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OPTIMISATION OF PROTECTION PERFORMANCE DURING SYSTEM DISTURBANCES

Working Group
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Edited by
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Preface

In August 1996 Study Committee 34 (Power System Protection & Local Control) decided to form a working group with the objective of investigating how protection performance could be optimised during system disturbances. The work scope included a survey of protection behaviour during disturbances over the previous decade and the preparation of a report indicating best practice to optimise protection performance. Of particular interest was the co-ordination of protection/control schemes between different plant within the power system e.g. transmission and generation equipment.

The working group (WG34.09) was formed during 1996 and met for the first time in 1997 in South Africa. In the interim period a comprehensive questionnaire was prepared and circulated to a large number of utilities. The final report on this survey was completed in 2000 and published by CIGRE as Report No. 212 – Report on Survey to Establish Protection Performance during Major Disturbances. It was published in summary format in June 2001 Electra. The Working Group also presented a number of papers:

- *Brief Overview of Power Systems Disturbances and the Behaviour of Protection and Control;* IEEE PES; PSRC Panel Session Tampa, 1998: System protection & Planning Preventing Wide Area Disturbances.
- *Protection Philosophy and Strategies to Counteract large Area Disturbances*; CIGRE Symposium on Working Power Plant and Systems Harder, London 1999.
- *Review of Protection Behaviour during System Disturbances*; CIGRE SC34 Colloquium, Sibiu, 2001.

This final report of the working group attempts to identify the potential vulnerabilities of protection schemes in the event of major disturbances and recommend strategies to optimise protection performance. Given the rapid pace of technology development reference is also made to possible future improvements in such defence schemes.

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1. INTRODUCTION & TERMS OF REFERENCE

1.1 BACKGROUND

Large-scale interruptions and failures on electricity bulk supply systems have always presented a challenge to power systems engineers. When system faults occur, their rapid clearance by protection relays is essential to prevent the onset of a wide area disturbance. The prompt response by the control system (whether manual or automatic) is also crucial in containing the extent of the disturbance. Corporate and technical developments over the past decade within the electricity supply industry (ESI) also impact on power system security. Corporate restructuring is reducing system operating margins while new technologies may offer solutions in the form of system-wide rather than solely plant specific protection schemes.

Within the ESI the trend world-wide is to restructure vertically integrated utilities catering for generation, transmission and distribution (or various combinations thereof) into smaller "unbundled" companies. Plant owners wish to minimise operating costs through greater utilisation of existing assets. Furthermore the construction of new generation and transmission plant – in particular transmission lines – frequently meet concerted opposition for environmental reasons. Both these factors will reduce the rate at which new transmission plant comes into service and reduce the operating security of existing networks.

During the same period rapid advances have taken place in the field of numerical technology. Traditionally, within substations, the protection and control functions were dedicated to individual plant. Wide area disturbances have revealed serious weaknesses in this approach and numerous examples are available where unwanted relay operation or delays in operator response to a critical situation hastened if not caused system collapse. The concept of "wide area" or "system" protection may offer a better solution. The new technological developments should facilitate this through the significant progress being made in power system control, substation control, protection relaying and broadband communications.

The challenge for today's ESI therefore is to maximise plant loading without compromising system security. This may be achieved if a reduction in system operating margins is compensated by the provision of sophisticated control and protection facilities that are designed to counteract the effects of a major disturbance.

To address these issues CIGRE Study Committee 34 in 1996 formed a working group WG34.09 *Optimisation of Protection Performance during System Disturbances* with Mr. M. J. Mackey as Convenor. The scope of the group was to:

- Establish the present status of protection performance in relation to system disturbances
- Investigate the behaviour of protection schemes during disturbances
- Formulate recommendations as applicable in relation to:
  - Network control
  - Network protection including auto re-closure
  - Generator control
  - Generator protection
  - Load shedding and restoration.

1.2 REVIEW OF THE TYPES OF DISTURBANCES WHICH OCCUR

Extensive literature is available on the disturbances that have occurred throughout the world, particularly over the past 25 years [1]. While the initial incidents that triggered the disturbances vary the ultimate result was one or more of the following:

- voltage instability
- transient and frequency instability
- cascade tripping due to overloading (by either active or reactive power flows).

These issues are now briefly reviewed.

1.2.2 Voltage Stability

Voltage stability is defined as [2]: The ability of a system to maintain voltage so that when load admittance is increased load power will increase such that both power and voltage are controllable. Instability occurs when heavy system loading creates large reactive power demands that result in an excessive voltage gradient between generation sources and load centres. Typically it arises when sources of reactive power are suddenly lost to a heavily loaded system e.g. due to tripping of a transmission link or a generator. In the past utilities have tended to rely on planning criteria and operational measures to ensure voltage stability. More recently, dedicated systems have been introduced to detect risk situations on the system and include remedial measures such as blocking the operation of transformer on load tap changers (OLTCs) [3,4]. Switched capacitor banks as well as static VAR compensation (SVCs) are being employed to maintain dynamic voltage stability. Under-voltage load shedding has been suggested also as a means of preventing voltage collapse [2] but little information is available on operational experience with such schemes. These will be discussed further in Sections 3 and 6.

1.2.1 Transient and Frequency Instability

Transient or angular instability is very often a precursor to frequency decline in a power system. It manifests itself through out-of-step generator behaviour or power swings. It is basically caused by the dynamic interaction between the rotors of the generators and prime movers that feed power to the system. The initial symptoms are power swings which, if sufficiently severe and if no corrective action is taken, will cause the generators to pole slip i.e. lose synchronism. Relays can be arranged to trip such that system separation takes place along a predetermined boundary and achieves a number of islanded sectors. This restricts the instability to individual sectors rather than affecting the power system as a whole.

In relation to instability prediction, simulations using the well-known equal area criterion continue to be performed. This proves very satisfactory as long as the two-machine model closely represents the power system. Sophisticated schemes utilising on-line information are also used nowadays and trip generation if critical interties are lost.

On islanded systems a generation deficit is immediately indicated by a frequency decline. By setting under frequency relays to shed load in predetermined blocks a stable generation/load match can be quickly restored.

1.2.3 Cascade Tripping

Cascading typically commences when the tripping of a transmission circuit, due for example to the operation of a protective relay, causes overloading of the remaining circuits. These then trip sequentially splitting the system into different sectors. Subsequent restoration is greatly assisted if system separation follows a planned pattern so that islands are formed which have the potential to stabilise a generation/load imbalance. If load shedding relays are installed this balance may be achieved quite quickly.

Cascade tripping of generators usually occurs during a voltage decline on the system when, in attempting to increase reactive power output, field current limiters operate to trip the units leading to a rapidly deteriorating voltage profile followed by similar tripping of remaining generators.

1.3 APPROACH ADOPTED BY WORKING GROUP

The Working Group concentrated on three areas:

- The impact and behaviour of traditional plant-dedicated protection during disturbances;
- The behaviour of traditional system protection schemes (e.g. load shedding) and modern improvements to such schemes;
- New control and protection systems that prevent or counteract major system disturbances.

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[3] Harmand Y.,Trotignon M., Lesigne J.F., Tesseron J.M., Lemaitre C., Bourgin F. *Analysis of Voltage Collapse Incident and Proposal for a Time Based Hierarchical Containment Scheme ;* CIGRE Paper 38/39-02, Paris, 1990.
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2 REVIEW OF DISTURBANCES

2.1 CASE STUDIES

The initial task of the Working Group was to review a sample of disturbances that had occurred in the recent past. The case studies, summarised in Table 2.1, were selected on the basis of giving a representative sample of disturbances on different types of system

Disturbance	Cause	Development	Effect/Severity/	Restoration
EDF, France 12/01/1987	Generation deficit causes severe volt drop in NW France	OLTC operations aggravate situation; voltage collapse spreads leading to generation loss; RCC instigate load shedding.	8,000MW of load lost; 14.5 System Min.	To all customers took 4 - 5 hours.
REN, Portugal 27/07/1989	Line faults caused a number of trippings; Central Control opened an important tie to Spain	Power swing developed between north and south causing 400kV tie to trip and splitting system into 2 sections	Voltage collapse in north, generation deficit; widespread tripping including ties to Spain causing blackout of northern section. 14.5 System Min.	Restoration took just over 2 hours.
ESKOM, S. Africa 08/11/1990	Spurious trip of important tie by OV protection	Second tie trips; third tie overloaded; system splits	Blackout in Cape 9.2 System Min.	Difficult, took 104 minutes
EGAT, Thailand 3/03/1993	Bus fault at protection blind spot; back-up line protection trips.	Line overloading leads to manual and cascade tripping	37% of load lost; grid split into 3 sections. 26 System Min	Took 2.5 hours; some confusion re communication in control rooms.
ENEL, Italy 20/, shown on Table05/1993	Important tie tripped correctly; spurious trip of second tie	Overload trip of third tie splits system	Approx. 4,000MW shed 3.8 System Min.	System restored within 15 minutes
San Andrés, Spain 24/8/1993	Clearance of substation fault in third zone back-up time due to lightning damage to primary protections and infeed at teed feeders	Due to voltage dip, auxiliary service under voltage relays trip the three neighbouring nuclear power plants, and a blackout in north eastern Spain ensues	6400MW lost 15 system minutes	40% restored within 2 hours, full restoration within 3.5 hours.
HEC, Australia 12/01/1994	Bus prot. failed to clear bus fault quickly; incorrect line trip	Power swings develop causing distance relay trips; overload cascaded trips.	75% of load lost	
ESB, Ireland 07/02/1994	Trip of important tie line and generator in quick succession	Frequency fall and load shedding	12% of load lost; 3.75 System Min.	86% load autorestored in 30minutes; remainder in 17-78Min
SECWA, Australia 24/03/1994	Weather conditions cause line trips	Line trips lead to generation loss followed by overload cascade tripping	Extensive blackout 214 System Min.	Complete restoration took 7 - 8 hours
ESKOM, S. Africa 07/06/1996	Slow clearing bus fault caused number of line backup trips; second busfault caused further trips	Power swing develops causing distance protection tripping system splits	Cape area sheds load and successfully islanded. 2.69 System Min.	Satisfactory, took 1hour to resynchronise system and 2 hours for all loads.
TNB, Malaysia 3/08/1996	Fault at stuck breaker; CB Fail and back-up E/F protections trip	922MW generation lost Frequency falls rapidly	Cascade tripping of gas turbines; level of load shedding inadequate; blackout	Took up to 4 hours
WSCC, USA 10/08/96	Combination of heavy load and transmission line outages together with line trips due to faults lead to overload tripping	Negatively damped power oscillations initiated; interties opened due out of step and low voltage.	System divides into 4 islands; extensive blackout in California 18.4 system-minutes	Up to 5 hours to full restoration

Table 2.1: Summary of the Disturbances - Causes, Development, Effects.

The objective was to study the behaviour of islanded, strongly interconnected and weakly interconnected power networks as well as systems from different parts of the world. Each disturbance is assigned a Degree of Severity defined as follows [1]:

Degree 1: An event having a severity from 1 to 9 System Minutes.
Degree 2: An event having a severity from 10 to 99 System Minutes.
Degree 3: An event having a severity from 100 to 999 System Minutes.

Of the twelve cases summarised on Table 2.1 [2,3,4] five of the most severe are now examined and the impact of protection and control evaluated.

2.1.1 Major Loss in WSCC System, 10 August 1996 [3]

Figures 2.1, 2.2 show the geographical extent of the WSCC system. The operating conditions on August 10 were characterised by very high load and. high north to south transfers. The power flow was within parameters established as a result of a previous disturbance on July 2.

Initiating Cause

During the day, at 14:01 and 14:52, two 500 kV lines in Oregon flashed over to trees. At 15:42 one more 500 kV line tripped after flashing to a tree. Other lines picked up the power increasing the reactive requirement. However with several 500 kV lines out of service significant MVAR transfer capacity was removed from the system. There were many alarms of low voltage in the area and the dispatchers requested maximum reactive support from the power stations. One plant that had responded dynamically to the loss of the 500 kV line with increased reactive output reduced output due to operator intervention after approx. 30 seconds.

At 15:47 a 115 kV line tripped due to a zone 1relay malfunction. A few seconds later an overloaded 230 kV line tripped after sagging too close to a tree and flashing over. At the McNary power station the units boosted their reactive output for a short time, then began tripping. This resulted from the erroneous operation of a phase unbalance relay in the generators exciter.

Development

An oscillation started within the system that became negatively damped. Shunt capacitors were switched in both automatically and by operator action. The oscillation increased to approx. 1000 MW and 60 kV at a station called Malin and the voltage collapsed (15:49). This changed the power level on the Pacific DC intertie (PDCI) and the remedial action scheme responded by inserting both a shunt capacitor group and series capacitors on three 500 kV lines. At the same time a 500 kV line tripped due to a zone 1relay operation.
Within the next two to three seconds the ties between northern California and neighbouring systems, and between Arizona/New Mexico/Nevada and Utah/Colorado opened due to out of step and low voltage conditions. Two seconds later northern California separated from the south because of out-of-step conditions and low voltage. Alberta also formed a separate island. The frequency in the northern California Island dropped and under-frequency load shedding tripped about 50 percent of the load. Numerous generators also tripped for various reasons such as loss of synchronism, loss of field, over-excitation (volts/hertz), under-frequency, vibration and line trippings.

At low frequency San Francisco was automatically separated from the rest of the Northern California Island.

Restoration
In total about 30,000 MW load was lost for 7,5 million customers. It took up to five hours before all were restored. In California restoration was impeded by the large loss of thermal generation. The first interconnection to Oregon was restored at 18:18 and to the south at 18:47.

Other observations:
Two Converters of the PDCI and an SVC unit blocked then the valve cooling systems tripped due to low voltage.

Conclusions
Some of the conclusions and recommendations made by WSCC:
- Pursue implementation of on-line power flow and security analysis to detect that the system is at risk.
- Review the application and setting of PSS and other possible oscillating damping controls such as HVDC modulation.
- Ensure that instructions to system operators relating to the reactive requirements of the system are adequate.
- Ensure that generating units will provide proper steady state and dynamic voltage support.
- Consider implementing under-voltage load shedding.

2.1.2 Blackout of Cape Area in ESKOM System, South Africa, on 8 November, 1990

Prior to the disturbance the ESKOM system was operating with a generation surplus in the northern part but a deficit in the southern network in the Cape area where one of two 920MW nuclear units was out of service. Power totalling 1,900MW was being transferred to the Cape via three incoming series compensated 400kV lines at Hydra substation - an important node in the ESKOM system [2]. See Figure 2.1.

Initiating Cause:

At 11.48.24h, at Hydra, a faulty selector switch on the battery charger booster caused intermittent failure of the DC supply. Due to a design defect this caused spurious operation of the over-voltage protection on one of the incoming 400kV lines. Because the series capacitor on one of the remaining lines was out of service load divided in the ratio 750/1,265MW. However the thermal limits (1,147/1,524MW) were not exceeded and operation remained stable. At 11.48.45h the second 400kV line, carrying 1,265 MW, was tripped at the remote end by the negative phase sequence (nps) element in the distance protection. Setting was 15% and estimates indicated nps currents of at least 13.5%.

The total load of 2,000MW now exceeded the transfer capability of the remaining uncompensated line and the two systems lost synchronism. Almost immediately, at 11.48.47h the remaining nuclear unit in the Cape tripped to house load. The remaining tieline tripped on overload at 11.48.59 resulting in complete blackout of the

Cape area. The total interrupted load was 2,464MW - all in the Cape area - with unserved energy of 3,336MWh.

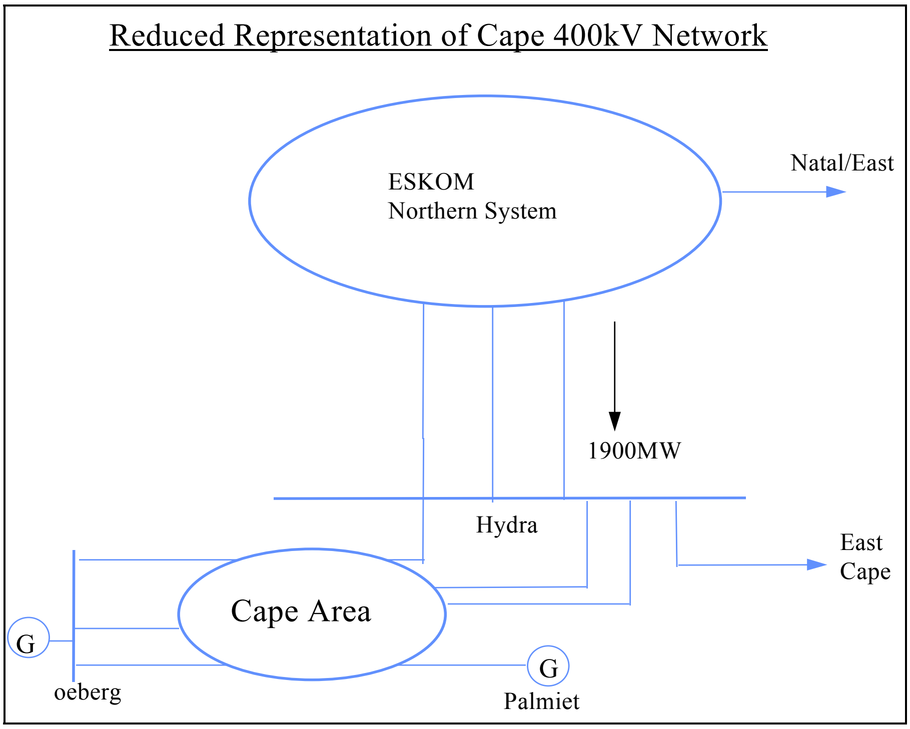


Figure 2.1: Simplified ESKOM 400kV Network in the Cape Area

Three unsuccessful attempts were made to re-energise the 400kV grid with the fourth attempt finally succeeding at 13.10h. At 13.18h the nuclear plant was resynchronised and all load was restored at 13.33h. Restoration of the main grid was delayed by a number of factors:

- Poor location and setting of power swing blocking/tripping relays prevented their operation; this rendered impossible the creation of an island around the nuclear plant that would have considerably reduced the severity of the disturbance.
- Relay defects caused distance protection to trip spuriously following re-energisation of the grid thus delaying restoration.
- The DC defect at Hydra also affected supply to power line carrier circuits routed through Hydra substation causing a number of vital RTU's to go out of scan in the affected area.
- Hydra was jammed with calls from protection and distribution staff, making communication between Central Control and Hydra very difficult.
- Procedures regarding information exchange between operating staff and National Control were unclear resulting in latter having inadequate information.

Conclusions

The severity of the disturbance was 9.17 system-minutes (severity degree 1).

The difficulties experienced have been addressed with the objective of preventing a recurrence in the future. The design defects which initiated the disturbance have been rectified by the manufacturers.

2.1.3. Islanding of Cape Area in ESKOM System, South Africa on 7 June, 1996

This disturbance arose because of two serious faults occurring in relatively quick succession causing the islanding of the southern (Cape) network from the rest of the ESKOM system [2]. See Figure 2.2 for simplified sketch of ESKOM transmission in the Cape area.

<u>Initiating Cause</u>:

At 16.00h in Grootvlei substation a CT on a 400kV bus coupler exploded initiating an R phase to ground bus fault. The busbar protection did not operate immediately and a

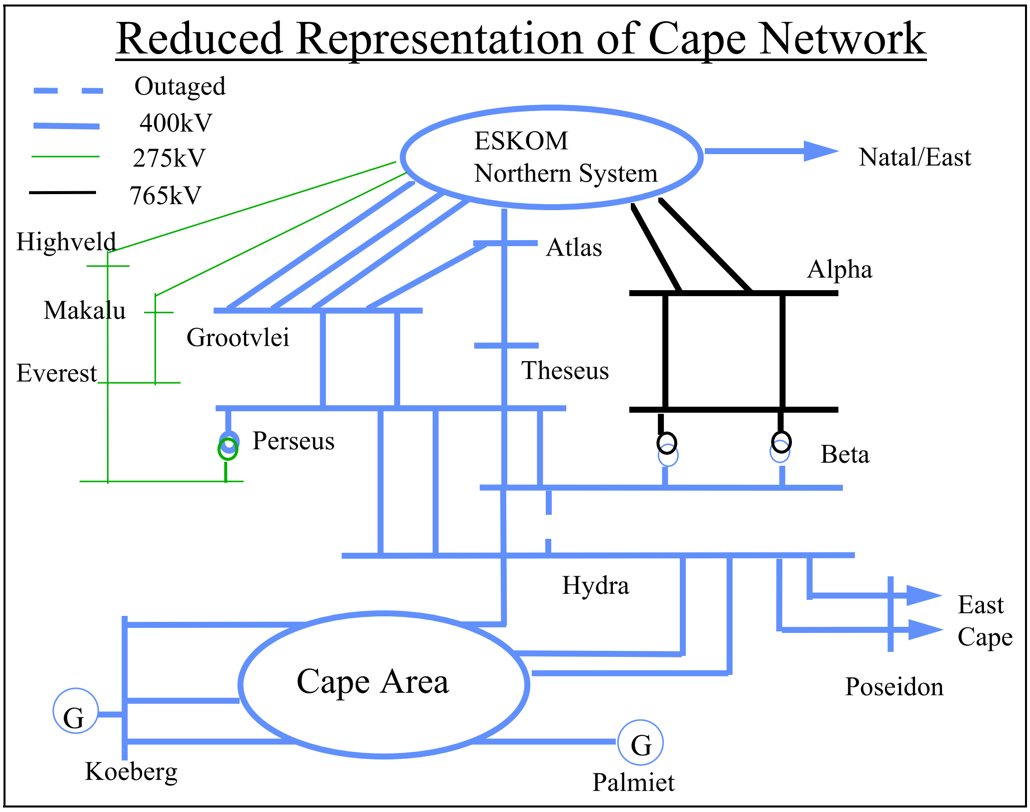


Figure 2.2. Simplified Representation of ESKOM System

number of distance protections on connected lines tripped on remote back-up. Within 0.5 seconds the fault had evolved to a two phase short circuit and the bus protection tripped all remaining circuits. The system at this stage remained stable and no load was lost.

Approximately 33 minutes later in the 765kV Alpha substation an open line/reactor busbar link on the Beta line flashed over initiating an S phase to ground fault. This was immediately cleared by the busbar protection in 32 ms.

Development:

The only ties now remaining between the Cape and the rest of the system to the north were one 400kV line (Atlas - Theseus - Perseus) and two 275kV lines (Highveldt - Everest, Makula - Everest). As this link was relatively weak a power swing developed between the northern system and Koeberg power station. In Perseus substation both Hydra breakers were tripped when the distance protections' zone 1 operated due to the power swing. The power swing blocking setting was inadequate.

After a further 1.1 seconds the same busbar link at Alpha flashed over again, this time on the reactor side of the link i.e. involving a different bus zone to the first flashover. The resulting phase to ground busbar fault current was too low for bus protection operation and the fault was only cleared after 404ms when the Alpha - Beta line was correctly tripped at Beta by distance protection zone 2.

After this second fault at Alpha the system was experiencing severe out of step conditions on remaining ties to the Cape with pronounced current and voltage oscillations. After a further 3 seconds power swings caused the tripping of a further three 400kV lines in the Cape subsystem by distance protection. In at least one case the power swing frequency was too high (2Hz) to block the relays which were set for 1.2Hz. (See also Appendix 1 for performance of out-of-step protection).

The Cape system was now operating as an island with generation at Koeberg.

Excessive reactive power led to severe over-voltages in the Cape (voltages of up to 540kV were measured) causing a number of feeders within the Cape subsystem to be tripped by over-voltage protection. The Hydra - Poseidon lines did not trip as they were not equipped with over-voltage protection. Hence Eastern Cape remained in parallel with the rest of the system.

A generation deficit of 860MW caused the frequency to fall to 48.2 Hz. Under-frequency relays shed 635MW in Southern and Western Cape. Koeberg reduced output from 1,390MW to 1,070MW and Palmiet automatically changed over from synchronous condenser operation to pick up 235MW. Although the Eastern Cape remained connected to the system, for reasons unknown 167MW were shed through the operation of some under-frequency relays. (Thus the total load shed of 802MW represented 3.5% of the prefault system generation of approximately 22,380MW).

The Cape separation caused a 2,400MW mismatch on the northern system. Within 12 - 16 seconds a 1,200MW generation reduction stabilised the frequency at 50.4Hz. The response would have been better except that fewer generating units were on AGC than was intended.

A consequential effect of the Cape separation was to introduce a power swing through the ZESA system to the north (in Zimbabwe). This caused distance protection on interconnecting lines to trip thus separating the ESKOM and ZESA systems (16.37h). The ESKOM frequency increased to 50.6Hz.

Restoration

The Cape island made up load with Koeberg supplying 1,350MW, Palmiet 235MW and other generators 144MW i.e. a total of 1,729MW. The philosophy of restoration was to obtain a strong system interconnection from the north into Perseus and Hydra prior to re-synchronising. This would ensure that instability would not recur and cause a second islanding situation.

Although inadequate knowledge of the complete extent of tripped breakers resulted in some complications the restoration process worked well and an additional generating station was started to reduce line loadings. Some difficulties resulted from the fact that at the control centre one transmission desk proved inadequate for different teams to work effectively together. Also the location of the fault in the Alpha GIS proved difficult and delayed restoration. At 17.36h the island was eventually resynchronised with the main system using a check synchronism relay in Proteus. Slow supervisory systems delayed load restoration. However most customers were reconnected by 18.30h.

Conclusions

The severity of the disturbance was 2.69 system-minutes (degree 1).

Performance of fault recording equipment was very good facilitating immediate, detailed analysis. While overall protection performance was very satisfactory, unnecessary tripping of five 400kV lines resulted from failure of power swing blocking on distance protection. Nevertheless most protection and frequency control systems operated correctly and quickly achieved a stable islanding of the Cape system. Some problems were identified for further attention. These mainly related to the primary equipment that failed.

2.1.4 TNB Blackout, Malaysia 3 August, 1996

When taking the Paka – Kenyit 275kV No. 1 Line out of service for maintenance work one pole of the circuit breaker at Paka failed to open due to a broken operating rod. Maintenance personnel unaware of this condition proceeded to open the associated isolators [5].

Initiating Cause

Whilst opening the line isolator at Paka an arc appeared across the opening Y phase (which was still live) of the line isolator contacts and it subsequently flashed over to the metallic support base. The fault was detected by Directional Earth – Fault. Comparison protection (echo feature) that initiated breaker failure protection to isolate the affected section. At the same time, backup over-current protections on a double-circuit IPP interconnection at Paka power station operated disconnecting the IPP generating sets (922 MW) from the Grid. Under frequency load shedding was activated including opening of the intertie to Singapore Power Ltd.

Development

+3 sec: Segari and KLPP gas turbine (GT) generators trip (340MW). Under frequency load shedding ensues.

+11 sec Serdang GT tripped (200 MW). Further under frequency load shedding.

+15 sec Segari, KLPP, Paka, Serdang GT tripped (427MW).

+16 sec Serdang, Pabau, CBPS, GT tripped (520MW)

+19 sec Remainder of gas turbine and steam plants tripped leading to total system blackout.

Too much information during initial stages presented problems for operators.

System Restoration

Time	Power Station Restoration	Capacity (MW)
20.20 pm	Temenggor, Jor, Woh	680
20.36 pm	Pasir Gudang, YTL Pasir Gudang	330
0.00-0.30 am	Kenyit, TYL Paka, PD Power, Bersia	380
2.00 am	Powertek, Serdang	330
3.00 am	Serdang, Port Klang GT, Segari	440
5.00 am	Segari, Kenering	60
6.00 am	Port Klang GT, PD Power, Kenyir	530
7.00 am	Pasir Gudang, PD Power, Penang, Segari	550
8.00 am	PD Power, Powertek	220
9.00 am	Kenyir	100
	Total Generation at 9.00 am	3620

Supply restoration was effected by initially operating power stations in six small groups. As each group stabilised, it was then synchronised to the grid system. Supply to the northern tip area was restored from EGAT (Electricity Generating Authority of Thailand) and in the southern area by power from SPL (Singapore Power Limited). Some units were able to black-start but failed to synchronise onto dead bus. A hydro unit that experienced hunting caused wide frequency excursions in the first 3 hours. System wide communications was not satisfactory because of insufficient telephone linesThe availability of telecommunication circuits was interrupted for certain substations during the disturbance due to the interruption of DC power supplies.

Conclusions

The severity of the disturbance was 573 system-minutes (severity degree 3).
The power system interruption originated from a defective 275kV circuit breaker at Paka substation resulting in an initial loss of 922MW generation from Paka and YTL Paka power stations. This resulted in rapid frequency decline. Cascaded tripping of Gas Turbines on “High Temperature” & “Flame out” ensued resulting in additional loss of 2113MW in the west coast.

Contingency measures taken to assist system recovery included the provision of 550MW spinning reserve and 1500MW underfrequency load shedding. However the generation loss was too high for the contingency measures to have any impact, thus total system loss was unavoidable.

Gas Turbines
Gas turbine units comprised 55% of total generation. Their performance during the disturbance aggravated rather than improved the situation. Gas turbines decreased power output to the extent of tripping out completely. In many cases this was caused by flame-out while overtemperature was also a prime cause.

Under-frequency relays
Some under-frequency relays were not in-service due to defects, while others had not yet been commissioned and/or not even installed. Also the load level set to be shed (1500MW) was inadequate.

Remote back-up protection performance
Back-up protection on the IPP interties operated slightly earlier then intended because it had been incorrectly set.

Operational procedures were reviewed and practised on an ongoing basis to minimise delay in restoration process. Spinning reserve was increased to a higher proportion of non GT generation. Under-frequency load shedding (UFLS) quantum was increased from 1500MW to 4000MW and redesigned to have more stages (from 5 stages to 17 stages). Latter is intended to minimise over-tripping and consequential over-voltages. New 275/132kV substations are to be equipped with substation automation systems. Selected existing substation will be retrofitted with similar systems.

2.1.5 San Andrés, Spain 24 August, 1993

The 220kV network in the Barcelona region of north east of Spain is heavily 220kV meshed. Prior to the disturbance, generation in the area included three nuclear units totalling 2600 MW and several coal plants totalling 1100 MW. The load in the area was 3700 MW.

A lightning strike to a 220kV substation near Barcelona initiated a double phase to ground fault that local protection systems failed to clear. Due to infeeds from teed feeders, remote back-up protection required up to 0.89 seconds to clear the fault. Prior to this, at 0.74 seconds the three nuclear units tripped on operation of their under voltage auxiliary service relays. At 0.79 seconds the four 400kV ties to the rest of the system tripped on distance relay operation and also due to one relay maloperation. At 1.62 seconds, the area was completely islanded and subsequently blacked out.

<u>Conclusions</u>

Protection application criteria applicable to all the Spanish utilities have been agreed upon and are being implemented. The objective of these criteria is to minimise disturbance escalation. In relation to short-circuits, the clearance time must be less than the critical clearance time even for n-1 protection system failures (including breaker failure). Critical clearance time (tc) is that below which the consequences of a disturbance are permissible to the system. Permissible is defined as generation loss not exceeding 1,000MW and retention of interconnection to France. Extensive dynamic simulations were carried out to identify tc for all the 220kV and 400kV nodes of the network. In several heavily meshed areas critical clearance time is not achievable with conventional protection practices. Other measures, such as reducing the probability of short-circuits or plant disconnection, must be considered. Criteria are also established for generators. Units must remain stable for as long as possible and the generator protection must be coordinated with the network protection systems.

Following detailed plant analyses, settings of the auxiliary services under voltage relays have been increased to the maximum possible in several large plants.

Teed lines in areas of the transmission network where short-circuit clearance time is critical have been unteed.

Overall restoration plans have been established. In this context it should be noted that a restoration process in an unbundled system involves more dispatching centers and this fact must be carefully catered for in the plans.

2.2 SURVEY

Country	No. Responses	No. Utilities
Brazil	3	1
Canada	1	1
Czech Rep.	1	1
France	1	1
Germany[1]	1	Various
Ireland	12	1
Italy	1	1
Japan	6	5
Malaysia	1	1
Norway	2	1
Portugal	7	1
South Africa	2	1
Spain	6	3
Sweden[1]	1	Various
Switzerland[1]	1	Various
United Kingdom[1]	1	3
USA[2]	23	21
Totals 17	70	42+

[1]No major disturbances reported
[2]All responses based on NERC records.

Table 2.2: Response to Questionnaire on Protection Performance

A survey, to cover the period 1986 to 1996, on the behaviour of protection schemes during large system disturbances was undertaken by the Working Group in order to establish the effectiveness of existing protection systems in preventing disturbances [6].

A total of 70 responses were received from over 42 utilities in 17 countries. Apart from 4 countries that recorded no disturbance in excess of the severity levels indicated in the time period concerned, over 60 major incidents were described. Table 2.2 refers. The evaluation and analysis of the questionnaire responses attempted to identify common behavioural patterns for the different networks surveyed and to examine the role played by protection equipment in curtailing or exacerbating the disturbance.

2.2.1 Details of Disturbances

2.2.1.1 General

Questions 2 and 3 in the Questionnaire dealt with the network data prior to the disturbance and the description of the entire disturbance (date, period, causes, severity, conclusions…). The level of response relating to system data immediately prior to the disturbances was poor. Consequently the available information was inadequate for reaching any particular conclusions. Table 2.3 indicates the severity of the different disturbances. Many responses did not indicate disturbance severity.

The objectives of the questionnaire were to:

- review significant disturbances which have occurred since 1986 (i.e. where load loss exceeded 1 system-minute or generation loss exceeded 10% peak demand);
- identify and categorise the cause and nature of the disturbances;
- collect user experiences relating to behaviour of protection and control systems during such disturbances.

The questionnaire was circulated - mainly through the SC 34 members - to 29 countries. It was composed of five parts dealing with information on different aspects of the disturbance:

- general information on the network and the utility.
- status of the network prior to the disturbance.
- disturbance, its cause and development.
- performance of protection and control during the disturbance.
- influence of the disturbance on the operational and control philosophy of the utility.

2.2.1.2 Causes of disturbances

The initial causes of the disturbances are summarised in Figure 2.3. The causes of disturbance escalation are also indicated. These allow classification of events in terms of the primary cause of each disturbance and are grouped as follows:

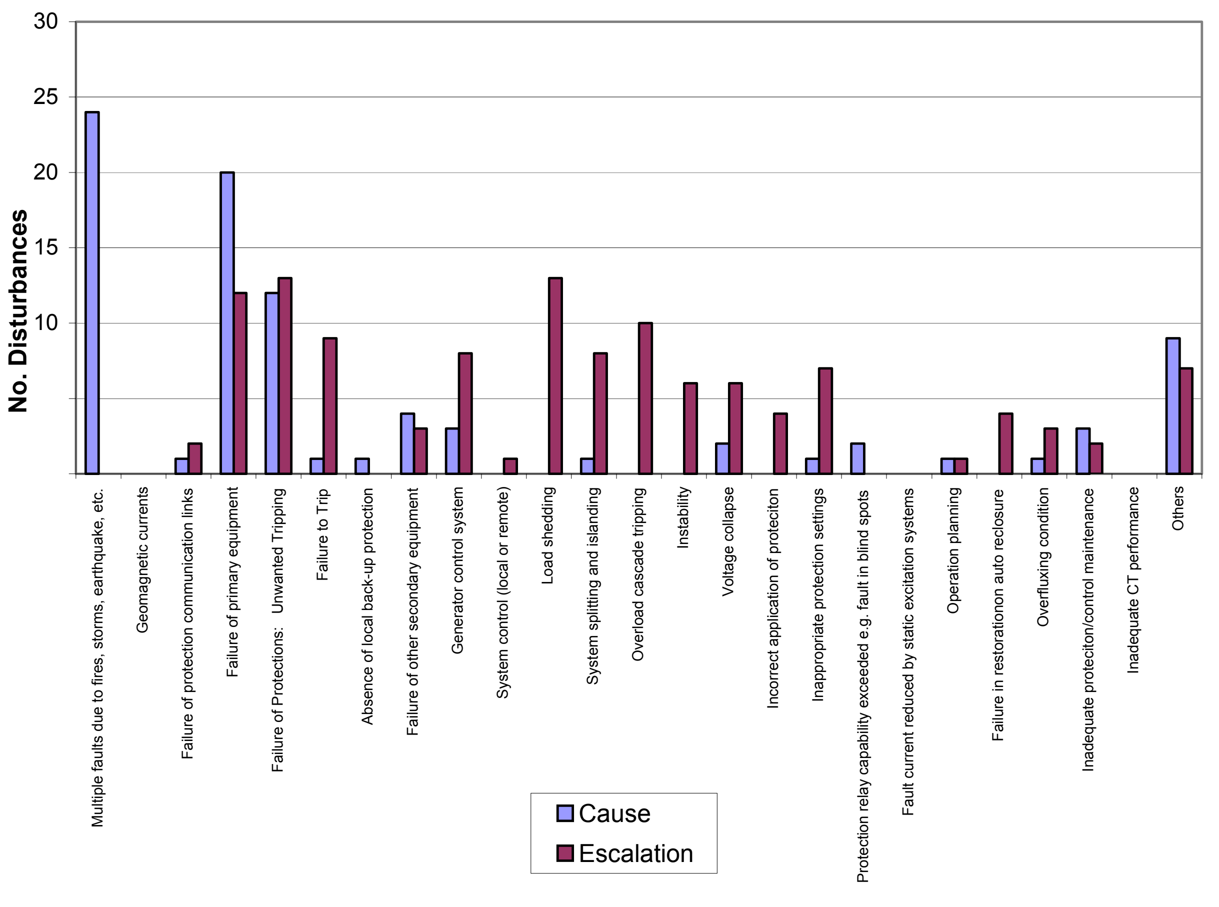
- Multiple faults due to natural events: Vegetation fires, storms, earthquake etc. (24 cases).
- Failure of primary equipment (20 cases).
- Protection maloperation (13 cases).
- Other causes (9 cases)
- Miscellaneous (20).

	No. of Disturbances by Region						
Severity	Asia excl. Japan	Japan	North America	South America	Africa	Europe	Total
1			2		2	8	12
2		1	2	3		7	13
3	1					1	2
4							0
Total	1	1	4	3	2	16	27

Disturbance severity category as defined by CIGRE SC39 in terms of system minutes [1]:
1-Energy loss between 1 and 9 system minutes. 2- Energy loss between 10 and 99 system minutes.
3-Energy loss between 100 and 999 system minutes.
System minute = system peak demand interrupted for one minute.

<u>Table 2.3: Summary of Disturbances – Level of Severity</u>

Figure 2.3: Immediate Causes and Factors Escalating the Disturbance



2.3 CONCLUSIONS

Analysis of the questionnaire responses was impeded by the lack of uniformity in the recording of information by the respondents. Furthermore a lot of questions received no response. For example, the lack of comparable data on generation/load/energy loss prevented analysis of the impact of the disturbances in that context. Nevertheless definite indicators are available from the survey. While the avoidance of large scale disruption is probably impossible during catastrophic natural disasters protection maloperation together with primary plant failure were primary causes in many disturbances (see Figure 2.3). In terms of escalating the disturbance protection maloperations and other related relaying functions such as failure of load shedding relays, cascade tripping, etc. played a significant role. Clearly there appears to be considerable scope for improvement in the area of protection and control.

The majority of the sixty plus events that were reviewed arose from multiple faults due to natural events or to the catastrophic failure of primary plant i.e. the majority of events resulted from the loss of multiple network elements during normal operation of the system. The optimum solutions to these events would be the construction of multiple redundant facilities to protect against multiple contingencies or to build generation sources closer to the loads. Both these options are not usually feasible from a resource or economic standpoint. However improved protection and control systems would considerably reduce the impact of such events.

The questionnaire responses were ranked on the basis of "1" for very unsatisfactory up to "5" for highly satisfactory. Approximately 15% of disturbances were caused by second contingencies resulting from unwanted protection operations or failure to operate for the initial event. While protection performance was reasonably good (overall score 3.9) there was a significant number of maloperations of feeder protection (average score 2.77). These were due to a variety of causes: failure to trip due to wiring error, out of step blocking fault clearance, inappropriate settings, low system voltage and/or overloads being the more common causes. Maloperation was usually due to a hardware failure rather than to a fundamental design deficiency. In many of these multiple contingency cases, Special Protection Schemes are already in place to shed large amounts of load and/or generation in an effort to stabilise the systems. Nevertheless more attention to the selection and application of relay settings, including adaptive features, will reduce unwanted operations while increased relay availability through better maintenance or self diagnostics will avoid failures to trip. The survey confirmed that fast clearance of faults, particularly on busbars, is vital to a system's ability to ride through disturbances. Duplication of protection systems and circuit breaker fail provision is essential on critical busbars and on high voltage lines since back up operation times often resulted in system splitting and cascading. The application of adaptive protection schemes to cater for transient conditions without tripping on power swings, overloads, etc., appear to promise significant benefits. This should be more easily realised with the widespread use of numerical relays. As mentioned a number of times in this report it would avoid instances where relay operation while correct was undesirable.

There were several instances of generator controls (e.g. AVRs) failing to operate correctly causing multiple unit losses that were unrecoverable from a system standpoint. Better co-ordination between generator and network control/protection schemes would be beneficial.

The remaining events were in general caused by events so catastrophic (earthquakes, extreme loads, multiple unit tripping, etc.) that no reasonable preventative actions could have been foreseen.

In the area of disturbance monitoring, time synchronisation of equipment was not widely used and could potentially be a great advantage in analysing major disturbances.

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3 REVIEW OF PROTECTION PERFORMANCE

3.1 BACKGROUND

Traditionally protection relays were equipment specific, albeit with the ability in many cases to provide back-up protection on adjacent equipment. Communications between devices was confined to end-to-end teleprotection links (to ensure fast fault clearance) or as part of system protection schemes (SPSs). The inter-tripping and rapid autoreclosure that this facilitated also had the objective of maintaining power system stability. An exception was the provision of under-frequency load shedding which was primarily intended to preserve system integrity through the avoidance of cascade tripping. In addition power swing protection was frequently employed as part of feeder distance protection relays. It was sometimes used to trip selected interties in an effort to confine disturbances to a particular sector of the network. More usually the power swing detection was used to block tripping as otherwise multiple uncoordinated network sectionalising could ensue during power swings. To eliminate the threat of damage to generation plant pole-slipping protection was employed to protect units considered to be at risk. No schemes were employed to prevent voltage instability although over-voltage and over-fluxing relays were used to protect plant in these particular situations.

In general unitised protection schemes will not operate in a fashion which will exacerbate a disturbed situation, e.g. differential or restricted earth fault schemes. Protection schemes based on over-current or impedance measurement however frequently exhibit definite limitations during system disturbances. Numerous examples demonstrate that the unwanted operation of such schemes propagate disturbances [1]. Furthermore this behaviour does not usually arise because of protection maloperation but rather because the characteristics of the schemes cannot distinguish between a disturbed situation on the network and a genuine fault within the relay's protection zone.

The development of frequency instability generally arises following the tripping of generators or heavily loaded transmission lines. In a number of incidents considered by WG 34.09 line distance relays operating on power swings exacerbated the disturbance and in some cases hastened system collapse [1]. The majority of distance relay trippings were due to line overloads, a combination of high load current with low voltage and power swings and these were generally correct based on the applied settings. Power swing frequencies were often higher than the settings on the relays. In a number of incidents distance relay defects have also prolonged restoration when spurious trips occurred following line re-energisation. In future it may be worthwhile to review the basis for such settings. More extensive investigation of the most suitable settings for particular applications is warranted. It is discussed further in Section 6.

The difficulties created by conventional protection during voltage disturbances are well documented [1, 2, 3, 4]. As in the case of frequency instability the major deficiencies are unwanted protection operation on line circuits due to the coincidence of high load current with depressed voltage and also due to overloads. Unwanted operation of generator field current limiters or similar over-current devices is another difficulty frequently encountered. These protections invariably exacerbate the already disturbed situation, often hastening complete voltage collapse. The situation is summarised in Table 3.1.

Unwanted Operation	**Affects Frequency stability**	**Affects Voltage Stability**
Dist. Protection: Power swing	X	
Dist. Protection: high I and low V	X	X
Dist., O/current Protection: O/load	X	X
Generator field current limiters, O/current		X

Table 3. 1: Impact of Protection Operation on Stability

In the past these limitations were not often exposed due to the network planning and operation principles adopted. In other words the network operating contingencies were adequate to meet the transfer demands of active load as well as the provision of associated voltage support (MVAr flows) even during maintenance periods. In today's utilities however this approach to ensuring security margins is under scrutiny. Possible improvements to relaying application in the context of counteracting large area disturbances will be considered in Sections 5 and 6. Significant progress is to be anticipated due to the advances in numerical relaying and communication facilities.

This Section briefly reviews the typical protection systems currently employed in relation to mitigating the effects of disturbances while Sections 5 and 6 examine the various schemes in detail.

3.2 PROTECTION AGAINST VOLTAGE COLLAPSE

Examination of the many voltage collapse incidents reported worldwide generally show that the disturbance progresses in two phases. The first slow phase consists of a gradual voltage decline over a period of many minutes. If certain actions are initiated at that time the final situation will be much less severe. As with frequency instability two approaches are followed to counteract voltage instability:

- Emergency early warning systems have been applied which monitor voltage profiles throughout the system and depending on network topology ascertain the level of risk involved, and convey potentially unstable situations to operators [2, 3, 5];
- Application of system protection schemes [2, 4].

This report mainly concentrates on the operation of protection schemes of which a number are available.

