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HARMONISATION OF PROTECTION POLICIES FOR POWER STATIONS AND GENERATORS AND OF PROTECTION POLICIES FOR HV NETWORKS

Working Group 01

Of

Study Committee 34 (Protection)

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CIGRE

SC 34

HARMONISATION

OF PROTECTION POLICIES FOR POWER STATIONS AND GENERATORS

AND

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REPORT PREPARED BY W.G. 34.01

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- F O R E W O R D -

-1ST PART-

THE EFFECTS OF HV NETWORK FAULTS AND SWITCHING OPERATIONS
ON LARGE TURBINE GENERATORS

-2ND PART-

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TO SEPARATE THE GENERATORS FROM THE NETWORK
UNDER ABNORMAL CONDITIONS OF VOLTAGE, FREQUENCY, OR OTHER

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F O R E W O R D

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System planning, operation and control become more and more difficult. That is due to four main reasons:

- electric supply plays a leading part in the life of modern society, so a large disturbance and, obviously, a black-out can be serious for the whole community (interruption of any activity, loss of money for the manufacturer, risk of disturbing the public security in large cities...);

- increasing dimensions of the system components and use of new technics (mainly nuclear power) are reasons why system disturbances can have very large financial impact for the utility (repairing of damaged system components; starting, as a back-up, of expensive units...);

- reciprocal actions between network and generating units are more and more intricate, so system operators have less and less margin;

- loading of generating and transmission facilities up to their critical limits due to postponed realisation of these facilities.

So we can easily understand why utilities have done and are doing their best to implement any means that can be considered (regarding both expenditures and technical feasibility) in order to prevent, detect, solve critical and dangerous situations.

The corresponding means must be searched for in the planning stage (system lay-out, generation sites selection...) and during the design of the system components (mainly generating units). These preventive means are to be accompanied by curative means, such as protective devices and automatic systems able, in real time, to detect and to solve critical and dangerous situations or, at least, to minimize adverse effects of disturbances.

This report is mainly dealing with the second type of means (curative ones); so this report:

- analyses what are the critical and dangerous situations that can appear on an electrical system (local disturbances, such as short circuit, and global disturbances, such as frequency drop, as well);

- examines, with regard to general principles, protective devices and automatic systems which enable them to perform corrective actions in accordance with basic goals (such as rapidity, security, selectivity);

- looks for the possibilities for harmonization of the protective devices of the generating units and of the components of the network; this to minimize the adverse effects of disturbances for the system as a whole.

This report has four parts that are more or less self-sufficient. The first three parts are dealing with the means helping to solve a critical or dangerous situation. The last part is dealing with the means helping network restoration.

- The first part is mainly treating fatigue and stresses of turbine generator shafts induced by network faults, switching operations and abnormal operation conditions.

- The second part examines criteria and equipments for isolating, in case of disturbance, generating units from the network. This part takes also into account the case of out-of-step operation of one unit.

- The third part is mainly dealing with disturbances that can affect an electrical system considered as a whole. So this part examines criteria for detecting situations that are potentially dangerous and states the means to be used to stop the evolution of such a situation. This part also takes into account the case of out-of-step operation between parts of a network.

- The fourth part examines the means enabling operators to perform a fast network restoration after a black-out. This kind of study is necessary because a network collapse must be considered as possible, since choices are always made to balance safety and expenditures (that means that the preventive and curative means to avoid a black-out cannot be absolute).

It is necessary to point out, as it is done all through the report, that, in almost all the cases, a compromise has to be reached:

. between minimizing the adverse effect of a system disturbance on generating units (meaning that units should be separated very quickly from the network),

. and causing an additional disturbance to the overall system if an excessive amount of power is removed from the system.

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1 ST PART

THE EFFECTS OF HV NETWORK FAULTS AND SWITCHING

OPERATIONS ON LARGE TURBINE GENERATORS

CONTENTS

1. INTRODUCTION

The power generating units and the transmission network operate as an interactive system. Faults and switching actions in the network cause electrical system transients which stimulate torsional oscillations along the turbine generator shaft.

In the past, the generator three-phase terminal short-circuit was considered as the most critical mechanical stress condition for the turbine generator unit.

