but this technology has not yet been applied directly to 750 kV or higher voltages and it is mainly limited to lower voltages or to transformer tertiary winding connection schemes.

Although similar to EHV/UHV transformers in many design details, EHV/UHV shunt reactors have some specific features. First, they may be switched approximately 100 times more frequently than transformers with a correspondingly higher number of switching overvoltages applied to their insulation. Second, when placed on the remote end of the switched line they experience more severe TOVs than transformers. Third, they require more of a linear magnetization curve then transformers in order not to become a powerful source of higher harmonics, which frequently leads to a gap in their magnetic core and magnetic shields preventing overheating of their tank. Four, if used in 4-legged reactor schemes for secondary arc suppression, they may need a somewhat increased level of insulation for their neutral.

Unfortunately, less attention is paid to the requirements and design of UHV shunt reactors compared that that for the transmission lines, circuit breakers, arresters or transformers, so available information is very limited. In Russia, 1150 kV shunt reactors were produced and put in operation and UHV shunt reactors will be an integral part of the 1000–1200 kV systems under development in China and India.

The main characteristics of UHV shunt reactors in Russian, China and India are summarized in Table 5.7.1. [7], [8], [9], [10]

***Table 5.7.1**. Main characteristics of UHV shunt reactors*

Country	***Russia***	***China***	***India***
Nominal/Maximum operating voltage, kV	1150/1200	/1000	1200/1250
Capacity of 3-phase group, MVA	900	600, 720 or 960 (preliminary estimate)	500 or 660 (preliminary estimate)
Positioned on line ends?	Yes	Yes	Yes
Switchable?	Yes	Yes	Yes
Automation for fast switching?	Spark gaps plus automation	?	
Application of 4-legged reactor	Yes	Yes	
Permissible TOVs, L-G, p.u.	20 s-1.30, 5 s-1.35	0.5 s-1.4	1.35
Level of switching surges on line end, L-G, p.u.	1.8 (1.6) *	1.7	
Power frequency 1-min withstand test voltage, L-G, for line side, kV ef	1100 (1000) *	1100 (5 min)	
Same for the neutral	120	?	?
Power frequency 1-hr withstand test voltage, L-G, for line side, kV	900	950	
Switching surge withstand test voltage, L-G, kVp	2100 (1800) *	1800	
Lightning impulse withstand test voltage for internal insulation, L-G, on full wave, kVp	2550 (2250) *	2250	
Same on chopped wave	3200 (2550)*	2475	

Note: * Values not within parentheses are for Russian equipment developed prior to 1985, protected by zinc oxide gapped arresters and actually installed on 1150 kV transmission lines; Values within parentheses are for equipment newly developed and protected with MOVs.

References

[1] China 2006, ACTECH006, "Study on Insulation Coordination in 1000kV UHV AC Transmission Project".

[2] China 2006, ACTECH007, "Study on Overvoltage and Insulation Coordination for 1000 kV AC Transmission System".

[3] IEC/CIGRE UHV symposium Beijing 18-21 July 2007, paper 2-5-1. "Development of 1100 kV AC GIS-arrester and the Verification Tests"

[4] IEC 60099-4, Edition 2.1, 2006-07 "Metal-oxide surge arresters without gaps for a.c. systems"

[5] IEC/CIGRE UHV symposium Beijing 18-21 July 2007, paper 2-5-1. "MO surge arresers for systems above 550 kV – Experience and challenges for the future –"

[6] A3-07(WG22)141 "Italien 1000 kV project" by E. Colombo.

[7] Reference Book on HV Electric Installations, I. Baumshtein and S. Bazhanov, Editors, Energoatomizdat Publishing House, Moscow, 1989, 768 pp. (in Russian)

[8] Gu Dingxie et al, "Study of Overvoltage and Insulation Coordination for 1000 kV AC Transmission System", IEC-CIGRE UHV Symposium, Beijing, July 18-21, 2007

[9] Shen Hong et al., Reactive Power Characteristics and Compensating Measures of UHV Transmission Systems, Ibid

[10] Du Shuchum et al., "Study of Insulation Coordination in 1000 kV UHV AC Transmission Project", Ibid

6 Conclusions and Future tasks

Technical specifications and service experience from all major UHV projects and trials have been reviewed in conjunction with relevant data from a number of commercially operated 800kV systems. From this review it is clear that there a number of technical topics which are particularly challenging in the UHV range and that, in many cases, simple extrapolation of assumptions from lower voltages is not appropriate. Several distinctive phenomena have been identified including a prominent Ferranti effect, large DC time constant of fault current, severe TRVs and slow front overvoltages, prolonged secondary arc extension and reduced first-pole-to-clear factor. All of these require study in more detail if UHV standardisation is to be successful.