3.2.1 Maximise reactive power resources [2]

The following actions can counteract a collapsing voltage condition:

- within the affected area low voltage detectors can be used to initiate manual or automatic switch in of the maximum number of shunt capacitors so as to achieve the greatest possible dynamic VAR margin[1];
- maximise the reactive power output from synchronous machines, if necessary temporarily overloading stator and field circuits; this will require the application of adaptive protection devices to prevent tripping on overload or over-current;
- if advantageous reduce generator active power output in order to maximise reactive power levels.

3.2.2 Control of On Load Tap Changers (OLTCs) [2, 3]

OLTCs when equipped with automatic voltage regulators (AVRs) operate to progressively tap up as the primary side voltage decreases thus hastening voltage collapse[2]. To prevent this two approaches are possible but must be applied to all transformers with OLTCs down to distribution level:

- Block the OLTC once a risk situation has been identified; locally it can be achieved using voltage relays with timers; unblocking ensues once the voltage recovers to an acceptable, stable level; a centrally co-ordinated scheme is also possible if adequate communications links are available; the relays communicate with the centre which then issues prioritised blocking signals to the substations.
- Reduce AVR set point; this is more advantageous than simple blocking as it reduces load.

In both cases the effectiveness depends on the voltage dependency of the load and the level of shunt compensation associated with it. It is most effective with highly dependent loads. Such schemes have been introduced in Europe.

3.2.3 Load Shedding

One form of protection against voltage instability is under-voltage actuated load shedding. It is the final defence in avoiding voltage collapse. Highly reactive loads are shed once voltage drops to a predetermined level for a preset time. It can proceed manually or automatically but the former is only effective during a slowly collapsing voltage profile. If the collapse is rapid automatic shedding is essential as it avoids operator delays which could be crucial in preventing collapse. Such a scheme requires careful design as it must distinguish between a genuine voltage collapse and a voltage depression for other reasons: transient faults, aftermath of fault clearance, total loss of voltage supply. Automatic schemes have not been widely implemented to date although some schemes are in operation (see Section 6.5).

The degree to which load must be shed will be determined by the success or failure of the actions described in 3.2.1 and 3.2.2 to reduce the severity of the disturbance during its initial phase.

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[1] Dynamic VARs refer to the reactive power available from synchronous machines and SVCs because, in contrast to fixed capacitors they respond instantaneously to reactive power demand.

[2] With dependent loads (where load increases with voltage) a decreasing voltage would result in a slightly compensating load reduction. OLTC counteracts this by tapping up thus restoring full load at a lower transmission voltage.

3.3 PROTECTION AGAINST TRANSIENT INSTABILITY

Transient instability occurs when the generator with the largest phase angle relative to the rest of the system accelerates and in so doing goes “out of step”. A typical catalyst for the onset of instability is:

- The occurrence of a severe multi-phase short circuit;
- The loss of critical transmision circuits due to system faults.
- Sudden loss of a generator under certain conditions.

Minimising the time associated with system faults or reducing line power transfers from the affected generators improve the chances of retaining transient or angular stability

3.3.1 Autoreclosure

Protection against transient (or angular) instability is usually realised by the provision of high-speed autoreclosure following fast line fault clearance. The success of such schemes in reclosing the tripped circuit is often crucial in determining whether stability is maintained. Different reclosing arrangements are adopted depending on the nature of the system (strong or weak?), network topology, and the philosophy of the operators. Some utilities employ both single phase and three phase high speed tripping and autoreclosure (HSAR) while others provide HSAR for single phase faults only and three phase reclosure ensues after a longer dead time (DAR) and usually a check synchronism is also performed. The approach adopted on three phase reclosure is influenced by the ability of the system to withstand reclosure onto a fault i.e. unsuccessful reclosure. System studies are necessary to determine the maximum fault clearance times permissible if stability is to be retained and also to evaluate the impact of no reclosure or unsuccessful reclosure.

Numerical technology promises to facilitate the introduction of much more successful schemes employing adaptive techniques. Chapter 6 (Section 6.6) deals in considerable detail with some of these systems.

3.3.2 Power Swing or Out of Step Detection

Power swing tripping relays have been used to detect the onset of angular instability. To mitigate its effects it is essential that the relays respond correctly and quickly. A further requirement is that the relays when operating ensure that the power system is sectionalised into a predetermined number of sectors. The heavily meshed nature of modern networks can make this a difficult task as large areas may be affected by the instability. Consequently power swing relays as traditionally applied will not adequately protect the power system. To prevent an escalation in frequency instability it may be necessary to have available information on the system conditions from both local and remote locations and to be able to adapt the relay behaviour accordingly (i.e. which should block, which should trip). This requires the application of adaptive relays at key points throughout the network and a central co-ordinating function. A prerequisite to success is the availability of reliable communications systems. In this context relaying schemes based on phasor measurement are becoming popular and have been introduced in France [5] and in the USA [6]. Trials to date with such systems are promising.

A different approach has been adopted in Japan [7]. Two on-line processing systems are employed to institute optimal generation or load shedding based on current system conditions. A transient stability controller (TSC) is intended to prevent the development of power swings and maintain stability following system fault clearance by shedding generation. Based on current system conditions detailed system stability calculations are performed at 5 minute intervals identifying the shedding preference for a number of contingencies should a fault occur. Hence generation is shed based on the actual network topology and taking into account on-line transient stability calculations. These are based on real time telemetered information obtained throughout the system. The speed of operation is about 150ms from fault inception.

On less heavily meshed systems traditional out-of-step relays (e.g. distance protection equipped with power swing detection) can still be effectively applied provided much greater attention is devoted to optimising the settings on the relays. This ensures that relays intended to block will do so and that system sectionalising will occur in a fashion optimally structured to facilitate restoration [8].

3.4 PROTECTION AGAINST FREQUENCY INSTABILITY

Frequency instability occurs whenever there is an imbalance between generation and load within the power system or island. It may be positive or negative and once system splitting occurs if one subsystem experiences a frequency decline the other subsystem is most likely having to cope with frequency rise.

3.4.1 Under-frequency Load Shedding

In islanded systems under-frequency load shedding has proved very successful in quickly re-establishing the load-generation balance. On strongly interconnected systems the frequency will not decline until islands are established by power swing detection system as described in 3.3.2 above or some other sectionalising scheme. In systems where load centres are remote from generation sources the loss of interties can be catastrophic. Hence it is very important that load is shed as soon as islanding occurs. Under-frequency load shedding must proceed very quickly and must shed sufficient load to restore frequency to an acceptable, stable level. In this regard the operation of the frequency relays should not be inhibited by a reduction in system voltage which often is a feature of such disturbances [9]. The application of rate of change of frequency (ROCOF) relays may also be advantageous in such situations.

A further very important consideration is that the increment of load shed is not excessive. If it is too large generators will accelerate too quickly, over-speed and possibly trip. Some systems have had this experience [10,11].

3.4.2 Protection against Over-frequency

Traditionally incidents involving frequency rise were corrected by reducing generator active power output. However on some systems this was not always fast enough and other means were introduced. Inappropriate reaction of generator protection/controls to over-frequency and under-frequency during disturbances is described in reference [10,11,12] and elsewhere.

3.4.3 Centralised Protection Schemes

An example of the centralised or wide area scheme approach is the system stability controller (SSC) applied in Japan. It is intended to prevent frequency instability. In the event of an imbalance of generation and load it determines the level of either which must be shed to restore equilibrium taking into consideration the network topology.

While all calculations are performed and the load shedding initiated centrally substation topology recognition (switchgear status, etc.) is performed in the substations and communicated to the central processor. Conversely shedding signals generated centrally only transfer trip load/generation provided the local under-frequency or frequency rate of change relay (ROCOF) has also operated.

3.5 PROTECTION AGAINST CASCADE TRIPPING

During disturbances cascade tripping of transmission circuits or generators occur when protection or control systems operate for reasons described in Chapter 3 (Section 3.1). Analysis of many disturbances [1] has shown that if more time were available to operators, their intervention to reduce load, get reserve plant on stream or take other corrective measures would significantly contribute to avoiding the complete collapse that eventually results. A prerequisite however is that the operators have accurate information on the system status, i.e. good communications to substations and regional control centres are essential to success.

The over-current thermal capability of any circuit relates both to overload magnitude and duration. On the other hand relay over-current settings usually take into account maximum continuous safe load plus a margin. It should be possible for effective remedial action to be executed within minutes of a disturbance occurring and therefore overloading for this period should, in most cases, not pose a problem for the equipment.

Cascade tripping of generators usually occurs during a voltage decline on the system when, in attempting to increase reactive power output, field current limiters operate to trip the unit leading to a rapidly deteriorating voltage profile followed by similar tripping of remaining generators.

To date no effective systems to prevent cascade tripping have been implemented apart from preventive early warning type schemes. However the advent of numerical relaying technology shows potential in this regard as it facilitates adaptive setting techniques. This topic is discussed further in later chapters (Sections 5.1, 6.2 and 6.3).

3.6 SURVEY OF PROTECTION AND CONTROL PERFORMANCE

3.6.1 Evaluation

From the review of disturbances [1] and an evaluation of the results of the Working Group's survey on protection performance [13] the following areas of poor performance were identified:

- Autoreclosing

- Under-frequency load shedding
- Automatic voltage regulation
- Manual load restoration
- Security of power supply to auxiliary plant
- Reconnection of isolated power system islands
- Information system overloaded with data avalanche
- Feeder protection maloperation

Examples of poor performance during different disturbances are described in the following together with the relevant explanation if available.

3.6.1.1 Autoreclosing

Unfortunately little information was available from the survey but the following cases illustrate some difficulties that can arise.

In a highly meshed network with high fault level a flashover at a distribution transformer failed to clear; the adjacent line protections maloperated immediately or operated due to power swings. While autoreclose should not have been initiated from any back-up protection operation there is some suggestion that this may have occurred. There were also some design considerations in reclosing a highly meshed system with a lot of local generation. Dead line charging should normally be at the end remote from a generating station but this will be difficult to attain on such a system. Furthermore high fault current will exacerbate the situation if the fault is persistent.

In another incident the only question related to the selected time for the reclaim timer. During storm conditions faults can re-occur within this time causing unnecessary lockout if the setting is too long. Consequently more serious consideration may be required when selecting the reclaim time setting.

3.6.1.2 Under-frequency load shedding

In at least six disturbances the situation was exacerbated by the failure of the load shedding scheme. Reasons were either defective relays (failure to trip) or a load shedding programme that did non disconnect sufficient load. Another issue was the ineffectiveness of under-frequency relays in heavily interconnected systems. In isolation they may not succeed in shedding load to preserve the system. Unless the system control and protection schemes are organised to split the network into islands, frequency will not decline even when local overloads are very high. Consequently cascade tripping by protection relays (typically due to over-currents) will take place before the frequency relays can operate.
The main conclusion from the survey however was that properly designed schemes with well maintained, high quality hardware are successful in limiting the effects and extent of major disturbances.

3.6.1.3 Automatic voltage regulation

Generally the AVR's performed to their capabilities. The negative impact of AVR action mainly arose due to its poor co-ordination with over excitation protective devices or network protection devices.

3.6.1.4 Manual load restoration

In some cases staff failed to make correct decisions based on the available information. Also unmanned substations were often restored following delays in operational staff arriving on site. Automated response seems much more promising in rapidly restoring the system.

3.6.1.5 Isolation of generator units

In almost half the cases performance was poor. In six instances generator or system related relay failures caused initial loss of generation where the response to this loss was not effective. In some cases the problems were due to basic failures but others related to gas turbine shutdown or islanding with subsequent shutdown. The harmonisation of load shedding with available generation can improve the situation. Furthermore all measures should be taken to prevent unnecessary generator loss. Another issue related to more catastrophic events when generators had to be tripped to prevent their being damaged. Clearly in these circumstances remaining connected and supplying house-load is the desired outcome. Such schemes are problematical to design as due to the voltage depressions which frequently accompany system disturbances the auxiliaries encounter problems which further exacerbate the situation.

3.6.1.6 Security of power supply to auxiliary plant

Seven survey responses indicated that the non-availability of power supplies when required inhibited restoration. Obviously more attention must be given to the design and maintenance of such systems so that they are capable of meeting emergency demands.

3.6.1.7 Reconnection of isolated power system islands

Reconnection proved difficult in a number of the cases reported. Reasons were poor communication between control centres or failure by utilities to determine the readiness of subsystems for reconnection. This suggests that more extensive modelling of different emergency scenarios would be beneficial.

3.6.1.8 Information system overloaded with data avalanche

In many cases data received, though large in volume, was of dubious benefit because it did not yield useful information to operators. The situation is likely to deteriorate with the wider use of numerical control and monitoring systems unless some form of automated decision making is introduced. While only four responses were received on the use of expert systems for analysis of alarms, indications, etc. all were considered highly satisfactory.

3.6.1.9 Feeder protection maloperation

The relaying failures that caused or escalated disturbances broadly relate to protections that failed to operate or performed unwanted operations. It is illustrative to mention some examples of both:

- On a line equipped with duplicate protections both failed during line fault; adjacent line was incorrectly tripped by its protection; widespread operation of remote back-up protection led to system islanding.
- Failure of breaker to open during fault on capacitor bank followed by failure of associated breaker fail protection resulted in extensive operation of remote protection.
- Failure of transformer protection during a transformer fault coupled with failure of a phase comparison relay resulted in multiple tripping by back-up relays.
- Poor settings resulted in distance relay not clearing a low level ground fault; persistence of fault caused multiple tripping of transformer ground fault protections leading to system blackout.
- Maloperation of a phase comparison relay tripped a line on three occasions during external faults leading to cascade tripping and loss of generation and transmission plant.
- On a 354kV line equipped with duplicate protections one failed during line fault; back-up protection was erroneously switched to test position; four 230kV lines tripped on remote back-up; widespread operation of transformer earth fault protection cleared the fault but resulted in significant load loss.
- Slow sequential clearance of a 3 terminal line fault caused remote relays to trip with significant load loss.
- Slow clearance of capacitor bank fault resulted in remote back-up tripping of generator intertie; on four other circuits tripping occurred due to an incorrectly wired switch-on-to-fault function; significant load loss resulted.
- Incorrect line protection operation during adjacent line fault triggered overloading and cascade tripping of lines and transformers.
- Teleprotection signalling incorrectly tripped major generation intertie resulting in power oscillations and generation reduction.
- Multiple operation of protections occurred to avoid overloading; operation was correct as designed but not optimal in context of curtailing disturbance.

In those cases where failure to trip was the malfunction the provision of reliable duplicate or local back-up protection would have been beneficial. Unwanted operations generally occurred due to hardware defects or incorrect setting. The solution here is more rigorous attention to relay maintenance and setting procedures. Also underlined are the limitations of using back-up protection to prevent circuit overloading.

3.6.2 Conclusions

The majority of the sixty plus events that were reviewed in the survey arose from the loss of multiple network elements during normal operation of the system. Improved protection and control systems would considerably reduce the impact of such events.

Approximately 15% of disturbances were caused by second contingencies resulting from unwanted protection operations or failure to operate for the initial event. While protection performance was reasonably good (overall score 3.8 out of 5) there was a significant number of maloperations of feeder protection (average score 2.8). Maloperation was usually due to a hardware failure rather than to a fundamental design deficiency. In many of these multiple contingency cases, Special Protection Schemes were already in place to shed large amounts of load and/or generation in an effort to stabilise the systems. Nevertheless more attention to the selection and application of relay settings, including adaptive features, would have reduced unwanted operations while increased relay availability through better maintenance or self-diagnostics would avoid failures to trip. The survey confirmed that fast fault clearance, particularly on busbars, is vital to a system's ability to ride through disturbances. Duplication of protection systems and the installation of circuit breaker fail provision is essential on critical busbars and on high voltage lines since back up operation times often resulted in system splitting and cascading. The application of adaptive protection schemes to cater for transient conditions without tripping on power swings, overloads, etc., appear to promise significant benefits. This will be more easily realised with the widespread use of numerical relays. As mentioned a number of times in this report it would avoid instances where relay operation while correct was undesirable.

There were several instances of generator controls (e.g. AVRs) failing to operate correctly causing multiple unit losses that were unrecoverable from a system standpoint. Better co-ordination between generator and network control/protection schemes would be beneficial. Dynamic system studies should be used to evaluate these functions.

The response of control and protection devices to declining voltage should be evaluated with a view to optimal co-ordination e.g. transformer tap change control, motor protection, network under-voltage relay, etc.

The remaining events were in general caused by events so catastrophic (earthquakes, extreme loads, multiple unit tripping, etc.) that no reasonable preventative actions could have been foreseen.

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4 FACTS, SPECIAL REGULATING PLANT, HVDC AND RELATED PROTECTION DEVICES

4.1 INTRODUCTION

The flow of power in a transmission network operated in *free flow mode* is determined and limited by the characteristics of the individual network components i.e. lines, cables, transformers, etc. For many years special plant has been installed to improve power transfers:

- Series capacitors to reduce line impedance
- Switched capacitor and reactor banks to control voltage
- Phase shifting transformers (PSTs) to regulate power flows between networks or to optimise load sharing between circuits.
- HVDC links to transmit power over long distances, control power flow between different systems especially if systems have different frequencies.

More recent developments have been: static var compensator (SVC), thyristor controlled series compensation (TCSC), unified power flow controller (UPFC), inter-phase power controller (IPC) and “point-on-wave” switched capacitor bank. These have permitted not just the steady state control offered by the earlier devices but also rapid dynamic response to sudden changes in operating conditions. Collectively these are called flexible ac transmission systems (FACTS).

To fully benefit from the advantages offered by such plant, it is important that protection schemes do not inhibit their performance while at the same time ensuring that faults are cleared swiftly and selectively.

4.2 SERIES CAPACITORS ON OVERHEAD LINES

Series capacitors are used to reduce transmission line impedance in order to:

- Improve power transfer capability
- Improve system stability
- Improve voltage regulation
- Optimise load sharing between parallel circuits.

4.2.1 Conventional (Fixed) Series Compensation (FSC)

Figure 4.1 illustrates a typical example of a capacitor bank arrangement on an EHV circuit. Normally the capacitor is subjected to only a small fraction of line voltage. However during external faults voltages comparable to the line voltage will appear across the unit. Dimensioning the capacitor to cater for this is not feasible and provision is made to bypass the capacitor during faults and reinsert it following fault clearance. Speed of reinsertion is important in relation to system stability. Traditionally spark gaps were used for bypass. Present practice is to use metal oxide nonlinear resistors and consequently reinsertion is instantaneous. Three different protection schemes, each designed for different reinsertion time requirements, are now described.

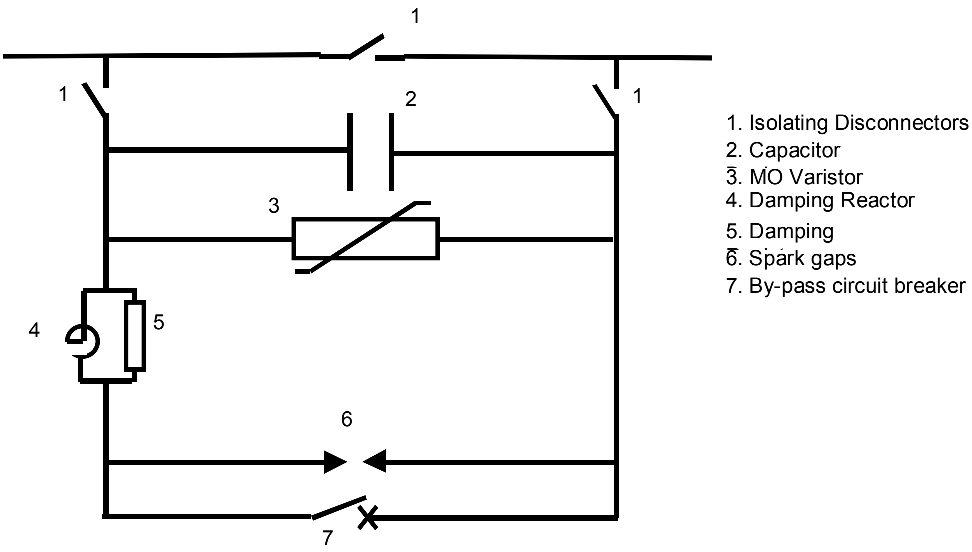

Figure 4.1: Typical Series Capacitor Arrangement on Transmission Line

Single-Gap Protective Scheme

The arrangement is similar to that in Figure 4.1 but without the varistor (3). The spark gap (6) in parallel with the capacitor bank by-passes the bank in the event of excessive over-voltages caused by system faults. A damping circuit limits the amplitude and provides the required damping of the capacitor discharge current. On detection of gap current the circuit breaker (7) closes by-passing the gap and the series capacitors. On detection of low levels of line current the breaker opens reinserting the capacitor.

The single-gap scheme is designed to provide medium speed reinsertion, 200-400 ms, which in most cases is fully adequate.

Dual-Gap Protective Scheme

The duration of the by-pass interval is a function of the de-ionisation time of the spark gap. An extra low-set spark gap with series connected normally closed circuit breaker by-passes the capacitors in this case. The breaker opens immediately when the line fault has been cleared and reinserts the capacitor bank in the transmission system. As a result, reinsertion will not be delayed due to the de-ionisation time, and high speed reinsertion (60-80 ms) will be obtained.

The high-set spark gap and a second by-pass breaker serve as back-up protection.

Metal Oxide Varistor (MOV) Protective Scheme

A non-linear resistor (of zinc-oxide) or MOV (3), limits the voltage across the series capacitors during a fault sequence and reinserts the bank immediately on termination of the fault current. The energy is normally absorbed by the ZnO varistor without necessitating the firing of the spark gap (7). The spark gap is provided as an extra back-up protection for the varistor. The series capacitors and the ZnO varistor are in circuit during the fault period and reinsertion takes place automatically and without delay when the line fault is cleared. For many situations it is not practical to dimension the MOV energy absorption capability for the worst case internal faults. A reasonable approach is to design the MOV to carry a maximum external short circuit currents while for internal or close up faults the spark gap is triggered thus reducing the energy dissipation in the MOV. The protection and control systems monitor the MOV duty cycle to trigger the gap at the correct instant. It will also close the bypass breaker to avoid prolonged gap currents.

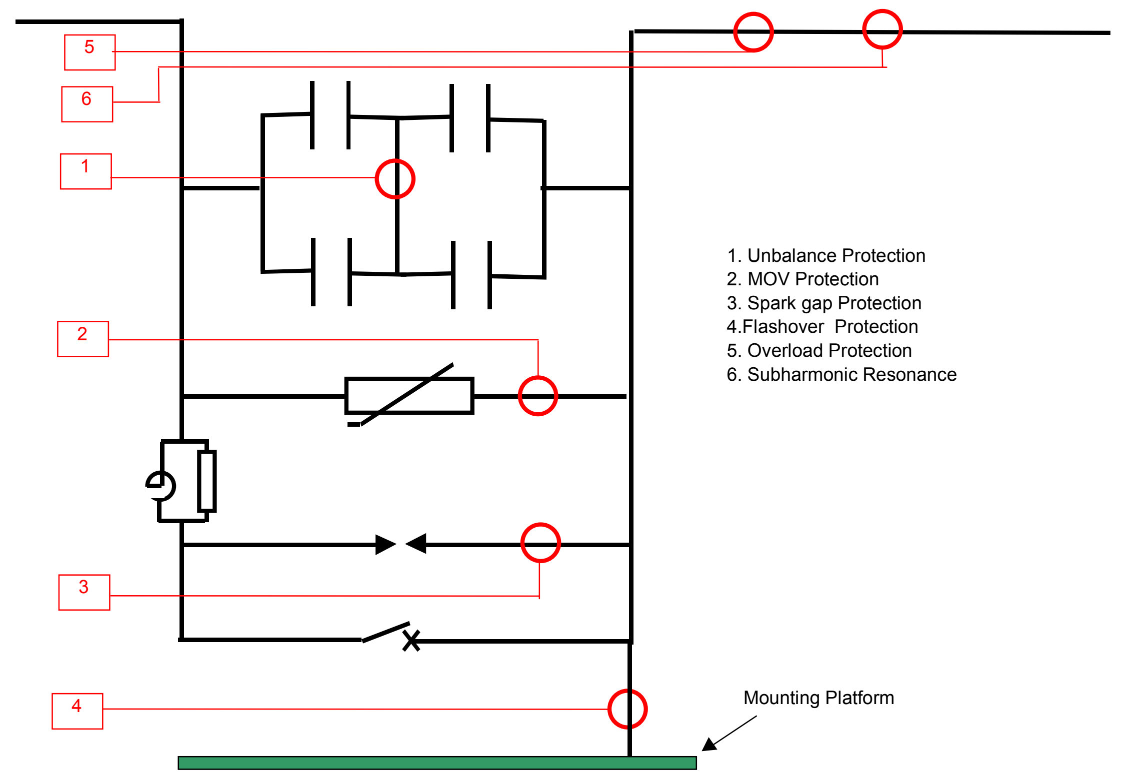

Figure 4.2 Capacitor Bank Protection

The advantages of this arrangement are reduced reinsertion transients.

The series capacitor bank together with its associated control and protection should be designed to give at least the same degree of reliability as that of the transmission lines, without any reduction in availability. The protection scheme to be provided depends on the transmission system configuration, the protective requirements and the reinsertion times i.e. the time from disconnection of a faulty circuit to when the capacitor is restored. This time is often the most important factor to be considered. Practical details may vary between different power systems but control and protection requirements remain essentially the same and may be summarised as follows [1,3].

Protection against Internal Faults

These protections operate for faults or failure within the capacitor bank installation. They include capacitor unbalance protection, flashover protection, spark gap fail protection, MOV failure protection and pole discrepancy protection. These are generally simple time/over-current relays except for the unbalance protection which is line current compensated. See Figure 4.2.

Protection against Abnormal Conditions

These protections prevent overloading of the capacitor and MOV and protect the spark gap. The determining factor for the capacitor overload is the permissible capacitor over-voltage likely to arise during system overloads. If this exceeds a preset level the bypass circuit breaker is closed. The MOV scheme is typically designed to bypass the unit for an internal or close up fault thus preventing over-voltages on the capacitor. The MOV itself is specified based on the type, number and duration of external faults. Bypassing is often allowed for external multi-phase faults but not for single phase faults. The number of external faults allowed before bypassing typically varies from one to three. The protection operates based on the MOV's accumulated energy, single shot energy, rate of rise and current level.

The addition of the capacitor to the network creates a resonance circuit having a subharmonic natural frequency. If it is anticipated that such resonances may occur protection should be provided to detect current levels exceeding a threshold (5% to 10% of rated current) at frequencies below about 35Hz. Protection operation closes the bypass switch.

On all of these protections the breaker is reopened after a delay but if the condition persists it may be closed permanently.

Control Measures

Capacitor control covers automatic insertion, manual insertion, by-passing and reinsertion. Practices vary between utilities e.g. interlock provision such that capacitor must be inserted prior to energisation and bypassed when de-energised.

The impact of series capacitors on the causes or propagation of disturbances is difficult as fault statistics are limited [1]. The survey carried out in preparation for this report received so few responses as to be non-indicative [2]. Consequently it is not possible to recommend any particular protection measures other than those described above. Recent developments are the more widespread application of optical instrument transformers and their connection by fibre to the protection and control system. This simplifies the cabling and insulation requirements to the mounting platform and should reduce risk of flashover.

4.2.2 Thyristor Controlled Series Compensation (TCSC)

A refinement of the fixed series capacitor (FSC) arrangement is the thyristor controlled series compensation (TCSC) using a thyristor controlled reactor (TCR) in parallel with the capacitor as shown in Figure 4.3. The TCSC has the ability to dynamically vary the transmission line impedance as required by stability or other considerations. It can both damp power oscillators and regulate power flow. Due to the TCSC's peculiar characteristics the protection must include some additional features compared with those for the FSC. These particular requirements are now considered.

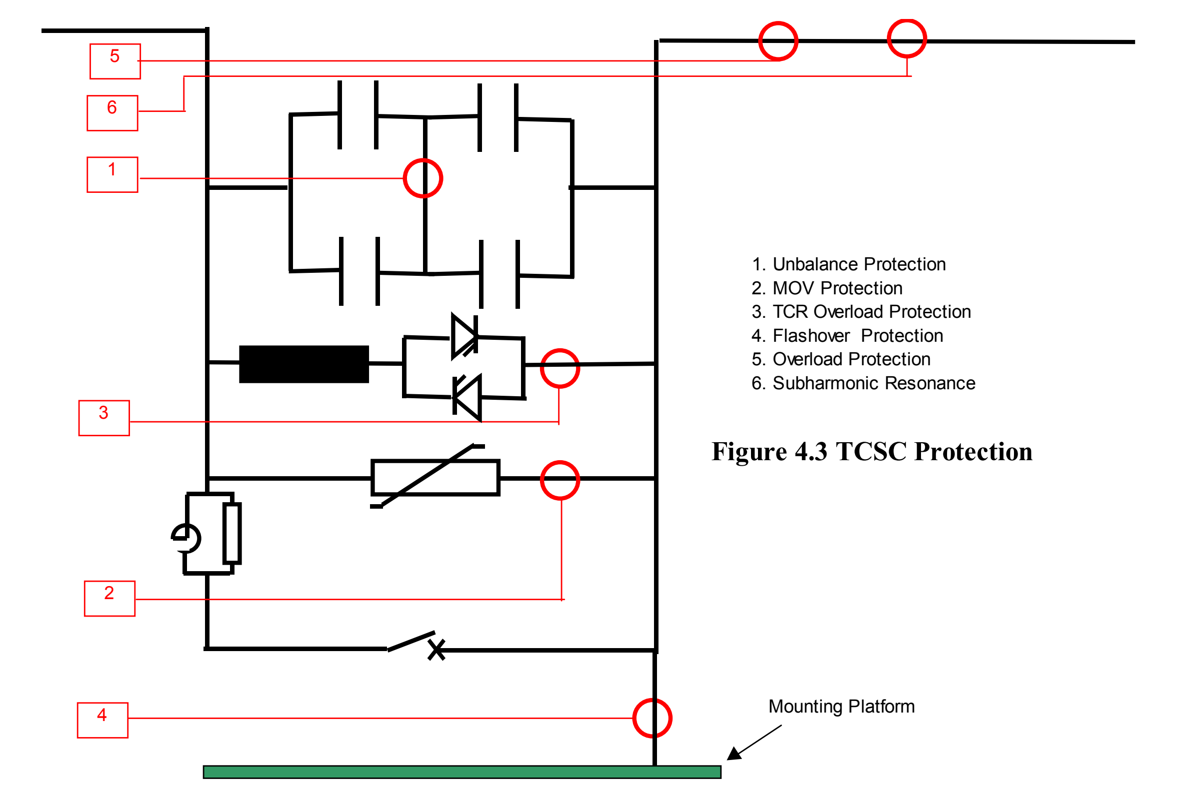

Figure 4.3 TCSC Protection

Capacitor Unbalance Protection

The current flowing in the TCR is in the form of pulses whose duration depends on the thyristor firing angle. Complementary pulses are superimposed on the capacitor current waveform and the capacitor bank imbalance protection must be able to accommodate and respond correctly to this current.

Capacitor Overload Protection

In the TCSC the capacitor current may exceed the line current [4] and the current is not sinusoidal. The line current is therefore unsuitable for capacitor overload protection and capacitor voltage is used instead. Also the capacitor will be overloaded more frequently in the TCSC than that experienced in an FSC. A more sophisticated integrating technique applied to the measured overload is preferred to the time-current relays typical on the FSC.

TCR Overload Protection

An additional requirement on the TCSC is the provision of TCR overload protection. One solution is a thermal replica based scheme that has the advantage of allowing the overload to persist for the longest time possible. Separate overload protection is recommended for the thyristors and reactor because of their different thermal characteristics.

Abnormal Conditions

The TCSC may include control functionality to damp power swings and subsynchronous resonance. However where these are too severe separate protection is provided based on line current as for the FSC. If the low frequencies exceed preset values the protection blocks the thyristor such that FSC type operation ensues. Thereafter if the problem persists the bypass switch is closed.

4.2.3 Line Protection

Experience has shown that series compensated lines can be adequately protected using phase segregated current differential protection, phase segregated phase comparison protection and non switched impedance protection with voltage memory to ensure correct directional measurement and a teleprotection link between line ends. These protections operate correctly even for sudden impedance variation due to spark gap operation. For TCSC compensated lines these protections are also suitable. In fact the conditions for line protection are less onerous as impedance change is more gradual.

4.3 SWITCHED SHUNT CAPACITOR AND REACTOR BANKS

Protection of shunt capacitor and reactor banks is relatively straightforward, well proven and is covered in the literature [1]. The survey performed prior to the preparation of this report indicated good performance during disturbances [2]. Apart from ensuring that relaying equipment is well maintained, special measures in relation to protection are deemed unnecessary.

4.4 STATIC VAR COMPENSATION

Static Var Compensator is a shunt reactive power compensation device. It consists of a parallel capacitor/reactor combination with thyristor switching to regulate reactive power flow. Protection requirements are similar to those for the capacitors and reactor associated with the TCSC but simpler as overloads and power swings are not an issue.

4.5 NEW FACTS DEVICES

Recent technological developments have produced new static devices for application on transmission systems. Examples are:

- Unified Power Flow Controller (UPFC) combines the functions of an SVC and a PST with the additional advantage over the latter that it has good dynamic response during disturbed system conditions.
- Inter-phase Power Controller (IPC) regulates active and reactive power flow by arranging an L-C circuit tuned to power frequency in series with two phase shifting units; these can either be PSTs or static equivalents. The advantage offered by IPCs is their ability to interconnect two power networks but without the transfer of disturbed conditions during faults.

As these devices are relatively recent in application little experience is available regarding optimised protection arrangements. In general, however, the following should be considered:

- If the devices mentioned are installed on a power line impedance measuring relays will be difficult to set as these devices exhibit varying values of impedance with different control settings. Special techniques, possibly involving artificial neural networks (ANN), are likely to be very beneficial in optimising protection performance [11].
- Individual protection is recommended for each element of the devices (similar to the approach for the Series Capacitor banks in 4.2); in the case of the IPC this means applying separate schemes to protect the capacitor, the reactor and the phase shifting devices.

4.6 PHASE SHIFTING TRANSFORMERS (PSTs)

PSTs are essentially steady state control devices that can regulate the active power through-flow by changing the phase angle between its input and output terminals referred to as source-side and load-side respectively. Consequently protection behaviour will not impact on their behaviour during disturbances. A typical arrangement for a symmetrical PST is shown in Figure 4.4.

In terms of providing adequate protection the scheme should consist of 2 protections as indicated on Figure 4.5 [5]:

- A primary protection consisting of a straightforward 3 leg differential without any phase or ratio correction; with proper CT choice the scheme is immune to saturation of the main series winding during external high current faults; this arrangement provides very sensitive protection for all primary winding faults.
- A secondary protection that interconnects CTs on the series winding source and load terminals with a CT in the neutral end of the excitation transformer secondary (the tapped winding). The HV side CTs are connected in delta to compensate for the phase shift on the series unit - which is effectively delta-star connected. This is the only compensation required. The tapped winding on the excitation unit does not alter the ampere turns balance across it and hence it does not necessitate compensation as is required on a conventional transformer with on load tap changer.

Conventional back-up protection can be provided as dictated by policy and co-ordination requirements but no other particular measures specific to the PST are required.

4.7 HVDC LINKS

Apart from the advantages offered by DC in the field of long distance power transmission HVDC links also contribute to ac system stability. This is due to the rapid response of the control systems employed. Through the use of supplementary controls additional features for improving ac system performance are also provided to improve:

- Damping of ac system electromechanical oscillations
- Transient stability
- Isolation of system disturbances
- Frequency control of power islands
- Reactive power control.

Typical protection schemes provided on HVDC systems will now be discussed.

4.7.1 HVDC Protection Schemes

4.7.1.1 DC Line Protection

For a fault on the DC link the converter control will limit the current to the set value based on the desired power transfer. Additional measures are required to reduce the fault current to zero. The typical protections on DC links are based on [6]:

- Current differential scheme
- DC Voltage change
- Current change directional comparison scheme
- Ground fault current detection scheme.

The protection scheme drives the rectifier station to inverter mode and the firing angles are adjusted at both rectifier and inverter adjusted to give a line voltage profile similar to that in Figure 4.6 [6]. This ensures current extinction.

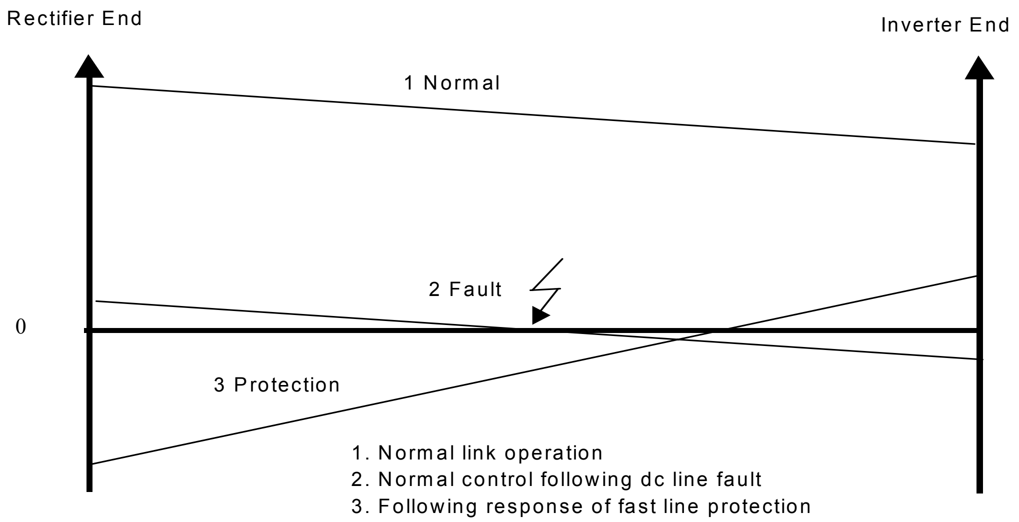

Figure 4.6 DC Line Voltage Profile

Following a de-ionisation time of 60 to 200ms the link is restarted. As with ac line protection the task is to ensure that protection devices are sufficiently sensitive to detect faults while avoiding unnecessary operation. Frequently when a fault occurs the initial differential current is "masked" by the dc discharge current through the fault. This delays protection operation. However new developments have resulted in differential schemes involving charging current compensation that promise improvements in response times [6].

4.7.1.2 Converter Faults

Most faults in the converters tend to be permanent, necessitating shut down of the pole. Current is forced to zero as quickly as possible (< 30ms) by adjustment of the firing angles as described in 4.7.1.1 for the line fault.

4.7.2 AC System Faults

The impact of ac side faults on HVDC operation is explained by reference to Figure 4.7.

The effect varies depending on whether the fault occurs on the ac network connected to the rectifier or to the inverter. Also historically HVDC links interconnected relatively strong networks (high short circuit level at converter bus) and the link had little impact on operation of the ac system protection. This is no longer universally true as SVCs are becoming more widely used for reactive power compensation and because of the relatively high levels of transmitted power on modern HVDC links.

4.7.2.1 Rectifier Side Faults

Remote three phase faults cause the rectifier terminal dc voltage to reduce. The current regulator reduces α thus increasing voltage to restore current to its set value. If the drop is such that α reaches its minimum value, then control is transferred to the inverter. By greatly increasing β the inverter voltage is reduced thus increasing the current. However, this increases the reactive power demand to possibly unacceptable levels. Power system conditions therefore influence the emergency control considerations. If low voltage persists the tap changers on the transformers operate to restore voltage.

In the case of close up faults the voltage will be severely reduced and the dc system shuts down until the fault is cleared. Close up unbalanced faults give rise to increased harmonic ripple in the dc voltage which are inadequately smoothed by the reactors and filters. This may result in current extinction and blocking of the dc link. Remote single or two phase faults rarely cause shutdown of the link.

4.7.2.2 Inverter Side Faults

Remote three phase faults result in a slight voltage decrease and current increase. The current control responds to reduce current. If the voltage reduction is significant commutation failure may occur. As an alternative the rectifier voltage can be reduced to reset the current level. If very low voltage conditions persist repeated commutation failure may occur and it may be necessary to block or bypass the valves and block the inverter until the voltage recovers.

Single or two phase faults may lead to commutation failure due to phase shifting of zero crossings in the voltage waveform. In such circumstances it may be necessary to block the inverter.

4.7.2.3 Converter behaviour following Fault Clearance

Recovery from ac network faults depends much more on system parameters than does recovery from dc link faults. Weak ac systems may be unable to provide sufficient reactive power to maintain or, in the event of blocking, to quickly restart the dc link. Furthermore voltage distortion (due to harmonics) may result in ongoing commutation failure. This delays recovery.

The time required for a dc link to recover to 90% of prefault power transfer is typically in the range 100ms to 500ms. This is influenced by the line inductance and capacitance, dc reactor inductance (L_D), line resonant harmonic frequencies, converter and transformer characteristics. The most important ac parameter is the short circuit ratio (SCR) i.e. ratio of ac system short circuit power (MVA) to the dc converter rating (MW). The voltage dependent current limit function [7] in the control system can play a significant role in system restoration following faults.

The following measures are also typically adopted to assist recovery of the HV DC system:

- During ac low voltage conditions in the rectifier the minimum value of α is increased from about 5° to 30°.
- Momentarily increasing γ in the inverter if it drops below the minimum value.
- To prevent commutation failure the firing angle limits during start-up of the second valve group are increased by approximately 10°.
- Following commutation failure β is immediately increased in order to fire the next valve early and assist recovery e.g. β could be adjusted to 40°, 60°, 70° on successive commutation failures.

In general HVDC systems perform well during disturbed conditions. The survey performed by CIGRE WG34.09 [2] indicated excellent performance (albeit based on a low response) both from the viewpoint of dynamic response and system restoration. This is also consistent with surveys performed by CIGRE on HVDC reliability [8]. These indicated that, based on a sample of thirty three HVDC links, the failures due to control and protection totalled 22% of 320 failures and the total outage time associated with control and protection amounted to 3.1% of 4,643 hours. These relate to 1994; corresponding data for 1993 were 31% of 370 failures and 10% of 2118 hours.

As with control and protection systems generally numerical technology has also introduced improvements to the behaviour and availability of HVDC links. This is achieved through the increased redundancy of control systems, self checking (watchdog) features and optimal sampling rates [9].

4.7.2.4 Behaviour of AC System Protection

Protection installed on the ac circuits in the vicinity of HVDC converter stations can be subject to particular limitations during faults. During normal conditions the harmonic voltages and currents on the ac lines are low due to the filtering effects of the compensation equipment and filters provided in the converter station. Furthermore this equipment generates the reactive power required by the converter. If however the link is suddenly blocked (e.g. due to fault as described in 4.5.2.2) the reactive power imbalance may cause the voltage to rise causing the transformers to saturate generating significant second, third and fifth harmonic. The behaviour of line protections is influenced by the harmonic content of the current and voltage waveforms. In this context the SCR is the most important parameter as a low SCR will result in a low fundamental current and a relatively large harmonic content. The critical value for SCR is about 7 [9]. In such situations static or numerical distance protection may be prone to maloperation and should be carefully selected with this in mind. Electromechanical impedance measuring and starter elements tend to be immune to harmonic effects.

For SCR values < 7 an evaluation of the risks should be undertaken to take into consideration influences other than SCR. A suitable risk factor f_r would be [10]:

$$f_r = \frac{r_{nf}\,Pdc}{Sr}\left[1-\left(\frac{U_{LF}}{U_{LO}}\right)^n\right]$$

where: r_{nf} = ratio of harmonic current in protection to generated harmonic current on converter bus
Pdc = transmitted dc power
Sr = short circuit power seen by relay
U_{LO} = prefault voltage on converter ac bus
U_{LF} = fault voltage on converter ac bus
n = 1 for rectifier and 2 for inverter operation respectively

This formula allows the risk to be quantified because all the other parameters can be determined. The relationship is valid for a converter station fed by up to two ac lines. Note that from experience an SCR of 7 typically corresponds to a risk factor of about 0.15. For higher risk factors the protection should be carefully selected. The following is a brief summary of relay suitability:

- Electromechanical Relays: due to the integrating effect of the electromechanical armatures they are unaffected by harmonics.
- Static relays: fast static relays will be affected at SCR < 4 unless special filtering provided; filters normally provided will not be adequate.
- Impedance protection: impedance measurement will be affected in both reach and direction by the presence of harmonics. Starter reach on switched schemes is an additional complication. Electromechanical designs are not significantly affected.
- Line differential protection can be used but some filtering may be required depending on SCR value and line capacitance.
- Travelling wave protection is not suitable unless supplemented with an additional measuring principle.

In general all designs can be used with suitable filtering and provided that the relay behaviour is modelled for simulation testing to verify the suitability of the protection scheme.

4.7.3 Conclusions

HVDC links provide significant support to power systems during disturbed conditions both in terms of dynamic response and system restoration. Evidence to date indicates that control and protection schemes function well. However new protection systems are being developed to improve ground fault detection on dc links. For ac networks in the vicinity of HVDC converters special consideration of the ac line protection is advised.

4.8 CONCLUSIONS

For a number of decades special regulating plant (PST's, IPC, etc.) and HVDC links have proved extremely beneficial in optimising electrical power transmission. More recently developments in power electronics have led to the introduction of FACTS devices that provide significant operational support under both steady state and dynamic conditions. It is essential that associated protection and control do not reduce the availability of such systems.