Intensive investigations of torsional stress, established that even higher stresses can occur on certain network faults and switching actions and that the turbine generator shaft is endangered by plastic deformation and by cumulative fatigue damage and consequential reduction in life expectancy. This problem has gained considerable importance with the growing size of turbine generators and the increasing power system short-circuit capacity.

Further, subsynchronous resonance and subsynchronous pulsating electrical components can cause long lasting low amplitude shaft vibrations which may be cumulative and cause dangerous loss of fatigue life.

As concerns system operation and protection a conflict situation is obvious and asks for a balanced solution.

On the one hand, when necessary, one should trip the generating unit as fast as possible on occurrence of a network disturbance and reduce the amount of switching actions to save life-time of the turbine generator shaft.

On the other hand, one should keep the power generating units as long as possible on the system to maintain stability and continuity of the power supply. But, one would have to accept certain risks of plastic deformation of couplings and shafts and of shaft fatigue in this case.

From the protection point of view, one should increase the speed and dependability which could imply some loss in security.

The synchronizing check conditions should be made more secure (smaller angle, lower voltage difference).

This however implies a certain risk to the system integrity due to possible:

- loss of generation and transmission facilities,
- blocking of resynghroniza tion of generation,
- blocking of auto-reclosure of transmission facilities.

2. TURBINE GENERATOR TORSIONAL STRESS PROBLEMS

2.1. BASIC PHENOMENA /5, 14, 19/

The torsional stress problems of TG shaft are caused by:

- sustained subsynchronous pulsating electrical components in the network or subsynchronous resonance,
- faults and switching actions in the network,
- out-of-step conditions.

The stress problems can be qualified as:

- possible loss of fatigue life,
- possible occurrence of high torques.

If the stress conditions last too long or occur too frequently, considerable expenditure of life time or even damage to the TG shaft could be experienced. Two instances of TG shaft damage due to subsynchronous resonance have been reported /10/.

Due to the high inertia of the generator and turbine rotors of thermal units and the low damping of low frequency oscillations, shafts are susceptible to excitation of low frequency.

Turbine blades could be susceptible to excitation of higher frequency oscillations (100/120Hz) /32/.

Problems of torsional stress are most important for big thermal generating units, whereas hydro generating units are equipped with turbines with higher stiffness of the shaft and of relative small inertia of the rotor in respect to that of the generator.

For thermal units, the critical size for the described problems seems to be about 500 MVA and higher.

This is due to the fact that:

- for generators of such large size, the stresses at rated power are high because of the increased density of current and flux,
- the stiffness of the shaft decreases with growing machine size because increasing of the rated power by enlarging of the dimensions of generating units can only be achieved by increasing the length of the shaft,
- these large units are connected to HV network of high short-circuit power.

2.2. INITIATING PHENOMENA

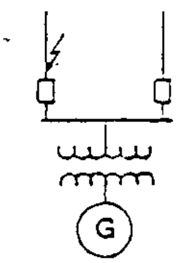
The impact of all operating disturbances can be categorized in terms of the number of successive electrical (air gap torque) transients /14/:

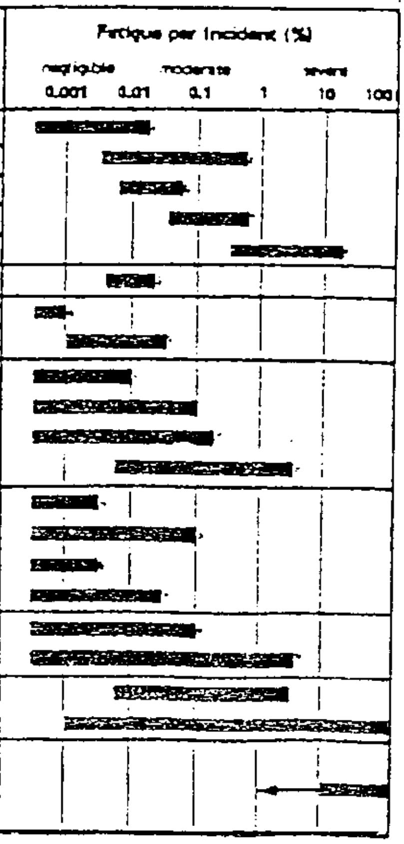
Class 1 - Single torsional excitation
Class 2 - Double torsional excitation
Class 3 - Multiple torsional excitation
Class 4 - Torsional resonance

A typical quantification of the impact of the different fault conditions and switching operations on the torsional fatigue of steam turbine generator shafts is given in the following Table (from CIGRE Paper 11-06, 1980).