To date the following conclusions can be drawn:

(1) Optimal insulation coordination to reduce the construction costs of UHV systems by applying compact transmission towers can be realised using high-performance MOSAs. The design of insulation coordination by means of accurate computer-aided simulations is common practise for such projects.

(2) The application of MOSAs can reduce the amplitude factors of TRVs for terminal faults, transformer limited or secondary faults and out-of-phase switching. Where such mitigation is applied circuit-breakers specifications could be modified accordingly however such reduction in TRV is not necessarily possible for so called long line faults where the TRV is generated at both sides of the circuit-breaker terminals.

(3) Circuit-breakers with opening resistors in combination with MOSAs can effectively suppress the TRV peak values and rates of rise for terminal faults, long line faults, transformer limited faults and out-of-phase switching. Where such mitigation is employed specifications should take account of the reduced requirements however without the application of opening resistors, careful specification of k_{af} and k_{pp} or even special test duties will be required.

(4) Several distinctive phenomena such as large DC time constant in the fault current, severe TRVs and secondary arc extension are created by the design of UHV transmission lines. Their effects on the specified duties of equipment should be considered in greater detail prior to standardisation.

(5) A range of DC time constants associated with fault conditions have been specified for UHV projects past & present, often exceeding the 75ms value specified in IEC for 550kV systems. Using the common assumption that the influence of the high DC component on the T100a test duty can be evaluated by the energy of the last major loop before the interruption, slope of current at the time of interruption and TRV characteristics, a value of 120ms appears to be appropriate to meet most UHV requirements. This value will be recommended as the special time constant for asymmetrical currents in test duty T100a based on international investigations.

(6) The line surge impedance for L90 and L75 duties could be reduced for rated voltages of 1100 kV and above on the basis that bundle contraction is unlikely to be completed when interruption occurs (within 50-80ms from fault initiation). This results from UHV transmission lines having 6 or more, large cross-section conductors, strung at high tensions.

(7) UHV shunt reactor switching overvoltages and mitigation measures (such as controlled switching) remain a topics for deeper investigation and development.

(8) Rapid auto-reclosing can be realised with either a high speed grounding switch or a four-legged shunt reactor scheme to suppress the secondary arc. A dead time of 0.3 seconds as commonly used for rated voltages up to 800 kV can be applied to UHV operating sequences.

Having reached these conclusions, WG A3.22 will continue to work towards developing a robust basis for UHV standardisation for substation equipment within the scope of SC A3 by pursuing the following activities:

- Collect further service experience from 800 kV systems and the latest testing experience from the UHV projects to ensure that "lessons learnt" are captured and disseminated.
- Study the effect of line length (especially long lines) on temporary, transient and switching voltages and overvoltages (TOV, SFO, FFO, TRV).
- Compare the data collected to date with new information from the Chinese (and maybe other) projects.
- Extrapolate the detailed studies and testing experience performed in Japan to address more general requirements.
- Consider, in a more general context, the physical effects and application possibilities of elements such as high grade MOSAs, opening resistors, MOVs in parallel with arcing chambers, controlled switching, etc.
- Consider, in a more general context, the effects, application possibilities, and relative merits of methods of secondary arc suppression (e.g. 4 legged shunt reactors, HSGS, switchable shunt reactors).
- Make specific recommendations for generally applicable values of key parameters for incorporation into future standards. As a minimum recommendations will be made with respect to first pole to clear factor(s), amplitude factors(s), peak factor/damping of transients, DC time constants, the need to cater for HF-components in SC-current, line surge impedance, out-of-phase switching conditions, effects of phase angle under stable condition, rate of rise of recovery voltage for transformer limited faults, TRV peak for long line faults, requirements for high speed grounding switches and for MOSAs, and capacitive (line) switching parameters.
- Review the service experience with 800 kV networks and equipment and make recommendations for the revision of the existing standards for EHV equipment if these are found to be deficient.
- Continued liaison with other Study Committees & Working Groups to ensure technical consistency within pre-standardisation recommendations.

This work will be reported in future technical brochures.