Evidence to date suggests that protection on these plants do not contribute to system disturbances and perform quite well. Nevertheless the protection schemes require special attention to ensure that they best meet the particular requirements. These have been summarised in the report. HVDC links also may create difficulties for relaying on neighbouring ac lines if the SCR is low. The optimal solution will require special studies and is best addressed on a case by case basis. These concerns will also apply to the more recently developed linear power links using voltage source converters (VSC's).

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5 SCHEMES TO IMPROVE OVERALL PERFORMANCE BY PREVENTIVE ACTIONS

5.1 EARLY WARNING SYSTEMS

The term early warning system refers to wide area preventive or protective systems that detect network conditions that could compromise system stability. These systems are usually designed to initiate appropriate preventive or remedial action. In this way the impact of the disturbance is either reduced or avoided altogether. Such systems are already in operation in Japan and France. In the former they are known as "failure extension protection system" (FEPS) [1] while in France they essentially cater for voltage stability. The schemes are briefly described in the following sections. They belong to the protection category "Special Protection Schemes" (SPS). Further details on the current status of SPSs are available in a recent survey report by CIGRE Working Group 39.08 [11,12].

5.1.1 Systems to Detect when a System is at Risk

The FEPS in Japan usually includes relaying schemes to cater for the following incidents.

<u>5.1.1.1 Angular or Transient Instability</u>

To cater for out-of-step phenomena the FEPS includes both predictive out-of-step protection relays and system sectionalising relays. The former operate in advance of abnormal phenomena (i.e. preventive) while the latter initiate sectionalising after the out of step condition has occurred (i.e. reactive). The techniques may be summarised as follows:

- <u>Predictive out-of-step protection relay</u>: If power swing phenomenon is predicted in the event of a severe fault, the relay prevents an out-of-step by generation shedding or system separation. The relay is installed on the transmission line where out-of-step phenomena is anticipated in the event of the line experiencing a fault or if fault clearance is delayed. The scheme is intended to provide protection for single generator out-of-step and power swings between different power systems or subsystems. A typical application is for the system connected to large generation sources over long transmission lines. The main protection features are generator shedding, system separation and load shedding. In some systems, the early valve actuator (EVA) or stabilising damping resister (SDR) are also operated by FEPS.
- <u>System separation relay:</u> After an out-of-step phenomenon has occurred, the relay separates the power system near the power swing centre to curtail the extent of the out-of-step condition and to minimise its influence. The relays are installed on the transmission lines or transformers where the power swing centre is expected to occur. If this centre passes near the tie-line between different utilities, the separation relay is installed on the tie-line to prevent the unstable conditions being exported to the neighbouring systems.
- <u>Wide area stability protection:</u> In particular areas of Japan, several large power systems are interconnected over long-distance transmission lines. In such power systems, large-scale generator loss in one system can cause wide area power

system instability because of the sudden increase in power transfers. FEP's are applied against this kind of disturbance.

5.1.1.2 Voltage Stability

If voltage begins to decrease, the FEPS operates to control the phase modifier. In some special cases, where very rapid voltage drop is anticipated, the FEPS sheds the minimal load required to stabilise the voltage.

5.1.1.3 Frequency Stability

FEPS are employed in the following ways to retain frequency stability:

- Prevention of frequency decline: The FEPS prevents a developing frequency decline due to generation loss including loss of important interties, by shedding loads or pumped-storage generators. The FEPS also prevents isolation of thermal and nuclear power stations following the frequency decrease.
- Overfrequency prevention**:** In the event of a large load loss (e.g. due to intertie trip) the FEPS prevents frequency increase by generator shedding. It also prevents isolation of thermal and nuclear power stations following the frequency increase.
- Maintenance of islanded system operation**:** When the power system is islanded following a line or transformer fault, the FEPS maintains the frequency of the system by shedding loads or generators. In some systems reactive power is also controlled by using phase modifiers in order to maintain system voltage as described in 5.1.1.2. If the system frequency continues to decrease after operation of pre-determined countermeasures, some FEPS sectionalise the power system in an effort to maintain the frequency of the islanded system.
- Tie-line separation with other utilities: Each utility maintains frequency by countermeasures within their own power system. However, when frequency abnormality continues for a certain time, the tie-lines with other utilities are separated to prevent abnormal extension.

5.1.2 Predictive Out of Step Protection (POPS) in Japan

Predictive out of step protection schemes (POPS) are in service in Japan [2]. As part of a FEPS various types of predictive schemes for the determination of instability risk are employed.

A number of algorithms exist for realising the stabilising calculation i.e. the assessment of stability and calculation of required quantity of stabilising control:

1. Off-line pre-calculation type: the result of simulation studies is entered on a control table. From a standpoint of this control table, it can be divided into two types: "fixed table" method where the control table stabilising values are set beforehand ; "build table" method where the control table is periodically updated by on-line system data. The former method is generally applied if the required quantity of stabilising control for each fault case does not change irrespective of system operating conditions. Otherwise the latter method is applied.
2. On-line pre-calculation type, the system periodically performs stability simulation, and all applied POPS follow the same calculation algorithm.

3. Real-time calculation: it carries out predictive calculation of system stability after a fault. Several kinds of predictive calculation algorithm have been developed and put into practical use. The possibility of stability loss is determined from the acquired predicted values.

Sampling parameters, such as power, phase angle or frequency, are derived from several ten milliseconds' monitoring of on-line voltage and current following a fault. The electric values are predicted using these sampling data, and the possibility of out-of-step is assessed from the predicted phase angle or the predicted power stability index. If assessed to be unstable calculations proceed on the basis of generator shedding or load shedding. The assessment is evaluated repeatedly until the index becomes "stable", and finally the required quantity of stabilising control is determined.

The total number of POPS currently operating in Japan totals 52.

5.1.2.1 Stabilising Techniques: Transient Stability Control and Frequency Stability Control

The FEPS used in Japan incorporate relaying schemes to stabilise both transient stability and frequency. The following describes a typical example of how these functions are realised in the System Stability Controller developed by the Kyushu Electric Power Co. (KEPCO). In terms of the FEPS and POPS described in Section s 5.1.1 and 5.1.2 the SSC employs the "Off-Line" pre-calculation type.

The Kyushu Electric Power Co. (KEPCO) is the transmission company in the Kyushu island area (the third largest island in Japan). Installed capacity is about 20,000MW some of which is exported to Honshu (the largest) island through the Kan-mon tie line. The KEPCO grid is divided into four zones three of which have generation plant. The maximum power flow is limited by considerations of power system stability rather than by transmission line thermal capacity. In order to maximise power flow, KEPCO introduced the power system stabilising controller (SSC).

Figure 5.1 shows the Kyushu power system divided into four zones as follows:
Western zone (Saga, Nagasaki area): The largest power source area in Kyushu with a capacity consisting of about 7,500 MW of nuclear and thermal plants. Generated power is transmitted to the central zone through 500kV and 220kV lines.
Southern zone (Kagoshima area): Generated power from nuclear and thermal plants is transmitted to the central zone over long 500kVlines.
Eastern zone (Fukuoka, Oita area): Large-scale thermal plant is located in Oita, and power is sent to Fukuoka area over 220kV lines. Fukuoka has the highest consumption in Kyushu with several thermal plants located there.
Central zone: Receives power generated in Western and Southern zones with some onward transmission to the Eastern zone and to Honshu Island.
In order to maximise power flow among above mentioned zones, SSC systems are installed in each zone.

SSC Developed by KEPCO, Japan.

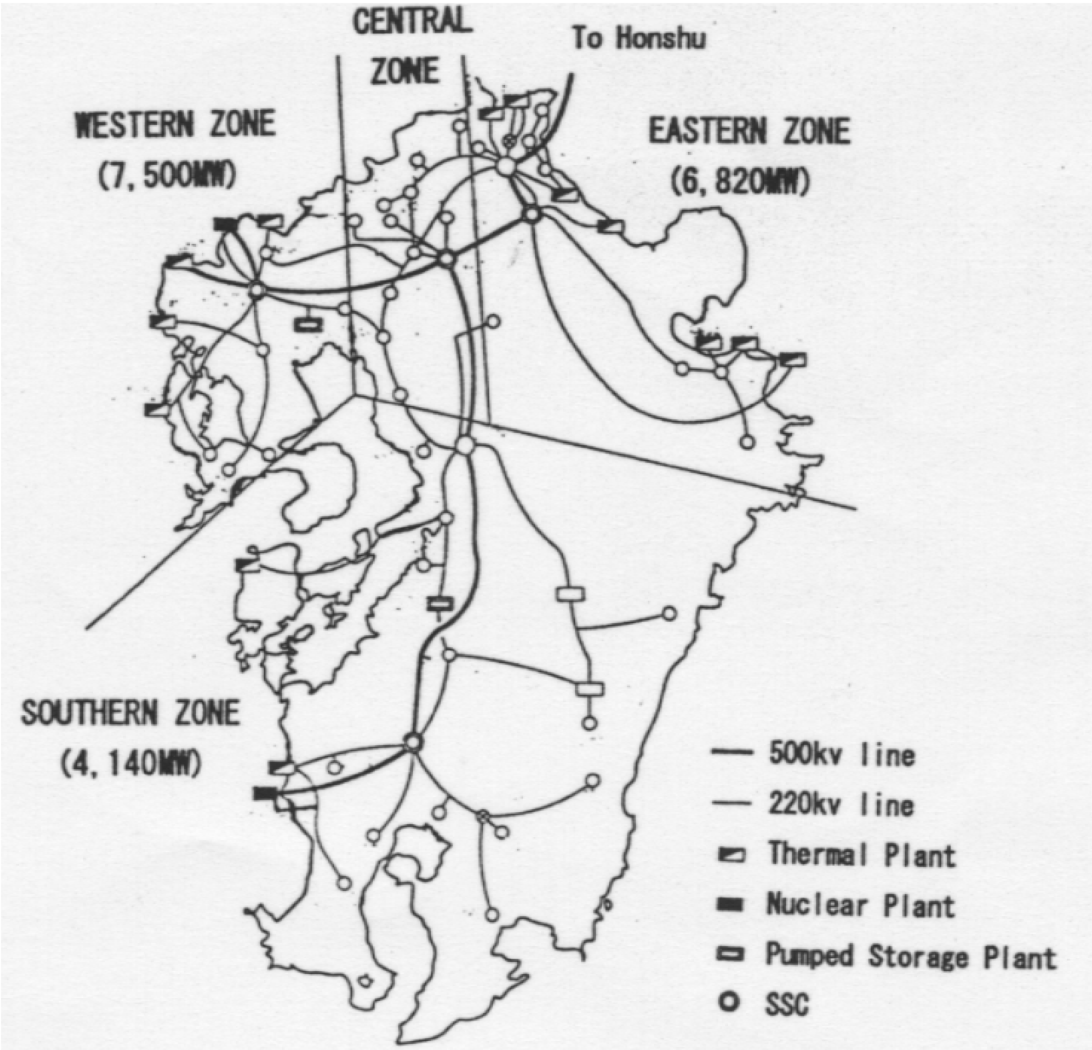

Figure 5.1 Kyushu Power System

<u>Methods of power system stabilizing</u>
The power system can not retain stability in the case of severe faults that cause transmission line trip/lockout, faults on double bus-bars or on transformers banks. In these cases, power system stability controllers (SSCs) are needed. Table 5.1 shows examples of severe faults that may cause instability in power systems and their countermeasures.

Fault Mode	Immediate Impact	Countermeasure
500kV / 220kV lines lockout	Generator transient stability	Generator shedding; system separation
500kV / 220kVdouble busbar fault		
500kV transformer bank	Overload	Generator shedding; line trip
Generation deficit	Frequency drop	Load shedding including pumped storage generators
Kyushu-Honshu tie line lockout	Frequency rise	Generator shedding
Trunk line lockout in Honshu		

Table 5.1 Countermeasures to Maintain Power System Stability

Countermeasure for transient stability

To prevent out-of-step conditions following severe faults, such as evolving faults in double circuit lines, bus-bar faults, etc. generation shedding is employed. If this proves inadequate then power system separation is initiated. Figure 5.2 shows an example of generator phase angles in the western zone after a severe fault. Fig. 5.2 (a) shows the angles without any countermeasure; it is clear that western zone generators are progressively swinging out-of-step with the remainder of the system. Fig. 5.2(b) shows the angles with appropriate generator shedding, where the generators are stabilised.

Generator shedding is effected as follows. A simulation study determines the limiting power flow P_0 for which the system would remain stable without any countermeasures in the event of a fault. If the power flow exceeds P_0, it is concluded that generator shedding is needed on the occurrence of a severe fault. The P_0 value varies with the fault type. The level of generation to be shed, PD, is calculated by the following equation;

$PD = (P - P_0)/ K$ ………………………………………………… (1)

$K = \Delta PE/PD$ …………………………………………………… (2)

where :

PD: generation level to be shed

P: present power flow

P_0: marginal power flow

ΔPE : increase of marginal power flow after generator shedding

Value K is determined by off-line simulation study.

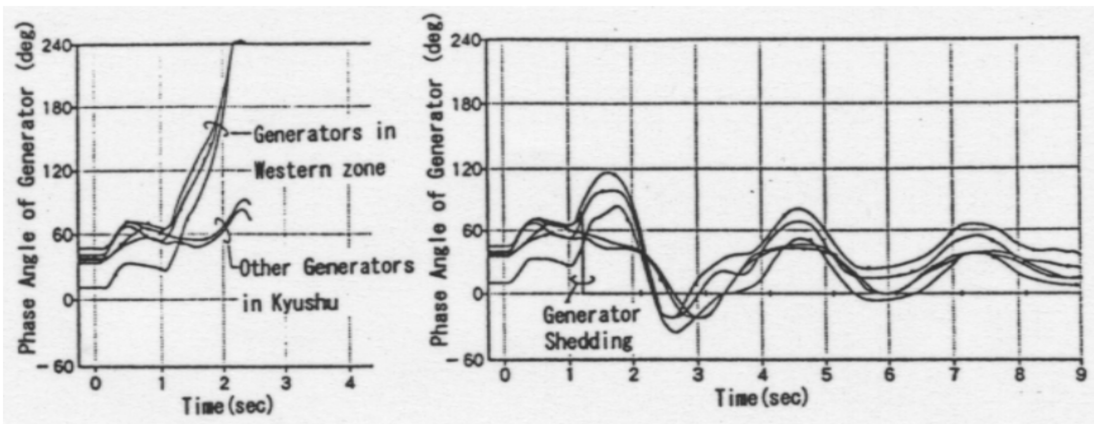

Figure 5.2 An example of power system disturbance in the case evolving fault in double circuit. (a)Without any countermeasure (b) With generator shedding

Countermeasures for overload

Overloading of transmission lines and transformers occurs following tripping of parallel heavily loaded circuits. In such events power flow is reduced by generator shedding or transmission line tripping. The value of generated power to be shed is calculated by the following equation;

$PD = (PK - \beta NP_R)/ \alpha$ ……………………………………………...(3)

where,

PD: Value of power to be shed

PK: present power flow
P_R: line rated power
α : branch effect ratio
β : permissible overload as multiple of rating
N: number of lines

Countermeasure for frequency excursion
If the Kan-mon tie line or certain transmission circuits in Honshu trip the frequency of the Kyushu power system will rise. To restore the frequency to normal, sufficient generators are shed – the level of shedding being determined by the tie line power flow. Conversely if generators are tripped due to plant faults the Kyushu system frequency will drop. In this case, loads including pumped storage generators are shed.

Structure of the SSC system
Countermeasures for power system stability are taken independently within each zone. In each the SSC systems are installed in representative substations. This approach also makes it possible to reduce data transmission and to perform high-speed control. If the shedding value is not sufficient in a particular zone, generators in the other zones can be shed. Figure 5.3 shows the arrangement of the SSCs in the four zones. Figure 5.4 illustrates the SSC structure.

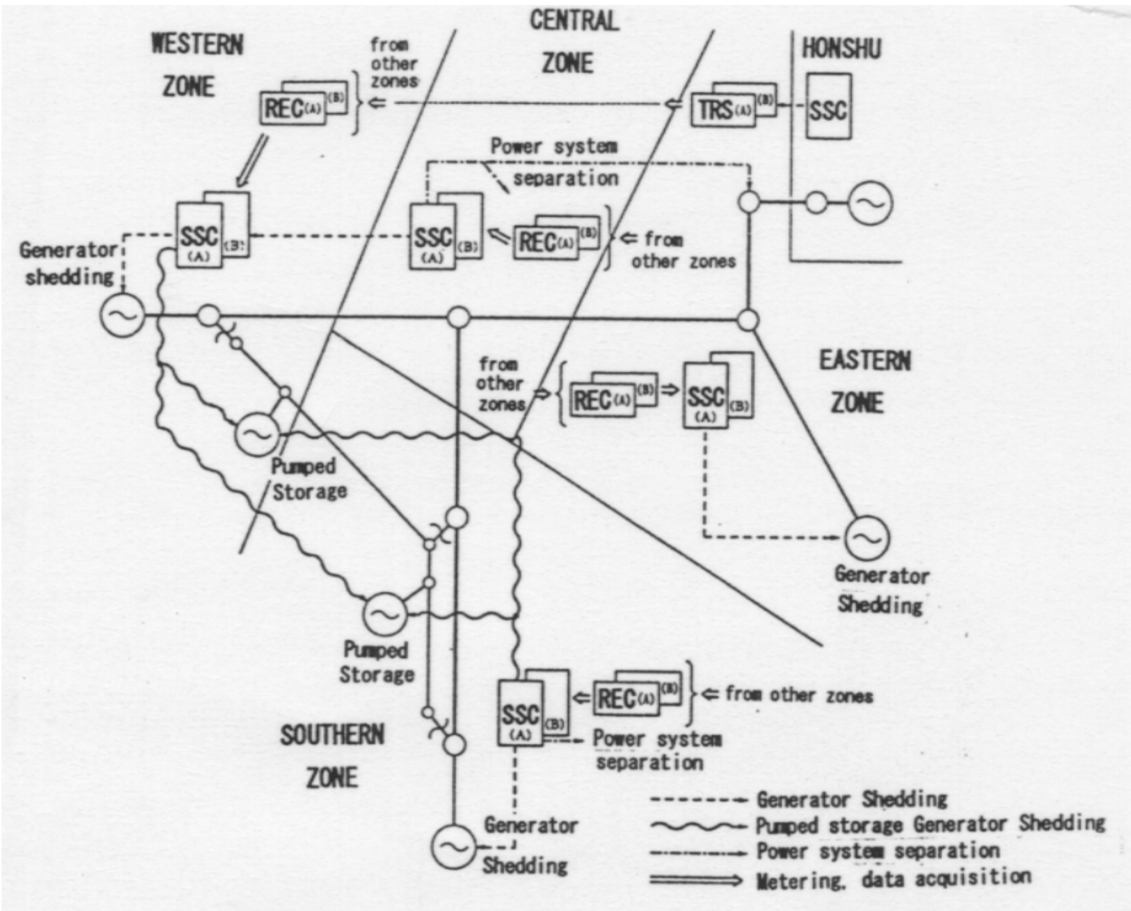

Figure 5.3 Outline of the SSC system in Kyushu

To improve availability the SSC is fully duplicated

Acquisition of fault data

The fault information transmitter (TRS) in a substation determines the fault mode from the protection relay signals e.g. single or evolving fault, one, two-phase or three-phase fault, successful re-close or not, etc. Evaluated fault modes are sent from TRS to SSC equipment via data transmitter for supervision (SV). Data transmission time delay with the SV is within 100ms. Fault information at local substation is acquired directly from the protection relays.

Acquisition of power system data

Power system information such as generator status, line and transformers power flows are sent via data transmitters for tele-metering (TM). Data transmission time delay is less than 4 sec.

SSC controller

The SSC response is determined by off-line simulation at ten second intervals based on parameters such as fault type and pre-fault power flow. Based on the network status and power flow the SSC calculates the intervention necessary to prevent transient or frequency instability i.e. the level of generator/load shedding, system separation etc. are determined prior to the fault. On receipt of the relevant relay signals (indicating a fault) the SSC immediately implements the most recently determined response action.

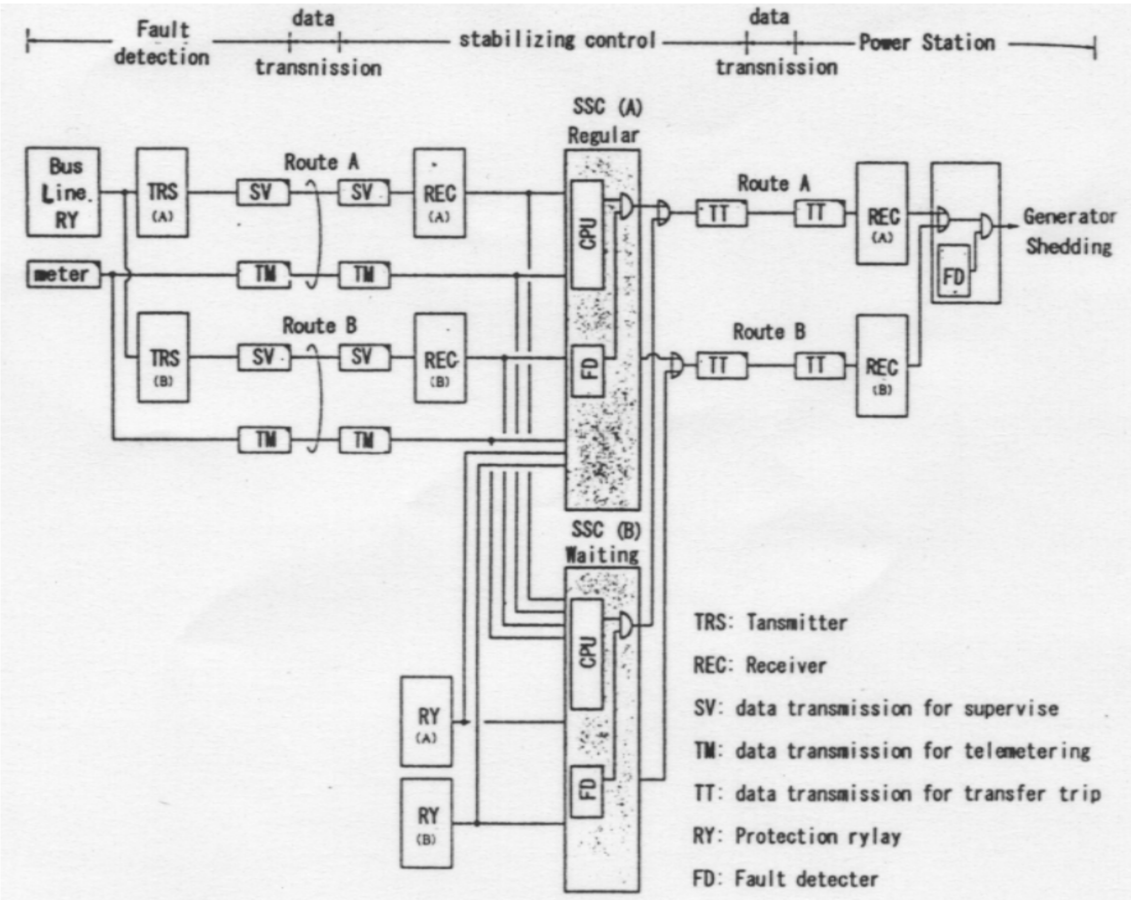

Figure 5.4 Structure of the SSC system

If an overload occurs the overload preventive function is triggered 30sec following fault occurrence. Operation commands are issued when overload is confirmed on three successive measurements by the SSC (every 10sec).

Calculated results from each duplicated system can differ because the two systems are not synchronised. So the dual system operates in an alternative (main/back-up) rather than as an OR condition. On fault occurrence the main system operates immediately. Only if it fails will the back-up system operate with 30ms time delay.

Tripping commands of generators and loads are transferred from the SSC equipment to the remote terminals via the intertrip transmitter (T.Tr). Data transmission delay is within 50ms.

Future Development
The SSC systems in the KEPCO have been developed in tandem with power system growth since 1973, when the first SSC was introduced. The power system will continue to be enlarged in near future and the SSC will also change using the state-of-the-art techniques.

5.1.2.2 Alternative Techniques for Transient Stability Control

The developments in measurement technologies and telecommunications facilitate the possibility of on-line analysis based on measurements. For example, the use of Phasor Measurement Units (PMUs) helps operators to view electrical distance between areas. This distance is determined by mean values of inter area phase angles i.e. the larger the angle, the greater is the electrical distance (impedance) between areas and the higher the risk of possible loss of synchronism. Operators then have different options as regards corrective/preventive actions e.g. system sectionalising, load shedding. The role of PMU in system protection schemes (SPS) is discussed further in Section 6.4. It is possible that in future such schemes will play a preventive as well as a reactive role in protecting power systems.

5.1.3 Voltage versus Time Detection

5.1.3.1 General

The variation with time of the receiving end voltage profile can be used to identify and/or predict voltage collapse [3]. Such a scheme operates by reference to the familiar PV operating curve for transmission links shown in Figure 5.5[1]. The effect of reducing voltage is to move the operating point O to the right. Once it passes a set margin, point S, load shedding should be initiated. The rate of change of voltage should also be included as a criterion. The strategy in future will be for prevention systems to intervene and make operators aware of impending emergencies. If necessary certain preventive actions can be undertaken automatically (see Subsections 3.2.1, 3.2.2). Nevertheless it is likely that severe, escalating voltage instability will occasionally arise. The detection relays can be used as a last resort to implement widespread load shedding in the event of a threatened collapse. A higher threshold can, if required, be used to communicate a deteriorating situation to central control.

[1] Ps = fixed source voltage; Vr=variable load voltage
P = power delivered to load; Pm is maximum power
possible i.e. when line and load impedances are equal.

5.1.3.2 Voltage Security Assessment (VSA) in France

In France early warning systems are being developed to assess whether a system is deemed to be "at risk" following changes to operating conditions. Examples of such changes are: load increase/decrease, loss of generator, tripping of transmission circuit, etc. The strategy adopted to determine the system security level is related to the dynamics of the expected disturbance. Basically two types of system dynamic phenomena can occur:

- Slow dynamic having typical times to collapse in the range of minutes to tens of minutes; examples are voltage collapse due to the operation of on load tap changers, the lack of reactive power sources or cascaded tripping of transmission circuits.

- Fast dynamic, typically leading to system collapse in the time range 100ms to 1 second; examples are frequency collapse due to loss of generation (~1 second) or dynamic instability leading to power swings an synchronism loss (~100—ms).

For disturbances having a fast dynamic the system must be protected by local dedicated protection systems based on fast acting techniques (See Chapter 6, Section 6.5 for further details). However for the more slowly developing disturbances security analysis can be carried out "on-line" in control centres using dynamic security assessment tools (DSA). This approach is realised in terms of voltage security assessment (VSA) by monitoring on-line the system power-voltage characteristic shown in figure 5.5 and calculating the acceptable security margin. This margin is the maximum acceptable load increase that can occur on the system that does not result in voltage collapse.

The architecture of the VSA tool used by EDF in the control centre is outlined in Figure 5.6 [4]. It is part of an integrated dynamic security analysis facility developed by Electricite de France (EDF) and the University of Liege [5].

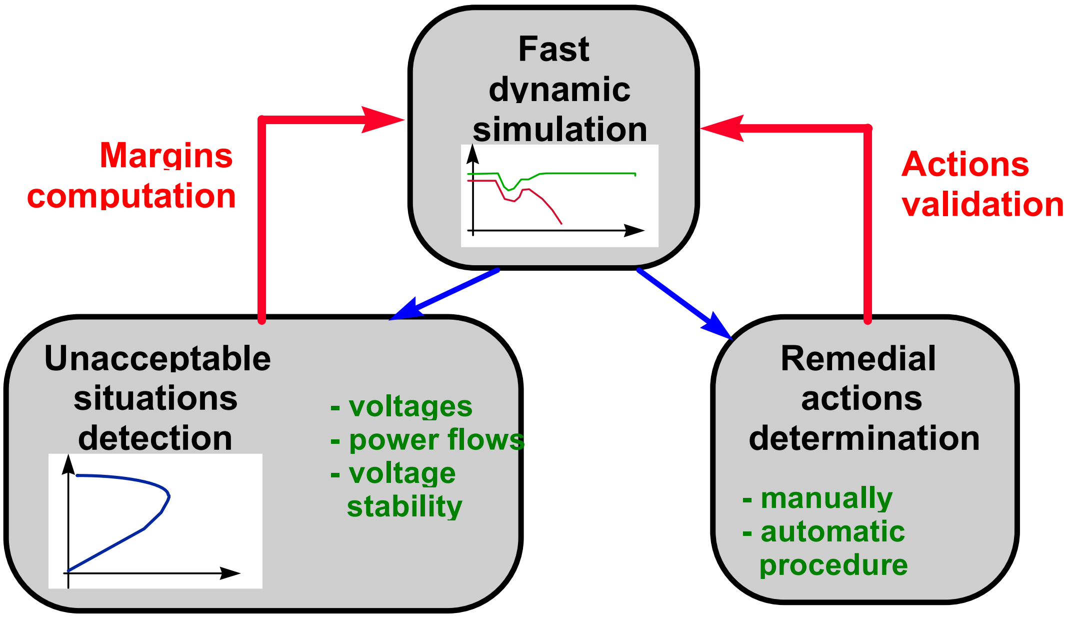

Figure 5.6: Architecture of EDF VSA Tool

For loss of synchronism or frequency collapse preventive methods using on-line analysis such as DSA are not appropriate due to the dynamics of the incipient collapse.

5.2 ANALYSIS OF PROTECTION BEHAVIOUR

5.2.1 Introduction

The risk of major disturbances in a power system is minimised if, during system faults, the protection systems never behave in a way other than intended. This is possible if a predictive approach is adopted i.e. if the way in which protection systems will operate can be ascertained beforehand and corrective actions implemented where the likelihood of maloperation or protection failure has been identified. Protection systems may operate many times per year. Data on their performance provides important feedback. This together with the fact that many of the relays installed are of a similar type facilitates the development of a predictive, co-ordinated response.
The basic task is the detailed behaviour analyses of the protection and re-closing systems involved in each major or minor disturbance originating on the transmission network. An assessment is prepared of the fault protection functions that operated or failed to operate. Performance is evaluated quantitatively. Also deficiencies in the response of the protection systems are identified and consequently corrective actions on a system-wide basis can be implemented. A number of utilities implement such systems. The following subsections describe the approach adopted in Portugal and the United Kingdom.

5.2.2 Implementation in Portugal

In 1995 REN, Portugal initiated a detailed analysis of protection system behaviour. It focused on the transmission network (400, 220, and 150 kV).

The behaviour of all protection functions is analysed for both correct and unwanted operation. This analysis is based on data obtained from protection oscillographs, fault

locators and sequence of event recorders as well as on information supplied by the control centres and other facilities within the power system.
Analysis results are held in a database and corrective actions are formulated as necessary. At the end of each year a number of performance indices are obtained. The causes of incorrect protection behaviour are described and a graphic display of the operation time of protection systems is plotted. The performance indices obtained are those recommended in the Final Report of the CIGRÉ WG 34.01, *Reliable Fault Clearance and Back-up Protection* [6], along with others developed by REN, as described in the following.

In [6] an interesting methodology is presented for planning protection systems. It is based not alone on fault statistics but more importantly on the protection performance indices.

To implement the approach proposed here, a team with extensive expertise in relaying equipment and protection systems is required. A detailed knowledge of the protection function within the overall power system is also essential in order to identify incorrect behaviour, quickly establish the reasons for same and formulate feasible solutions. The validation and the execution of some corrective actions however often require the performance of very complex tests.

5.2.2.1 Performance Indices

To assess the performance of protection schemes it is essential to quantify its behaviour. For this purpose various indices were developed. In this regard a number of paramaters are defined as follows [7,8].
N_c – number of correct operations

N_f – number of failures to operate during internal system faults.

N_s – number of spontaneous unwanted operations

N_u – number of unselective unwanted operations; it includes incorrect trippings by test/maintenance staff.

N_I – number of incorrect operations i.e. failure, spontaneous or unselective operation.

N_M = Number of imperfect operations i.e. a protection operation that is incomplete although the initial response to the particular incident is correct

Protection functions

The dependability index gives the probability of a protection function not experiencing a failure to operate within a given time interval.

$$\text{Dependability :}\quad D = \frac{N_c}{N_c + N_f} \times 100 \quad (\%) \qquad (1)$$

The security index shows the ability of a protection function to avoid an unwanted operation, either spontaneously or due to unselective operation.

$$\text{Security :}\quad S = \frac{N_c}{N_c + N_s + N_u} \times 100 \quad (\%) \qquad (2)$$

The reliability of a protection function is the combined ability to avoid an unwanted operation and not experience a failure to operate.

Reliability: $R = \dfrac{N_c}{N_c + N_f + N_s + N_u} \times 100 \quad (\%)$ ………………………………...(3)

For distance protection functions, the three performance indices described here are obtained for each type of technology.

Protection Systems

A protection system is effective when its operation is selective, fast and operates completely as intended i.e. when it has "correct operation".

Effectiveness: $E = \dfrac{N_c}{N_c + N_I} \times 100 \quad (\%)$ ………………………………………... (4)

To further quantify the quality of the protection systems the concept of correct/incorrect behaviour is introduced. Incorrect behaviour of a protection function (failure, spontaneous, unselective or imperfect operation) differs from incorrect operation (failure, spontaneous or unselective operation). A protection function can have a correct operation and an incorrect behaviour when it has a maloperation. In this context an imperfect operation is defined as *a protection operation that is incomplete although the initial response to the particular incident is correct.* For instance, when a distance protection trips in a specified situation and locks out, this is a correct operation but an incorrect behaviour if the scheme was intended to allow auto-reclosing. Other examples of imperfect operations would be teleprotection system defects, wiring defects preventing reclosing, etc. Imperfect operations can result in a significant number of incorrect behaviours (4 in 36 in 1996 and 6 in 25 in 1997 on the Portuguese network). To identify and correct the causes of imperfect operations is essential if a quality index of 100% is to be achieved. If the number of incorrect operations of a protection function is added to the number of imperfect operations the number of incorrect behaviours of a protection function is obtained. Similarly if we subtract the number of imperfect operations from the number of correct operations we have the number of correct behaviours.

If we define the total number of incorrect behaviours as B_I and the total number of correct behaviours as B_C then:

$$B_I = N_S + N_U + N_F + N_M$$

$$B_C = N_C - N_M$$

A protection system is deemed to have operated with good quality when the system including all related protection functions and tele-protection systems had a correct behaviour.

Quality: $Q = \dfrac{N_g}{N_g + N_b} \times 100 \quad (\%)$ …………………………………………….. (5)

N_g – number of operations with good quality

N_b – number of operations with bad quality i.e. less than 100% correct.

To achieve a quality index of 100 % for the protection systems in service in a network means that all faults that occurred in the power system over a year were cleared with the best operation expected from the installed protection systems.

A 100% quality index over a number of years means that, for the immediate future, the protection systems in service will operate as expected i.e. behaviour is predictable.

A protection system has selective operation when it opens only those circuit breakers which are essential to eliminate the fault.

$$\text{Selectivity: } S = \frac{N_s}{N_s + N_u} \times 100 \quad (\%) \ldots\ldots (6)$$

<u>Teleprotection systems</u>

The reliability of a teleprotection system can be defined as the probability of the tele-protection system not having an incorrect behaviour.

$$\text{Reliability: } \quad R = \frac{B_c}{B_c + B_i} \times 100 \quad (\%) \ldots\ldots (7)$$

B_c – number of correct behaviours (correct operation of all component parts)

B_i – number of incorrect behaviours (incorrect operation of any component part)

A teleprotection system can be defined as a group of equipments designed to ensure the transfer of protection function signals between terminals of a line. Therefore, the teleprotection and transmission terminal equipment, their interconnection, the communication channel and the auxiliary circuits belong to the teleprotection system.

<u>Automatic reclosing</u>

An automatic recloser is 100 % reliable when the probability of having an incorrect behaviour is zero.

$$\text{Reliability: } \quad R = \frac{B_c}{B_c + B_i} \times 100 \quad (\%) \ldots\ldots (8)$$

B_c – number of correct behaviours

B_i – number of incorrect behaviours

An automatic recloser is defined as the control function designed to initiate the automatic closing of circuit breakers after the operation of the protection function of the associated circuit. Included in the definition of automatic recloser are its associated auxiliary circuits.

$$\text{Effectiveness: } \quad E = \frac{N_e}{N_e + N_n} \times 100 \quad (\%) \ldots\ldots (9)$$

N_e – number of effective automatic reclosings

N_n – number of non-effective automatic reclosings

An automatic reclosing is effective when, following a correct or incorrect behaviour of an automatic recloser that caused a circuit breaker to close, this equipment stays closed because the fault in the power system has been cleared and has not reappeared.

5.2.2.2 Causes of Incorrect Behaviours of Protection Functions and Protection Systems

Protection Functions: At the end of each year the causes of incorrect protection function behaviour (spontaneous, unselective, failure and maloperation), are identified. Some of these can be due to faults and/or defects associated with:

- Current Transformers
- Voltage Transformers
- AC wiring
- Trip wiring
- Trip coil
- DC system
- Protection and control scheme design
- Protection Co-ordination
- Selected Settings
- Relay type and quality
- Teleprotection systems

Protection Systems: The causes of the incorrect behaviours of the protection systems are also classified at the end of each year. Some are often those already described for protection functions.

5.2.2.3 Operating Time of Protection Systems

On an annual basis the percentage number of incidents during which protection systems at each voltage level operated in a time less than a specific target value should be established.
The operating time of a protection system is the time between the beginning of a power system fault and the tripping of the last protection function of the protection system which is essential to eliminate the short-circuit by opening the associated circuit breakers.

5.2.2.4 Benefits obtained on the Portuguese Transmission Network

Prior to the introduction of protection evaluation procedures the Portuguese transmission network had the following protection systems installed on line circuits.

400 kV lines: Duplicate main protection either phase comparison plus distance or duplicate distance. For both arrangements: earth-fault directional protection (complementary protection – normal inverse curve) and PUTT scheme on distance protections (permissive criteria: zone 2)
220 kV lines: Duplicate main distance protection. Earth-fault directional protection (complementary protection – normal inverse curve) and PUTT scheme on distance protections (permissive criteria: zone 2)
150 kV lines: Two distance protections (zone 3 as remote back-up) or distance protection (main) and non-directional over-current protection (back-up). With both arrangements: earth-fault directional protection (complementary protection – normal inverse curve) and PUTT scheme on distance protections (permissive criteria: zone 2)

The evaluation, performed over a two year period, identified the following main items for improvement:

- The permissive criterion for the telecommunication PUTT scheme for passive line terminals (i.e. radial or tail feeders), based on ground over-current relays, should be replaced by under-voltage relays. The former criterion does not detect high resistance faults or faults not involving earth.
- The permissive criterion – zone 2 – for the telecommunication PUTT scheme between distance protections should be replaced by the zone of maximum directional reach. This reduces the fault clearing time for internal line faults, improves the selectivity of protection systems and the auto-reclosing performance.
- Co-ordination of protection systems on the few existing three terminal lines should be upgraded even to the extent of changing some protection relays. The infeed problems on these lines, especially on the more asymmetrical ones, makes the detection of faults in zone 1 or even in zone 2 very difficult, when applying classical co-ordination criteria.
- Co-ordination should be improved at other selected nodes of the network also, which would result in better selectivity and fault clearing time.
- Telecommunication systems reliability should be improved. This improves selectivity, fault clearing time and auto-reclosing performance. It is considered a very important area for enhanced performance.
- Corrective actions in protection systems should be executed within a very short time period.
- The use of computer simulation programs applied to protection systems is essential in the diagnosis of some incorrect behaviours. By simulating the behaviour of the protection functions during faults these programs are also very useful in finding and validating the best solutions when designing protection systems for special or unusual applications. Some packages also allow the automation of protection co-ordination and protection settings, by programming the co-ordination criteria and modelling the protection functions. Besides saving time this approach reduces the number of incorrect behaviours due to human error.
- The number of digital oscillograph recorders that store data in COMTRADE format should be installed. Testing protection equipment with actual fault currents and voltages helps ascertain more quickly the reason of an incorrect behaviour (some times it may be the only way). Furthermore the currents and voltages resulting from simulation programmes can be used to test the protection equipment.

Improvements have been implemented in all areas.

5.2.3 Implementation in England and Wales

Following a system incident field staff record all information on protection relay behaviour which is then entered into a database [9]. Protection system defects detected during normal operation or through maintenance activities is similarly entered. Through trend analysis protection specialists can identify relays or components that exhibit poor performance or a tendency to fail. Performance is assessed on two levels:

- Impact on the transmission system
- Performance of the protection equipment

5.2.3.1 Transmission System Performance

The important indices used when monitoring system performance are the *Power System Fault Dependability Index* and the *Power System Fault Security Index* Which are defined as follows:

$$PowerSystemFault\ Dependability\ Index = \left(\frac{A - F_1}{A}\right)x100\%$$

$$PowerSystemFault\ Security\ Index = \left(\frac{A - F_2}{A}\right)x100\%$$

Where: A = total number of power system faults

F_1 = number of power system faults where a circuit breaker failed to trip

F_2 = number of power system faults where an unwanted circuit breaker trip occurred but no circuit breaker failed to trip.

The *Discriminative System Fault Performance Index* indicates the overall system protection performance and is defined as:

$$\left(\frac{A - (F_1 + F_2)}{A}\right)x100\%$$

By using the information from the database on the defective performance of protection systems during fault trippings and unwanted trippings the associated risks can be established and targets for the above defined performance indices proposed.

Fault performance data is used to quantify the performance of the complete protection system including autoreclose devices.

5.2.3.2 Protection Equipment Performance

Two indicators are used to monitor protection equipment performance:

$$Index\ of\ Correct\ Performance = \frac{N_C}{N_C + N_S + N_U}$$

Note: Corresponds to *Effectiveness* in Subsection 5.2.2.1.

$$Index\ of\ probability\ of\ Failure = \frac{N_F}{N_C + N_F}$$

Where as before:

N_C – number of correct operations

N_F – number of failures to operate during internal system faults.

N_S – number of spontaneous unwanted operations

N_U – number of unselective unwanted operations; it includes incorrect trippings by test/maintenance staff.

Protection performance is analysed to establish the causes of both unwanted operations and failures to operate. Consequently it is possible to identify specific problems or trends e.g. hardware problems with particular relay type, wiring installation errors, etc. This formal company wide system of data collection ensures consistent identification of similar problem despite the wide diversity of equipment on the system.

5.2.4 Summary

Analyses of the behaviour of both protection functions and systems yield the following benefits:

- Information obtained either confirms the adequacy of the protection criteria applied to the network or highlights the necessity for modification to current policies, procedures and practices including those relating to the maintenance of protection devices.
- Identification of protection systems that need to be partially (some equipment) or totally modified or upgraded (replaced).
- Information supporting decisions on acquisition of particular types of protection equipment and the implementation of particular scheme designs.
- Information supporting decisions on network planning.

5.3 ON LOAD TAP CHANGER ACTION

See also Chapter 3, Section 3.2.2.

5.3.1 OLTC Blocking

The blocking of on-load-tap-changer (OLTC) operation typically functions as follows. Within the section targeted for the prevention of voltage collapse the voltage at the different substations is monitored. If the voltage declines below a threshold value for a preset period (e.g. 30 seconds) then all OLTCs in that sector are blocked. Thus the OLTC will not alter tap to increase the LV side voltage and thereby further increase current and reduce voltage at the HV level. Blocking is most effective when installed on the OLTCs of HV/MV transformers rather than on EHV/HV units.

However studies [10] have shown that blocking is not always effective. Detailed assessments indicate that on heavily meshed systems OLTC blocking is effective because in such cases the voltage decline tends to be slow. Hence supply to consumers can be maintained albeit at poorer quality. On weakly connected systems however the loss if a transmission circuit under certain circumstances my represent such a severe condition that voltage decline is accompanied by increased flows on other circuits resulting in overload and cascade tripping. Nevertheless, depending on the speed of the voltage decline it may provide operations staff with valuable time to undertake load shedding or other corrective actions.

A further influencing factor is the load type: dependent or independent. OLTC blocking is not as effective with independent loads, e.g. motors, as the load tends to draw increasing current with reducing voltage. Dependent load however does not present this problem to an OLTC blocking scheme.

In conclusion while OLTC blocking is theoretically advantageous in preventing voltage collapse studies should be performed to assess its effectiveness. Such studies should model not only the transmission system but also the connected load type. On weak systems OLTC blocking is unlikely to arrest voltage collapse. In such cases fast acting automatic solutions such as undervoltage activated load shedding will also be required.

5.3.2 OLTC AVR Set Point Reduction

Reducing the AVR set point will reduce the load and hence give greater support to the transmission voltage than simply blocking the OLTC. However the negative impact on consumer power quality will be more severe. Otherwise the same limitations apply as for the blocking scheme.

5.4 CONCLUSIONS

Centralised schemes have been employed for many years in Japan to maintain transient and frequency stability. Data is acquired from substations throughout the system relating to network status and power flow. Based on this information the SSC calculated the intervention necessary to prevent transient or frequency instability following a particular fault type. Should a fault occur the most recently determined response is implemented. The scheme also improves transient stability if generator shedding is required by precalculating the level of generation to be shed. However in this case the scheme is operating in reactive rather than preventive mode.