TABLE I

Class	Fault Conditions and Switching Operations			
Class 1 Single Torsional Excitation	Phase - to - Phase Unit Short Circuit	High-Voltage Side (System Bus)		
		Low-Voltage Side (Gen. Leads)		
	Three-Phase Unit Short Circuit	High-Voltage Side (System Bus)		
		Low-Voltage Side (Gen. Leads)		
	Faulty Synchronizing	90 °C ≤ δ ≤ 120 °C		
	Full-Load Rejection			
	Normal Line Switching	ΔP ≤ 0.5 p.u.		
		ΔP > 0.5 p.u.		
Class 2 Double Excitation	Clearing	Line-to-Line Fault		V_r = 0.2
				V_r = 0.0
		Three-Phase Fault		V_r = 0.2
				V_r = 0.0
Class 3 Multiple Torsional Excitation	Reclosing	Line-to-Ground Fault	Triple-Pole Reclosing	successful
				unsuccessful
			Single-Pole Reclosing	successful
				unsuccessful
		Line-to-Line Fault	Triple-Pole Reclosing	successful
				unsuccessful
		Three-Phase Fault	Triple-Pole Reclosing	successful
				unsuccessful
Class 4 Torsional Resonance	Subsynchronous Resonance	(lower fatigue limit depends upon protective measures, e.g. filters, supplementary damping, switching operations, etc.)		





As regards network faults, those with double and multiple torsional excitation are in relation to fatigue and high torques much more severe than faults with single excitation.

The reason is that in case of double and multiple excitation, each excitation may have such small phase shifts that each stimulation acts in the amplifying sense and the resulting oscillating torque can reach an extreme high level.

In the case of a fast cleared short-circuit in one circuit of a multiple connection between generator and network, the following torsional excitations will be experienced by the shaft:

1. Fast negative jump of the air gap torque of the generator at fault inception. The magnitude of this jump depends on:
   - the load of the generator before fault inception;
   - the remaining average load of the generator during the fault.

2. First 50 (60) Hz alternating air gap torque after fault inception due to the DC component of the short-circuit current in the stator.

3. First 100 (120) Hz alternating air gap torque during the short-circuit due to the inverse component of the short-circuit current in the stator in case of an unbalanced fault.

4. First change of the air gap torque due to voltage regulator action after fault inception.

5. First change of the turbine torque due to speed control action after fault inception.

6. Fast jump of the air gap torque at the moment of voltage recovery at the generator terminals at the moment of fault clearing.

The sign and magnitude of this jump of the torque depends on the jump of the stator current at the moment of voltage recovery and therefore depends on:

a. the angle between the EMF of the generator and the equivalent (THEVENIN) EMF of the network,

b. the impedance between the EMF of generator and network and so on the subtransient reactance of the generator, the reactance of the step-up transformer and the short-circuit power of the network.

The angle at the moment of voltage recovery depends on:

- the prefault load,
- the inertia of the shaft,
- the fault clearing time.

7. Second 50 (60) Hz alternating air gap torque after voltage recovery due to this voltage recovery on the generator.

8. Second 100 (120) Hz alternating air gap torque due to the fact that a circuit-breaker does not interrupt the three phases at the same time.

9. Second change of the air gap torque due to voltage regulator action after voltage recovery.

10. Second change of turbine torque due to speed control action after voltage recovery.

This is an extensive history of events, the most important for the shaft duty are excitations 1, 2 and 6.

If the angle between generator EMF and the network EMF gets too high, out-of-step operation may occur with additional excitations of the shaft.

If fast auto-reclosure is applied and the reclosure is unsuccessful, additional excitations of quite the same types as mentioned above occur.

Studies performed by utilities and manufacturers demonstrate that extreme high risks to the generating units can occur in case of three-phase faults, if fast three-pole auto reclosure (HSR) is applied on:

- lines of the network in case of three phase faults on short electrical distance of big units,

- connection lines between generating units and the network /3.11/.

3. MEASURES TO PROTECT THE TURBINE GENERATOR SHAFTS AGAINST EXCESSIVE STRESSES CAUSED BY SYSTEM DISTURBANCES AND SWITCHING EVENTS

3.1. GENERAL

Excessive stresses in shaft give rise to the problem of :

- plastic deformation of couplings and shafts /42/
- shaft fatigue.

The shaft fatigue problem is discussed world-wide/31/. As results from answers to a CIGRE SC 34 questionnaire, practically all utilities having steam turbine units larger than about 300 MVA are concerned by the possibility of shaft fatigue damage. However, a general consensus on the quantitative amount of loss of fatigue life and suitable countermeasures has not yet been achieved.

This may be due to the following reasons:

- Network disturbances which could cause high fatigue damage in one incident (e.g. 3-phase fault clearance or false synchronization) appear very seldom. The worst case is hoped never to appear or at least to be tolerated due to the very low probability of occurrence.

- The cumulative effect of loss of fatigue life can only be estimated by sophisticated probability studies /11/. The modelling and simulation programs involve a large number of parameters which scatter considerably (e.g. fault statistics, network parameters) or are affected with a significant uncertainty (shaft metallurgical properties).

- In order to limit the studies to an economically justifiable expense, simplifications have to be made (general population of fault statistics, constant fault rates, even fault distribution).

- Thus, probability methods may be useful to develop general strategies (e.g. qualitative comparison of different autoreclosing practices /3/), but will be difficult to apply in the individual practical case.

- The determination of fatigue damage and corresponding life expenditure is an extremely complicated matter /8/. It depends not only on steel material properties, but also on the manufacturing and operating history and on the nature of the applied stresses /14/. The existing sophisticated calculation methods for conversion of a shaft torque history into the corresponding loss of shaft life (stress life time curve, Rain Flow Method, etc.) must therefore be corrected by practical engineering factors which lead to considerable uncertainties especially when they are not based on the manufacturer's design knowledge and experience.

The present methods and programs permit the quantitative comparison of the impact of different network disturbances and of the effect of countermeasures.

Further data must be collected from in-service stress monitoring and evaluation equipments to allow a more accurate cumulative fatigue damage assessment.

- All measures must be harmonized as to their effect on generating units and the transmission network. In many cases, measures have an opposite impact. In case of a network disturbance, an earlier separation of the turbo generator unit from the grid provides higher security against fatigue damage but increases the risk to the network (integrity, stability). A delayed separation backs the grid integrity but bears the higher risk of fatigue damage at the turbo generators.

The problem of decision is, therefore, often very complex and may, for the same problem lead to contrary decisions depending on the individual power system conditions. One example is the criterion for tripping the turbine generator unit in case of an out-of-step condition. Some countries intend to keep the machine on the system even for a larger number of slip cycles (France up to 20 at the present time) to enable a controlled network decoupling in favour of grid stability. The majority of utilities with strong networks and most of the manufacturers require an undelayed trip of large units in the first slip cycle to protect the turbo generator shaft against loss of fatigue life.

Though there are some uncertainties which concern the accurate absolute values of loss of life per incident, the order of magnitude is generally accepted. This is established by the fact that the figures published in different papers /3, 14, 31, 32, 37/ show comparable values in this respect. In the following discussion of countermeasures against loss of fatigue life we distinguish between the low-cycle (high stress) fatigue and the high cycle (low stress) fatigue.

The low cycle fatigue is caused by a lower number of high stress amplitudes which occur with heavy disturbances and consume a high amount of fatigue life per incident. From Table 2, we can take the most severe low cycle incidents:

Table 2

Incident	Consumption of shaft fatigue life per incident
False synchronization	< 20 %
Close-in three-phase fault and clearing	< 10 %
Nonsuccessful highspeed reclosing into a close-in three-phase fault	up to 100 %
Pole Slipping after a severe fault	< 20 % *

* order of magnitude in a very unfavourable case, such as 5 seconds out-of-step at full load.