Using a voltage security assessment technique and data obtained on-line from substations the available security margin for the network "Power-Voltage" characteristic can be computed. This gives operators the time to avoid disturbances developing on the system. Such a scheme is being implemented in France.

The systematic collection and analysis of protection performance data during both fault and quiescent conditions facilitate the identification of particular deficiencies in the overall protection schemes. Solutions or improvements can then be implemented. The quantification of protection behaviour by the application of performance indices enables the level of expected and acceptable performance to be established and to provide a benchmark against which it can be evaluated. Consequently the effectiveness of the protection systems is enhanced.

The blocking of OLTCs on HV/MV transformers will in certain circumstances prevent or delay voltage collapse. Reducing the AVR set point further enhances this effect. However the effectiveness of such schemes is heavily influenced by the type of network (level of meshing) and by load type (dependent or independent). Studies should be performed to predict the benefits for each application.

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6 SCHEMES TO MINIMISE THE IMPACT OF DISTURBANCES

6.1 NEW PHILOSOPHIES FOR OUT-OF-STEP PROTECTION AND POWER SYSTEM SECTIONALISING

One of the more traditional ways of containing a disturbance is through network sectionalising based on power swing or out-of-step tripping (OST). This must be complemented by the blocking of impedance relays during power swings. Otherwise network separation at other than the pre-selected sectionalising nodes may occur. The application of such schemes is illustrated in the following reports from South Africa and France (Sections 6.1.3 and 6.1.4 respectively). The latter report also refers to new techniques for detecting synchronism loss.

6.1.1 Introduction

Large fluctuations in machine electrical output characterise power swings and out-of-step conditions. The performance of protections that monitor power flow, voltage and current may be affected by the system behaviour in the presence of such phenomena. These protections include over-current, over-voltage, distance, pilot and loss of excitation protection. Additional features must be provided in such protections to avoid incorrect operation. In this context out-of-step blocking (OSB) protection is beneficial in avoiding unwanted tripping.

However it is often also necessary to protect the system so that, during unstable conditions, some protection will operate to isolate unstable generating stations or network sections. Out-of-step tripping (OST) tripping schemes are frequently used for this purpose.

Both out-of-step protection types (blocking and tripping) detect power swings and out-of-step conditions by using the fact that the voltage/current variation during a power swing is gradual while it is virtually a step change during a fault. More recently schemes based on phasor measurement to detect power swings have been developed [2]. A further evolution of this technique is its application in wide area protection systems – also known as system protection schemes (SPSs) [3]. A comparison of the latter with more traditional methods is made in 6.1.4.3.

6.1.2 Traditional Application of Out-of-Step Blocking and Tripping Protection

The traditional philosophy for the application of OSB and OST protection schemes can be summarised as follows [1]:

1. OST relays are located in the area identified as the electrical centre of the system during out-of-step conditions.
2. All distance relays are equipped with OSB features when OST protection is enabled.
3. The locations of out-of-step tripping relays determine the points where system separation (islanding) takes place during a power swing. However, transfer tripping can be employed to achieve separation at a different network node if required.

4. The out-of-step relay forward and reverse reaches are usually determined by calculating the source impedance "seen" by a relay, in both the forward and reverse directions (Thevenin impedance).
5. The timer settings of the relays are calculated from a maximum swing frequency determined by studying the rotor speeds during out-of-step conditions; it is assumed that these speeds always remain constant during these conditions.

However, this rather simplistic approach requires further elaboration. It is also necessary to consider the following:

1. During a power swing the point in the network where the voltage is closest to zero is identified as the electrical centre. However, the behaviour of the impedance locus at the electrical centre may be such that it does not facilitate the successful detection of an out-of-step condition. Simply placing out-of-step tripping relays at the electrical centre ignores this impedance locus behaviour and may result in an incorrect relay response.
2. Global application of OSB protection, irrespective of whether the need exists at the various locations, may result in unnecessary cost, increased risk of maloperation and increased co-ordination complexity.
3. The nodes identified for system separation are not necessarily the correct locations for islanding as they may not create stable islands with minimum load shedding.
4. The generator swing frequency relative to a second generator or to a strong source (normally a group of large generators) does not remain constant. This arises due to the dynamic response of control systems (such as AVRs and SVCs) and the dynamic behaviour of load. These dynamic effects influence the MW and MVAr flows in the transmission lines and therefore the rate of change of the impedance locus as measured by the relays. The frequency for which the OSB/OST timers must be set is therefore not always equal to the swing frequency.
5. Using an equivalent source impedance (Thevenin impedance) may in many cases produce inadequate reach settings because of the configuration and characteristics of the system (parallel lines, long lines which may or may not be series-compensated, strong sources and weak sources, load composition, etc.).

6.1.3 New Approach to Out-of-Step Blocking and Tripping Protection

Experience with out-of-step tripping/blocking schemes during disturbances has exposed limitations in performance. The South African case described in Appendix 1 illustrates some of these limitations.

Considerable work has been undertaken to improve the traditional approach and also introduce new methods [1]. To improve performance some refinements to the application philosophy for out-of-step protection is necessary. These can be summarised as:

1. Perform system rotor angle stability studies to identify system stability constraints and to establish system operating scenarios that will ensure compliance with such constraints.
2. Determine the optimal locations for the provision of out-of-step protections during power swings.

3. Determine the optimal location for system sectionalising (islanding) during out-of-step (unstable) conditions; this will depend on the interconnecting impedance between islands as well as their inherent potential to attain a stable operating regime.
4. Establish the maximum timer setting requirements as well as the minimum forward and reverse reach settings required for successful detection.
5. Create mathematical simulations of the out-of-step blocking and tripping relay detection and operation behaviour; when performing the rotor angle stability studies the relay simulations should be included in the power system model

.

6.1.3.1 System Stability Studies

The requirement for out-of-step protection (blocking and tripping) on a power system depends on whether a rotor angle stability constraint exists. This is usually determined from transient stability studies involving numerous contingencies. These stability studies identify:

- the stability limits of the system for the different contingencies
- those parts of the system that impose limits on system stability (i.e. high impedance paths created when losing lines or generation)
- generating stations that are susceptible to system disturbances
- generating stations that tend to remain stable during severe disturbances
- generating stations that tend to group together during disturbed conditions
- those which tend to separate during unstable rotor angle conditions can also be identified

6.1.3.2 Optimal Locations for OST and OSB Relays

The apparent impedance is a function of the MW and MVAr flow on a line and is calculated from the results of the stability studies:

$$R = \frac{V^2 P}{P^2 + Q^2} \; and \; X = \frac{V^2 Q}{P^2 + Q^2}$$

where

P	=	MW power flow
Q	=	MVAr power flow
V	=	the busbar voltage

During unstable conditions the impedance Z = R+jX varies and its locus as plotted on an R-X diagram is illustrated on Figure 6.1.1. Assuming the quadrilateral represents the maximum permissible impedance reach to avoid load encroachment then the following criteria may be employed to identify the optimal locations for out-of-step tripping and blocking.

During an out-of-step condition the impedance locus transverses the R-X plane (from right to left as shown but the swing can also be from left to right) entering at a point R_I, X_I and exiting at $R_O X_O$. The point $Z_C = R_C + jX_C$ represents the point closest to the electrical centre of the swing.

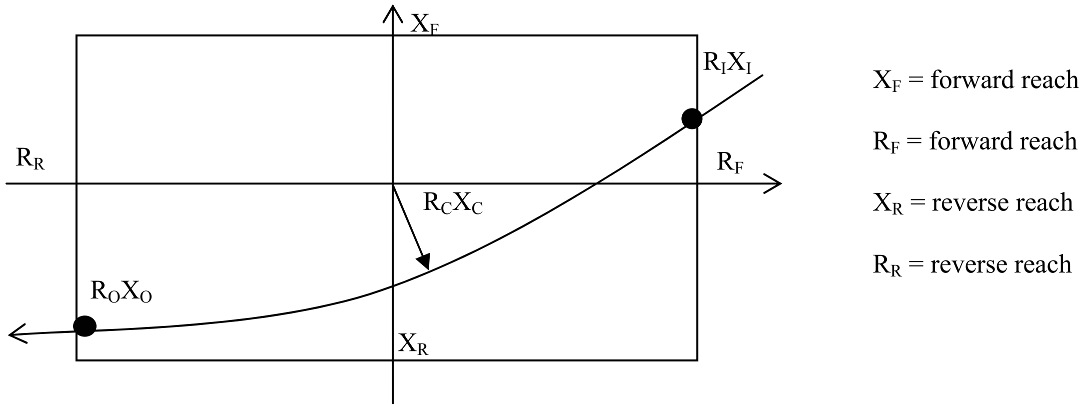


Figure 6.1.1: Power Swing Locus on R-X Plane

The criteria for selecting the preferred locations for out-of-step tripping (or blocking if that is the more appropriate response for the location in question) are:

$\sqrt{R_c^2 + X_c^2}$ to be low i.e. as close to zero as possible
R_I to be close to R_F in value
R_O to be close to R_R in value
R_I,R_O to be of opposite sign
$X_I \leq X_F$
$X_0 \leq |X_R|$
For the different system stability studies the apparent impedance locus should be determined and the values R_I, X_I, R_O, X_O, R_C, X_C calculated from the R-X diagram. This gives the critical values applicable to each scenario studied.

6.1.3.3 Optimal Location for System Islanding

Having identified possible locations for separating the system into islands it is essential that the sectionalising arrangement chosen achieves stable operating conditions within the islands. In this context the following are important:

1. A reasonable generation/load balance must exist in each island prior to separation. To ensure the minimum of generation or load shedding the island should be selected such that the load demand balances the available generation to the greatest extent possible i.e.

   $$\frac{P_G}{P_L} \approx 1$$

   where P_G is available generation and P_L is load demand.

   Various generation and loading patterns for the total system should be studied before selecting the most appropriate islands.

2. The demarcation between potential islands should be clear i.e. the intervening impedance should be large. A high impedance between operating centres

represents a "natural" point of separation. However, between generators in the same island it will be a source of instability and should be avoided.

3. Stability within the island following the disturbance and ensuing system separation must be considered. The degree of stability within the island for the different scenarios is determined by taking into account the damping of power swings for the total system and rate of oscillatory decay within the island following separation.

4. Islands should, where possible, involve a mix of generators with large and small inertias. A machine's inertia determines the speed of angular response to disturbed conditions. Concentrating low inertia machines together should be avoided as stability will prove more difficult to achieve given their rapid development of oscillatory behaviour during a disturbance. The inertia constant of a machine with reference to other machines within the system is defined as the kinetic energy stored by the rotor of the machine at its rated speed divided by the MVA base of the system. This can be written as:

$$H_{mach} = \frac{\frac{1}{2}Jw^2}{MVA_{system}} = \frac{Jw^2}{2S}$$

where

J = moment of inertia of the rotor (kg.m²)
w = rated speed of the rotor (rad/s)
S = Total MVA of all connected units on the system

6.1.3.4 Relay Settings

To ensure the optimal performance of the OSB and OST relays the settings must be carefully selected for the conditions likely to prevail during power swings. During the swing the impedance locus will oscillate between a maximum and minimum value at the slip frequency f_s. The behaviour can be illustrated in an impedance/time plot (|Z| vs. Time) as shown in Figure 6.1.2.

Timer Settings

The two broken horizontal lines represent the impedance characteristics set on the relay (Z_I, Z_O). The time which the impedance takes to traverse between the zone settings determines the time setting required i.e. if the entry time at Z_I is t_I and at Z_O is t_O then the time to traverse between Z_I,Z_O is t_O-t_I. For the different stability studies corresponding values of t_O-t_I can be calculated. If the maximum value so obtained is taken to be the setting then the relay will operate for any power swing having a higher swing frequency (i.e. lower value of t_O-t_I).

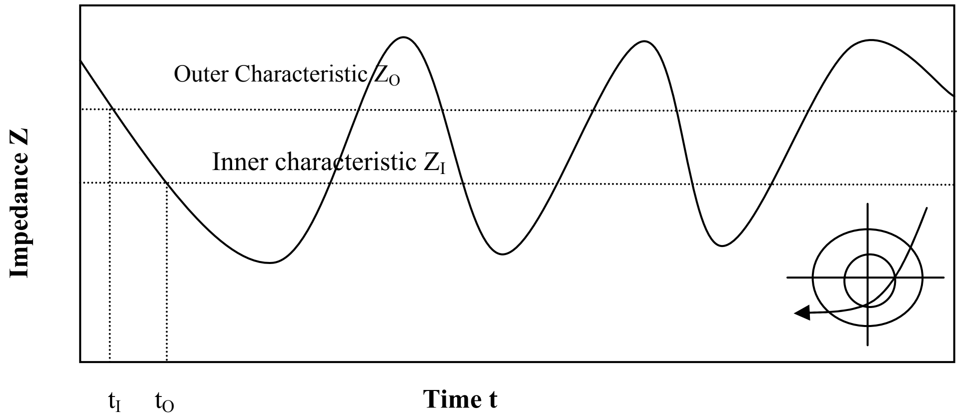


Figure 6.1.2: Timer Settings
$t_O - t_I$ = time that Z remains within zone

Reach Settings

The maximum forward and reverse reach settings are determined from X_I and X_O as calculated in Section 6.1.4.2 (see Figure 6.1.1). Again, for the various stability studies a number of these values could be determined for a given location. The desired reach settings are again simply determined from the maximum values obtained for X_I and X_O.

6.1.3.5 Protection Modelling

The relay characteristics can be modelled mathematically. The impedance detection principle and power swing frequency determination can be simulated based on the relay data provided by the manufacturer.

The protection models obtained in this way should be included in the stability study as it will indicate the effectiveness of the protection relays in catering for the following requirements:

- correct OST operation at the designated locations
- correct OSB operation where required including blocking of distance relays
- correct system islanding.

6.1.4 System Sectionalising

As noted in Section 6.1.3 network sectionalising is important as a method of containing the disturbance to a particular region. This islanding of parts of the system prevents a complete collapse by cascade effect following a serious disturbance in one particular sector. The following islanding strategy has been developed by EDF [3]. It depends on the network structure (size, meshed/unmeshed, dispersed/concentrated generation, degree of connectivity to other utilities and import/export level…) and on the network's susceptibility to the different types of disturbance: voltage/frequency collapse, cascading line tripping, loss of synchronism (system stability). A typical islanding strategy has the following steps, many of them based on dynamic simulation:

1. Within the same potential island unify those parts of the system that have the same dynamic behaviour
2. Analyse the generation/load balance for each potential island or groups of islands and verify that it is compatible with the maximum load shedding levels associated with under-frequency and/or under-voltage load shedding schemes
3. Establish the parameters that best describe the general behaviour of an island (voltages at selected major nodes, mean phase angle, power flows on interconnectors…)
4. Identify thresholds for those values that indicate when the system is at risk.
5. Develop an islanding procedure and associated corrective actions (immediate tripping of all interconnection lines, associated load shedding and/or start up of power plants)

To illustrate this approach the EDF defence plan against loss of synchronism is described below.

<u>6.1.4.1 Loss of Synchronism Defence Plan</u>

The French system consists of many, dynamically coherent islands. Consequently during a period of instability all the units of the particular area loose synchronism with the main system. Within these areas generators are strongly connected to each other while between areas the links are weaker. Following a loss of synchronism, unit tripping with pole slip relays protects the generator but does not necessarily avoid a system collapse. This is particularly the case when the system is highly meshed. The prevention of instability propagation throughout the system is best achieved by isolating the area (or areas) that has lost synchronism. Sectionalising the network in this way contains the disturbance to a particular sector.

Following several incidents in the 1970's, out-of-step relays were installed at both terminals of the lines crossing the boundaries of the dynamically coherent areas (potential islands). The scheme named "the DRS Plan" operates as follows.

The out-of-step relay monitors the voltage locally. It triggers when significant voltage oscillations are detected (one of the effects of power swings) and trips the line. The triggering criteria are the magnitude and number of swings. These criteria are set with the help of simulation tools for each voltage level. This protection scheme operates locally at only one voltage level and needs no particular communication with any other devices. The successful use of out-of-step relays in this way requires that the distance relays on other lines do not trigger during power swings or pole slips. In order to avoid unselective circuit tripping only the DRS schemes should operate to trip the tie lines traversing the sector boundaries. To ensure that unwanted tripping does not occur, distance relays should be equipped with out-of-step blocking schemes.

The French system is divided into 19 areas, all equipped with the DRS protective relays on the boundary lines, including the interties to neighbouring utilities. These schemes have been in operation for more than 15 years. Although they proved to be generally effective the out of step schemes may in some cases lead to a non optimal islanding of the disturbed area because of certain inherent weaknesses:

- The measurements are processed locally in one location whereas when a generator loses synchronism, depending on its distance from other generators, the voltage oscillation will vary.
- The voltage oscillation itself is an effect of synchronism loss (power swing) - not the cause which is angular instability; the scheme is therefore reactive and not suitable for a preventive approach.
- Sequential line tripping: All the lines are not tripped simultaneously, leading in some cases to delays in the isolation of the unstable zone.
- Isolation completion: Some lines may not be tripped because the magnitude of the voltage swing stays below the criterion threshold (for example if the relay is located sufficiently distant from the centre of the swing) but is still able to induce loss of synchronism.
- Selectivity: The definition of the homogeneous zone assumes that when frequency instability occurs, the largest swings are expected on the boundary tie lines between two homogeneous areas. When a number of zones are equipped with out-of-step relays, the voltage swings may sometimes be observed over a wide area in a diffuse manner. It is not certain that the relays located at the out-of-step sector boundaries will trip first and unwanted or disorganised feeder tripping is possible.

A particular maloperation is described in Appendix 2.

6.1.4.2 Remedial Actions after Islanding

Once the disturbed area has been isolated from the rest of the system the two sub-systems evolve separately. The out-of-step relays cater for no further corrective measures. The latter are entirely at the discretion of the system operators.

In the EDF system, the south-eastern part often exports energy to the rest of the system. If a loss of synchronism occurs in an "exporting" area, isolating it from the rest of the system means that the main system becomes energy deficient and its frequency will start to decline. Corrective action is normally by the operators but this introduces a time delay. If the frequency decline is faster than the response time of the operators it is arrested by under-frequency load shedding schemes.

6.1.4.3 The Syclopes System : Co-ordinated Scheme against Synchronism Loss

The advantages and weaknesses of the power swing defence plan (described above) were highlighted by major contingency studies in the early 1980's. System modelling and analysing tools (Eurostag) then being developed identified a more complete solution to the containment major disturbances. The defence plan based on out-of-step relays is easy to implement as it is based on local information. However this is also its weakness because while it detects/reacts to the effects of the system disturbance at a single point the loss of synchronism frequently affects large areas.

A superior detection method is one based on the fundamental indicators of the instability i.e. angular and frequency difference between two points. This is best obtained by processing the voltage phasors of each sector (homogeneous group of generators) and then continuously comparing the angular difference between the homogeneous areas. This principle is used in the second generation of system protection schemes (SPS) against loss of synchronism. It was again developed by EDF and is called "Syclopes".

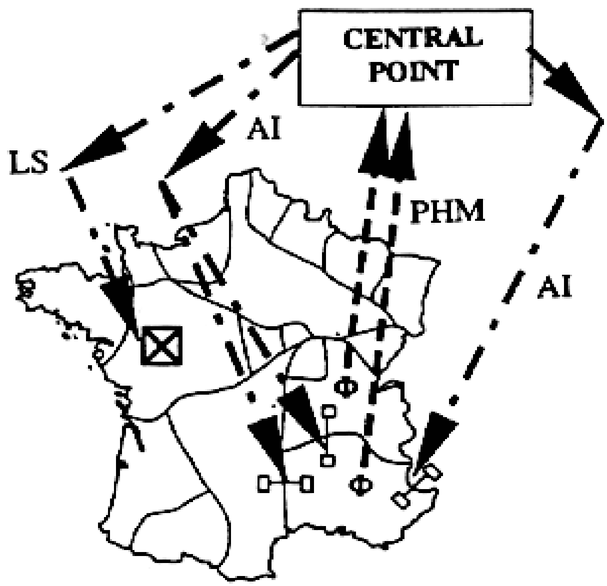
The functions performed by Syclopes are :

- Detection of loss of synchronism
- Tripping of all the lines bordering the sector that looses synchronism,
- Initiation of load shedding if necessary.

With this new SPS the information of the whole power system is processed at one central point as a global and co-ordinated task:

- Local measurements on the network are sent to the central point,
- Information from the complete system is processed in the central point computer, and the affected zone is identified,
- The central point issues corrective commands to substations in order to local isolate the affected zone by opening all interconnected tie lines.
- If necessary, the central point issues commands to HV/MV substations for load shedding, so as to prepare the active power balance for the post islanding phase, and maintain the frequency in a suitable range.

The hierarchical arrangement is indicated in the following sketch.



PHM = Phase measurement
AI = Area Islanding
LS = Load Shedding

Syclopes was developed initially for the isolation of two south-eastern areas in the French network that were identified as critical in relation system stability. These areas export large amounts of active power and may during a disturbance require loads to be shed elsewhere on the system to prevent induced loss of synchronism. When compared to the “DRS plan”, the co-ordinated SPS "Syclopes" brings the following improvements:

1. Loss of synchronism by phasor measurement more closely identifies the origin of the event, reduces the detection timeand hence the overall response time.
2. Global processing gives selectivity and accuracy of the response actions.

3. A simultaneous and complete tie line tripping process with limited delay preserves the stability of the generators in remote areas.
4. Coordination of the load shedding and the tie line tripping processes ensures that the status of the rest of the system is improved from viewpoint of frequency stability and networks integrity.

Every part of the SPS needs to be highly reliable and secure to guarantee that the risk of unwanted actions such as line tripping or load shedding is acceptable and to ensure a correct response in the event of synchronism loss (power swing or pole slip condition). The different components are:

- Phasor measurements and local pre-processing,
- Information transmission to the Central Point,
- Real time information processing at Central Point,
- Command transmission to substations
- Command application (line tripping, load shedding at HV/MV substations).

Additionally the speed of the phenomenon requires rapid two-way communication media (from local to Central Point and back). To achieve these requirements, a two way communication network (telephone-line/satellite) is used. The arrangement is outlined in figure 6.1.3.

The Syclopes co-ordinated SPS has been installed in the two south-eastern sectors. Two other sectors are being considered for future application.

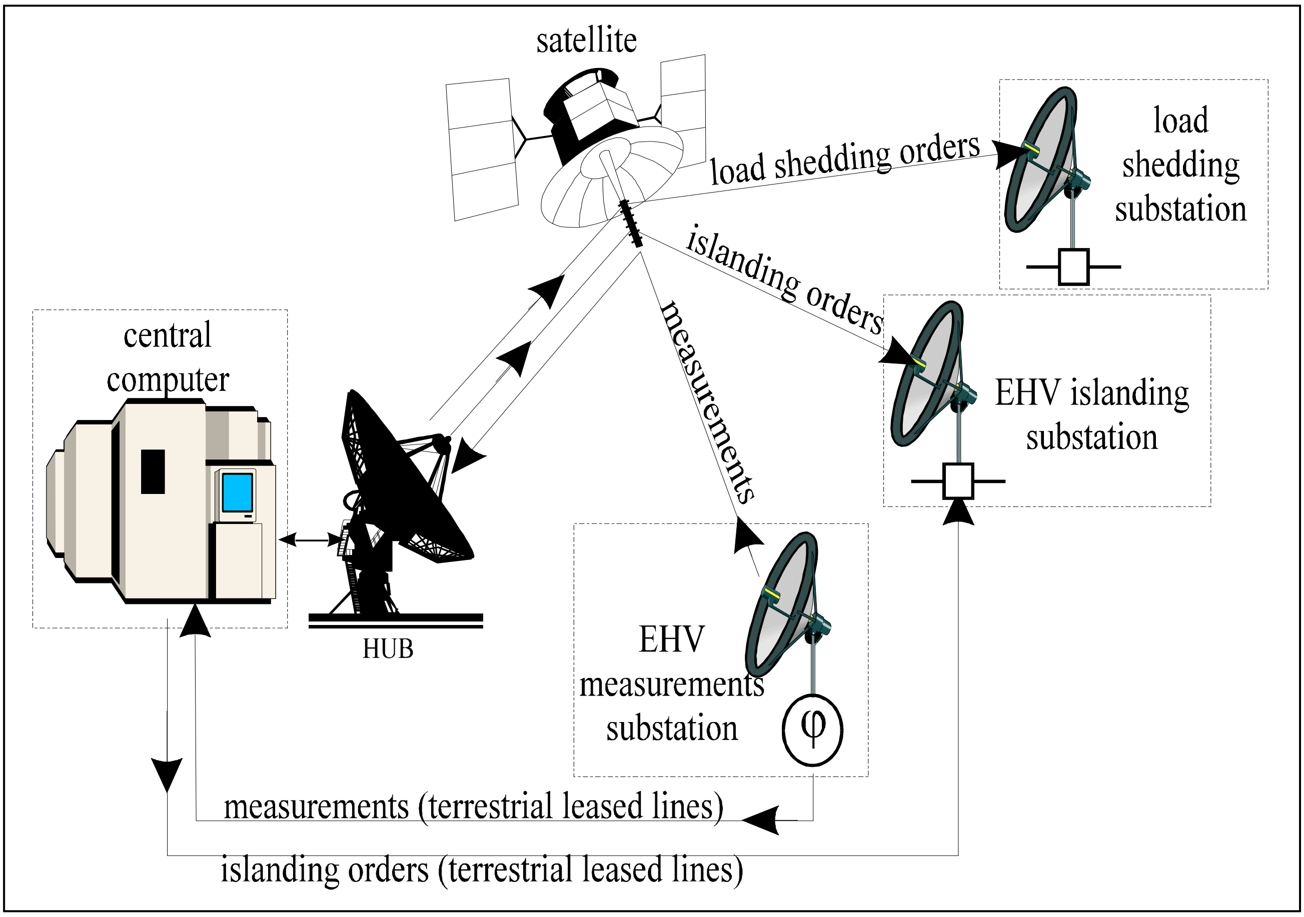


Figure 6.1.3 Communications Network for "Syclopes" SPS

6.1.5 Wide Area Protection

Conventional protection devices provide dedicated protection to individual equipment items (transformer, generator, line etc.). By contrast wide area protection systems (WAPs) are intended to protect the power system as a total entity focusing on maintaining power system integrity. The philosophy envisages that WAP complements the existing control and protection systems. Analyses of major disturbances [4] reveal that they are mainly caused by multi-contingencies. While it is impossible to prevent all contingencies that may lead to power system collapse, WAP has the potential co-ordinate measures that will prevent large area disturbances or mitigate their impact. This increases power systems reliability and minimises outage requirements.

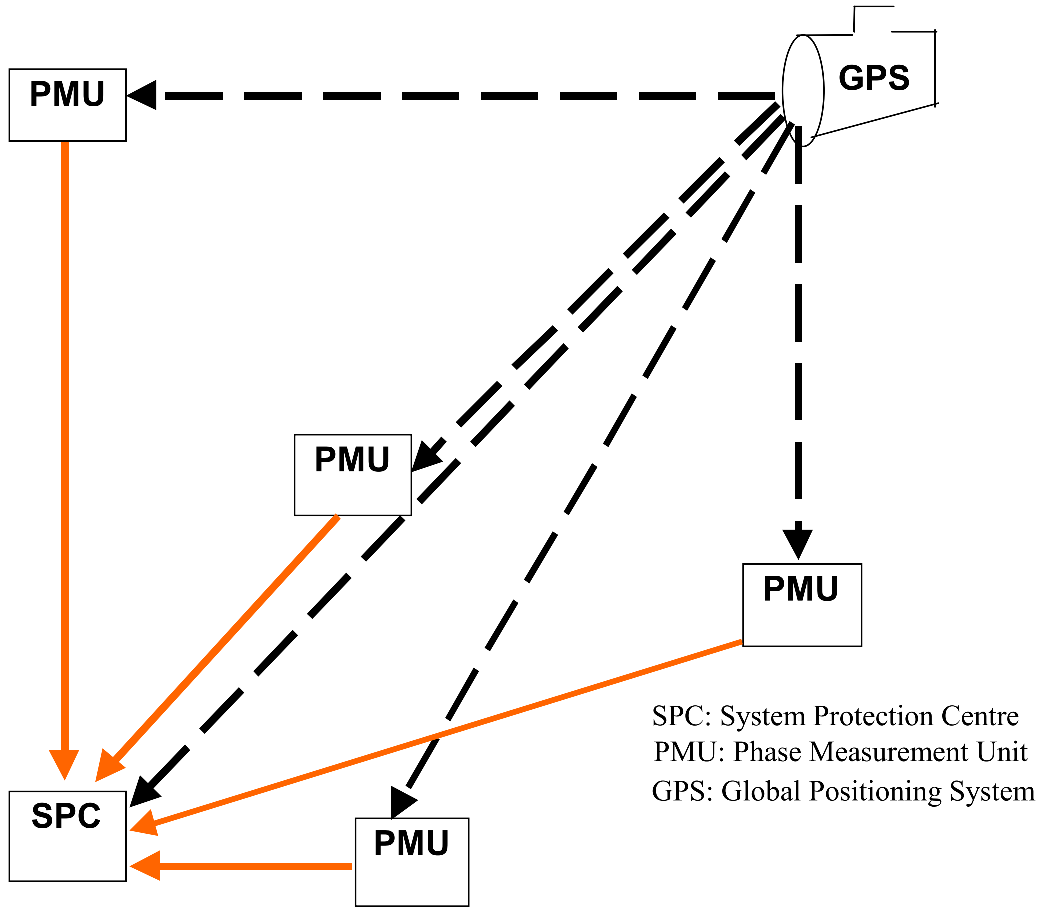


Figure 6.1.4: Phasor Measurement Arrangement

Typically the WAP monitors system stability by taking GPS synchronised instantaneous voltage and current measurements at critical nodes throughout the power system. The measurements are realised on phasor measurement units (PMUs) at the relevant nodes. Stability is assessed by considering the inter-node voltage phase angle. Figure 6.1.4 outlines a possible arrangement. WAPs maximise the utilisation of the existing network capacity by online assessment of safety margin in relation to the onset of system instability. Power transfer limits were traditionally based on planning simulations based on worst case scenarios. Online assessment of both thermal and stability limits using real time data allow improved exploitation of the transfer capacity. This improved protection regime permits deferral of network expansion.

Integral to the success of WAPs is the availability of a system wide broadband telecommunication system with a speed that would satisfy the SPS processing time of between 0.1 to 10 seconds. Dedicated telecommunication networks would be very expensive while use of network wide WAN operating in conjunction with substation based LANs appear to offer more economic solutions. However consensus is still lacking as regards the technical acceptability of this approach. Work is currently ongoing in IEC TC57 to standardise on switched Ethernet and TCP/IP bus systems to be used in future station automation applications [5].

Other WAPs being considered employ expert systems. One such scheme provides back-up protection for a network section or region [6]. Through a process of ascertaining the most likely plant item to be faulted, based on information derived and fed to the central evaluation system, it is hoped to eliminate the possibility of cascade tripping. Results to date on simulated case studies are promising.

6.1.6 Conclusions

New developments promise significant progress in ensuring effective sectionalising of a disturbed network. An example of such a scheme is the “Syclopes” development in France. Loss of synchronism is detected by phase measurement whereupon sectionalising at preselected nodes ensues. This is followed by appropriate load shedding in the affected zones until the situation is stabilised.

New techniques are being applied to older principles in the application of Out of Step Tripping and Out of Step Blocking (OST and OSB) devices. Through the use of sophisticated modelling the most appropriate location for sectionalising (i.e. the OST node) is determined. With such schemes it is essential that the OST and OSB settings on all relays, including embedded functions in distance protections, are correctly co-ordinated.

Although at an early stage of development, wide area protection promises significant advantages both in predicting and minimising the impact of disturbances. Few are currently in operation on any significant scale but efforts are being made to develop schemes that will be both realistic in scale and cost effective.

6.2 CO-ORDINATION OF TRANSMISSION AND GENERATOR PROTECTION SYSTEMS

The behaviour of generating plant during system disturbances has major impact on the success or otherwise of system protection strategies. The networks and generating units form an interactive system that react dynamically during network faults. Network generated transients can impact negatively on machines while the response of speed governors is very influential in maintaining transient and frequency stability. Obviously close co-ordination between relaying policies for both generation and network plant will optimise overall power system performance during disturbances [1]. Apart from the traditional co-ordination of relay settings however a number of measures can be undertaken to better utilise the performance of generator units during emergency situations. This chapter describes some examples.

6.2.1 Turbine Related Actions

Generator and turbine protection systems are primarily provided to ensure that the generator is disconnected from the power network as quickly as possible in order to minimise damage to the machines. However, in many cases with steam plant it is not essential to immediately trip the machines; instead a more gradual shutdown can be arranged. Gas turbines also have capabilities that can be useful during system disturbances. The systems that can be provided to improve the contribution of generation plant in counteracting large scale disturbances will now be examined.

<u>6.2.1.1 Steam Turbines</u>

<u>Instantaneous Output Increase</u>
Fuel type and boiler/turbine unit design can have a significant effect on the dynamic response of steam units during sudden load fluctuation. This results from the relatively large mechanical inertia of the turbo-alternator's rotating masses so that through the release of stored energy output is momentarily increased. Other associated measures are:

- Reduction in the power consumption of electrical auxiliaries
- Condensate stoppage: valves on turbine steam extraction lines are closed rapidly such that the steam instead flows through the following turbine stages thus providing a power output increase.

<u>Delayed Unit Tripping (Fast Load Wind-down)</u>
For many unit faults immediate tripping is not necessary. In such cases it is sufficient to reduce plant load over a period of up to one minute before opening the HV circuit breaker. This technique is called fast load wind-down; it avoids sudden mismatch of generation and load and gives the opportunity for start up of reserve generation e.g. pumped storage.

<u>Fast-Valving (Early Valve Actuation)</u>
Chapter 5 describes how for stability reasons generation is tripped following the forced outage of high capacity transmission lines or the loss of significant load. When the generator is tripped by opening the main circuit breaker it rejects all load apart from the demand of its own auxiliaries. Following fault clearance or the restoration of stable network conditions the machine is resynchronised. However, this can take

several minutes to achieve (at the very minimum) and is further complicated by the fact that the system is experiencing a generation deficit with the associated impact on frequency stability. An additional aspect is that this so-called tripping to house load is not always successful in practice since, depending on the design of the system, large dynamic changes may expose other weaknesses. Fast-valving also has the important additional benefit that by rapidly and temporarily (see below) reducing mechanical power input it minimises the extent to which machines drift apart during a severe network short circuit, when synchronising forces are minimal. In most circumstances fast-valving is an alternative to generation shedding. Rapid closure of turbine control valves has been considered since the 1920's as a means of preserving system stability following severe network faults; the technique is typically applied as follows:

- Network fault detection devices (over-current, under-impedance, etc.) issue a command to the fast-valving scheme on occurrence of a fault
- After a delay of typically about 0.08 to 0.1 seconds the valves are closed in a manner typical to that for load rejection
- The instantaneous level of power output reduction can be controlled by the speed of valve closure e.g. HP turbine valves close in less than 0.1 sec. while IP stage (intercept) valves close more slowly [3,6].

In fast-valving systems the intercept valve control is very important as these valves may control up to 70% of turbine output while the main control valve on the HP stage instantaneously controls much less [6]. The system should be tailored to suit the transient behaviour characteristics of the power system being considered. Some early fast-valving systems were implemented by simply fully closing all steam valves. However, on weak systems (i.e. where unit is relatively large relative to total capacity) the back swing following the first rotor angle peak may ensure second swing instability. Another risk is that of frequency instability due to the large generation loss. This is avoided by rapid reopening of the valves or a less extensive reduction in output power by a more controlled valve closure [4]. Two types of fast-valving can be implemented:

- Temporary valving where the control and/or intercept valves quickly reopen to their original positions so that output power returns to its prefault value.
- Sustained valving where the valves reopen to less than the prefault value so that the generated power is at a reduced level compatible with the post fault conditions.

Sustained valving is intended to cope with long duration faults or disturbances that result in a weakened transmission network. It requires significantly more sophisticated modification to the control systems than temporary valving. Modelling of the system should first be performed to select the optimum mode of operation. Details of fast-valving application and the implication for steam plant is covered extensively in the literature [3, 4, 5, 6].

The survey carried out by Working Group 34.09 indicated that in general fast-valving performed reasonably well during system disturbances [7].

More recently developments have been proposed to enhance the fast-valving technique by also utilising the generation excitation to increase synchronising torque [8]. The system operates by rapid valve closure on the occurrence of the fault and rapid changes in excitation to decrease the emf as the machine swings into the motoring mode while increasing excitation as it swings back to generation mode. This reduces the amplitude of the "motoring" swing while increasing synchronising torque and hopefully rapid resynchronisation. In this scheme it is envisaged that valve closure is achieved in 0.1 to 0.4 seconds. Rapid excitation reduction/increase is realised by alternating the excitation voltage between its upper (+) and lower (-) limits. Developments in control technology will make the implementation of such sophisticated systems more possible than heretofore.

6.2.1.2 Gas Turbines and Combined Cycle Plant

Many gas turbines (GT) have an overload or peaking capability (temperature limit raised). During periods of a sudden generation loss GTs can be arranged to immediately go to peaking operation which can amount to 10% of additional output [2]. If the GTs are part of a combined cycle plant (CCGT) it is necessary for the steam cycle to be suitable for the higher operating temperatures associated with peaking. This can be achieved in different ways. Examples are:

- Increase base load temperature in proportion to frequency decline; this compensates for natural tendency of GT output to decline with frequency (when operated as base load plant) and thus maintain GT power output at prefault level.
- Initiate peaking once frequency decline drops to preset level; governor droop can then be employed to increase generated power

These modes of emergency operation are most effective if they are co-ordinated with the unit protection.

6.2.2 Rotor Over-current to Boost Excitation

The generator excitation system responds to changes occurring on the transmission system in an attempt to keep the generator terminal voltage within a predetermined range. The excitation system's response to a wide area disturbance will primarily depend upon the change in the system's reactive power requirements. A depressed generator terminal voltage will require boosting of generator excitation to raise the voltage. In an extreme voltage reduction case, the excitation is increased to its highest permissible level (ceiling voltage) as a temporary measure. Such field forcing strengthens the synchronising ties between machine and power system. The excitation system is normally sized above that necessary for operation at rated generator output. In some cases, the thermal limits of the rotor will be the most restrictive element of the excitation system.

Each component of an excitation system has long and short time limits that can be represented as either a current or voltage. Depending upon the system design, shunts in the generator rotor/main exciter and pilot exciter, field voltage, thyristor temperature or current, static exciter transformer voltage/current and generator terminal voltage measurements are used to determine the operational parameters of the excitation system. The generator regulator usually incorporates automatic limiters that respond to related conditions such as volts per hertz, maximum excitation, over-voltage and minimum excitation. These functions incorporate an inverse characteristic in modern systems, so that the time to operate decreases with increasing severity of the condition. Very severe field over-current conditions are addressed by fast acting functions that respond by tripping the generator field. Additional external protective devices can be used to provide generator tripping for most of the above conditions. These devices would be set higher to co-ordinate with their respective limiters.

Heating of the generator rotor is a function of the field current, the rotor resistance, the initial field temperature condition, the effectiveness of the generator cooling system and the duration of the transient. Direct measurement of the rotor temperature is impractical, and may not include hot spot locations. Field voltage and current measurements are generally used to calculate the field temperature. If the generator design does not permit measurement of the field voltage and current, coolant temperatures can be used as an approximation of overall thermal conditions. Rotor short-time thermal requirements are specified in ANSI C50.13-1989, Section 7.2. The ANSI limits result in an inverse curve when plotting the percent of rated field voltage versus time. Limits for specific generators should be obtained from the manufacturer. Operation at these limits has the general understanding of occurring a limited number of times, either annually or over the life of the machine. Protective devices should be set to approximately match the short time thermal curves, with a 5 to 10% margin. Artificially low setting limits corresponding to a fixed percentage above the continuous full load field current should be avoided in order to maximise the exciter capability during a disturbance. Additionally, the use of limiters with an inverse characteristic will allow the user to take full advantage of the rotor's capability. Limiters should be set to alarm and initiate automatic corrective actions to reduce the field current to an acceptable value. If this is unsuccessful, tripping of the generator should be initiated, after an additional time delay. The tripping may also be initiated by another protective device, with similar inverse characteristics and a longer operating time. The settings of the generator and unit transformer protective devices should be reviewed to determine if they would operate during a wide area system disturbance. These devices include voltage-controlled over-current, phase distance and volts per hertz relays. Co-ordination of the generator field over-excitation protection and volts per Hertz limiter with the unit transformer volts per Hertz protection is required to avoid unnecessary tripping of the unit. In general such co-ordination should recognise that transformers are more susceptible to over-fluxing than rotating plant.

More recently techniques have been developed [9] that determine rotor temperature based on load flow calculations. These uses a mathematical rotor thermal model and only require load flow studies to determine temperature. Also proposed is that the pattern recognition principle be supplemented by machine rotor voltage and current measurements. These drive mathematical thermal models that ascertain if the rate of rise will result in over temperature trips. Thus a suitable time delay can be chosen before any such occurrence.

6.2.3 Braking Resistor Application

When a power station loses a significant portion of its load such that it risks becoming unstable a braking resistor can be switched in to create a substitute load for a short period. This avoids the necessity to trip the unit. An example is described in [1] of a power plant in Australia where a 300MW resistor is switched in 150ms after fault detection for a period of 400ms. A sudden power change is the criterion for fault detection.

6.2.4 Conclusions

The response of power systems to curtail the escalation of wide area disturbances is significantly enhanced through maximising the support potential of generation plant. Fast load wind-down allows a relatively smooth load transfer between generator units while measures such as auxiliary load reduction can be employed to momentarily increase output. The peaking capability of gas turbine plant can also assist in this regard. The use of fast-valving can be very successful in maintaining machine stability following a major loss of load or of transmission inter-ties. Other measures such as excitation boosting and braking resistor insertion are also beneficial.

These measures are essentially intended to maintain the power transfer capability of the transmission network. Their implementation requires close co-operation between generator plant and network operators. In the traditional vertically integrated utility this could be accomplished relatively easily. However, in the unbundled electricity supply industry structures common in many countries today, the issue is more complex and the provision of such systems is likely to require specific contractual arrangements. These, while important, are outside the scope of this report.

6.3 TEMPORARY FEEDER OVERLOADING

6.3.1 Introduction

The cascade tripping of transmission circuits frequently escalates a disturbance to a much higher level of severity. Allowing temporary feeder overloading has advantages not only for optimising plant utilisation but also in mitigating the effects of disturbances. To ensure successful application an implementation strategy must be prepared. Transformer overload protection should also be included.

6.3.1.1 <u>Overloads</u>

Overload protection of transmission feeders is, for most utilities, reasonably covered by operational procedures. At the simplest level overloads are limited to a certain level for a prescribed time. A more realistic approach also considers prevailing ambient conditions (e.g. temperature and/or wind speeds). Subsequent operator action caters for equipment integrity and overload protection including distance protection back-up zones must therefore be selective with the operational practices.

The availability of adaptive techniques makes it possible for system operators to temporarily increase circuit overloads provided the equipment can cope. Such adaptive settings should include both current magnitude and duration. These techniques would have been beneficial in many of the cases reviewed by WG34.09.

Overloads cannot be sustained indefinitely without damage to plant. Consequently schemes permitting plant overloads are only effective if accompanied by a system of either quickly getting active and/or reactive power reserves on stream or, failing this, ensuring that load shedding schemes reduce demand to a level that the system can meet. An overall co-ordinated approach is required.

6.3.1.2 <u>Transmission System Congestion</u>

In the liberalised energy markets there is a growing concern at the decreasing reserve in the transmission capacity of many power systems. It is especially true on vital overhead line corridors where the problem of transmission system congestion has become much more complicated in the multi-player, deregulated environment. This constraint can, in many cases, no longer be addressed by the construction of new lines as such developments are either delayed or prevented altogether by public opposition and/or environmental considerations. Consequently maximising the use of existing capacity becomes a high priority task. A number of techniques and strategies have been developed to optimise efficiencies in the use of existing transmission capacity, notably:

- optimisation of the power flows by power electronic devices (FACTS)
- temporary overloading of transmission lines and cables, within the limits allowed for actual ambient conditions
- implementation of system-wide protections and monitoring schemes, capable of:
    - early detection of vulnerable states,
    - initiating actions against further deterioration,
    - avoiding cascading loss of supply.

The objective of this chapter is to review the principles and practical implementation of Real Time Monitoring systems for parameters that impact the load ratings of transmission lines and cables. Accurate prediction of overload capability involves thermal models of heating and cooling cycles as well as consideration of mechanical and meteorological factors. For example, if the capability of an overhead line is defined as the "maximum electrical current which can be carried by the conductor without a reduction in its tensile strength or without exceeding the maximum sags consistent with electrical clearances", then overload prediction must include appropriate combinations of measurements of the load current, mechanical tensions, sags, conductor and ambient temperatures, sun radiation and wind velocity.

6.3.2 Methodology: Overhead Lines and Underground Cables

Real-time monitoring of overload capability is very beneficial during emergency operation or during system restoration following major incidents. However "sweating the network" based on thermal considerations alone does not guarantee a successful outcome during vulnerable or emergency system conditions; it must be part of a co-ordinated strategy that also considers other system operating criteria e.g. voltage regulation, stability limits and protection operation. Therefore, controlled overloading is related to the more general topic of operating the power system closer to the stability limits and to the security and contingency analysis functions in any Energy Management Systems employed.