The high cycle fatigue is characterized by a high number of low torsional amplitudes. It appears when a continuous subsynchronous excitation exists in the network (subsynchronous converter cascades) or a subsynchronous resonance occurs (series compensated network). The worst condition happens when the exciting frequency coincides with a natural torsional shaft frequency.

High cycle fatigue also occurs with incidents containing a low number of relatively small stress amplitudes but with a high repetition rate of the incident itself like with switching actions.

In the following we distinguish between preventive and protective measures.

Preventive are all measures which help to prevent the occurrence of plastic deformation and fatigue.

These measures can be provided in the primary (HV) system, e.g. a better lightning protection to reduce the number of faults. Measures arranged in the secondary system (control system, monitoring system) or in the tertiary system (load dispatch) are also considered as preventive.

Protective are all measures which help to clear the dangerous situation which has arisen, with consequent minimization of deformation and loss of fatigue life.

These measures are part of the TG-Unit and network protection and the autoreclosing system.

3.2. PREVENTIVE MEASURES

The following points should be considered to prevent plastic deformation and cumulative loss of fatigue life.

3.2.1. Preventive measures against high cycle, low stress fatigue. Avoid resonant conditions

The power system should be checked for potential excitation mechanisms. Application of series compensation can lead to subsynchronous resonance. This is now a well-known effect which has caused two shaft failures in the Mohave station in Nevada, USA, in 1970 and 1971 /10/. The advantage of higher transmission capability must be weighed against the danger to TG-Unit shaft.

Control systems and devices have been developed to damp the subsynchronous oscillations. Other devices use a current relay which detects subsynchronous components in the generator current and initiates corrective actions (e.g. removal of a portion of series capacitors) before any significant loss of life occurs /32, 42/.

Controlled rectifiers and converters can cause subsynchronous pulsating components in the electrical torque of the generator which result in torsional resonance. A case is reported where power converter controlled asynchronous motors (boiler feed water pumps) caused torsional vibrations in the turbine generator /37/. The further excitation of these vibrations has been avoided by quickly passing the critical speed range of the pump. Stimulation of torsional subsynchronous resonance has been found to be caused by HVDC system inverter banks /41/. The rectifier control system had to be changed in this case.

Such vibrations of small amplitude with a large number of load cycles can only be detected by continuously monitoring the torsional duty of the shaft. The sensitivity of the monitor must be set below the fatigue endurance limit of the TG-Unit.

3.2.2. Line and Unit Switching Actions

Switching actions in the power system cause active power changes at the TG-Units which stimulate torsional vibrations.

Factors like pre-event loading of the machine, proximity of the generator to the switching point, etc., determine the torsional stress amplitudes. These vibrations last for tens of seconds due to the weak damping of the TG-shaft.

Torsional shaft oscillations which exceed the stress endurance limit build small loss of fatigue life increments which can accumulate to remarkable loss of life figures. For a plant with several outgoing lines, it was estimated that the unit may experience 10 to 40 shocks per year with average ΔP values between 0.1 and 0.3 p.u. /32/.

A "Screening Guide for Planned Steady-State Switching Operations to Minimize Harmful Effects on Turbine Generators" has been published by I.E.E.E. /34/. The recommended guidelines permit a maximum ΔP or ΔI of 0.5 p.u. per switching action. This provides for a limitation of the peak negligible loss of life in the order of 0.01% per incident.

It would be of great advantage if future control and monitoring systems with on-line load flow and state estimation programs would also provide /32/:

- the capability to select the switching actions on criteria which result in a minimum stress to the TG-shafts,

- the capability to adjust the loading of the generators and lines so as to minimize the severity of the switching event.

However, it should be kept in mind that the proposed minimization of stress would naturally result in reduced switching freedom, which could be dangerously limiting in the emergency case. This problem only applies in situations with notable difference of angle between the voltage on both sides of a transmission facility of low impedance.

3.2.3. Preventive measures against low cycle, high stress events

These measures are mainly aimed at events like false synchronizing, a three-phase fault and back-up clearance or a fast three-pole reclosing after a close-in three-phase short-circuit, which can consume a very high amount of fatigue life per incident and can cause serious deformation of couplings and shafts.

a. Improved TG-Unit Construction

Up to now, the generator terminal two and three-phase fault is the design criterion when assessing the impact of electrical disturbances. Some countries (U.K., France, Sweden) seem to look for the 120° false synchronization as an additional design criterion /33/. In the U.K., studies are directed towards the use of shear bolts on special stub shafts between the main shaft sections designed to shear at torques greater than the torques corresponding to the generator terminal fault.

A manufacturer statement considers, however, a change of the design criteria as premature as calculation methods and the determination of material characteristics are in an early stage of development /3/.

b. Improvements in the transmission network

Measures against conductor galloping and improvements in the lightning protection can be proposed. Some utilities apply special precautions during maintenance and repair work on lines and busbars.

In one country, consideration is being given to connecting large TG-Units through two half-sized main step-up transformers into separate network parts or two separate busbar sections which are decoupled in case of a close-in multiphase fault. This measure shall keep a minimum load on the generator to slow down the rotor acceleration during the fault time and, therefore, reduce the resynchronizing shock at the instant of fault clearance.

c. Influence of regulator systems

It can be assumed that the voltage regulator as well as the turbine regulator and fast valving have no significant influence in case of instantaneous fault clearing (< 150ms) and HSR /31/. Thus, the impact of the most critical low cycle fatigue cases (three-phase fault clearance and unsuccessful HSR into a three-phase fault) can hardly be lowered through regulator systems.

3.3. PROTECTIVE MEASURES

The network protection must guarantee a reliable and quick fault clearance to prevent multiple torsional excitation which could cause plastic deformation, high loss of fatigue life or even shaft crack initiation in the worst case. In case of transient faults, the tripped line must be restored as fast as possible to prevent network instability and to ensure a continuous supply of energy. The reclosing practice, however, must be handled carefully in order to avoid an amplifying of the fault induced torsional shaft oscillations. This may require some restrictions in the reclosing program. The generator protection should only come into action when the network protections fail to clear the fault in a predetermined time or when high cycle fatigue stress endangers the shaft (subsynchronous resonance in the network).

3.3.1 Network Protection

A widely practised way to increase the protection dependability is to provide two redundant line protection systems which operate in a 1 out of 2 connection.

These protections should preferably have different operating principles, e.g. distance protection and phase comparison protection or differential protection.

The protection system must especially be capable of providing fast clearance in the case of close-in multiphase faults.

The worst conditions occur when the circuit-breaker is closed onto an earthed feeder. The distance relays should, therefore, be equipped with a voltage memory to ensure correct directional measurement with close-in three-phase faults. The distance protection should further be provided with a so-called "switch onto fault facility", i.e. with closing the breaker, an offset zone or the starting elements should be released to trip for a short time interval (e.g. 200 ms).

3.3.2. Busbar Protection

Busbars are equipped with a fast busbar protection. It is not usual to double this protection. On the contrary, a check-zone is sometimes provided which is connected to form a two-out-of-two scheme. Here, the trend goes to more security to avoid the risk of losing a larger number of feeders. In cases of high short-circuit power, however, high set current relays or short zone distance relays are sometimes used to decouple bus sections to reduce the "voltage recovery effect" on the torsional stress initiation.