6.3.2.1 Overhead Lines (OHLs)

In overhead line (OHL) terminology, distinction is made between the continuous static thermal rating defined for a maximum conductor temperature and a particular weather condition and the dynamic thermal rating, which takes into consideration variable weather conditions. Besides long-time static or dynamic capability, protective relay settings should also allow for the short-time overload capability of the line. This is typically in a range of up to 30 minutes.

In practice transmission overhead lines can have considerable thermal overloading capability due to:

- conservative design criteria adopted in the planning stage
- wide differences between the actual and design ambient temperatures
- equipment design margins adopted by the manufacturer.

Very long OHLs have a significant short-time (dynamic) up-rating potential as they are subject to wide variations in ambient conditions. This contrasts with the situation for substation mounted equipment, for cables buried in ground or for forced cooled plant.

The quantification of the thermal capability reserves of the OHL and the issue of guidelines for system operators are covered in numerous theoretical and practical publications [1,2]. In general a system for real time OHL monitoring consists of:

- specialised software for modelling the thermal or/and mechanical behaviour of the transmission line
- real-time communication links to external sensors for ambient conditions, sag clearances etc.

A number of different models are in use:

- temperature-based model, using the line current, conductor surface temperature and air temperature for calculating actual ratings;
- weather-based model, using information from several conventional weather stations, appropriately positioned along the line route, to calculate the actual rating from a balance between radiation plus convection heat losses and resistive heating (I^2R losses) plus solar heat gain;
- sag or tension model, based on sag clearance and/or on conductor tension.

Two categories of real time monitoring systems [3,4,5] are implemented:

- direct systems, using direct information from the monitored line, such as clamp-on surface temperature measurements, line current, sag or conductor tension measurements by load cells placed in the insulator strings;
- indirect systems, using only information from the line route area, namely weather stations.

Irrespective of the technique adopted, the main purpose is to transmit over conventional SCADA to the system control centres information for assisting the operators in controlling the transmission network power flow or for initiating over-load alarms [6]. Some utilities are embedding the real time monitoring information in expert systems while others use it simply for the definition of summer and winter ratings.

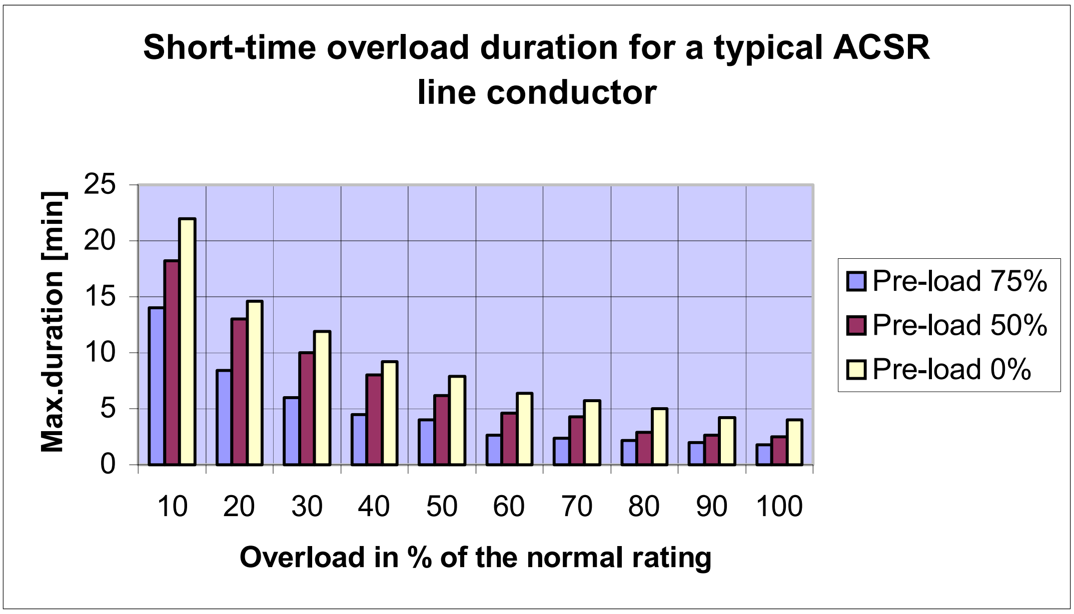


Figure 6.3.1 Permissible minimum over-load duration (minutes) for a typical ACSR conductor under reference weather and different pre-loading conditions referred to the normal continuous current

A typical short-time minimum overloading capability for an ACSR 420mm^2 conductor under summer conditions (20° C ambient temperature, 100 mW/cm² solar radiation, moderate wind speed) is shown in Figure 6.3.1. For a pre-load equal to 75% of the normal permanent rating, the conductor can withstand 30 to 40 % overload for around 5 minutes. Depending on the particular environmental conditions, type of conductor and OHL design, this limit can in practice be much higher (in the range of

20 minutes). In many real situations this time period provides a window of opportunity for remedial measures to be initiated. Such counter-measures can be manually or automatically effected and include actions such as starting of stand-by generation capacity, load shedding or load redistribution. Therefore, determining the real time value of available line overload capability is a both a key element in the efficient use of the energy corridors and in avoiding the rapid tripping (within a few seconds) of line circuits by the intelligent application of protective relay settings.

In the case of multi-section lines, the settings must consider the limiting section, which can, for example, be an underground cable (UGC) section. In the latter case, the resultant capability is in general determined by the thermal overloading of the cable.

6.3.2.2 Underground Cables (UGCs)

When considering cable overload, distinction is made between an operation region "with limited overloading risks" and a "prohibited overload region". Unlike the overload patterns of the OHL, these regions exhibit a relatively sharp limitation with respect to the insulation temperature, which if exceeded results in irreversible changes to the insulation's chemical structure. The commercially available Real Time Monitoring systems for the temperature measurement use optical time domain reflectometry over optical fibres integrated in the power cable [7].

The UGC thermal models for real time monitoring systems are more complex than those for OHL, since they are significantly influenced by the cable type, method of cooling and burial conditions. For example, an extruded dielectric cable model considers the conductor losses, dielectric and sheath losses, the thermal resistances of the insulation, jacket, jacket to duct, duct and backfill [8]. Some practical case studies like the one exemplified in Table 6.3.1 show significant differences between short-time dynamic rating and the long-time normal rating, hence also overloading potential.

Duration	Design rating A	Real time rating A	Difference %
20 minutes	2500	3925	57
3 hours	1600	2190	37
Long time	1400	1470	5

Table 6.3.1 Comparison between design and real time ratings obtained by Dynamic Feeder Rating software for 345 kV transmission cable (source Con Edison)

It is interesting to compare some relevant figures about the expected overloading reserves of OHL and UGC. These are illustrated by Figure 6.3.1 and Table 6.3.1 respectively. Of interest for the operational decisions and for the protective relaying considerations is the s*hort-time overload* capability in the time range of up to a couple of minutes. The *long-time or continuous thermal rating* is defined for a maximum conductor temperature and a particular weather condition.

6.3.3 Impact on Protection Functions

In relation to real time monitoring of the equipment ratings, two protective relaying issues deserve attention:

- back-up of the monitoring operation by protection relays equipped with thermal overload functions;
- co-ordination between the monitoring function and protection settings.

Attempts to fully use the line overloading capability must be accompanied by an overload protection function. This is carefully co-ordinated with the line load monitoring systems and with the operational functionality of the system control. Typically the protection closely supervises the maximum permissible time of operation at overloads of up to 30 % of the long-time ratings. In this range standard feeder back-up protection functions are in general not supposed to trip and are set accordingly. Traditionally used on distribution networks, the thermal overload function is now included in many multifunctional protection terminals for HV and EHV feeders. Numerical relays are particularly suited for this task as they contain a number of supporting functions and facilities, generically termed adaptive settings.

In their simplest implementation (1st order thermal models), the inputs to the thermal model are the phase RMS current, the thermal time constant of the line conductor, a reference temperature or current (continuous maximum pre-loading) and one or two temperature rise settings for alarm and trip. All algorithms in current use are based on simplified assumptions for the heat transfer under short-time overload conditions; accordingly, the time required for reaching a steady state temperature θ_t under constant current is given by the expression:

$$t = T \ln \{[(I/I_{NOM})^2 - \theta_0/\theta_{NOM}] / [(I/I_{NOM})^2 - \theta_t/\theta_{NOM}]\}$$

where T is the equivalent heating time constant of the body, θ_{NOM} is the rated temperature rise reached under current I_{NOM} , θ_0 is the actual (initial) temperature of the body and I the actual overload current. In more accurate implementations, distinction is made further between the normal heating time constant for currents $0.1 < I < 2I_{NOM}$ and the adiabatic heating time constant for $I > 2I_{NOM}$.

The standard feature of the numerical relays, namely external switching between different setting groups, can be used to implement an adaptive behaviour of the trip logic. It is arranged to select an appropriate characteristic from one of the following:

- Summer or winter continuous load rating
- One or two circuits in operation (in case of double circuit lines)
- Normal and abnormal system conditions (biased towards either dependability or security of the settings)

Switching between the settings can be done by simple circuit breaker status information, temperature measurement inputs, communication links to the real time line monitoring systems or by links to a centralised substation or system control.

In the case of multiple section lines, the settings and parameterisation of the function must consider the weakest link, which may be an underground cable section. Since the thermal behaviour of a UGC depends on both the insulation and the conductor characteristics, relays based on second order thermal models ("two body models") are preferable for increased accuracy. The parameterisation requires two different heating time constants (insulation and conductor) and a weighting factor.

Another feature available in the more elaborate overload relays is the modelling of the cooling process; if the current is lower than a set minimum load value, the protected object is considered in the cooling state and the temperature rise calculation is switched to the cooling equation. A "thermal memory" accurately records heating-cooling cycles e.g. during successive attempts to effect manual or automatic line reclosing. Some of the relay models have temperature measurement inputs. These can be arranged to initiate a direct trip if the associated sensor directly monitors the protected element itself (e.g. oil temperature of a HV oil-insulated cable) or alternatively, switches to another setting group, upon receipt of information regarding local or remote ambient temperature on a section of the protected circuit.

6.3.3 Protection Co-ordination Issues

The success of a correctly set overload function depends on good co-ordination with the higher zones of distance and time-overcurrent relays. The latter are traditionally arranged to discriminate between load and fault currents based on measurement principle and on time setting. Typical tripping times of the back-up protections are in the range of 2 to 10 seconds for currents between 1.3 and 2 times the peak load (calculated by load-flow programmes) or as dictated by the design ratings of the circuit. These settings may impose much too conservative limitations compared with the real overload capabilities of the circuits and require further consideration. Switching of setting groups may not be a practicable solution since many of the transmission circuits in operation are still using non-adaptive relay types. Even when available, the external setting switching is often dedicated to other tasks, like tee-off feeder logic or adaptive impedance reach settings.

A difficult co-ordination case is the long double circuit transmission line protected by distance relays. It is common practice to avoid load encroachment in any impedance zone or power swing supervision unit during single circuit operation. This ensures service continuity in the case of a forced outage of one circuit. Furthermore special system conditions may temporarily require a power transfer of more than 100% of the single circuit rating. To achieve this some utilities set the distance relays so that they do not start in case of a single circuit outage (shorter resistive reach setting or load blinders) and retrofit the lines with thermal overload protections.

The widespread application of numerical distance relays having polygon characteristics with separate and continuous adjustment of the resistive and reactive reaches has considerably eased the task of discriminating between the fault and load impedance. Some numerical distance relays feature different resistive reach settings for phase-to-phase faults and for single phase faults. This permits the application of different settings to cater for symmetrical heavy load and for correct phase selection during single phase faults superimposed on a heavy load.

The following illustrates the approach adopted by two Spanish utilities to the question of overload co-ordination in relation to distance protection:

Utility 1:

- Third zone settings for HV line distance protections must not exceed 80% of maximum line load impedance.
- Resistive reach of polygonal EHV line stepped distance protections must not exceed 80% of minimum load resistance.
- Overreaching zones in EHV line directional comparison schemes must not operate during maximum load conditions, and must therefore be set at 80% of the impedance of maximum line load.
- Power swing blocking units must not operate during maximum load conditions. Resistive reach of polygonal characteristic, as above.
- Directional earth fault EHV line backup protection must not operate during single phase reclosure dead time for full load conditions, pickup and time dial settings increased as required.

Utility 2:

- Line relays provided for short circuit protection must not trip upon overload. Setting criteria ensure that transient (20 minute) overload parameters (current, impedance) remain outside tripping and blocking zones based on a safety margin of voltage (90%) and power factor (45º).
- Overload loci must be referred to blocking zones (out-of-step blocking characteristics) to ensure correct power swing blocking on heavily loaded systems.
- On double circuit lines, the overload reference also takes into account the transient overload on tripping of one circuit. Twice peak historical maximum load is considered.
- Where generator transfer tripping is initiated from the transmission line protection, the transient overload, until the excess generation trips, will in general exceed the settings applied in accordance with the above overload criteria. Up to 150% rated line load capacity is adopted as a general criterion, although a specific maximum overload is considered for each case.

The overload co-ordination would obviously be simplified if overload protection was provided using dedicated functionality based on the overload capability of the protected plant. Modern relays are providing this feature to an increasing extent.

6.3.4 Transformer Over-Load Protection

Specifying the thermal overload capability of transformers is an established practice with both IEC and IEEE issuing application guidelines. Proprietary monitoring devices are available to permit overloading in accordance with these guides. Such devices provide information to operators via SCADA. However, overload guides are based on presumed load patterns for particular ambient temperatures. As short time loadability is in fact variable depending on ambient temperatures and load current, a more exact approach is to establish the actual real-time transformer loading, ambient temperature and top-oil/hot-spot temperature relationships. Furthermore, on the basis of the ageing rate of the insulation [8], the permissible level of overload and the associated time period can be chosen. A relay pre-programmed to calculate the hot spot temperature rise therefore only requires as inputs the load current and ambient temperature. The duration of the allowable overload is determined by the ambient temperature. The relay thus permits:

Hot Spot Temperature	Ageing Acceleration Factor
110°C	1
117°C	2
124°C	4
131°C	8
139°C	16
147°C	32
156°C	64
164°C	128
173°C	256
180°C	425

Table 6.3.2: Rate of Insulation Ageing [8]

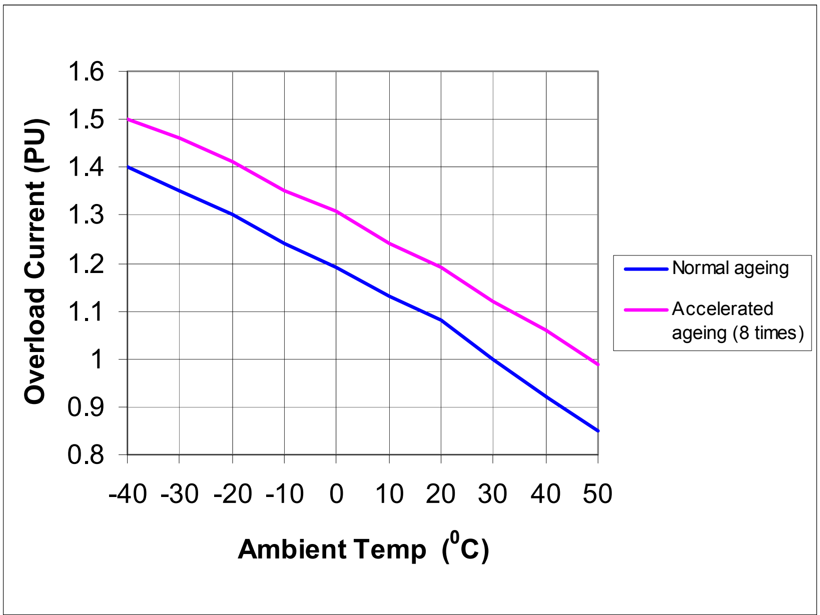
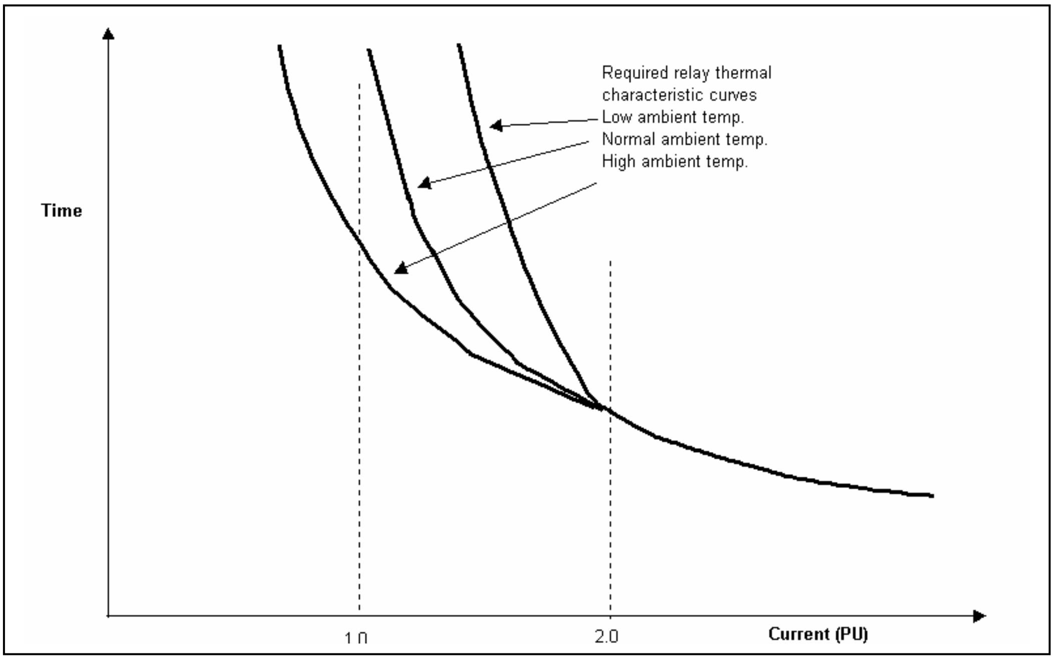


Figure 6.3.2: Maximum Permissible Load Currents at different Ambient Temperatures [8]



<u>Figure 6.3.3: Overload Relay Protection Characteristic – adaptive to suit ambient temperature [8].</u>

- Increased steady state loadability (above the nominal value) when ambient temperatures are lower than nominal.
- Increased overloads at any ambient temperature based on the acceptable rate of insulation ageing.

Such relays are currently being developed and will both assist the optimal utilisation of transformer capacity and improve performance during disturbances by reducing the likelihood of cascade tripping.

Table 6.3.2 shows the typical ageing rates for transformer insulation as used by IEEE. The variation of permissible continuous load current with ambient temperatures is shown in Figure 6.3.2 while Figure 6.3.3 illustrates the relay characteristic requirements.

6.3.5 Conclusions

In many practical cases there is considerable potential for short-time overloading of transmission feeders. Full use of this capability as part of a general strategy to overcome system bottlenecks and to cope with system disturbances requires concerted and co-ordinated actions of operators supported by real-time monitoring of the equipment or of the ambient conditions.

In addition to the extensive use of transmission line overloading capability, it is recommended to provide relays incorporating a thermal overload function in addition to the standard fault protections; the trip characteristic can be made adaptive through communication with the real-time line monitoring systems or with the system control centres. For correct parameterisation of the thermal model by the user, experimental and theoretical work is required in the choice of heating and cooling cycle parameters of the EHV/HV OHL, UGC and transformer.

The settings of the standard fault protection functions must be revised for co-ordination with the short-time overload capability. In the case of the distance protection this must include safety margins to cater for symmetrical load encroachment and correct selection of the faulty phase during single phase faults.

Utilising short term overloading capability promises significant advantages for system operators under disturbed conditions. It is therefore expected that relay manufacturers will further refine the thermal overload functions currently available in the transmission line protection terminals, especially with respect to the modelling of EHV/HV cables and the incorporation of signals from the real time monitoring systems. It is also to be expected that overload relays will be developed to permit temporary overloading of transformers. Significant progress has already been made.

6.4 UNDERFREQUENCY LOAD SHEDDING

6.4.1 Introduction

In the immediate aftermath of a major disturbance on large interconnected power networks the frequency remains virtually unchanged due to the system's inertia. The rate of frequency decline is determined by the power coefficient (MW/Hz) of the particular system. On large interconnected power networks this ratio is very large and only the loss of significant generation will result in a frequency reduction. However in the region or network sector where generation is lost other threats to system stability are likely to occur: voltage collapse, cascade feeder tripping due to circuit overloading, power swings. Consequently the installation of under-frequency schemes on such systems will be of little benefit unless accompanied by other measures. Only when the main system is sectionalised does the frequency drop to facilitate the restoration of generation/load balance through frequency activated load shedding. Usually this issue is addressed in three stages

- Network sectionalising (see Section 6.1)
- Under-frequency load shedding
- Frequency/voltage stabilisation and load restoration

Typical under-frequency regimes for a number of countries are described in Appendix 3.

If, following sectionalising, the electrical power demand within a power sector (island) is not covered by sufficient mechanical power generation the machines will begin to decelerate leading to frequency decline. This can arise either as a result of a forced generator outage or the tripping of important transmission circuits. If the spinning reserve response and other measures to quickly reduce load are insufficient an unarrested frequency decline will ultimately lead to system collapse as generators are tripped by their own under-frequency protection e.g. for thermal units on a 50Hz system this typically occurs at about 47.5Hz [1].

6.4.2 System Behaviour when Overloaded

The rate and extent of frequency decline due to a generation deficit (or overload) can be quite difficult to predict due to the dynamic nature of frequency response, the level and response time of spinning reserve and also the impact of load disconnection on voltage behaviour. These issues are now discussed further.

6.4.2.1 Frequency Behaviour

The rate at which frequency will fall and stabilise at some lower value depends on: the percentage overload, the system inertia, the system load reduction ratio. In this context governor action, which occurs in the initial 30 seconds following the disturbance, is usually ignored as it caters for no more than about 2% of the total load[1]. The relative overload, p, within a sector (island) is expressed as:

[1] The UCTE requirement is that primary (governor) regulation must cater for a generation loss of up to 3,000MW (which is between 1 and 2% of the estimated UCTE load). It must be 100% available in 15 seconds for disturbances of up to 1,500 MW, and in 15 to 30 seconds, increasing linearly, for disturbances between 1,500 and 3,000 MW. The quasi-steady state frequency deviation, for a 3,000 MW disturbance, must be under 200mHz considering no load reduction factor, and under 180mHz

$$p = \frac{P_L - P_G}{P_G}$$

where P_L is the active power load in sector and P_G is the active power generation. The required load to be shed to restore balance, p_{SL} is expressed as :

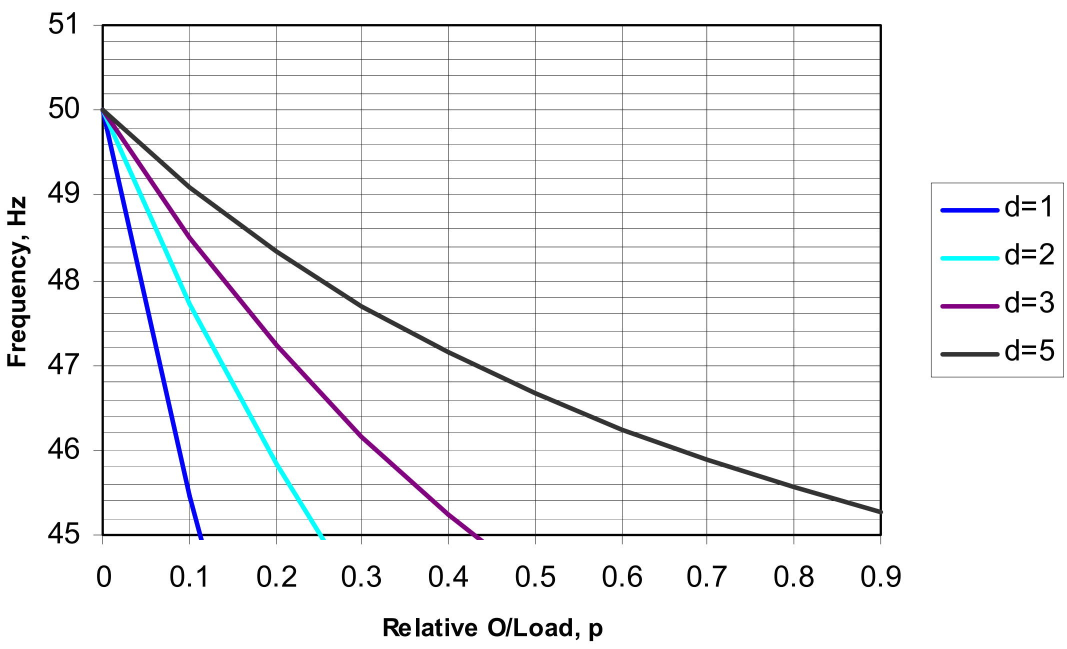
$$p_{SL} = \frac{P_L - P_G}{P_L} = \frac{p}{1+p}.$$

Thus to correct a 25% overload it is necessary to shed 20% load. This assumes that load remains constant during frequency decline. In fact load decreases with falling frequency.[2] Consequently the latter will generally stabilise at some value below nominal where load and generation again balance. The load reduction ratio, d, is defined as the percent reduction in load for a 1% drop in frequency. Studies in different systems indicate d values in the range 1% to 8% but typically 1 to 3% [2, 3, 14, 15][3]. The influence of load reduction factor is illustrated in Figure 6.4.1 and expressed as:

$$f = \frac{f_0}{1+p} x \left[1 + \frac{d-1}{d} p\right]$$

where f, f_0 are actual and rated system frequencies respectively.

Figure 6.4.1 Frequency Decline v O/Load for different Reduction Ratios



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considering 1%/Hz load reduction factor. The transient frequency deviation must not surpass the first load shedding stage, at 49 Hz.

[2] The rate of load reduction will depend on load type

[3] UCTE considers d value to be between 1 and 2% for the determination of the 18,000 MW/Hz reference value for the total interconnected system.

Minor power fluctuations may not necessitate load shedding. The ability of the system to compensate is determined by the mechanical inertia of all the rotating machines. The inertia constant is given by [4]:

$$H = \frac{Ke}{S} = \frac{J}{2S}\frac{f_0^2}{P^2} x10^{-6} \text{ seconds}$$

where: J is moment of inertia of all rotating generator units on the system (kg.m^2)

Kinetic energy, $Ke = \frac{Jf_0^2}{2P^2} x10^{-6}$ (MW.s)

f_0 is the system rated frequency (Hz)

P is no. of pole pairs

S is the total apparent power of all connected generator units (MVA).

For a complete system H can be obtained from the values of the individual units; however staged tests give better results.

The relationship between the speed of a synchronous machine and its power input and output is given by the *generator swing equation* [4]:

$$\frac{2SH}{(\varpi_0)^2}\frac{d\varpi}{dt} = Tm - Te \quad N.m$$

Where H is the inertia constant, ϖ is the rotational speed ($2\pi f$), Tm is the prime mover output torque and Te the generator output torque. In the context of load shedding studies this equation can be rewritten as [5] [4]:

$$\frac{df}{dt} = \frac{P_G - P_L}{S}.\frac{f_0}{2H} = \frac{f_0 p}{2H}\frac{P_G}{S}$$

6.4.2.2 Influence of Reserves

The level of primary spinning reserve available significantly influences the system's behaviour following a disturbance that results in a generation deficit. This level can vary significantly but in any case it is unlikely that more than 2% of total load can become available within the 30 seconds following a disturbance[5].

Note that in a multi-machine system the frequency response is a composite value of the individual machine responses within a particular bandwidth [6]. This bandwidth is determined by the inter-machine oscillations throughout the system. This in turn depends on the strength of network interconnection (low impedance), machine automatic voltage regulator (AVR) and governor response, magnitude of initial

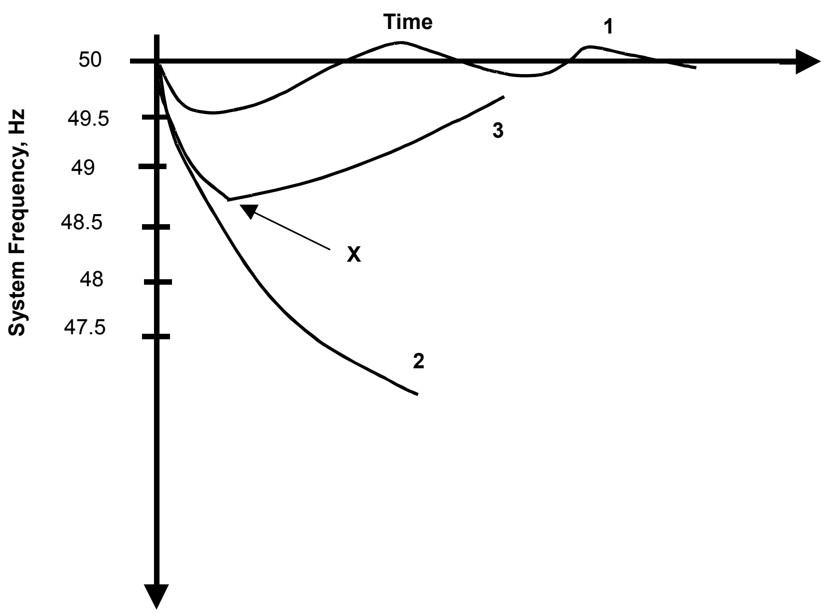
[4] In some literature H is expressed in terms of P_G rather than S; frequency change equation is then written: $\frac{df}{dt} = \frac{P_G - P_L}{P_G}.\frac{f_0}{2H} = \frac{f_0 p}{2H}$.

[5] See note 1. Spinning reserve is made up of primary reserve, load-frequency control (30 seconds to 10-15 minutes response time) and tertiary reserve (operator activated).

disturbance and the impact of any load shedding. The impact of reserve is best explained by reference to Figure 6.4.2.

In the case of a small generation deficit or where significant spinning reserve is immediately available the response follows Curve 1 and load shedding is unnecessary. Curve 2 illustrates the case where generation deficit exceeds the reserve available then in the absence of load shedding frequency continues to decline. (It may eventually stabilise but at an unacceptably low value; see Section 6.4.3). If load shedding were applied in sufficient quantity the response depicted by Curve 3 results. The initial recovery in frequency following load shedding at point X is due to the surplus of generation over demand due to excessive load shedding and also taking available reserve into account. Thereafter the response is determined by the generator governor control characteristics and the steady state frequency depends on the system speed-droop characteristic. If shed load is less than the generation deficit and the latter is compensated by spinning reserve then the frequency will stabilise below rated value. Conversely if excess load is shed the frequency will overshoot the rated value.

Figure 6.4.2 Frequency Response following Sudden Generation Loss



Spinning reserve is very beneficial in responding to relatively small generation deficits. Furthermore it plays a major role in rapidly restoring frequency close to rated value. The effectiveness of spinning reserve depends not only to the level of reserve available but also to how quickly that reserve responds. However for large sudden deficits it has minimal initial impact as even if sufficient reserve is available the response will be too slow [6, 13]. For such situations load shedding is essential to prevent frequency collapse. In such cases the availability of HVDC links are particularly beneficial as power can be imported from neighbouring power networks so that the level of load shedding necessary to retain stability is reduced.

6.4.2.3 Voltage Behaviour

Under-frequency load shedding dynamically interacts with the reactive power balance as depending on network topography and load type the system may experience significant voltage rise that in turn will increase demand from voltage dependant loads. In extreme cases over-voltages may occur. For example a cable network on which 50% load is shed may experience a voltage rise of 10% to 20% resulting in a load increase of 21% to 44%. This will further exacerbate the frequency decline. In such cases it is essential that reactors, SVCs etc. are installed to stabilise the network voltage close to rated values [5,11].

6.4.3 Under-frequency Load Shedding Strategy

The objective of a load shedding scheme is to shed sufficiently to arrest frequency decline and restore frequency to nominal value. This necessitates shedding slightly more than that simply required to arrest decline, typically a margin of 5%. It is also important that excessive shedding is avoided as it tends to result in machine acceleration and system instability. (Numerous examples are described in the literature [6,7]). To optimise this approach load shedding is invariably implemented at distribution level where multiple load blocks are shed at discrete frequency and time intervals.

A further requirement is that the frequency stages of the shedding scheme must co-ordinate with other frequency activated generation enhancement, load reduction or generator protection measures. Examples are:

- Tripping of pumped storage units if motoring, or load pick up if in minimum generation or synchronous condenser mode.
- Switch in of shunt reactors to reduce voltage and thus load; it improves the potential of available generation reserves to arrest the frequency decline.
- Tripping of consumers on interruptible load tariff.
- Tripping of generator units by under-frequency protection.

The generator protection is typically set to about 47Hz to 47.5Hz on 50Hz systems and this sets the lower limit for load shedding relay settings. In fact 48Hz would be the lowest value considered for load shedding while the higher values should lie below those associated with the other three functions mentioned above; typically the first stage would then be set to about 49Hz. When such measures are not provided the required setting will be higher. However intervention by load shedding is not required for relatively small overloads as they can be catered for by a combination of the load reduction ratio influence, machine inertia and spinning reserve. The first stage setting should take this into account. From Fig. 6.4.1 it can be seen that with a 4% overload and d = 3% the frequency will stabilise at about 49.4Hz. In this case it is probably more prudent to allow reserves to restore the frequency as a load shedding stage set to 49.5Hz, for example, would shed significantly more than this, possibly up to 10% bearing in mind that the amount shed may have an additional margin to allow for frequency restoration [3].

The parameters to be considered therefore when designing an under-frequency activated load shedding programme are:

- Relay frequency setting
- Step size (load block to be shed)
- Number of steps
- Relay time delay setting.
- Frequency derivative setting (if required)

6.4.3.1 Frequency Setting

Once the upper frequency limit for load shedding has been decided the stage settings and load block sizes for the under frequency scheme can established. The greater the number of blocks/stages the more rapidly and accurately will the generation/load balance be restored. However cost and complexity factors impose an upper limit and typically about 2 to 4 stages are employed. The amount of load shed is typically between 25% and 40%. Nevertheless some utilities may opt for up to 5 or even 10 steps [6,7] and also shed significantly less (e.g. 15%) or significantly more (e.g. 90%)

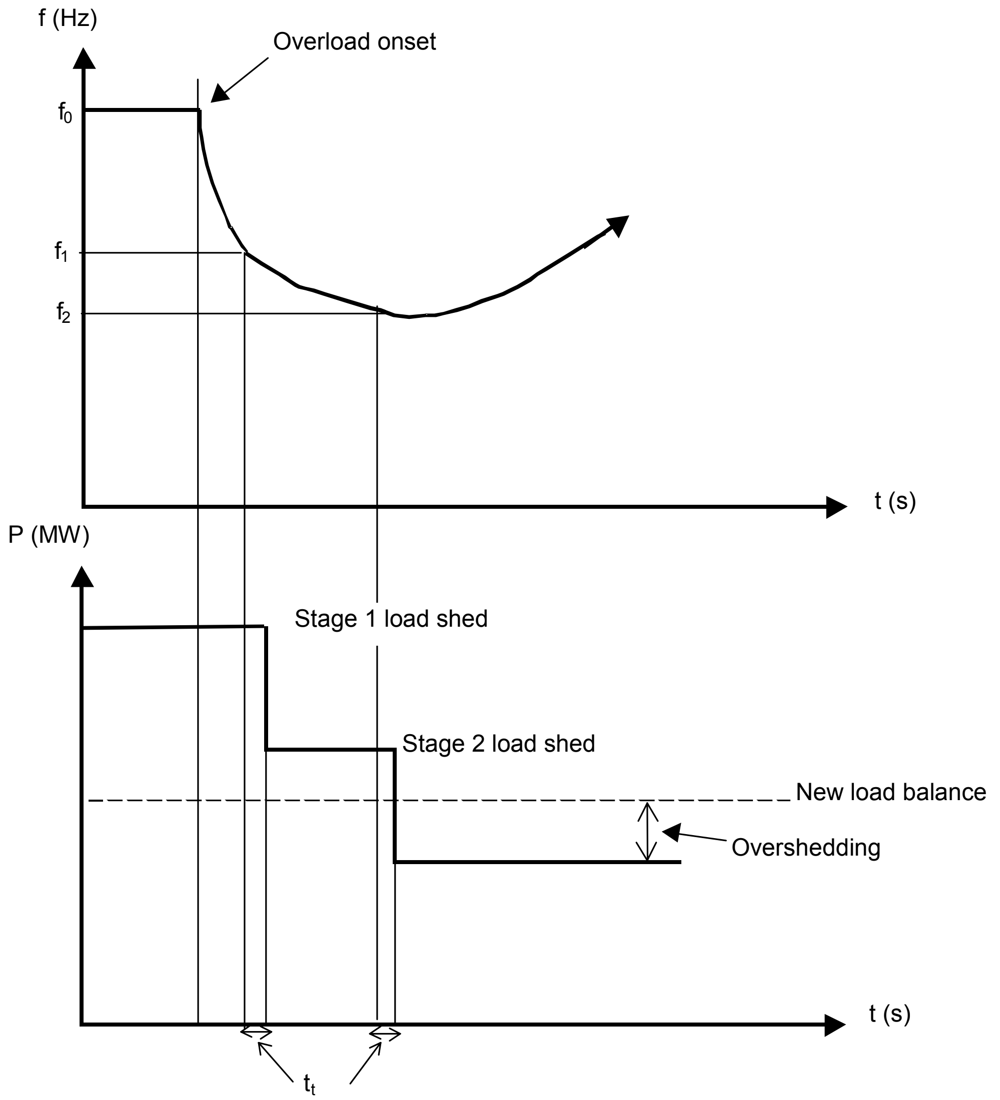


Figure 6.4.3 Basic Underfrequency Load Shedding Arrangement with 2 Frequency Stages

To ensure that sufficient load is shed quickly enough and thus avoid co-ordination failure between stages the rate of frequency decay must be considered. The new frequency f_t after a particular time interval, t, is given by:

$$f_t = f_o - t\,df/dt$$

As the rate of change of frequency is given by $\frac{df}{dt} = \frac{f_0 p}{2H}\frac{P_G}{S}$ then:

$$f_t = f_0\left(1 - \frac{pt}{2H}\frac{P_G}{S}\right)$$ and the time to decline to a particular frequency, f_1, is:

$$t_1 = \frac{2H(f_o - f_1)}{f_o p}\frac{S}{P_G}$$

To ensure grading between stages 1 and 2 it is necessary that f_2 is set lower than f_t. f_t will be lower than f_1 due to the operate time associated with the relay and circuit breaker i.e. if the relay and circuit breaker times is given by t_t then the frequency at interruption will be:

$$f_t = f_1 - t_t\frac{pf_1}{2H}\frac{P_G}{S}$$

The second stage setting f_2 must be set below this. Similarly suitable settings must be calculated for f_3 and f_4. It must of course be recognised that this best attempt at co-ordination may not necessarily be satisfied under all system operating regimes because any substitution of values into formulae presupposes particular system conditions.

Figure 6.4.3 illustrate such an arrangement for a 2 stage load shedding programme.

6.4.3.2 Time Settings

In general time delays on the frequency relays are kept as short as possible to minimise the voltage decline. Short time delays also facilitate the co-ordination between frequency stages described in 6.4.3.1. However, a minimum delay is required to avoid spurious tripping. This is usually in the range 100-200mS and includes the inherent relay delay.

If the number of frequency stages is low, e.g. one or two, then load blocks based on time settings within each frequency stage are sometimes introduced. This ensures excessive over-shedding is avoided with its associated risk of pronounced frequency transients. This application is not common and has the obvious disadvantage of delaying the amount of load shed during a major generation deficit.

Timers are however used in a back-up mode to avoid the situation where following shedding the frequency stabilises at an unacceptably low value. This can arise when the load shed approximates to the generation deficit and sufficient reserves are not available [5, 12]. After a set time delay the relay should trip part or all of the next frequency block. The delay should allow sufficient time for reserves to take effect (20 to 60s).

6.4.3.3 Rate of Change of Frequency (ROCOF) Relays

For very large overloads the frequency decline may be so rapid that it will fall below the value at which generation units trip before the load shedding relays can respond. In such a situation cascade generator tripping followed by system collapse is likely. In this case the pronounced frequency derivative (rapid rate of frequency decrease) may be a more suitable shedding criterion. A ROCOF relay (e.g. instead of the final under-frequency stage) can be arranged to shed all load normally shed by under-frequency stages 1, 2, 3 (and higher stages if such are provided) as appropriate. For example if the rate of frequency decline corresponding to the large overload (e.g. p = 30-40%) is determined as df/dt=1.55Hz/s then the relay is set marginally below this at say 1.50. Experience shows that to cater for generation deficits due to the loss of critical interties, relays having a setting range of up to 5Hz/s may be required [9].

For security ROCOF relays are generally interlocked with a relatively high set under-frequency setting e.g. $>0.99f_0$.

6.4.4 Future Developments

6.4.4.1 Deficiencies of Conventional Load Shedding Schemes

Conventional load shedding strategies as described in the foregoing suffer the following disadvantages:

- They are static in terms of response characteristics while overload/under-frequency incidents are dynamic in behaviour.
- The amount of load to be shed to compensate the generation deficit is not known in advance.
- The amount of load actually being shed at the different frequency stages is uncertain e.g. a distinction cannot be made between heavily or lightly loaded feeders.

Conventional static schemes, as we have seen, provide a solution in a trial and error fashion i.e. one stage after another is shed until the frequency is stabilised. Inevitably this sometimes leads to over-shedding with customers unnecessarily disconnected.

6.4.4.2 Advantages of New Technology for Static Load Shedding

The advantages offered by numerical devices for static schemes are essentially confined to ease of reallocation of feeder priorities. This can be implemented to take into account network topology changes within the substation e.g. due to maintenance outages. Reallocation can also be implemented to cyclically change feeder priority within the shedding sequence in order to ensure that the risk of disconnection is shared more evenly between customers.

6.4.4.3 Dynamic Load Shedding

The major advantage offered by numerical devices arises from the communication features that can be easily realised between such devices within the substation. The essential difference compared with the static approach is that a predefined number of feeders are not shed. Instead a predefined percentage of the measured total load within the substation is interrupted. As for static schemes network simulation is required to establish the parameter settings.

The dynamic scheme requires that the load shedding relay continuously monitors the load in each distribution feeder either directly from the CT's, VT's or more likely by serial connection from individual bay control units on feeder protection relays. Once the first stage criterion is satisfied (e.g. $f<f_1$ and/or $df/dt>\Delta f_1$) then a preset load percentage, p_1, is shed by tripping the appropriate number of feeders. Each feeder is assigned a priority and the load shedding relay establishes the minimum number of feeders in ascending priority (F_1, F_2 … F_N) to be tripped so as to just exceed the setting p_1. If this is not adequate to arrest the frequency decline a second shedding sequence is initiated using another percentage value of total load p_2 and second set of feeders. A time delay of up to 1 sec. is recommended before activation of the second stage to allow the frequency sufficient time to stabilise and increase.

Such schemes offer the obvious advantages of much better matching of load shed with the generation deficit. Consequently, they will contribute to a more rapid return to frequency stability within a power island following major disturbances. This is illustrated by reference to Figure 6.4.4 as compared with Figure 6.4.3 for the conventional static scheme.

6.4.5 Conclusions

When developing an under-frequency activated load shedding strategy a number of factors influence the choice of scheme to be implemented.

- Nature of the network – islanded or interconnected.
- If interconnected the first step is to identify the points of sectionalising or islanding (see also Section 6.1).
- The load imbalance likely to arise within the sector (or complete island on an isolated network) and the likely spinning reserve carried; if very large generation deficits are likely then frequency derivative as well as under-frequency relays may be required.
- Impact of the load reduction ratio; this will influence the first stage frequency settings, the larger the ratio the greater the capability for frequency to stabilise without load shedding; reserves and operator intervention then restore normal frequency conditions.
- Provision of other measures to correct overload conditions
    - tripping of pump storage machines if pumping;
    - switch-in of shunt reactors to temporarily reduce voltage and consequently load. This allows more time for reserves to be effective.

It is obvious that depending on the conditions pertaining, load shedding strategies will vary between systems. To establish optimum load block sizes and the under-frequency relay setting points simulation studies of network disturbances and their impact on frequency behaviour are necessary. Such simulations should include the dynamic frequency and voltage response as well as allowing for the effect of the load reduction ratio and the spinning reserve response. In general relay operate times are as low as possible bearing in mind security constraints. Typical values are 0.1 to 0.2s.

Shedding too much load will bring associated problems of over-frequency and system instability. While the greatest number of frequency stages will give the smallest block sizes and hence the superior frequency response, its full implementation is rarely realistic on cost grounds. A further complication is that loads on distribution feeders vary with time of day, day of week and seasonally. Consequently an ideal solution is rarely possible. Nevertheless with careful planning and implementation under-frequency load shedding provides an excellent tool to prevent system collapse. Numerous examples exist of their successful application on islanded systems.

Developments in numerical technology will in future result in more sophisticated load shedding programmes where load shed is closely matched to the actual generation deficit. Furthermore with the more widespread use of broadband communication such schemes are likely to form part of overall system protection systems (SPS) that dynamically respond to disturbances.

6.5 UNDERVOLTAGE LOAD SHEDDING

Under-voltage (UV) load shedding is analogous to under-frequency load shedding. It is utilised following severe voltage decline when measures such as switch in of additional reactive compensation, transformer tap changer blocking, etc. are not available or too slow in response to prevent voltage collapse. While such schemes have been uncommon in the past they are now being implemented. Requirements may differ considerably depending on network topology and load type. Consequently operational objectives may not be the same on all networks and the philosophy of associated under-voltage load shedding schemes may differ significantly. To illustrate issues that can arise a number of different schemes are described in the following sections.

6.5.1 Introduction

There is increasing experience of low voltage conditions on power systems that rapidly escalate into a major disruptive phase. Systems susceptible to this phenomenon are typically characterised by long lines carrying reactive power to feed distant loads. Export of reactive power (MVAr lagging) is required at the generating stations. This may be inadequate at the load points and may need to be supplemented by some form of voltage support (MVAr leading) at the remote substations. Various studies have highlighted the increased reactive power requirements arising when lines are lost during system faults [1]. The increased flows on the remaining circuits attempt to supply the same load as before further reducing load voltages due to increased volt drops. This can be simply illustrated by a practical example. Consider a double circuit line with an impedance of Z = R+ jX ohms per circuit that is supplying a bulk supply point with a load impedance of $Z_L = R_L + jX_L$. See Figure 6.5.1. The sending voltage V_S at the transmission substation is related to the load current I_L by:

$$V_S = I_L\left[(R + jX)/2 + (R_L + jX_L)\right]$$

The total power demand at the transmission station is given by:

$$P + jQ = \frac{V_S^{\,2}}{R/2 + R_L + j(X/2 + X_L)} = \frac{V_S^{\,2}(R_L - jX_L) + V_S^{\,2}(R - jX)/2}{R^2/4 + RR_L + R_L^{\,2} + X^2/4 + XX_L + X_L^{\,2}}$$

and the line active and reactive power loss is:

$$P_1 + Q_1 = \frac{RI_L^{\,2} + jXI_L^{\,2}}{4}$$

Assuming that the load impedance does not change, initially following the trip of one line, the receiving end voltage will drop. Depending on the nature of the load and the presence of on-load tap changers on load transformers, the low transmission voltage may result in greater current flows and increased line reactive power demand in an attempt to boost voltage to original levels such that following the tripping of one circuit the active and reactive power demand of the remaining line is given by:

$$P_1 + Q_1 = RI_L^{\,2} + jXI_L^{\,2}$$

i.e. losses have quadrupled. Further negative effects are the reduced effectiveness of capacitive compensation at lower voltages. These detrimental effects create a demand for more reactive power than can be sustained.

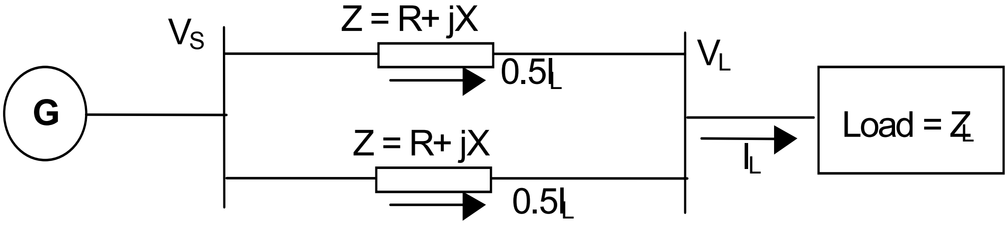


Figure 6.5.1: Simplified representation of power flow from source to load

The phase described above can take over a minute to develop and so lends itself to remedial action before plant items start to trip on overload. In some cases however voltage decline may be both sudden and significant. For example when a weakly connected load centre loses an important tie line. In the absence of instantaneously available compensation (SVC, Capacitor Banks) or where the voltage is too low for compensation to be effective, plant overloading and cascade tripping are inevitable. Time delayed under-voltage load shedding can alleviate the problem with the choice of settings being critical. The amount to be shed must represent the power margin on the P/V graph (see Chapter 5, figure 5.5) between the pre-fault safe operating point and the post-fault safe operating point. An under-voltage load-shedding scheme should provide against voltage collapse for any number of N-2 contingencies in an area. The following sections describe different types of UV load shedding schemes to cater for various conditions.

6.5.2 Ireland: UV Load Shedding

The under-voltage scheme is intended to prevent voltage collapse following loss of critical 110kV tie-lines to weakly connected 110/40kV subtransmission substations. The scheme must provide a delay so that it will not operate for short-circuit faults on the 110kV/40kV/10kV networks. The scheme monitors the 110kV voltage as reference and sheds load at the 40kV outlets. Load is shed in two stages. The initial trip setting is at 77kV (0.7 p.u.) with a delay of 1.2 seconds and a back-up trip setting of 86kV (0.78 p.u.) with a delay of 2.5 seconds.

The scheme in its initial step sheds sufficient 40kV load to recover the voltage after any N-2 contingency in that area. In the case of the second stage tripping the times should be staggered with 0.2 seconds intervals between feeders.

The scheme is sufficiently sophisticated to cater for: (a) failure of 40kV circuit breaker tripping, (b) abnormal 40kV sectionalising in the area and (c) inadequate load shed in the initial tripping.

A number of these schemes are now in service.

Load is restored manually i.e. auto-restoration is not employed.

6.5.2 Spanish Protection against Voltage Collapse

The load in Southern Spain is highly reactive especially in the summer. Power is imported from the rest of Spain and the region is susceptible to voltage instability problems. Conversely to compensate voltage during periods of low load reactors are installed at the 400kV level. Also located in this region is the terminal substation for the interconnection with Morocco. This 400kV, 600MW rated submarine cable is equipped with reactors at both ends for reactive compensation. On the Spanish side there are in fact two 150Mvar reactors: the cable reactor and a network reactor for voltage compensation and as back-up to the cable reactor.

To reduce the probability of voltage collapse due to external disturbances, a protection has been developed and installed on the Spanish side of the interconnection. In service since summer of 2000, it operated as specified during a low voltage disturbance on 29/7/02, when voltage dropped to 383kV. Its logic is as follows:

- If voltage < 385kV (96%) for 10s, it trips the network reactor.
- If voltage < 380kV (95%) and power flow to Morocco exceeds 700MW for
  - 5s, it trips the network reactor
  - 10s, it trips the cable reactor.
- If voltage < 380kV (95%) and power flow towards Morocco exceeds 700MW and incoming reactive power drops below 100Mvar for 30s, and voltage under 375kV (94%) during the 5s following, it trips the interconnection.
- With voltage over 405kV (101%), it re-closes the cable reactor.

6.5.3 Portugal: UV Load Shedding

<u>Substations without Automatism and Telecommand Remote Units (ATRU) and Numerical Command and Control Systems (NCCS)</u>

Under-voltage relays are installed on the MV busbars (≤ 30 kV) of subtransmission substations that are set to 85% of nominal voltage and trip in-feeding power transformers and capacitor banks after a delay of 3s. In a small number of substations MV feeders are also disconnected. Restoration is manual.

<u>Substations with ATRU and NCCS</u>

These substations have two different under-voltage load shedding and restoration schemes, one for HV (60 kV) and another one for MV (≤ 30 kV).

On detection of voltage loss on a HV busbar, for more than 1s, the HV and MV breakers associated with power transformers connected to the HV busbar are opened. Also feeders are opened. After the stable appearance of the voltage (5s), all the breakers of the power transformers and HV lines that were opened are reconnected manually, one by one.

Detection by the under-voltage relay of an MV busbar voltage below 85% of nominal value for more than 1.5s results in tripping of all the breakers on MV feeders and capacitor banks connected to the MV busbar. Once the voltage has stabilised at nominal value for more than 5s the MV feeders are reconnected in individual sequence if conditions permit (e.g. live-bus/dead-line conditions prevail). Reconnection of capacitor banks is not automatic. It can be made by telecommand if required.

6.5.4 Saudi Arabia Load Shedding

In the Saudi Arabia Western Region (SEC-WR) the peak load of about 5,800 MW consists to a large extent of air conditioning [2]. The transmission system consists of more than 5,000 km of 380kV and 110kV lines. During a fault on the sub-transmission or distribution systems the voltages can become very low causing the air conditioning plant motors to stall. This in turn retards voltage recovery. The voltage recovery is primarily influenced by:

- The level of air-conditioning load
- The low load impedance represented by stalled air-conditioning motors.

The installation of under-voltage load shedding in weak parts of the system has proved to be an effective way to improve the voltage recovery and to avoid voltage collapse. SEC-WR has installed such a system. Investigations to select the best locations for the UV relays are first carried out. These include load flows, dynamic modelling of plant and rate of voltage recovery based on load modelling. Agreement between simulations and actual disturbance recordings of both the voltage dip and subsequent recovery/collapse is very close. Associated simulation studies are employed to choose the most appropriate settings.

The existing scheme sheds between 30% and 60 % of the load in different regions if the voltage drops under 0.75 p.u. for 0.9-1.2 seconds. A further extension to the scheme is proposed in which between 50% and 65% of the load can be shed.

It should be noted that the problem of poor voltage recovery described can be solved through network reinforcement (i.e. the impact of stalled rotor on load voltage is reduced). However this will be a very expensive solution in most networks so that a well designed load shedding scheme represents a cost-effective alternative.

6.5.5 UV Load Shedding in Israel

In Israel an elaborate system is deemed necessary as a defence against voltage collapse [3]. The Israel Power system is an isolated system. Its peak load is approximately 8,000 MW and the transmission system has 400kV and 161kV overhead lines and cables. A combination of under-voltage and over-current is used as the load-shedding criterion. Both fast acting local schemes and slower centralised systems operating via the SCADA network are employed.

System studies concluded that:

- the most effective action to prevent system collapse is automatic load shedding based on local criteria such as under-voltage or circuit over-loading; this is performed within seconds.
- to restore acceptable operating conditions a centrally based co-ordination system is required.

The load shedding criteria adopted is that voltage should decline below 0.88 p.u. or that load would exceed 1.8 times the circuit thermal capability. If load shedding in the local station is not sufficient to achieve this, shedding signals are transmitted to remote stations in receipt of excessive power flows. The locally applied settings are in two stages:

Under-voltage:	0.86 p.u.; 3 seconds time delay; 0.88 p.u.; 6 seconds time delay.
Overload:	1.8 p.u.; time delay 1-2 seconds if a risk of distance protection tripping exists; 1.8 p.u.; time delay 3-10 seconds if no risk of distance protection tripping exists.

Under-voltage load shedding is blocked in event of VT fuse failure. It is also blocked in the event that the station loses all supply e.g. bus protection trip, loss of incoming feeders, etc.

Load shed by the under-voltage scheme can be restored automatically in a multi-step sequence that avoids voltage fluctuation. Restoration from the National Control Centre (NCC) is also possible and in this case local restoration can be blocked.

Load shed due to circuit over-loading can be restored from NCC only.

6.6 CONCLUSIONS

Automatic under-voltage load shedding is becoming widely accepted as a measure to prevent voltage collapse. Power system characteristics vary significantly resulting in different voltage behaviour following disturbed conditions. This dictates different philosophies to suit particular requirements. Each case should be considered carefully with the objective of optimising performance of the load shedding scheme. The following factors should be addressed:

- Level of load to be shed and location of such loads
- Load characteristic e.g. motor, heating, industrial, domestic, etc.
- Choice of locally or centrally controlled load shedding or both
- Voltage levels at which shedding is initiated
- Number of stages and associated time delays
- Co-ordination with other voltage support measures
- Possibility or desirability of auto-restoration.

A further important factor when designing the scheme is the behaviour (dynamic as well as static) predicted by simulated disturbances on the modelled system. The literature available suggests very good correlation between the modelled results and recordings during actual network disturbances.

6.6 AUTOMATIC RECLOSING

6.6.1 Introduction

Automatic reclosing of circuit breakers following clearance of a transmission line fault, has been very useful for improving service reliability and generally counteracting or mitigating the effects of system disturbances. There are broadly three modes of automatic reclosing related to their dead time settings: high-speed reclosing (HSAR), medium-speed reclosing (MSAR) and slow-speed reclosing (DAR). They are further subdivided according to the number of phases opened: single-phase reclosing, three-phase reclosing, single-phase and three-phase reclosing, polyphase reclosing, etc. The automatic reclosing modes differ depending on the characteristics of the system to which they are applied: system voltage level, neutral point treatment, network topology, location of various types of generation plant and load centres, etc. All reclosing schemes aim at improving power system reliability and more effective load restoration including the following items:

(1) Improved ability to maintain interconnection between systems and subsystems,
(2) Reducing the risk of system transient instability,
(3) Reduction of overloads on other circuits and equipment when a circuit is opened due to a system fault,
(4) More rapid system restoration,
(5) Reduction in the interruption time of supply to consumers.

High speed polyphase reclosing and loop continuity-check are sometimes applied to important extra high voltage lines. Such reclosing has a high success rate with simultaneous double circuit faults and enhance the reliability of electric power delivery. In this context the importance of reclosing is much greater than in the past.

This section reviews the data on reclosing operation. It considers the actual application and concept of various automatic reclosing modes and the influence of technology in different utilities to contribute to the design, planning and operation of automatic reclosing. It also summarises common considerations and the future direction for the application of the automatic reclosing. Finally technology developments in relation to automatic reclosing are reviewed in the context of satisfying more sophisticated system requirements.

6.6.2 Categories and Modes of Automatic Reclosing

The reclose category (HSAR, MSAR, DAR) selected depends on the application objective and appropriate dead time. The modes of operation available are: polyphase, single-phase, three-phase reclosing, etc. The most suitable mode is selected and applied according to the importance of the network, the capability of the main protection system to identify the faulted phase, the purpose of reclosing, etc.

6.6.2.1 High-speed, Medium-speed and Slow-speed Reclosing

The automatic reclosing categories applied by the utilities differ according to application. They are summarised in Table 6.6.1.

Table 6.6.1 High-speed, Medium-speed and Low-speed Reclosing Protection Modes and Their Purposes

Category	Dead Time	Purpose
High-speed Reclosing (HSAR)	0.35 to approx. 1 sec.	Improved system stability. Retention of system interconnection. Reclosing after a specified time depending on arc extinction.
Medium-speed Reclosing (MSAR)	2 or 3 to 25 sec.	Maintenance of system interconnection & automatic system restoration when the conditions for HSAR not satisfied. Reclosing occurs after a specified time, depending on attenuation of turbine generator shaft vibration; attenuation of the residual induction motor voltage; attenuation of conductor vibration due to wind/snow damage .
Slow-speed Reclosing (DAR)	2 or 3 to 70 sec.	Automatic and faster system restoration.

The reclosing sequences also differ between utilities depending on overall objective of the application. They can typically be divided into the following cases.

Case 1: High speed reclosing is executed to maintain system interconnection. If conditions not satisfied lockout ensues after an active time or if reclose is unsuccessful reclosure lockout is executed.
Case 2: As for Case 1but for single phase tripping. Three phase tripping results in MAR or DAR on single or double shot basis depending on utility practice.
Case 3: High-speed reclosing is executed to maintain system interconnection. However, if the conditions for high-speed reclosing are not satisfied, medium-speed reclosing is effected. If both fail or the conditions for them are not satisfied, slow-speed reclosing is executed.
Case 4: High-speed reclosing is executed to maintain system interconnection. However, if the conditions for high-speed reclosing are not satisfied, the following is executed to restore the system automatically.

a. Failure of high-speed reclosing or conditions for high-speed reclosing not satisfied - then slow-speed reclosing is executed.
b. Conditions for high-speed reclosing not satisfied - then medium-speed reclosing is executed. Failure of medium-speed reclosing - then slow-speed reclosing is executed.

Case 5: Reclosing is executed once only, and if high-speed reclosing fails, the circuit is locked out. If the conditions for high-speed reclosing are not satisfied, the following is executed to maintain system interconnection.

a. Conditions for high-speed reclosing not satisfied: Medium-speed reclosing is executed.
b. Conditions for high-speed polyphase reclosing not satisfied: The remaining phases are opened.

High-speed simultaneous six-phase reclosing is executed.
High-speed loop reclosing is executed.

Case 6: Medium-speed reclosing is executed to maintain system interconnection where high-speed reclosing cannot be applied due to the turb-generator shaft torsional torque limitations. If medium-speed reclosing is unsuccessful or if the conditions for medium-speed reclosing are not satisfied, slow-speed reclosing is executed.

Case 7: To restore the system automatically, either of the following reclosing modes is executed once according to the operating duty of the circuit breaker.

a. Medium-speed reclosing
b. Slow-speed reclosing

Cases 1, 2 are common throughout the world. Cases 3,4,5,6,7 are also widely used in Japan.

Table 6.6.2 shows the reclosing sequence that are applied in the case of nine utilities in Japan A,B,C,D,E,F,G,H,I.

Table 6.6.2 Reclosing Sequences in Japanese Utilities

Voltage	Extra High Voltage									154 to 110 kV								
Case \ Utility	A	B	C	D	E	F	G	H	I	A	B	C	D	E	F	G	H	I
3	○			○				○								○		
4-a	○					○	○						○		○	○		
4-b					○									○				
5-a		○							○		○	○						
5-b			○															
6							○											
7-a											○	○						
7-b										○			○			○	○	○

6.6.2.2 Polyphase, Single-phase and Three-phase Reclosing Protection Modes

The most common modes of automatic reclosing are: polyphase, single-phase and three-phase reclosing.

Polyphase Reclosing: When double-circuit multiple faults occur, only the faulted phases are opened. Power transfer continues over the two or more remaining phases. After dead time expiry high-speed reclosing is executed. The reclosing conditions are set taking into consideration system stability, reduction in turbo-generator shaft torque in the case of unsuccessful high-speed reclosing and other factors, such as the requirements for maintaining system interconnection.

Single-phase Reclosing: Only the faulted phase is opened for a single-phase ground fault. Synchronism maintained over the other two phases. High-speed reclosing is executed.

Three-phase Reclosing: All three phases simultaneously tripped by protection relay. Once conditions are satisfied three phase reclosing in HSAR, MSAR or DAR is applied.

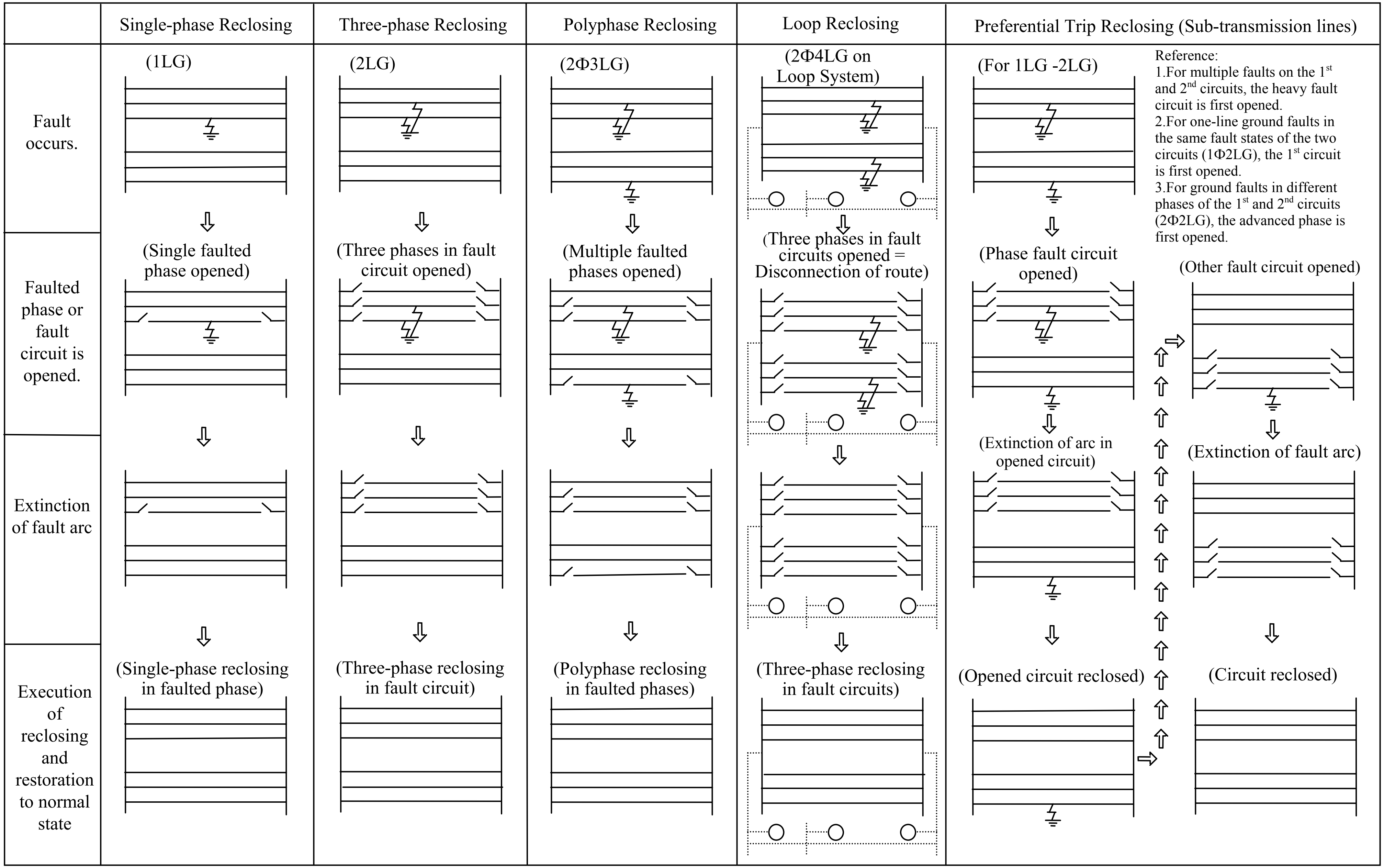
The following are also applied in Japan:

Loop Reclosing/Protection: For looped lines even when the route is disconnected on one parallel double circuit the interconnection is maintained over the remaining section of the network between the outaged line ends. For this condition reclosing is executed by a signal sent along the loop to check whether there is a power flow and whether the circuit breakers are opened or closed or if the voltages at both ends are in synchronism.

Preferential Trip Reclosing/Protection: This reclosing is applied to impedance grounded systems and its purpose is to avoid disconnection of the route when double-circuit multiple faults occur on a parallel double circuit transmission line equipped with three-phase circuit breakers that have three pole mechanisms. The circuit on which the multiphase fault has occurred is opened first and then high-speed three-phase reclosing is executed. If it succeeds then the remaining circuit with the single phase ground fault is opened and high-speed three-phase reclosing is again executed. This protection/reclosing scheme determines the tripping time for each circuit by selecting the conditions for preferential trip depending on the fault type. Therefore it is mainly applied to segregated phase current differential protection which can unambiguously identify the faulted phases even on double-circuit faults. Due to the long time to clear single-phase ground faults, time co-ordination with back-up ground fault protection is important.

Table 6.6.3 shows typical operation examples of the automatic reclosing protection modes described above.

Table 6.6.3 Typical Operation Examples of Various Reclosing Protection Modes



6.6.3 Evaluation of Automatic Reclosing Schemes

The majority of overhead transmission line faults are caused by natural phenomena. A very small percentage of such faults result in damage to the facilities. Therefore, the effectiveness of reclosing in maintaining continuity of power transmission is very important. Techniques have been developed to improve the reclosure success rate. For example if the fault involves two phases only then on the assumption that the cause of the fault is wind, rain, ice or snow some utilities change the speed of reclosing from high speed (HSAR) to medium speed (MSAR). The following is an evaluation of reclosing performance at different system voltage levels in Japan.

6.6.3.1 Reclosing on 187kV to 275kV Systems

For systems at this voltage level, the fault details are clearly established based on the data obtained from each phase relay and from oscillograph recordings. Determining the reclosing success rate involves investigating the failure rate for each fault type for high speed and slow speed reclosing. The results are shown in Table 6.6.4.

Table 6.6.4 Reclosing Failure Rate by Fault Type at 187 to 257 kV

	Fault Type				Number of Faults
	1ϕG	2ϕG	3ϕG	2ϕ	
Reclosing Failure Rate at High Speed	9.9 %	6.7 %	-	19.2 %	203 Cases
Reclosing Failure Rate at Slow Speed	5.9 %	6.7 %	0 %	4.5 %	37 Cases

Notes: Reclosing Failure Rate = (Number of Failures in Reclosing / Number of Reclosing Actions) x 100
-: No fault

For the 2ϕ fault type, the reclosing failure rate with HSAR is high while for DAR and MAR it is low; accordingly an improvement in the reclosing success rate can be expected by changing to slow speed reclosing. When the fault state is 1ϕG, 2ϕG or 3ϕG, there is little difference in the comparative reclosing failure rates. If high-speed polyphase reclosing is applied, the success rate can be expected to be almost the same as that for 1ϕG.

6.6.3.2 Reclosing on 110 to 154 kV Systems

According to the reclosing failure rates shown in Table 6.6.5, the rates are low for the transmission lines that apply high-speed reclosing.

Table 6.6.5 Reclosing Failure Rate by Fault Type at 110 to 154 kV

	Fault Type				Number of Faults
	1ϕG	2ϕG	3ϕGS	2ϕ	
Reclosing Failure Rate at High Speed	1.9 %	0 %	0 %	-	173 Cases
Reclosing Failure Rate at Low Speed	4.0 %	0 %	4.3 %	3.4 %	351 Cases

Notes: Reclosing Failure Rate
= (Number of Failures in Reclosing / Number of Reclosing Actions) x 100
-: No fault

6.6.4. Considerations for Application of Automatic Reclosing

Automatic reclosing modes are selected based on system voltage, system configuration, the importance of the network, the phase selection capability of the main protection system, the purpose of reclosing, etc. The following factors are considered when selecting the reclosing mode to apply.

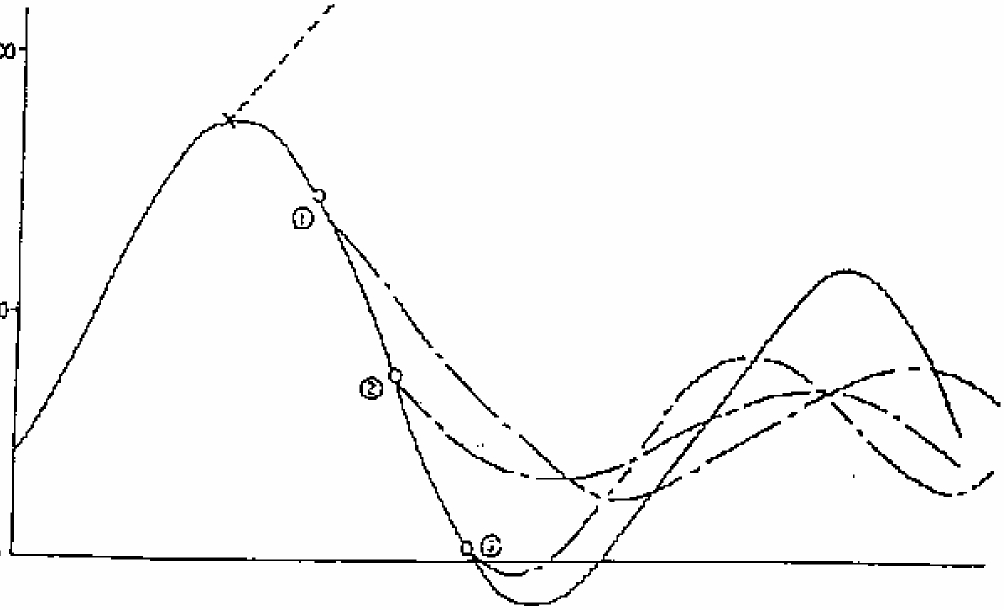
6.6.4.1 Arc Extinction Time

With high-speed reclosing, a shorter dead time is generally advantageous for system stability. However reclosing must not be executed before the fault arc has been extinguished. Therefore the time required for arc extinction determines the dead time for high-speed reclosing. The selection of suitable dead times is described in Appendix 4.

6.6.4.2 Stability

While dead times should be as short as possible in order to improve system stability and reliability, reclosing onto a permanent fault undermines stability. Likewise if a second fault occurs before the initial fault has been cleared this may have a considerable destabilising effect on the system. In this case reclosing at a particular instant can reduce the extent of a system disturbance compared with the case where reclosing is not executed at all. This is illustrated in Figure 6.6.1. In general, reclosing should be executed a little before the load angle returns to its initial value on the phase angle swing curve.

As well as the instant of reclosure dead time and execution mode also impact on stability. The optimum dead time is selected based on the location of the transmission line in the network and on the system configuration. Various fault types are considered as worst case scenarios:



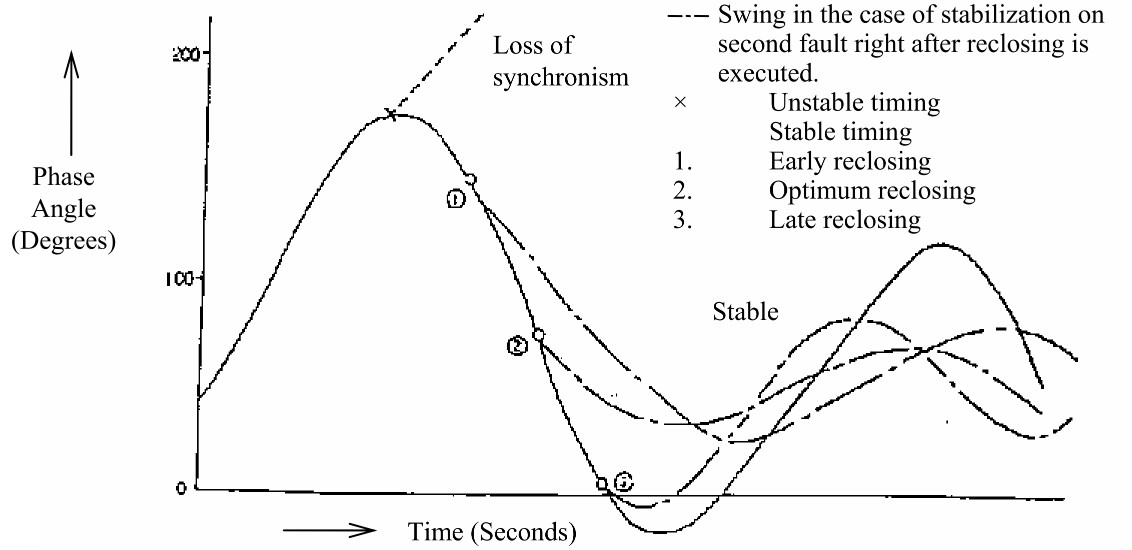


Figure 6.6.1: Optimum Reclosing Timing from Viewpoint of System Disturbance Control

6.6.4.3 Shaft Torque

With the growth of transmission systems the electrical distance between a fault point and a generator is reduced. Furthermore at the higher system voltage levels the area affected by a fault is more widespread.

An important factor for the strength of turbo-generator shaft materials is the oscillatory torsional torque loading imposed on the shaft when the system state is changed. In this context an unsuccessful reclosing, especially one involving a three-phase fault, has a severe impact. This is an important consideration for auto-reclosing of transmission lines in the vicinity of turbosets.

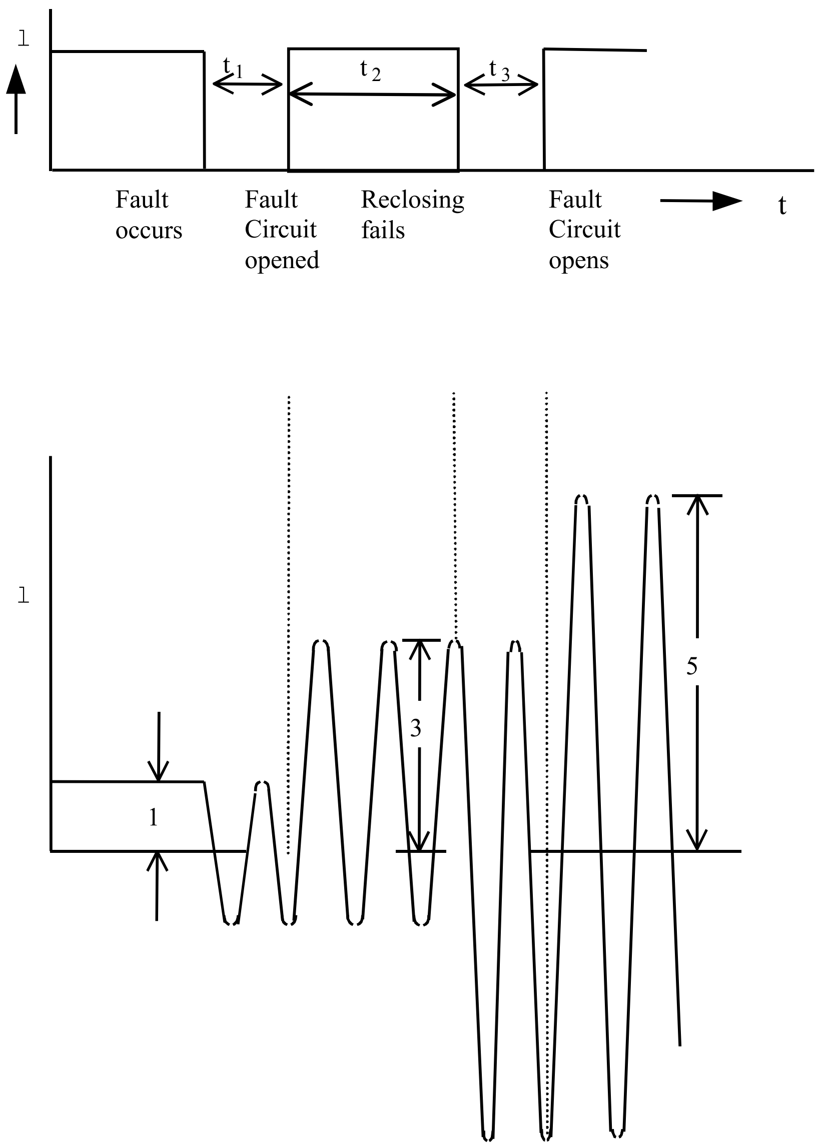


Figure 6.6.2 Shaft Torsional Torque in Worst Case

A turbine-generator shaft is subjected to impact torques during an unsuccessful reclosing cycle at the following instants:

- On fault occurrance.
- On fault clearance.
- Following unsuccessful reclosing (restrike or permanent fault).
- On fault clearance.

The severity is directly influenced by the instant of circuit breaker operation related to the transient torque waveform. In particular, if the circuit breaker is reclosed at the torque peak the resulting shaft torque can be five times as large as the prefault load torque, as shown in Figure 6.6.2.

Different reclosing arrangements are employed to minimise torque oscillations:

(a) Reclose Category Changeover
To avoid the severe impact of unsuccessful reclosure, changeover from HSAR to MSAR or DAR is effected during some three phase faults.

(b) First Closing on Load Side.
Closing is first executed on the load side of the transmission line, and then on the power source side following voltage check. With this method, even if reclosing is not successful, the electrical distance to the fault point is increased (relative to that pertaining during simultaneous high speed reclosure). The transient torque increase experienced by the generator is consequently reduced.

(c) Others
Other techniques are also available:

- Variation of the nominal dead time depending on conditions.
- Sequential phase by phase reclosing i.e. the circuit breaker poles are reclosed one by one; as the protection will trip after first or second pole reclosure the recurrence of a three-phase fault is prevented.

6.6.4.4 Countermeasures against Faults caused by Wind and Snow

Faults between adjacent phases on line circuits often occur due to “sleet jump”. This is caused by the accumulation of snow on the conductors and then suddenly dropping off so that the tension release causes the conductor to jump and make contact with an adjacent phase. High-speed reclosing often fails if the dead time used is that applied for lightning faults, because the phases are still in contact with each other. Therefore, medium- or slow-speed reclosing with their longer dead time is more effective for this type of fault. See Appendix 5 for more details of dead time selection to cater for sleet jump.

In the case of vertically arranged phases on double circuits, to identify the fault type use is made of the fact that wind/snow jump invariably results in two phase faults free of earth. By contrast lightning initiates flashover faults involving earth (single phase, two phase and three phase to ground faults). Depending on whether zero-phase sequence current is present or not high-speed or medium-speed reclosing is selected. This method is applied by some utilities in Japan. This distinction cannot be made in the case of some single circuit flat configurations where sleet jump may result in a conductor clashing with an earth-wire.

6.6.5 Future Developments

6.6.5.1 Enhancement of Automatic Reclosing by Digital Technology

With traditional technology irrespective of relay type (electromechanical or static), various reclosing modes are selectively applied to the relays based on the importance of the system, the faulted phase identification capability of the main protection relay, the main purpose of reclosing and any other relevant factors. For all protection modes the treatment of essential items is very important, e.g. verification of the reclosing conditions, the setting of the dead time and the circuit breaker operating time.

This basic concept is no different for numerical relays. However, the digital devices facilitate improved telecommunication performance, the enhancement of existing functions and the creation of new applications. This is achieved through the integration of multiple functions into the equipment and such improvements are progressing rapidly. Some examples are given below to show the enhancement of automatic reclosing through the application of numerical technology. To meet the increasing demands for improved and more reliable power system operation, new reclosing protection modes are being created.

1. Increase in Transmission Capacity of Power System Information and Creation of New Functions.
   An essential condition for successful reclosing is that the voltage conditions are synchronised at both line ends. To ensure this the criterion for system interconnection is generally verified. For example, power flow detecting devices or the protection function on adjacent circuits frequently provide the interconnection detection for the reclosing condition. The constraints in hardware and signal transmission capacity associated with analogue equipment compromise optimal reclosing.

On the other hand modern protections, such as the pulse code modulated (PCM) current differential protection that uses a digital relay, can transmit a large mount of information required for the reclosing condition or the lock-out condition. Information on the circuit breaker of the other terminal is transmitted at high speed by using subcommutation bits in the protection information transmission format. It can also transmit information on the voltage waveform for phase comparison to ensure that synchronised conditions exist. This allows the addition of reclosing modes such as high- and medium-speed loop reclosing, including different-voltage multiple loop interconnection, by means of end-to-end synchronism checking. Such reclosing modes have been difficult to realise with conventional analogue relays.

2. Integration of Multiple Functions into Equipment.

   Traditionally the equipment installed to provide automatic system restoration was often configured quite independently of the protection equipment. This was due to a constraint in hardware capacity rather than for any philosophical reason. Nowadays, DAR as well as MAR and HSAR is often integrated into the protection equipment, or alternatively the DAR function and the back-up system restoration function are integrated into the substation digital control system in which all the substation control functions are combined and co-ordinated. This integration utilises the fact that numerical devices can easily perform all the reclosing sequence processing (which on analogue equipment was realised using auxiliary relays or transistor circuits or by adding logic such as a reclosing module etc.).

6.6.5.2 Adaptive Autoreclosing

Developments associated with adaptive protection devices promise significant benefits for auto-reclosing. The primary focus is on avoiding reclosure onto faults. Optimising reclosure dead time and improving reclosure logic are important when attempting to increase the successful reclosure rate. Compared with the traditional trial and error approach of autoreclosure practice, techniques that attempt to avoid reclosure onto fault offer definite advantages, particularly as evidence to date suggests that the probability of incorrect reclosure blocking is negligible.

From the literature available various types of adaptive reclosing techniques are being evaluated in different countries. Most promise improvements in reclosure logic. The following summarises the different approaches currently being evaluated.

- Three-phase tripping, followed by single-phase reclosure to establish whether a permanent fault exists, through voltage measurement of the three phases, is mentioned in reference [1]. This reference describes the results of an investigation into the possibilities of using digital techniques to adapt transmission system protection. The same authors in [11] further analyse the effect of fault type, transposition and shunt compensation on the resulting coupled voltages of the de-energised phases. Coupled voltage limits for a wide variety of line construction and fault types are determined by computer simulation, and results favourably compared to field tests performed on a 765kV transmission line. The paper includes a functional block diagram and a specific circuit breaker control circuit for the proposed adaptive auto-reclosure technique. No further literature has been identified on the subject.

During single-phase tripping, analysis of the faulted phase voltage enables the transient or permanent nature of the fault to be determined and the instant at which de-ionisation on a transient fault occurs. The information obtained is applied to avoid reclosure onto fault and to optimise dead time. Field-tested prototypes are frequently described.

- Based on the analysis of the open phase voltages, reference [2] develops three criteria to distinguish between transient and permanent single-phase faults: a voltage criterion for moderate length 220kV-500kV non compensated lines, and a more complex criterion for long 220kV-500kV lines and for lines compensated by 330kV-500kV shunt reactor. Fault resistance is not considered. A prototype employing voltage and compensated voltage criteria was field tested on a 330kV, 60km line with satisfactory performance. Measurements were also carried out to identify the influence of fault resistance on a device employing the voltage criterion; results showed that the device operated correctly for faults having resistances of up to 3kΩ in the application studied.

- References [3] and [4] describe an adaptive single-pole auto-reclosure technique based on an artificial neural network. The design and implementation of a prototype, are presented. The voltage of the faulted phase is sampled and time divided, into sets of one-cycle windows. For each cycle, a frequency spectrum analysis provides six significant characteristics of the waveform studied: DC component, fundamental, 3rd harmonic, 2nd plus 4th plus 6th, 5th plus 7th plus 9^{th,} and 500Hz and above. This vector is fed into the neural logic, which outputs fault "on" or fault "off". After a preset time without fault "off" output appearing, a signal is sent to trip the two other breaker poles. In the case of a transient fault, it defines the precise extinction time. The prototype has a sampling frequency of 600Hz, and the neural network generates an output every twelfth of a cycle. It selects the faulted phase from an external status input. The output of the neural network is compared to a threshold over a number of successive outputs before a decision is made. This increases the security of the rendered output and also confidence in the "safe to reclose" condition in relation to the post secondary arc de-ionisation time.

  EMTP simulation has been used to generate training and test data for the neural network. Several conditions were simulated to include the influence of source parameters, fault location, instant of fault, pre-fault loading and breaker opening time. Noise within the measured signal, non-linear arc phenomena and CVT response were modelled. The importance of CVT modelling for the training cases was identified. Extensive digital and analogue tests with previously unseen data proved very satisfactory.

- Other tests and developments are described in [5]:
  - The neural network was trained with a large number of simulated faults for a typical UK 400kV line. Tests were carried out with real recorded cases from a 132km long ESKOM 275kV transmission line. Results proved the following potential benefits: faster reclosing time, one reclosure onto fault would have been avoided. There were no incorrect operations. No permanent faults had been recorded.
  - To increase the number of successful reclosures, maximum dead time should be increased as much as possible. This requires co-ordination with pole discrepancy relays and backup earth fault protections.
  - New possibilities for reclosing schemes are introduced: a 1+3Φ scheme can be modified to progressing directly to the three phase dead time if required (by tripping of the two healthy phases) without going through an unsuccessful reclosure and trip.

- Further field-tests on the prototype relay trained with simulated and real fault records from the 275kV 132km ESKOM transmission line and on trial on the same line, are described in [6]. Results indicated good performance and the device can have wide application provided costs are not excessive.

- Continuation of work, on the modelling and recognition of fault types other than single phase, and on the modelling and control of three phase autoreclosure systems, is described in [7].

Also being developed are methods, based on the analysis of the fault waveforms, to detect the presence of an arc thus indicating the presence of a transient fault; this information is then applied to avoid reclosure onto fault. This methodology is valid for both single-phase and three-phase tripping schemes. No prototype information has been encountered.

- Reference [8] develops algorithms that calculate and analyse the arc voltage to identify transient (with arc) or permanent (without arc) faults. The arc voltage is obtained through calculation, from the faulted current and voltage waveforms and the fault distance information determined by a distance protection. Reliable information can be obtained within 30ms after fault inception. The algorithm yielded correct results in all cases played on a laboratory test circuit. The development is for symmetrical faults, the authors indicating that work on unsymmetrical faults is under way.

- In [9], transient versus permanent fault identification is approached by analysis of the high frequency current transients generated by the fault. On zero crossing, the arc current will extinguish and then re-ignite, producing a peculiar high frequency current transient. The choice of the data window is important, due to phase displacement of the terminal current zero crossing because of load current and due to the difficulty in capturing the desired signals at the beginning of the fault, in the presence of large high frequency current transients. Third zero crossing before breaker operation is proposed. Dyadic wavelet transform has been chosen as the most suitable tool for the analysis of the transient signal. An advantage of this approach is the absence of voltage measurement requirements. EMTP simulation studies for faults on a 330kV, 100km line have proven the ability of the algorithm to distinguish between transient and permanent faults for both single phase and three phase reclosure.

A different approach for the avoidance of reclosure onto fault, applicable to three phase tripping, is to increase the dead time of the reclosing relay as much as the power system transient stability margin allows. In [10], the establishment of auto-reclosure dead time is proposed as follows:

- if the stability margin is so small that the recovery of stability is impossible even with successful high-speed auto-reclosing, auto-reclosing is prohibited;
- if the stability margin is large enough, low speed reclosing with dead time over 10s is applied;
- for a stability margin in-between, a dead time varying from the de-ionisation time to 10s in proportion to the stability margin is applied.

An algorithm for the calculation of the transient stability margin based on local information (line currents, voltages, pre-fault power across the line…) is proposed. For its on-line calculation, the authors define an artificial neural network approach, the usefulness of which was demonstrated through simulation studies.

Also to be mentioned in this context are the various sophisticated reclosing logics used in Japan and already described in earlier parts of this Section.

6.6.5.3 Application of Reclosing to 1,000 kV Systems (High-speed Grounding Reclosing Protection)

On EHV transmission lines (particularly if untransposed) when a fault occurs the arc at a fault point continues for a few seconds or longer after the faulted phase is opened due to the capacitively induced current from the adjacent healthy phase. This is shown on Figure 6.6.4. See also Appendix 3 for explanation of capacitively induced currents.

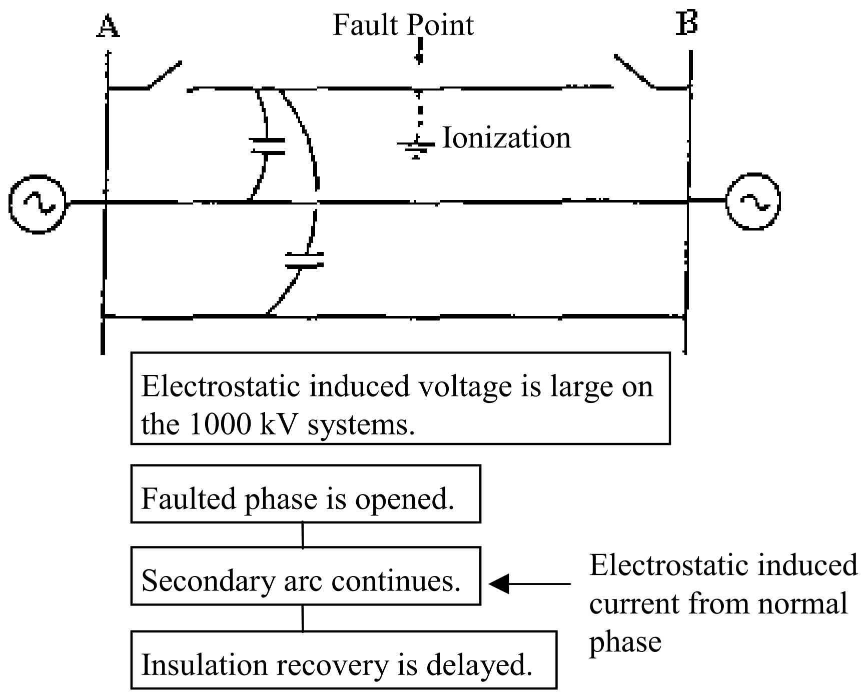
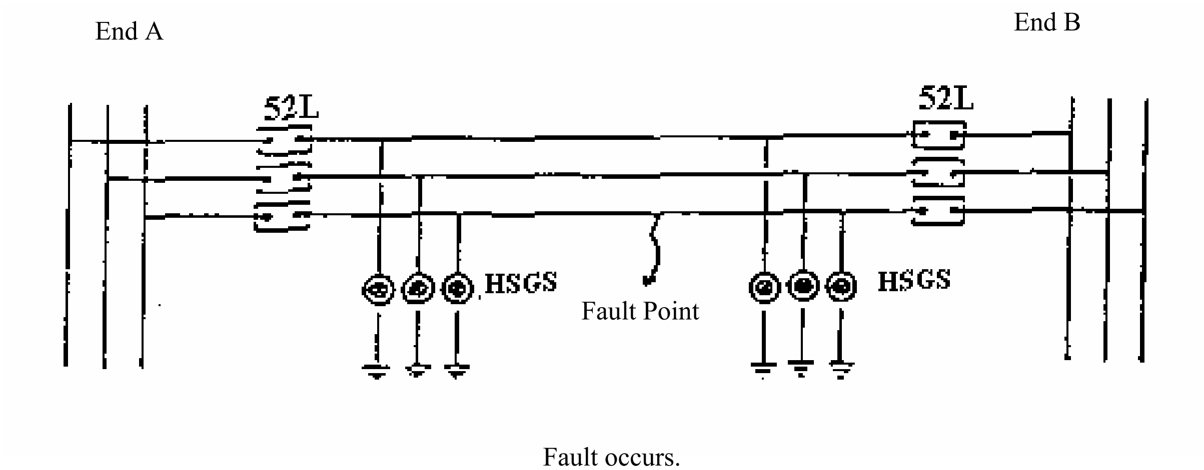


Figure 6.6.4: Electrostatic Induced Current from Adjacent Phases

On the 1,000 kV transmission lines in Japan this problem was resolved by equipping the line ends with high speed grounding switches. When the circuit breakers at both ends of the faulted phase are opened the phase is grounded at both ends by the high speed grounding switches to forcibly extinguish the arc. The grounding switches are then opened to permit reclosing of the circuit breakers. This allows reduction of the dead time to about one second which improves system stability. This reclosing scheme is referred to as "high-speed grounding reclosing protection". Figure 6.6.5 shows the main circuit configuration and operational sequence of the high-speed grounding reclosing protection. Experimental work in Japan indicates that arc extinction times are reduced by about 3.5 seconds to 1 second when this technique is applied, compared with natural arc extinction.

Other EHV systems use compensating neutral reactors. These are tuned to the line capacitance and fitted in the neutral of the three phase reactor that is usually connected to the EHV line for voltage control.



Fault occurs.

↓

Circuit breaker (52L) in faulted phase is opened.

↓

High-speed grounding switch (HSGS) is closed.

↓

High-speed grounding switch (HSGS) is opened.

↓

Reclosing is executed.

Figure 6.6.5: Main Circuit Configuration and Basic Reaction of High-speed Grounding & Reclosing

6.6.6 Conclusion

Traditionally autoreclose schemes have significantly contributed to system stability and supply continuity. However, this was done essentially on a trial and error approach e.g. multi shot reclosing. Differences exist between automatic reclosing protection modes applied by electric utilities. These tend to be dictated by the different power system configurations and use of different technical arrangements based on their experiences e.g. the change of the dead time on a fault due to sleet jump. However as regards the primary purpose of reclosing the objectives tend to be the same: improvement in system stability and service reliability, labour saving in system restoration and rapid circuit reclosure i.e. the overall mitigation of the consequences of system disturbances.

In recent years the application of digital relays such as PCM current differential relays allows easy realisation of reclosing modes such as loop and preferential trip reclosing following disconnection of a circuit. The realisation of such modes using conventional analogue relays is very difficult. The advent of numerical relays has led to improvement not only in reclosing performance but also in reclosing reliability. Therefore the more widespread installation of numerical protection relays is desirable.

The various modes and categories of reclosing discussed in earlier subsections demonstrate the advantages of "intelligent" reclosing schemes.

Advanced reclosing logics used in Japan and already described in earlier subsections, make use of segregated current differential and other digital protections and of the communication possibilities between line ends. Polyphase reclosing is applied on double-circuit transmission lines. If two or more phases will stay interconnected for electric power to be transmitted and to maintain synchronism, only the faulted phases are tripped. After the set time, high-speed reclosing is executed. Loop reclosing is used for loop lines, even when the route is disconnected in a parallel circuit line, if the interconnection is maintained in the remaining section of the loop. Reclosing is executed by a signal sent along the loop to check whether there is power flow and whether the circuit breaker is open or closed, or if there is synchronism between line ends. Preference trip reclosing is applied to impedance grounded systems and its purpose is to avoid double-circuit tripping on multiple faults on parallel circuits using three-phase circuit breakers. One of the faults must be single-phase. The circuit with the heavier fault is opened and then high-speed reclosed. If reclosing is successful, the singe-phase faulted circuit is then tripped and high-speed reclosed. Time coordination with ground back-up protection is required.

Adaptive reclosing that differentiates between transient and permanent faults promises a major improvement in auto reclose success rates. Various techniques are used such as neural networks [3] based schemes utilising the induced voltage on the faulted phase or fault generated high frequency currents that indicate restrikes [9]. Prototypes have been successfully tested. While such developments are not widely implemented at present numerical technology should hasten their more widespread application on transmission systems. Another aspect that warrants consideration is the behaviour of reclosing when circuits are incorrectly tripped during external faults; the reclosure of such healthy lines would be beneficial and it is to be expected that the algorithms and techniques developed perform to satisfaction.

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7. SYSTEM RESTORATION

7.1 INTRODUCTION

This chapter deals with restoration schemes that have been developed from a relaying perspective to assist system restoration following major disturbances. It does not cover emergency control procedures or related operational activities.

Power network sectors that becomes islanded during a major disturbance can continue to operate successfully if the emergency control or wide area system protections automatically shed adequate load or generation such that a stable generation/load balance is achieved. Resynchronising to the main system should then proceed as soon as possible to facilitate restoration of the shed generation or load. Historically co-ordination difficulties and the deployment of personnel to unmanned substations has resulted in relatively long time periods for manual system restoration. Automatic restoration systems are therefore more attractive. This applies both to intersystem resynchronising and to load restoration. To achieve the optimal automatic restoration scheme design it is essential that the dynamics and constraints of resynchronising are established.

Various analyses [1] on synchronising generators to a power system have been conducted for many years. More recently synchronisation has been studied in relation shaft torque phenomena [2,3] and the impact on shaft life of rapid reclosing [4]. The machine constraints for generator synchronisation are the magnitude of the generator torque and armature current. When paralleling islanded systems however, one of the main restrictions is whether all generators are synchronised without pole slip i.e. overall system stability is retained. A further problem is whether power plant stability can be maintained when frequency differences exist at the instant of resynchronising. These issues have been studied in a number of countries and, particularly in Japan, detailed simulations have been performed [5]. Section 7.2 of this report describes the current status of system paralleling in some Japanese utilities and the development of a system paralleling simulation program that was verified by tests on CRIEPI's AC-DC power system simulator.

A slightly different approach in the case of generation loss within an islanded system is to rapidly reduce load to achieve frequency stability. Automatic load restoration on rising frequency may then proceed. This topic is discussed in Section 7.3. Restoration following voltage collapse is covered in Section 7.4.

7.2 INTERSYSTEM RESYNCHRONISING IN JAPAN

Presented below is a summary of the current status of intersystem paralleling employed by power utilities in Japan. In particular it focuses on the work undertaken to prepare practical network models that can be incorporated into system protection/control systems.

7.2.1 Location of Intersystem Paralleling Equipment

In Japan one power company has adopted the following approach. If a system is separated following serious plant failures stable operation is re-established by frequency stabilisation. This is realised by generation and load shedding within the islanded system using a System Stability Controller (SSC) as described in Section 5.1. The islanded system is then resynchronised to the main system using an automatic synchronism check scheme (ASC). The ASC scheme has been installed as standard since 1982 at the following locations:

- Suitable system separation points as determined by SSC.
- Predetermined system separation points (this may be more appropriate for an islanded system containing thermal power plants).
- Normally open points between system sections capable of being paralleled.

The ASC detects whether conditions favourable for successful resynchronising exist between systems but performs no intersystem parameter control to establish such conditions. The provision of ASCs facilitate the following:

- Increasing the number of unmanned substations.
- Reducing the burden on system operators during intersystem paralleling – a scenario that they rarely encounter as major disturbances are infrequent.

7.2.2 Description of ASC

Table 7.1 summarises the main components in the ASC. The synchronism check relay 25 issues the “close” instruction such that the circuit breaker closes at the instant when the phase difference is zero degrees and provided that frequency and voltage differences are within the specified tolerances. Relays 84B and 84L (busbar and line voltage monitoring relays respectively) prevent malfunction of the synchronism check relay 25 due to transient voltages appearing across the circuit breaker. Relay 25FS is a fail-safe relay for the check synchronism relay to ensure that voltage and phase difference are within limits.

Relay	Dev. No.	Purpose	Setting example
Synchronism detection	25	Synchronism check	Frequency difference: <0.2Hz Voltage difference: <7% Target: 0^0
Synchronism detection (Fail safe)	25FS	Fail safe for the synchronism detection (25)	Voltage difference: <10% Phase difference: <30%
Voltage Detection relays	84B 84L	Prevention of malfunction of synchronism detection (25)	Voltage: >80%

Table 7.1 Settings of ASC Relays

7.2.3 Paralleling Problems due to Differences in System Conditions

At the instant of synchronising, generators develop torques and currents having alternating components with fundamental and second harmonic frequencies. These diminish relatively quickly and change with generator swing [6]. Their effects are summarised below.

1. If the resynchronised systems are connected over a very short inter-system transmission line length, large generator torques and AC current components may be generated depending on the phase difference at the instant of synchronising. The withstand limits of the equipment may be exceeded.
2. A long inter-system line results in lower transient torques and currents but loss of synchronism is more likely to occur. The time constant of the alternating torque component becomes shorter with increasing line length since the time constant of line is less than that of the generator armature. The AC component time constant is typically as short as 0.1 seconds.
3. To achieve successful synchronising the frequency of both systems must coincide for a short period (e.g. 1 second). However generating plant must be able to tolerate the output change caused by the rapid frequency change. Out of step conditions do not occur below frequency differences of 3.4% but depending on generator mode the frequency difference may result in valves closing causing the unit to trip and rendering stable operation following synchronisation impossible. This is particularly so if the equivalent line length is short and the phase angle at synchronisation is large.
4. It is obvious from the above that problems relating to generator synchronising or system paralleling vary depending upon system configurations before and after the instant of synchronising.

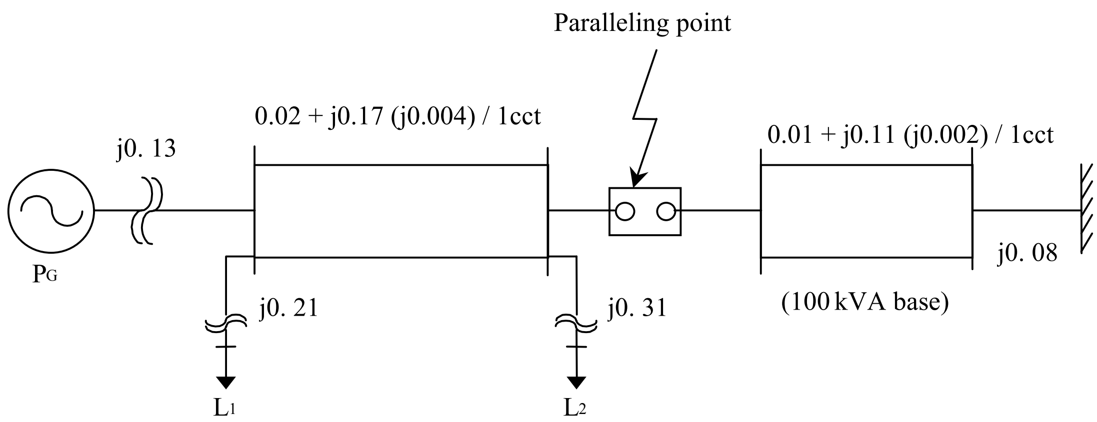
The important factor when synchronising a generator is the relationship between the maximum value of generator torque/current produced and the equipment withstand capability. Successful inter-system paralleling, on the other hand, depends more on minimising the risk of pole slip and providing the network conditions favourable to achieving stable plant operation. To address the former rigorous analytical techniques are required that take the variation of transient AC components into consideration. Power system dynamic analysis is adequate for the latter since the AC components are not a problem.

7.2.3 Analysis Methods for Intersystem Paralleling

The likelihood of pole slip and the stable operability of plant are important factors to be examined. The magnitudes of synchronising torque and current are not so critical for successful synchronisation when the electrical distances between generators in the systems to be synchronised are relatively long. This is usually the case with intersystem paralleling and arise because the changes in the AC components of generator torque are small at the time of paralleling and because their time constants are short. For these reasons, a simplified program capable of analysing intersystem paralleling was developed by modifying the power system dynamics analysis program. Its effectiveness was proved by comparison with results from a detailed simulation program (where generators and lines were represented by differential equations) and also by the results obtained from the AC-DC power system simulator tests as described above. These indicate that the simplified approach is more than adequate for system re-synchronising analysis.

7.2.4 Test Model

The tests with the AC-DC power system simulator were conducted to find the conditions of stability for the synchronising of a simulated 100 kVA generator with outputs of 62 kW and 88 kW to an infinite bus with parameters of phase and frequency differences. Figure 7.1 shows the system and power flow conditions for this simulation. Simplified governor and exciter models were included in the generator model.



Power Flow Condition		
P_G	L_1	L_2
62 kW	30 kW	30 kW
88 kW	42 kW	42 kW

Figure 7.1: Power System Configuration and Power Flow Conditions for Tests on AC-DC Power System Simulator

7.2.5 Results from Tests and Simulation

The comparison of analytical and test results for a 100kW test machine is detailed in Appendix 6. Fairly good agreement is shown between these results confirming the suitability of the simplified analytical model as a tool in achieving successful system re-paralleling.

From the results features of the paralleling process involving a loaded generator are identified as follows:

- All pole slips result from generator acceleration.
- A wider area is stabilised after paralleling if the generator frequency is lower i.e. negative frequency difference.
- Over a range from small positive to negative frequency difference the generator is able to reach stable equilibrium after several pole slips.

Possible reasons for these characteristics are:

- Paralleling a loaded generator affects the torque-phase angle curve after paralleling; when generator frequency is higher the initial torque and acceleration energy is larger, resulting in acceleration pole slip.
- Effects of AVR and governor, especially the latter, are significant. If the frequency difference is negative generator speed increases after paralleling because it accelerates to the infinite bus frequency. Since the governor operates in governor-free mode in simulator tests, turbine output is reduced by the governor after paralleling. This response is reversed in case of positive frequency difference and the turbine output increases after paralleling. The system is more likely to be stabilised with negative frequency difference for this reason.
- Similarly after paralleling with a large positive value of frequency difference the increasing turbine output makes synchronisation after pole slip less likely and accelerated pole slipping results

7.3 AUTOMATIC FREQUENCY ACTIVATED LOAD RESTORATION (AFR)

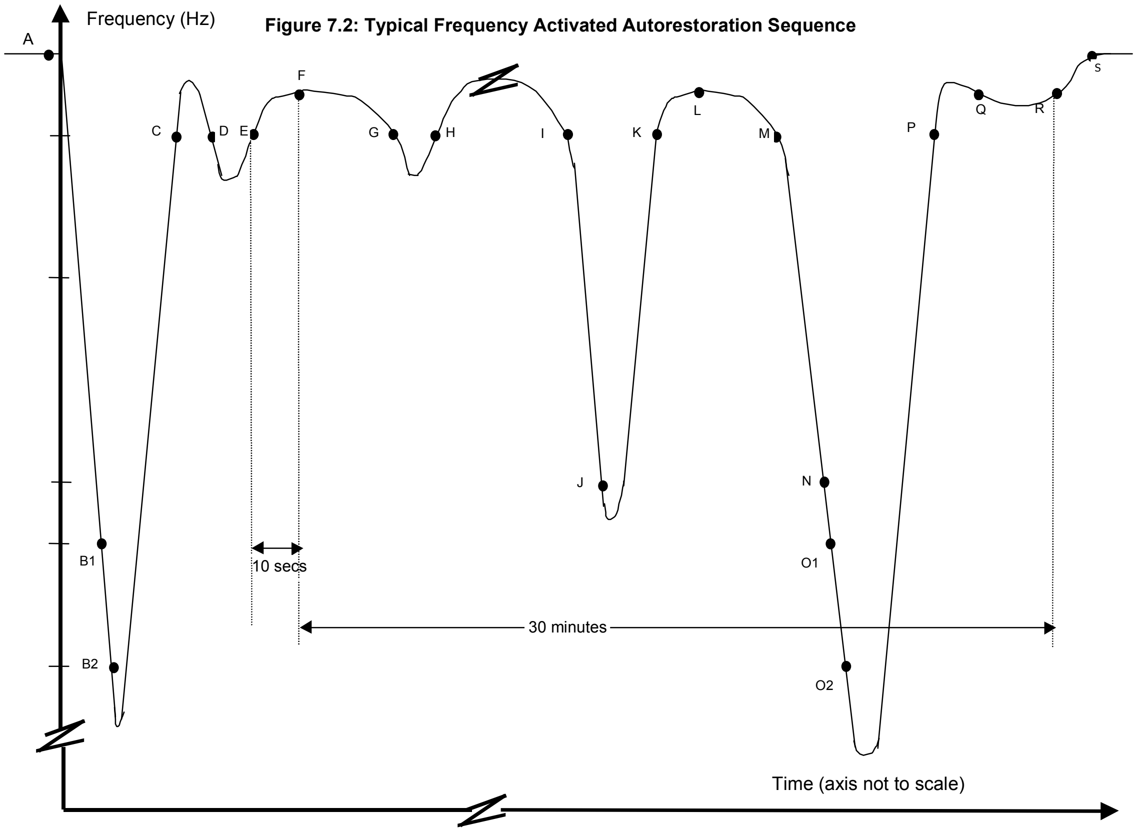
A major objective to be achieved following any major disturbance should be the restoration of supply to all consumers in the shortest possible time. However tremendous difficulties have been experienced following many disturbances in relation to load restoration [10]. It is the authors' view that with an effective islanding system in place considerable advantage can be obtained from well designed auto-restoration schemes.

Typical features for the success of such systems are:

- Appropriate selection of the frequency at which restoration is initiated; this may be just above or below the rated value depending on the preference of system operators (e.g. 50.2Hz, 49.8Hz on a 50Hz system); restoration only takes place when frequency exceeds the set value for a set delay e.g. at least 10seconds.
- The provision of sufficiently small restoration blocks to prevent severe frequency drop on reconnection; typically the block size is less than 1% of system load.
- The provision of sufficient delays and interrupts such that if a severe frequency drop does occur during restoration (e.g. cold load pick-up) the cycle can be interrupted, but not completely reset, until the frequency again stabilises at the restoration value; for example the load blocks 1, 2, 3 can be reconnected after delays of 5,10,15 seconds respectively; if after 10 seconds when restoring block 3 the frequency falls below the set value the sequence is interrupted and the block is reconnected 5 seconds following resumption of restoration.

A typical AFR sequence is illustrated in Figure 7.2.

Figure 7.2: Typical Frequency Activated Autorestoration Sequence



Sequence:
1. A: Frequency stable at 50Hz (pre disturbance)
2. During disturbance frequency declines,at B1 (48.8Hz) AFR scheme triggered; at B2 (48.5Hz) underfrequency load shedding commences.
3. Frequency recovers to above C (49.8Hz); no restoration as frequency again declines (D) before the initial restore timer setting (10secs) is exceeded.
4. Frequency again recovers above 49.8Hz; when time E-F elapses restoration commences and proceeds to G when frequency has dropped below 49.8Hz restoration is interrupted
5. At H restoration immediately resumes and continues until I.
6. At J a sinificant frequency decline (<49Hz) occurs; restoration is interrupted and the initial delay time is reintroduced.
7. On recovery to 49.8Hz restoration proceeds K-L-M exactly as for E-F-G previously.
8. N-O1-O2 represents a serious frequency decline such that restoration interrupted at M, initial delay reintroduced at N, scheme reset at O1 and load shedding takes place for the second time at O2.
9. Restoration sequence recommences at P and proceed until load is eventually restored P-Q-R-S by which time the frequency has recovered to its normal value

7.3.1 Auto-restoration in Ireland

In some islanded systems these schemes have proved very beneficial. In Ireland, for example, over a 10 year period the ESB system experienced a number of Category 1 disturbances[1]. A high percentage of shed load (load shedding details are shown in Appendix 3) was quickly restored automatically once the frequency recovered to the target value of 49.8Hz. Table 7.2 shows some examples.

[1] Disturbance severity category as defined by CIGRE SC39 in terms of system minutes [See Table 2.3]:

Year	Severity (System-Minutes)	%Shed Load Automatically Restored	Frequency Stabilisation to Restoration (Minutes)
1987	2.91	81	4
1987	1.73	66	4
1993	7.3	97	5
1994	4.73	86	4

Table 7.2 Typical Examples of Auto-restoration Times following Frequency Stabilisation

Typically over 80% of shed load is restored within 5 minutes. A window of 30 minutes is allowed for the restoration cycle whereupon the scheme locks out for 1 minute before resetting [11]. Such schemes if properly designed to the particular system requirements can form an important component in restoration strategies.

7.3.2. Under-Frequency Load Shedding and Restoration in Portugal

Substations equipped with Automatic and Telecommand Remote Units (ATRU) or Numerical Command and Control Systems (NCCS) have an under-frequency relay, set at two different frequencies: 49 Hz and 48.5 Hz. Each setting is associated with one group of MV feeders. This association is defined in the load shedding plan (load shedding details are shown in Appendix 3).

When the under-frequency relay starts, the tripping of the associated feeders is instantaneous. High priority feeders are excluded from both groups, so they are not shed. When the frequency returns to its nominal value (50 Hz) all shed feeders are reconnected on instruction from National Control Centre.

7.4 UNDER-VOLTAGE RESTORATION

7.4.1 Under-Voltage Load Shedding and Restoration in Portugal

As described in Chapter 6, Section 6.5.3 an under-voltage condition at an MV busbar (voltage below 85% of nominal value for more than 1.5s) results in tripping of all the breakers on MV feeders and capacitor banks connected to the MV busbar. Once the voltage has stabilised at nominal value for more than 5s the MV feeders are reconnected in individual sequence if conditions permit (e.g. live-bus/dead-line conditions prevail). However reconnection of capacitor banks is not automatic. It can be made by telecommand if required.

7.5 CONCLUSIONS

Analytical models are now available to improve the success probability when resynchronising separate power sectors. Apart from the usual in-synchronism criteria the relative frequency of the generator with respect to the main system (infinite bus) is also important. Laboratory tests have confirmed the suitability of the simplified analytical model developed in Japan. It is intended to include already developed plant models (7, 8, 9) into this program and reduce the settings on the synchronising equipment if found permissible to do so.

Future developments relate to an auto-synchronising system to re-parallel an islanded power sector. Frequency differences between systems will be adjusted through controlling generation and load. Voltage differences will be adjusted through controlling shunt capacitors, shunt reactors and reactive power of generators in order to automatically establish paralleling conditions. The analytical tools described in Section 7.2 will be utilised in this process to achieve an effective, automated method for resynchronising islanded power systems.

When generation on an islanded system has been lost, frequency stability can be maintained through frequency activated load shedding. Furthermore load can be rapidly restored through the use of frequency activated restoration schemes. An essential prerequisite to the success of such systems is that their design is tailored to best suit the particular network.

While under-voltage load shedding is becoming more common automatic under-voltage activated reconnection of circuits is rare.

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8 FUTURE DEVELOPMENTS

8.1 BACKGROUND

Load growth without a corresponding increase in transmission capacity is leading to reduced operational margins for many power systems world-wide. This results in the operation of power systems closer to their stability limits and the creation of unanticipated power flow patterns. Coincidentally the world-wide trend in the electricity supply industry is towards unbundling of the traditional vertically integrated utility. Consequently power utilities exposed to these pressures are demanding new solutions both to minimise the risk of major disturbances and to optimise plant operation through more extensive network monitoring.

The traditional measures to prevent major disturbances can be broadly divided into two categories:

- measures adopted during power system planning and system design
- measures taken during power system operation.

Measures adopted during power system planning and development correspond to preventive action i.e. eliminating the impact of major faults or extensive forced outages. To rely solely on this approach requires a level of redundancy in primary and secondary plant that is expensive and unlikely to be acceptable on commercial grounds. Furthermore network expansion may also be constrained by environmental issues.

Measures taken during power system operation can be categorised into three classes according to the stage of operation: preventive control, emergency control to minimise escalation and restorative control to ensure smooth recovery. Rare contingencies are best catered for by a combination of system operation measures.

In preventive control, power flow and voltage levels are monitored continuously by system operators. When the values exceed nominal, actions such as system re-configuration or generation adjustments are applied. In some utilities, assumed contingency scenarios are simulated based on online network information, and measures taken, if required.

Emergency control is not typically required for a single (N-1) contingency, except in the following cases:

1. Plant requirements specified at the power system planning and development stages are not fully implemented due to economic (or other) reasons.
2. Events occur that were not envisaged as a contingency in the reliability criteria on which the power system planning and equipment designs were based.
3. Contingencies arise beyond the preventive control measures adopted for power system operation.
4. Wide-spread contingencies such as breaker failure.

Restorative control is usually implemented through the application of high speed auto-reclosing following line protection trips. This secures transient stability. However when a wide-spread blackout occurs, measures such as reconnection of isolated island systems or, in the worst case, blackstart facilities may be required. In most cases to date, these measures have been carried out manually. To assist the restoration process, some utilities open the circuit breakers on dead busbars to mitigate any over-voltage during the restoration process. This is frequently achieved by under-voltage relays. Similarly when generators are shed they are arranged to trip to house load as it facilitates faster resynchronisation.

Some utilities have introduced systems to automate to varying degrees the emergency control function. A recent CIGRE survey found approximately 50 such schemes operating in 15 countries [1, 2]. These “Special Protection Schemes” avoid delays associated with manual intervention and the rapid response to disturbed conditions reduces the likelihood of escalation to more severe conditions. Such schemes vary significantly, both in function and complexity, from relatively simple automatic load shedding schemes (see Chapter 6, Sections 6.4 and 6.5) to the system stabilisers applied in Japan (see Chapter 5, Section 5.1).

Other developments relate to relaying schemes based on phasor measurement. These are becoming popular and have been introduced in the USA [3] and in France [4]. The latter publication describes a scheme that uses phasor measurement to determine relative phase angle difference in the 22 sectors into which the EDF system is divided. Measurements are made locally and communicated to a central co-ordinating system. Measurement synchronisation is performed locally by the satellite Global Positioning System (GPS). Two types of instruction may then issue if transient instability is detected:

- Tripping of transmission ties to isolate the unstable sector;
- Load shedding to prevent further destabilisation.

Trials to date with such systems are promising. The great advantage offered is the ability to determine the relative stability of different nodes on the network through the monitoring of voltage phasors at those nodes. This facilitates the concept of “system protection” or “wide area protection”.

The protection schemes described in the foregoing are designed to take predetermined corrective actions (apart from faulted equipment isolation) to preserve system integrity. Consequently they have been designated by CIGRE taskforce TF38.02.19 as “System Protection Schemes” (SPS).

The concept of adaptive relaying has existed for some time. However its realisation in electromechanical or static analogue technology was limited to very basic functionality. Using the sophisticated functionality now available with numerical devices, adaptive relays promise significant advances in protection and emergency control.

The following sections elaborate further on the developments likely to impact on system protection performance in future.

8.2 TRADITIONAL SYSTEM PROTECTION SCHEMES

A severe fault even when cleared may result in power system oscillations, out of step conditions or abnormal frequency where stable operation is no longer possible. The traditional SPSs, formerly known as "Special Protection Schemes" are frequently applied to address such situations. They typically operate emergency controls to stabilise the power system and prevent escalation of the disturbance. An IEEE/CIGRÉ Committee Report defined a Special Protection Scheme as "a protection scheme that is designed to detect a particular system condition that is known to cause unusual stress to the power system, and to take some type of predetermined action to counteract the observed condition in a controlled manner" [5].

SPSs are broadly divided in three types:
1. Behaviour-confirmation type
2. Behaviour-assumption type (pre-fault calculation)
3. Behaviour-prediction type (post-fault calculation)

The most prevalent class is the behaviour-confirmation type. It applies control functions on detection of a confirmed disturbance, such as out of step, abnormal frequency, voltage instability or overload cascading. All conventional relay-type SPSs belong to this class e.g. under-frequency load shedding. Recently, some utilities have also used adaptive versions of SPSs to prevent out of step conditions. Once the out of step condition is confirmed it collects online information from the substations and performs centralised corrective control.

The behaviour-assumption type of SPS assumes instability phenomenon following severe contingencies under various system conditions. It predetermines the appropriate control measures. Once an actual contingency occurs, the SPS carries out predetermined control and prevents possible system instability. This type of SPS prevents out of step or abnormal frequency. While the behaviour-confirmation type of SPS, described above, implements system separation following an out of step occurrance and so prevents further escalation, the behaviour-assumption type executes control before out of step happens and prevents it from occurring. A typical control scheme of this type is generator shedding, or prompt isolation of accelerating generators immediately following a fault. The calculation method used to determine the amount of generation to be shed could be called "pre-fault calculation". It uses simulation to determine beforehand the relationship between various severe contingencies and the controls necessary to minimise the impact of the disturbance. This simulation is normally carried out by power-system analysis engineers. However, adaptive SPSs have recently been developed which perform simulations and determine control actions automatically based on the on-line information from the power systems. The behaviour-assumption SPSs for abnormal frequency are more sophisticated than the behaviour-confirmation type such as under-frequency relays. The appropriate levels of generation/load to be shed for different contingencies are calculated periodically beforehand. When an actual contingency occurs, the SPS promptly executes controls according to the calculation. Thus frequency instability can be prevented. (See Chapter 5, Section 5.1).

The behaviour-prediction type of SPS is also called "post-fault calculation type". Calculation starts after fault occurrence based on real-time measured values, executes predictive control actions and prevents power system instability. This application is practical only for out of step contingencies. After a fault occurs, this type of SPS measures voltage and current during the "incubation period" before onset of out of step. Controls are then implemented according to calculations and predictions on whether the fault may evolve to an out of step situation. While the behaviour-assumption type can only deal with assumed contingencies, the behaviour-prediction type can also address actual contingencies because it applies controls based on observation of the actual disturbances. However the observation dependent control tends to be slower than the behaviour-assumption type. (See Chapter 5, Section 5.1)

In the past the SPS consisted of distributed local protection relays co-ordinated at central level with settings based on system stability requirements. Future SPSs will operate more accurately and prevent/limit disturbances based on calculation using post incident real time data. Relaying systems will become multifunctional with integral continuous monitoring, preventive control, emergency control, and restoration control. Neighbouring systems will monitor each other and use co-ordinated operations to stabilise the power system. The amount of generator shedding or load shedding will be minimised. Such performance can be achieved by fast operating control systems based on state-of-the-art numerical devices interlinked over wideband telecommunication channels. In addition, contrary to conventional systems, which can only deal with predetermined contingencies, future systems will have the flexibility to cope with undefined contingencies. In future therefore, the SPS is likely to play an increasingly important role in the operation and protection of power systems. There are however some disadvantages such as high cost and a lack of flexibility in adapting to system expansion.

8.3 WIDE AREA PROTECTION

Wide area protection systems (WAPs) are intended to protect the power system as a total entity focusing on maintaining power system integrity. They therefore constitute a more comprehensive type of SPS. WAPs function by accessing operating data at a number of nodes on the system and while it is impossible to prevent all contingencies that may lead to power system collapse, WAP has the potential to co-ordinate measures that will prevent large area disturbances or mitigate their impact. (See Chapter 6, Section 6.1.5).

More widespread application of WAPs is likely to result in deferral of network expansion. This will help in economically justifying their installation which at present appears relatively expensive. Essential to the more widespread acceptance of WAP is the availability of a system wide broadband telecommunication system with speeds that satisfy the SPS processing time of between 0.1 to 10 seconds. Dedicated telecommunication networks are very expensive. While use of network wide WAN operating in conjunction with substation based LANs appear to offer more economic solutions consensus is still lacking as regards the technical acceptability of this approach. The work currently ongoing in IEC TC57 to standardise on switched Ethernet and

TCP/IP bus systems to be used in future station automation applications [6] is very important in this respect.

8.4 ADAPTIVE RELAYING

The availability of adaptive techniques make it possible to temporarily increase line overloads provided the line equipment can cope. Such settings should include both current magnitude and duration. Similarly allowing generator plant to temporarily increase reactive power output above rated value will provide essential voltage support at a critical time. This would have been beneficial in many of the cases reviewed in this Report. (See Chapter 2 and Chapter 3, Section 3.6 for further details). Such schemes are only effective if accompanied by a system of either quickly getting active and/or reactive power reserves on stream or, failing this, ensuring that the load shedding schemes in place reduce demand to a level which the system can meet. In other words an overall co-ordinated approach is required. A prerequisite for the success of such an approach is the ability of the relays to adapt their settings to best suit the prevailing situation. The ability to permit circuit loading based on the actual capability rather than a fixed preset level will avoid cascade tripping and give operators valuable time in which to take remedial action. (See Chapter 6, Section 6.3 for further details).

A second advantage introduced by adaptive techniques relates to autoreclosing. Making the reclose cycle more intelligent to best identify fault type and arc extinction instant will improve reclose success rates. (See Chapter 6, Section 6.6 for further details).

8.5 OTHER ISSUES

The unbundling of the vertically integrated electrical utility into a multiplicity of transmission, distribution and generation companies will impact on system reliability and protection optimisation. Unless the overlapping protection and control issues are addressed in a formal way by the entities involved, protection co-ordination will not be optimal resulting in poor performance during network disturbances. In particular this relates to the protection settings applied on the generator units if no consideration is given to their effects on network integrity during fault conditions. As seen in Chapter 6, Section 6.2, generator protection and emergency control can have a major impact on minimising the impact of some disturbances.

8.6 CONCLUSION

The introduction of numerical technology and adaptive concepts to protection relaying will significantly enhance the functionality of SPSs as well as facilitating the introduction of new techniques for preventing and/or limiting the extent of disturbances. These future schemes will require extended processing and communication capabilities that are now becoming more readily available. The application of appropriate wide-area system protection will prevent widespread blackouts more effectively than previously achieved.

The major impediment at present to the more widespread adoption of such schemes appears to be cost – particularly the expense associated with the provision of broad-band telecommunications links. It is to be expected that such costs will reduce over time. Similarly adaptive relaying will become more widely utilised as the cost/benefit ratio decreases.

Finally the influence of utility reorganisation cannot be ignored. The relevant cross-boundary co-ordination issues must be addressed in order to achieve optimal system protection performance.

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9 CONCLUSIONS AND RECOMMENDATIONS

This chapter summarises the conclusions of the Working Group as described in earlier sections. The relevant chapters for the particular topic are shown in brackets. Finally guidelines on protection requirements to address system disturbances are described.

9.1 CONCLUSIONS

9.1.1 Causes of Disturbances (Chapter 3)

The survey performed by the Working Group indicated that the majority of disturbances arose from the loss of multiple network elements during normal operation of the system. Improved protection and control systems would considerably reduce the impact of such events.

More attention to the selection and application of relay settings, including adaptive features, would have reduced unwanted operations while increased relay availability through better maintenance or self-diagnostics would avoid failures to trip. The survey confirmed that fast fault clearance, particularly on busbars, is vital to a system's ability to ride through disturbances. Duplication of protection systems and the installation of circuit breaker fail provision is essential on critical busbars and on high voltage lines since back up operation times often resulted in system splitting and cascading. The application of adaptive protection schemes to cater for transient conditions without tripping on power swings, overloads, etc., appear to promise significant benefits. This will be more easily realised with the widespread use of numerical relays. As mentioned a number of times in this report it would avoid instances where relay operation while correct was undesirable.

Generator controls (e.g. AVRs) failing to operate correctly caused multiple unit trippings. Improved co-ordination between generator and network control/protection schemes, verified by dynamic system studies would be beneficial.

The response of control and protection devices to declining voltage should be evaluated with a view to achieving an optimal co-ordination e.g. transformer tap change control, motor protection, network under-voltage relay, etc.

The survey confirmed that no reasonable preventative actions could have been foreseen to avoid system failures caused by catastrophic events (earthquakes, extreme loads, multiple unit tripping, etc.).

9.1.2 Protection of Special Plant (Chapter 4)

Special regulating plant (PST's, IPC, etc.), series line compensation and HVDC links optimise electrical power transmission. More recently, developments in power electronics have led to the introduction of FACTS devices that provide significant operational support under both steady state and dynamic conditions. It is essential that associated protection and control do not reduce the availability of such systems. Evidence to date suggests that protection on these plants performs well and does not contribute to system disturbances. However the protection schemes require special attention to ensure that they best meet the particular requirements. HVDC links also may create difficulties for relaying on neighbouring ac lines if the SCR is low. The optimal solution requires special studies and is best addressed on a case by case basis. These concerns will also apply to the more recently developed linear power links using voltage source converters (VSC's).

9.1.3 Early Warning Systems – Preventive Actions (Chapter 5)

The systematic collection and analysis of protection performance data during both fault and quiescent conditions facilitate the identification of particular deficiencies in the overall protection schemes. Solutions or improvements can then be implemented. The quantification of protection behaviour by the application of performance indices enables the level of expected and acceptable performance to be established and to provide a benchmark against which it can be evaluated. Consequently the effectiveness of the protection systems is enhanced. Significant potential for the effective use of such data exists. It appears to be unrealised in many utilities.

Centralised schemes have been employed for many years in Japan to maintain transient and frequency stability. These System Stability Controllers (SSCs) acquire data from substations throughout the system relating to network status and power flow. Based on this information the SSC calculates the intervention necessary to prevent transient or frequency instability following a particular fault type. Such schemes are also employed to improve transient stability through generator shedding by precalculating the level of generation to be shed. In this case the schemes are operating in reactive rather than preventive mode.

A voltage security assessment technique using data obtained on-line from substations can be used to evaluate the available security margin for the network "Power-Voltage" characteristic. This enables operators to take corrective action and avoid disturbances evolving to a system collapse situation. Such a scheme is being implemented in France.

The blocking of OLTCs on HV/MV transformers will in certain circumstances prevent or delay voltage collapse. Reducing the AVR set point further enhances this effect. However the effectiveness of such schemes is heavily influenced by the type of network (level of meshing) and by load type (dependent or independent). Studies must be performed to predict the benefits for each application.

Phasor comparison techniques (as described in Chapter 6, Section 6.1.4.3) also lend themselves to preventive applications. The phase angle shift between nodes in the network can be used to monitor stability and indicate operator corrective intervention is required.

9.1.4 New Philosophies for Out of Step Protection and Network Sectionalising (Chapter 6.1)

New developments promise significant progress in ensuring effective sectionalising of a disturbed network. An example of such a scheme is the "Syclopes" development in France. Loss of synchronism is detected by phase measurement whereupon sectionalising at preselected nodes ensues. This is followed by appropriate load shedding in the affected zones until the situation is stabilised.

New techniques are being applied to older principles in the application of Out of Step Tripping and Out of Step Blocking (OST and OSB) devices. Through the use of sophisticated modelling the most appropriate location for sectionalising (i.e. the OST node) is determined. With such schemes it is essential that the OST and OSB settings on all relays, including embedded functions in distance protections, are correctly co-ordinated.

Wide area protection promises significant advances both in predicting and minimising the impact of disturbances. Few are currently in operation on any significant scale but efforts are being made to develop schemes that will be both realistic in scale and cost effective.

9.1.5 Co-ordination of Transmission and Generator Protection Systems (Chapter 6.2)

Generation plant significantly enhance the capability of power systems to curtail the escalation of wide area disturbances. Fast load wind-down allows a relatively smooth load transfer between generator units while measures such as auxiliary load reduction can be employed to momentarily increase output. The peaking capability of gas turbine plant can also assist in this regard. The use of fast-valving can be very successful in maintaining machine stability following a major loss of load or of transmission inter-ties. Other measures such as excitation boosting and braking resistor insertion are also beneficial.

The implementation of these measures requires close co-operation between generator plant and network operators. In the traditional vertically integrated utility this could be accomplished relatively easily. However, in the unbundled electricity supply industry structures common in many countries today the issue is more complex and the provision of such systems is likely to require specific contractual arrangements. These contractual issues, while outside the scope of this report, are crucial to the success of a co-ordinated response strategy for major disturbances.

9.1.6 Temporary Feeder Overloading (Chapter 6.3)

In many practical cases there is considerable potential for short-time overloading of transmission feeders. Use of this capability requires the concerted and co-ordinated actions of operators supported by real-time monitoring of the equipment or the ambient conditions.

It is recommended to supplement the standard feeder fault protections by the provision of thermal overload functionality; the trip characteristic can be made adaptive through communication with real-time line monitoring systems or with the system control centres. Experimental and theoretical work is required in the choice of heating and cooling cycle parameters of the EHV/HV overhead line and underground cable circuits to be used in the thermal models.

The settings of the standard fault protection functions must be closely co-ordinated with the short-time overload capability. In the case of the distance protection this must include safety margins to cater for load encroachment and correct phase selection during single phase faults.

Utilising short term overloading capability promises significant advantages for system operators under disturbed conditions. It is therefore expected that relay manufacturers will further refine the thermal overload functions currently available in the transmission line protection terminals, especially with respect to the modelling of EHV/HV cables and the incorporation of signals from the real time monitoring systems. Significant progress has also been made in adaptive relaying to facilitate the more efficient loading of transformers.

9.1.7 Under-frequency Load Shedding (Chapter 6.4)

Under-frequency activated load shedding schemes must take into account a number of factors that influence the response of power system.

- Nature of the network – islanded or interconnected.
- If interconnected the first step is to identify the points of sectionalising or islanding (see also Chapter 6.1).
- The load imbalance likely to arise within the sector (or complete island on an isolated network) and the likely spinning reserve carried; if very large generation deficits are likely then frequency derivative as well as under-frequency relays may be required.
- Impact of the load reduction ratio; this will influence the first stage frequency settings, the larger the ratio the greater the capability for frequency to stabilise without load shedding; reserves and operator intervention then restore normal frequency conditions.
- Provision of other measures to correct overload conditions
  - tripping of pump storage machines if pumping;
  - switch-in of shunt reactors to temporarily reduce voltage and consequently load. This allows more time for reserves to be effective.

Load shedding strategies vary between systems. To establish optimum load block sizes and under-frequency relay setting points simulation studies of network disturbances and their impact on frequency behaviour are necessary. Simulations should include the dynamic frequency and voltage response as well as allowing for the effect of the load reduction ratio and the spinning reserve response. Relay operate times are as low as possible consistent with security constraints. Typical values are 0.1s to 0.2s.

Over-shedding causes problems of over-frequency and system instability. A large number of small size frequency stages gives a superior frequency response. Its full implementation is rarely realistic on cost grounds however and the typical number of stages is four or five. As loads on distribution feeders vary with time of day, day of week and seasonally an ideal solution is rarely possible. Nevertheless with careful planning and implementation under-frequency load shedding provides an excellent tool to prevent system collapse. Numerous examples exist of their successful application on islanded systems.

Likely future developments in numerical devices will result in more sophisticated programmes where load shed is closely matched to the actual generation deficit. Furthermore with the more widespread use of broadband communication such schemes are likely to form part of overall system protection systems (SPS) that dynamically respond to disturbances. (See Chapter 8 also).

9.1.8 Under-voltage Load Shedding (Chapter 6.5)

Although introduced as a countermeasure against voltage collapse relatively recently, the number of such schemes in operation is increasing. It is to be expected that with operational experience the load shedding scenarios will become more sophisticated and effective (similar to the evolution of under-frequency load shedding). Solutions must be tailored for particular circumstances because the power-voltage characteristics vary significantly depending on network topography: remoteness of load from generation, availability of local reactive compensation, load characteristics and power demand

9.1.9 Autoreclosing (Chapter 6.6)

Autoreclose schemes significantly contribute to system stability and supply continuity. Differences exist between automatic reclosing modes applied by the various electric utilities. These tend to be dictated by the different power system configurations and the use of different technical and operational arrangements based on local experiences. However the primary objective of reclosing tends to be the same everywhere.

The advent of numerical relays has led to improvements not only in reclosing performance but also in reclosing reliability. The application of digital devices such as PCM current differential relays allows easy realisation of reclosing modes such as loop and preferential trip reclosing following disconnection of a circuit. Therefore the more widespread installation of numerical protection relays is desirable.

Advanced reclosing logics used in Japan already make use of segregated current differential and other digital protections and of the communication possibilities between line ends. Poly-phase reclosing is applied on double-circuit transmission lines. Preference trip reclosing is applied to impedance grounded systems and its purpose is to avoid double-circuit tripping during multiple faults on parallel circuits using three-phase circuit breakers. Time co-ordination with ground back-up protection is required.

Adaptive reclosing that differentiates between transient and permanent faults promises a major improvement in autoreclose success rates. Various techniques are used such as neural networks based schemes utilising the induced voltage on the faulted phase or fault generated high frequency currents that indicate restrikes. Prototypes have been successfully tested. While such developments are not widely implemented at present numerical technology should hasten their more widespread application on transmission systems. Another aspect that warrants consideration is the behaviour of reclosing when circuits are incorrectly tripped during external faults; the reclosure of such healthy lines would be beneficial and it is to be expected that suitable algorithms can be developed.

9.1.10 System Restoration (Chapter 7)

Analytical models improve the success probability when resynchronising separate power sectors. Laboratory tests have confirmed the suitability of the simplified analytical models developed in Japan. It is intended to include already developed plant models into this program and if found permissible to do so, reduce the settings on the synchronising equipment.

Auto-synchronising systems to re-parallel an islanded power sector are being developed. Inter frequency differences are adjusted through controlling generation and load. Voltage differences are adjusted through controlling shunt capacitors, shunt reactors and reactive power of generators in order to automatically establish permissible paralleling conditions.

When generation on an islanded system has been lost frequency stability can be maintained through frequency activated load shedding. Furthermore load can be rapidly restored through the use of frequency activated restoration schemes. An essential prerequisite to the success of such systems is that their design is tailored to best suit the particular network.

While under-voltage load shedding is becoming more common, automatic under-voltage activated reconnection of circuits is rare.

9.2 RECOMMENDATIONS

The following is a general guideline to ensure that protection schemes behave in an optimal way to minimise the impact of power system disturbances. Essentially two requirements should be targeted:

- The availability of protection schemes is maximised
- The arrangements and settings applied on protection schemes throughout the power system are co-ordinated to the greatest extent possible.

This minimises the risk of slow cleaning faults and even if such an unlikely event occurs the co-ordinated approach reduces the likelihood of cascade tripping.

9.2.1 Protection Availability:

The availability of protection systems can be improved by:

- A well planned regime of <u>preventive maintenance:</u> Users should decide on the optimal frequency of testing for the protection equipment. In this regard older equipment will require a greater frequency than modern numerical designs using self diagnostics.
- Maximum use of <u>self diagnostics</u> in relaying; testing will still be required however to verify circuit breaker operation and reclose cycles.
- Extensive <u>analysis of network and protection fault records</u> to identify areas for improvement based on relevant performance indicators; this approach will obviously influence if not determine maintenance programmes.

- Enhanced performance of critical busbars and circuits; protection should be provided on all major busbars; critical circuits should be equipped with duplicated protection and breaker fail protection

9.2.2 Protection Co-ordination:

Co-ordination refers not only to the grading of time/current/zone-reach, etc. on plant protection but also includes the co-ordination of protection/control schemes across generation, transmission and distribution systems:

- Feeder Overloading: Distance and over-current protection should be set so that they never trip during temporary overload conditions. To cater for excessive overloading, devices having a thermal overload characteristic should be applied. The advent of relays having adaptive settings also provides a solution whereby under certain conditions overloads are permitted for a preset time.

- Co-ordination of control and protection between generation and networks: A number of facilities exist or can be provided on generating plant that significantly help to maintain system integrity during disturbed conditions.
    - Fast wind-down avoids sudden load rejection.
    - Fast valving (early valve actuation) avoids generation tripping during severe network faults and improves post fault stability.
    - Peaking operation in gas turbine stations (can contribute up to 10%).
    - Temporary excitation system boosting; rationale here is similar to that for temporary feeder overloading; it is particularly useful in preventing voltage collapse.
    - Breaking resistor insertion is useful in stabilising a unit following sudden load rejection.

  The relationship prevailing in the industry between the various stakeholders (i.e. transmission owners, generators, regulators) will have an important impact on how these facilities are deployed.

- Network Sectionalising: When curtailing disturbance escalation by sectionalising the system it is essential that the sectionalising points predefine the islanded network. This is important in order to achieve rapid islanding of the disturbed sector. Based on comprehensive computer based simulation studies the appropriate sectionalising nodes can be identified. Out of step tripping and blocking relays can then be deployed. It is essential that out of step functionality on distance protection should block and that the applied settings correctly recognise any power swings likely to occur in the particular network. Experience has shown that out of step relays in the past failed to identify a power swing because the swing frequency was lower than that set on the relay.

  Methods of sectionalising, currently being developed using phasor comparison techniques, avoid these limitations but are not yet widely used.

- Under-frequency load shedding can rapidly stabilise frequency within an islanded network. The scheme should be carefully designed for the particular system characteristics so that over-shedding is avoided to the greatest extent possible. In fact with conventional relays an exact load/generation match is unrealistic and the objective is to achieve the best compromise possible.

New relays promise more exact generation/load match as they directly monitor generation deficit and adapt the load shedding block accordingly.

- Under-voltage load shedding is a more recent development but is essential to arrest voltage collapse if all other measures have failed. Exact arrangements must be tailored to the particular network conditions. Centralised schemes that identify the security margin available on the PV characteristic of the transmission circuit are more sophisticated but at any early stage of development.

- Autoreclosing makes a significant contribution to preserving system stability. It should be applied to the greatest extent possible. In some cases this will only be possible using end to end communication (e.g. loop reclosing). Polyphase reclosing is also beneficial to cater for multiple faults on double circuits.

  Reclosers using adaptive techniques to identify arc extinction promise significant advantages and should be considered.

- Systems Restoration is typically an operational rather than a protection function. However, some utilities have benefited through the provision of automated restoration systems. Chapter 7 discusses auto synchronising systems to reparallel islanded networks as well as schemes to restore distribution feeders on rising frequency and voltage.

- System Protection Schemes (SPS) continue to play a role in minimising disturbances. Initially they tended to be tailored to particular network requirements. More recently, wide area protection (WAP) schemes are being developed that are more generic in application. For more details on such systems refer to Chapters 5 (Section 1), Chapter 6 (Section 1), Chapter 8 and associated references.

APPENDICES

Appendix 1

ESKOM experience with power swing blocking and tripping relays during a major disturbance on the 7 June 1996.

1. Introduction

About 90% of generation and a major portion of the load on the ESKOM Power System is located in the North – Eastern part of the country. The Koeberg nuclear power station (2000 MW) supports the load in the South – Western part of the country (Cape Town area) and is some 1500 km distant from the major generating centre. The Cape load and generation is strongly interconnected with the "main generating area" via 765kV and series compensated 400kV line circuits. However the potential exists for the development of dangerous power swings when this interconnection becomes weak. The philosophy applied to protect the interconnection against unwanted separations and out-of-step conditions is to:

1. block all distance relays against unwanted operation during stable or unstable power swings and
2. install OST tripping relays to detect an OST condition and sectionalise the power network into sustainable islands.

Dynamic simulation studies were conducted for most probable scenarios that could lead to system instability. Based on the results the best locations for installation of OST relays were determined in terms of ease of monitoring and controllability. The highest swing frequency was established at 1.2Hz and all power swing relays were set accordingly.

2. Instability incident on the 7 June 1996

The conditions that led to a major disturbance on the 7 June 1996 (see Section 2.1.3) were not considered during simulation studies as probable (loss of two 765kV and two 400kV interconnecting lines). Consequently, the locations of OST relays were not adequate for the power swing that occurred. The relays were situated much too close to Koeberg power station and were unable to detect the swing. None of them operated during the incident that resulted in three unstable swings before islands separated, exposing transmission equipment and customers to severe voltage oscillations for 3 seconds.

During the first unstable swing (~1Hz frequency), the apparent zero impedance locus fell into the zone 1 protection characteristics of three parallel lines. Two of them were equipped with digital protection and one with phase 2, electronic relays. The digital relays used rate of change of measured resistance (dR/dt) for power swing detection. Settings were calculated to block swings of frequency below 1.2Hz based on the "classic" theory of the power swing locus traversing the X/R plane. The actual rate of change of the resistance was higher and the relays on both lines issued trip commands and initiated ARC sequence. See figure A1.1 below.

The electronic relays measured the impedance rate of change (dZ/dt) using modified MHO characteristics and were able to block the tripping elements effectively.

After tripping of the next two lines the interconnection was maintained by one 400kV line that did not trip. Swing frequency increased from 1Hz to 1.85Hz and the apparent zero impedance locus moved closer to Koeberg. With the higher swing frequency than 1.2Hz none of the distance relays were able to block and the system separated after zone 1 tripping of another three lines closer to Koeberg. See figure A1.2 below.

Once the impedance locus moved closer to Koeberg it entered the tripping zones of OST tripping relays. The relays however could not detect OST condition, as the swing frequency was already too high.

Imprecise co-ordination between power swing blocking elements resulted in prolonged OST conditions and tripping of more than the necessary number of lines which made restoration more difficult. The premature tripping of two 400kV lines during the early development of the swing almost led to a much more extensive disturbance. This would have resulted in an additional 1500MW of load shedding – assuming it was possible to maintain stability in the island at all.

After the incident ESKOM reviewed design and application of OST tripping relays in conjunction with blocking of impedance relays. New dynamic simulations studies were conducted. The OST relays were relocated and re-set to cover the widest possible area yet still ensure satisfactory active power balance and stability within islands after separation. New firmware versions were requested for digital relays having a wider setting range for dR/dt in order to ensure adequate blocking.

3. Conclusions

The analysis of the above incident highlighted issues that are important for the correct co-ordination between power swing blocking elements of distance relays and the OST tripping system which is applied.

1. Linear models to determine settings of power swing detecting elements becomes progressively more inaccurate with the growing application of FACTS devices and faster controlling capabilities of generating units. For more precise settings, dynamic simulation should be used.
2. Dynamic simulation studies used to determine location of OST tripping relays should cover as many scenarios as possible in order to ensure that applied tripping systems will not fail in any situation while distance relays are effectively blocked.
3. It seems to be beneficial to set power swing blocking elements of distance relays to a certain swing frequency above which blocking will not be effective. In case of unstable conditions and OST tripping scheme failure (particularly where transfer tripping is utilised) the system separation can still be achieved by the distance relays as the swing frequency tends to increase.
4. The same swing frequency used for the setting of blocking and tripping relays ensures that system separation, where necessary, will be achieved in all possible conditions either in a controlled way via OST tripping or less controlled via operation of distance relays.
5. Co-ordination of power swing detection elements that are using different principles is difficult and always leaves an area of uncertainty as each swing condition may be different. In such cases the results of dynamic simulation

studies and recordings of previous unstable conditions should be used in support of setting calculations.

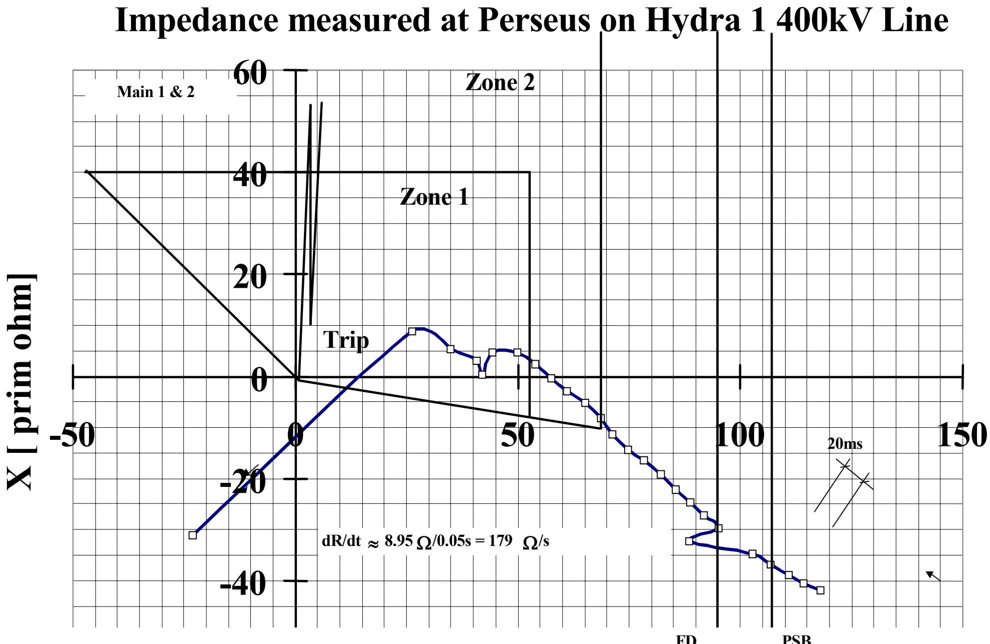


Figure A1.1: Higher dR/dt than setting resulting in zone 1 tripping of two 400kV lines. (Persus, Hydra are 400kV substns.)

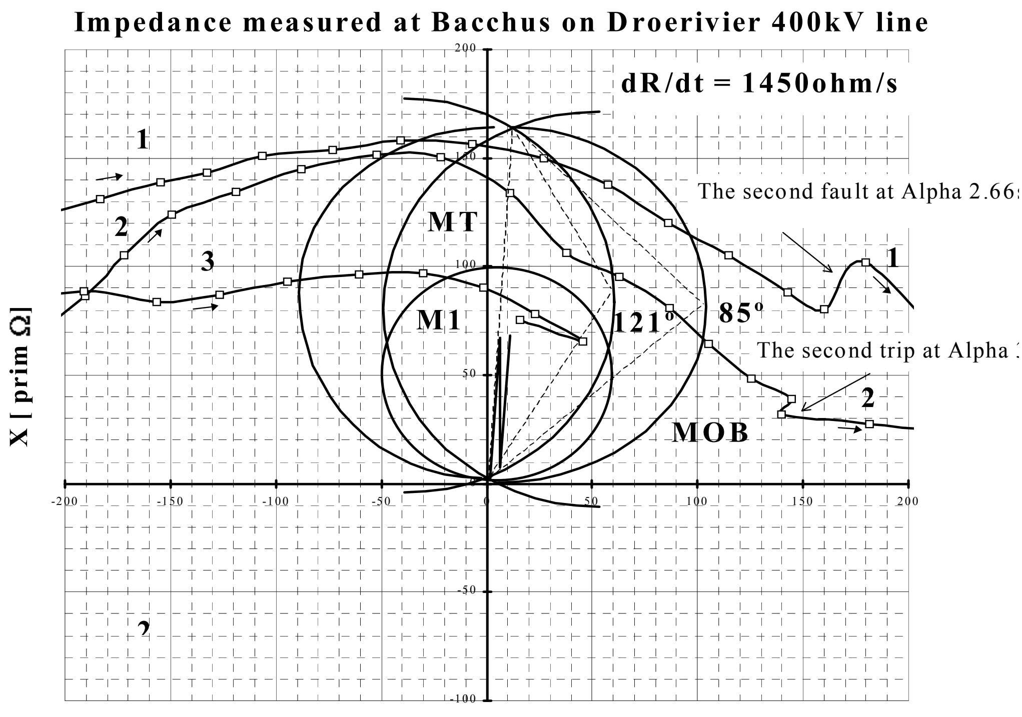


Figure A1.2: Higher dR/dt than setting resulting in zone 1 tripping of third 400kV line. (Bacchus,Droerivier are 400kV substns; Alpha is a 765kV substn.)

Appendix 2

EXPERIENCE WITH DRS RELAYS

Chapter 6, Section 6.1.4 refers.

Due to its mode of operation, under certain circumstances the DRS relay may incorrectly interpret a short-circuit as a power swing. The relay monitors the envelope of the voltage waveform. Swings are identified by detecting at least ten successively decreasing half cycles followed by four increasing ones. However if the lower point of the voltage oscillation comes below a set threshold, this oscillation can be added to the number of swings needed for the relay to trip. To avoid misidentification of a short-circuit as a power swing, there must be at least four decreasing half cycles above the threshold setting, otherwise the relay ignores the dip as being an indication of a power swing.

Some years ago a short-circuit occurred on a Spanish 220kV line near the French border. The single-phase fault evolved to double-phase in 3.5 cycles and was cleared in 8 and 9 cycles respectively by the line end relays. The voltage seen by the DRS on the nearby 400kV interconnection line was as follows: progressively decreasing during 18 half cycles, it crossed the set threshold between the 16th and the 18th half cycle, and started to recover during the open-pole dead time. The relay understood this as a power swing and, set to trip on detection of the first swing, tripped the interconnection as expected.

A possible modification of the relay was considered: adding under-voltage units to independently detect short-circuit voltage dips. In the meantime, the relay was provisionally set to trip on detection of the second power swing.

Appendix 3

Typical Under-Frequency Load Shedding Settings

The following briefly summarises the under-frequency load shedding regimes applied in a number of countries to arrest frequency collapse.

<u>Sweden</u>

In the southern regions of Sweden load shedding is implemented as follows. Auxiliary plant are individually equipped with the appropriate frequency relays to trip as required while frequency activated schemes are provided in the substations to shed customer load.

Frequency (Hz)	Action	Comment
49.4 for 0.15 sec	Trip boiler/heat pump, P > 35MW	
49.3 for 0.15 sec	Trip boiler/heat pump, 35MW>P>25MW	
49.2 for 0.15 sec	Trip boiler/heat pump, 25MW>P>15MW	
49.1 for 0.15 sec	Trip boiler/heat pump, 15MW>P>5MW	
48.8 for 0.15 sec		
48.6 for 0.15 sec	30% of load	
48.4 for 0.15 sec	disconnected in 5	
48.2 for 0.15s & 48.6 for 15s	equal step sizes	
48.0 for 0.15s & 48.4 for 20s		

Reconnection is controlled by the system operator i.e. auto-restoration is not permitted.

<u>Portugal</u>

<u>Substations without Automatic Telecommand Remote Units (ATRU) and Numerical Command and Control Systems (NCCS)</u>

Underfrequency relays are set at eight different frequencies. Each setting is associated with one group of MV feeders. When the underfrequency relay operates, tripping of the associated feeders is instantaneous. High priority feeders are excluded. Maximum load to be shed is 58.5%. All the shed feeders are reconnected on instruction from National Control Center once the frequency stabilises at nominal value (50Hz).

<u>Substations with ATRU and NCSS</u>

Underfrequency load shedding in these substations operates similarly to that already described. The difference is related to the restoration process. After the permission given by the National Control Center the MV feeders are reconnected in individual sequence if conditions permit (e.g. live-bus/dead-line conditions prevail).

The introduction of an interruptible load tariff for large consumers is proposed.

Frequency (Hz)	**Action**	**Comment**
49.5 to 49.1	Pump storage cease pumping	
49	Shed 17.5%	
48.9	Shed 8%	
48.8	Shed 7%	
48.7- 48.6	Shed 4%	
48.5 – 48.4	Shed 11%	
48.3 – 48.2	Shed 6%	
48.1	Shed 3%	
47.9	Shed 2%	
47.5	Power plants trip on under-frequency limit	Not all plants may trip

<u>Spain</u>

In the Spanish peninsular system load shedding of 50% connected load is implemented as follows.

Frequency (Hz)	**Action**	**Comment**
49.5	50%Pump storage cease pumping	
49.3	50%Pump storage cease pumping	
49.0	Shed 15%	
48.7	Shed 15%	
48.4	Shed 10%	
48.0	Shed 10%	

Ireland

A number of frequency activated measures employed prior to load shedding. Total load shed is 65% and all shed load is auto-restored.

Frequency (Hz)	Action	Comment
49.98	Gas Turbine units to peaking	2 Designated Units
49.9	Auto-restoration commences	
49.8 – 49.0	Pumped Storage:	
	Pumping Mode: Trip pumps	
	Generating Mode: To full output automatically	
	Standstill Mode: Auto synchronise & full output	
49.25	Auto switch-in of 40kV reactors	Momentarily reduces load
49.3	Interruptible tariff customers tripped	During 8 – 23hrs.
48.5	Shed 13%	
48.4	Shed 13%	
48.3	Shed 13%	
48.2	Shed 26%	
48.0	Northern Ireland interconnector trip	
47.5	Coal fired generating units trip	
47.0	Other steam/hydro units begin to trip	
46	Combustion turbines trip	

Comment

From the setting detailed in the tables it is obvious that under-frequency is used to perform a number of emergency actions before load shedding is initiated: generator auxiliary trip, reactor switch in, pump storage activation, interconnector trip. Only in Ireland is a scheme employed that, based on frequency recovery to a set value, restores 100% of load shed. While a frequency activated restoration scheme is instaled in Portugal it has not operated due to the fact that an under-frequency condition has not arisen.

Appendix 4
Insulation Recovery

Insulation Recovery Time following Fault Current Interruption

At the point of fault the air is ionized by the fault current. Furthermore following current interruption residual ions continue to exist in the former arc path. The time required for extinction of those residual ions is referred to as “insulation recovery time”. The insulation recovery time determines the recloser dead time. It is generally longer at the higher system voltages and for larger fault currents as shown in Fig. A4.1.

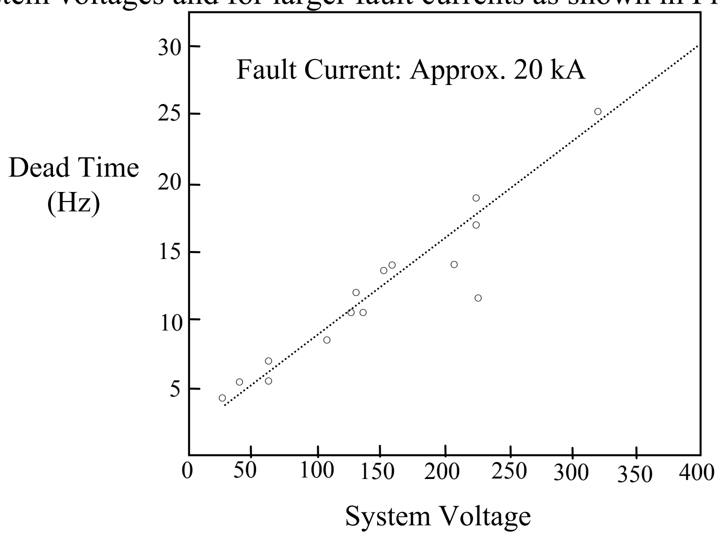


Figure A4.1: System Voltage and Insulation Recovery Time

(Source: Protection and Control System for Power System, Volume V)

Secondary Arc Extinguishing Time

If the faulted phase is opened on a line equipped with single-phase or polyphase reclosing, voltage is induced in the faulted phase both by electrostatic induction due to capacitive coupling (Cm) to the healthy phases voltages and by electromagnetic induction due to interphase mutual inductive coupling with the healthy phase currents.

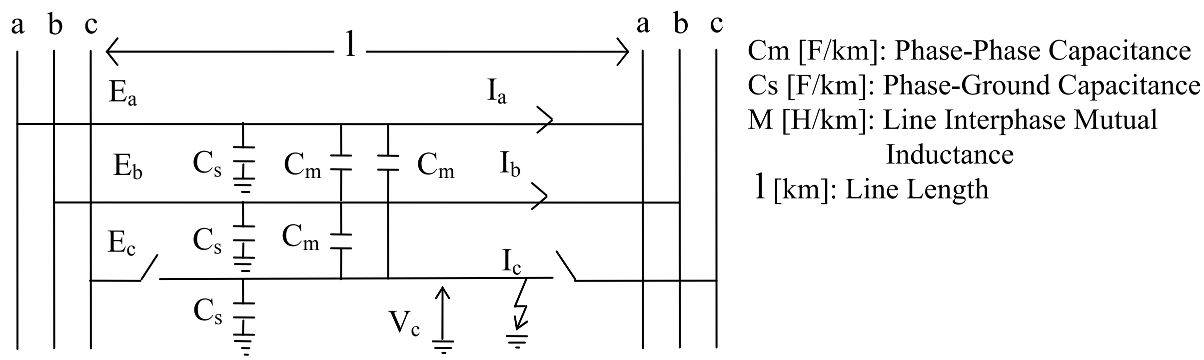


Figure A4.2 Electrostatic and Electromagnetic Coupling on Single-Circuit Single-phase Reclosing

The electrostatic (capacitively) coupled voltage, Vc, induced in the faulted phase following opening of the circuit breaker pole is calculated using the following expression:

$$Vc = \frac{Cm}{Cs + 2Cm}(Ea + Eb)$$

The value of Vc increases with increasing system voltage and a phase to phase capacitance; it also increases with reducing phase to ground cspacitance. The electromagnetic coupled voltage Vm is obtained using the following expression:

$$Vm = j\omega M(Ia + Ib)$$

Vm is zero for a fault in the middle of a line and maximum for a fault at the ends. The sum of these two voltages is applied to the faulted phase. The resultant is referred to as a secondary recovery voltage. It causes tens of amperes of current to flow at the fault point where residual ions exist. This current is referred to as secondary arc current. The secondary arc current generated by the electrostatic coupled voltage Ic is obtained using the following expression:

$$Ic = j\omega Cm \bullet \ell \bullet (Ea + Eb)$$

It increases in proportion to the line length and the system voltage.

From the above results, for the 500 kV systems in Japan, the dead time as shown in Table A4.1 is required for the arc ion extinguishing time.

Table A4.1 Necessary Dead Time for 500 kV Systems

Reclosing Type	75 km	150 km
Single-circuit Three-phase	30 to 35 Hz	30 to 35 Hz
Single-circuit Single-phase	30 to 35 Hz	40 to 45 Hz
Double-circuit Polyphase	35 to 40 Hz	50 to 55 Hz

(Results of Study Using System Model)

Appendix 5

Sleet Jump Simulation

Tests to evaluate the effects of sleet jump on power lines are summarised in the following results. Chapter 6, Section 6.6.4.4 refers.

The expected "elapsed time" influences the selection of the most appropriate dead time for autoreclosing. The configuration of the conductors is important. Horizontal arrangements are unlikely to be affected while vertical phase spacing is directly impacted.

Appendix 6

Comparison of Analytical and Test Results using a Power System Simulator

Tests were conducted on an AC-DC power system simulator, developed by CRIEPI, Japan, to establish conditions of stability during synchronising. The test model represented a 100 kVA nuclear generator having outputs of 62 kW and 88 kW which was connected to an infinite bus for different phase and frequency differences. Figure 7.1 in Chapter 7, Section 7.2.4 shows the system and power flow conditions for this simulation. Simplified governor and exciter models were included in the generator model.

Results from Tests and Simulation

Results from analysis and tests have revealed the following features.

1. Comparison of stable operation region

Figures A6.1 and A6.2 compare results, from both tests and simulations, of the stability limit for generator outputs of 62 kW and 88 kW after paralleling. They are seen to agree well.

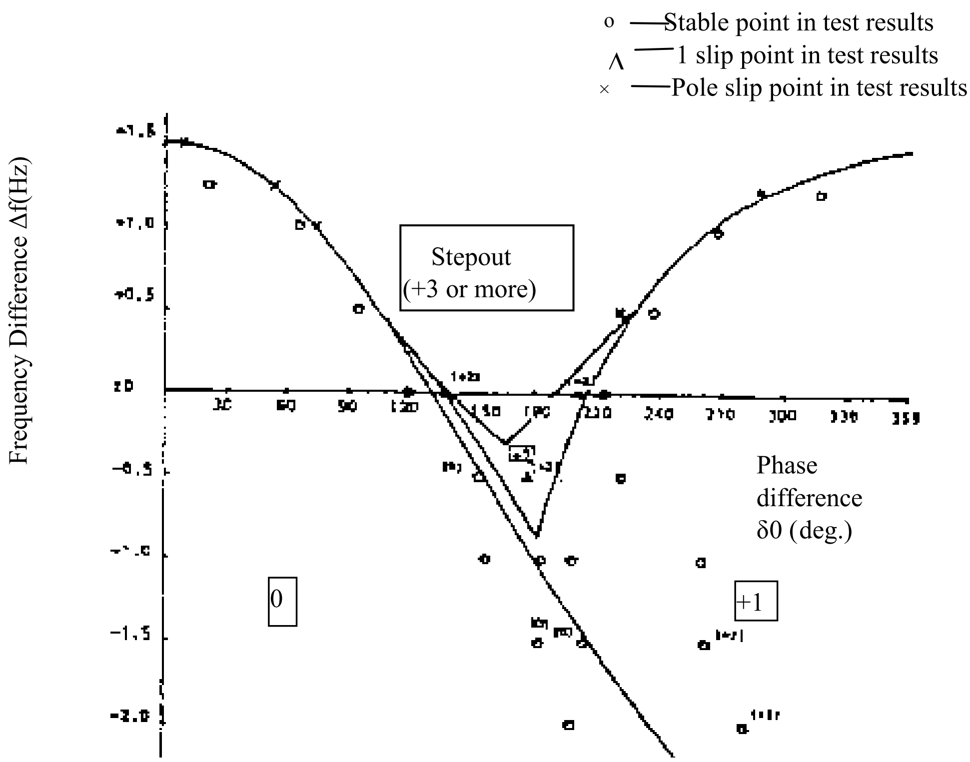


Figure A6.1 Comparison between Test and Analytical Results (Generator Output: 62 kW)

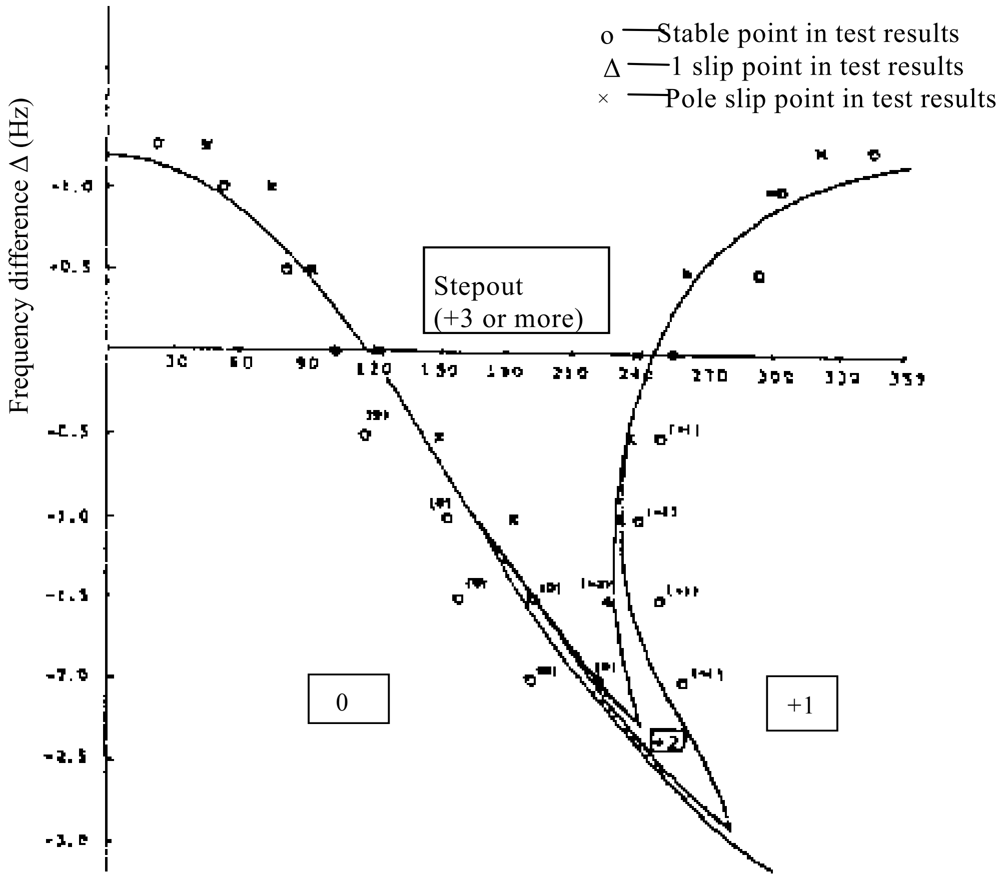


Figure A6.2: Comparison between Test Results and Simulation Results (Generator Output: 88 kW)

The stable equilibrium point in these figures is shown in FigureA6.3.

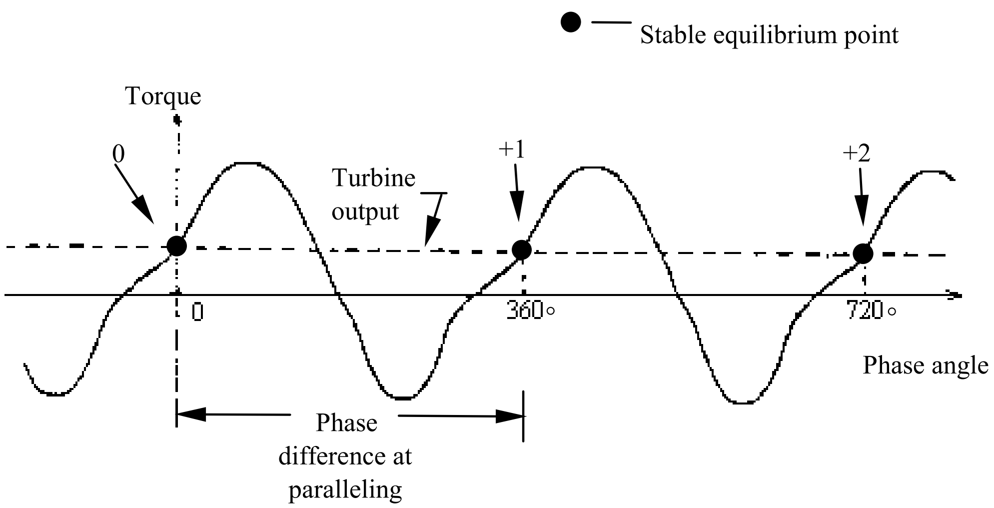
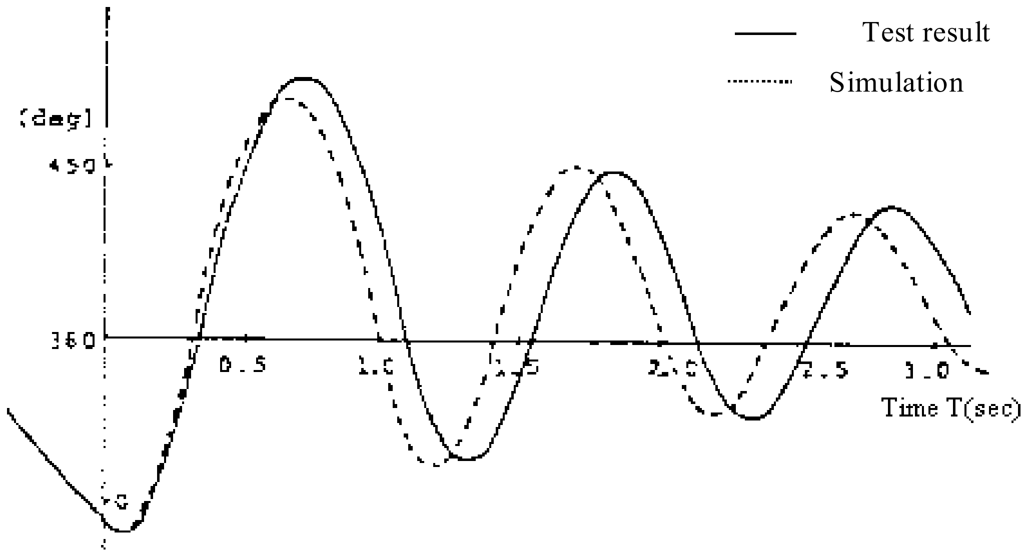


Figure A6.3: Stable Equilibrium Points after Paralleling

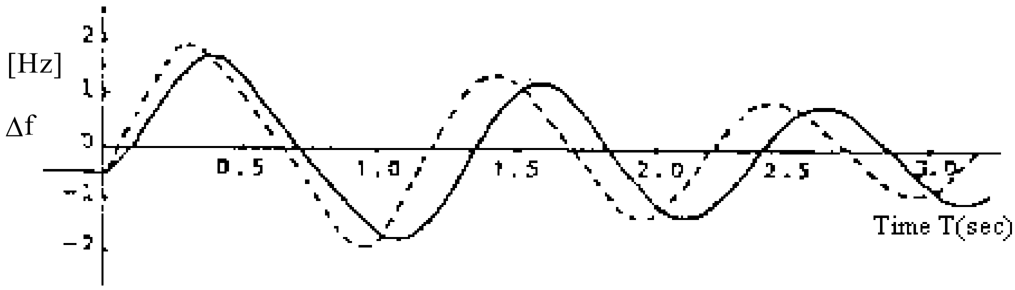
These figures indicate that following the paralleling of a loaded generator:

- All pole slips are in the form of acceleration.
- A wider area is stabilised after paralleling if the generator frequency is lower than the system frequency.

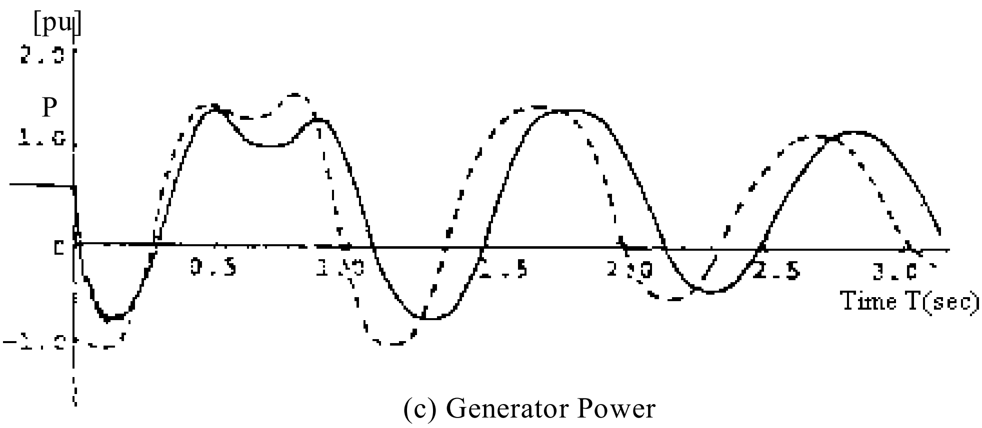
Over a range from small positive to negative frequency difference the generator is able to reach stable equilibrium after several pole slips.



(a) Generator Phase Angle to Infinite Bus



(b) Frequency Deviation



(c) Generator Power

Figure A6.4: Comparison between Test and Simulation Results
(P = 62[kW], Δ f = -0.5[Hz], $\Delta\theta$ = [+221 ^{o}])

Possible reasons for these characteristics are (see also note below on governor free turbine operation):

- Paralleling a loaded generator influences strongly the torque-phase angle curve after paralleling; when the generator frequency exceeds the system frequency the initial torque and acceleration energy is larger, resulting in acceleration pole slip.
- Effects of AVR and governor, especially the latter, are significant. If the frequency difference is negative the generator speed increases after paralleling in order to coincide with the infinite bus frequency. Since the governor is operated in governor-free mode in the simulator tests, turbine output is decreased by the governor after paralleling. This is reversed in case of positive frequency difference and the output of turbine increases after paralleling. The system is more likely to be stabilised with negative frequency difference for this reason.
- Furthermore after paralleling with a large positive value of frequency difference, the increasing turbine output makes synchronisation after a pole slip less likely and accelerated pole slipping results.

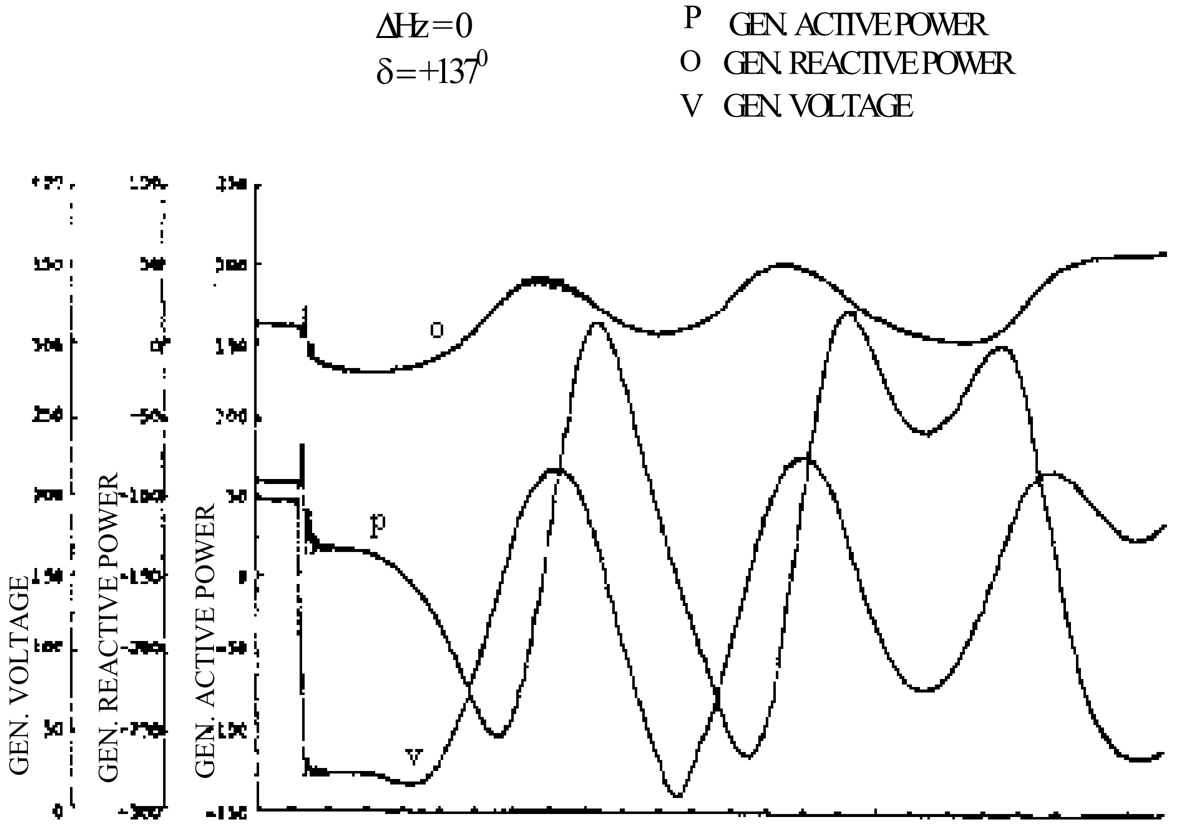


Figure A6.5: AC Component Change at Test (P = 62[kW], Δf = 0[Hz], Δθ = +137[deg])

2. Comparison of waveforms

Figures A6.4 (a), (b), and (c) show the measured values between generator and infinite bus of phase angle, frequency and electric power, together with results obtained by analytical simulation for a generator output of 62 kW. For both cases the initial frequency difference was –0.5 Hz, and the initial phase difference was +221 degrees. Fairly good agreement is shown between these results.

Figure A6.5 shows AC component changes in generator electrical power for a frequency difference of 0 Hz and a phase difference +137 degrees. The attenuation time constant of electric power is as short as 0.05 second.

<u>Note on Governor-free operation</u>

When the generator operates in governor-free mode prior to system separation, the governor control signal is adjusted to maintain turbine output at steady state after separation as follows:

$$Po = P_{So} - KSgo$$

Where Po: Steady state turbine output after separation i.e. prior to resynchronising
P_{So} : Governor demand (control signal)
K: 1/Frequency droop
Sgo: Deviation of speed
$\Delta f = fg - fs$, the presynchronising difference between generator (fg) and system (fs) frequencies.

Governor response is then given by

$$P_{So} = Po + KSgo$$

Therefore, the governor acts to lower turbine output when the generator pre-synchronising speed is lower than rated ($\Delta f < 0$, $Sgo < 0$), and conversely to raise turbine output when the pre-synchronising speed is higher ($\Delta f > 0$, $Sgo > 0$). Accordingly, when paralleling islanded systems with different frequencies, the output of the generator in the islanded system with lower frequency before the paralleling will decrease while that of the islanded system with higher frequency before the paralleling will increase after paralleling.