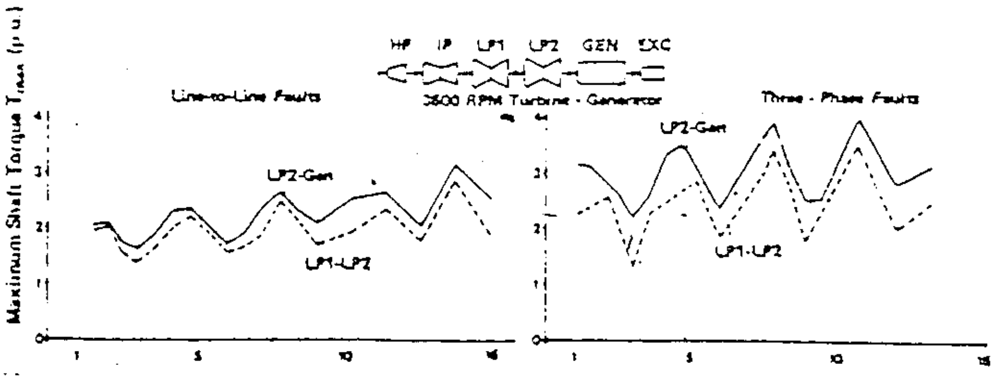
3.3.3. Protection Operating Time

The torsional impact depends strongly on the precise instant when the fault is cleared relative to the shaft vibrations excited by the fault incidence. The following figure (from /14/) shows the typical course of the maximum shaft torque as a function of the fault clearing time.

The curve exhibits an upward trend, indicating that the probability of more severe shaft stress increases with the fault clearing time. This is of course due to the fact that the generator EMF-phasor advances against the system voltage phasor proportionally to the fault duration. However, it can also be seen that reduction of the fault clearing time in the order of one or two cycles will not necessarily lead to lower torsional stress. This is due to the undulatory course of the time stress curve.

The expense for further reduction of the fault clearing time (< 100ms) may thus not be justified if only torsional shaft stress is considered. The decisive criterion remains the critical fault clearing time, determined by the stability limit especially in weak networks, and the possible reduction of the back-up protection times (e.g. breaker failure protection).

Fault clearing times higher than about 150ms however, can cause dangerously increased torsional



Fault clearing time (cycles)

shaft stress and can lead to an out-of-step situation of the TG-Unit with the risk of high loss of fatigue life (up to about 20%, (see remark at the bottom of Table 2).

3.3.4. Autoreclosure Practice

Reference N°11 defines a variety of reclosing strategies. The calculations described in this reference have shown that the unrestricted high speed reclosure (HSR) can cause high losses of fatigue life and even shaft crack initiation in case of an unsuccessful HSR into a three-phase fault close to a power station. Few years ago, it was generally accepted that HSR should not be performed on lines terminating at power stations; at the present time, some utilities have backed away from this strong position. There is also increasing use of high speed check synchronizing to control HSR.

A further means to reduce the impact on the TG-shaft is to apply "delayed reclosing". Delay times of about 10 seconds are recommended to allow the damping of the shaft oscillations.

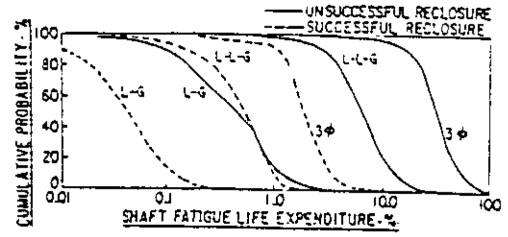
The "Sequential reclosing" designates a practice of reclosing first from the end which is remote from the plant, after which the plant end breaker is closed automatically using synchrocheck relays. This practice lowers the risk of closing onto a close-in fault, however, it is of less benefit in closely interconnected power systems where practically all line terminals are electrically close to large TG-Units.

"Selective reclosing" is a practice where HSR is allowed only for single-phase or single and phase-to-phase faults. Herewith, the dangerous case of HSR into a three-phase fault is eliminated. This strategy is becoming more popular.

The practice with the lowest impact on the TG-shaft is the "single-pole autoreclosure". The loss of fatigue life increments are here below 0.1% per incident.

Many utilities have changed to more conservative reclosing practices as a consequence of the recognized potential for excessive shaft fatigue duty from HSR /3,11/. An I.E.E.E. working group is organised to develop guidelines on reclsing practices.

Each TG-Unit is exposed to a high number of torsional fatigue incidents during its life time (say about 40 years). The amount of fatigue life loss in this time depends on a lot of parameters, like fault statistics, autoreclosure practice, power system parameters, TG-shaft material properties, etc.



L-G : single-phase earth fault
L-L-G: double-phase short-curcuit + earth fault
3 Ø : three-phase short-circuit

The cumulated loss of TG-shaft fatigue life can be estimated by probability calculation methods (Monte Carlo method). Thus a comparison of the different types of autoreclosure is possible as regards the impact on shaft fatigue duty /11/. The earlier figure shows a typical diagram.

Though this method may be questionable as to the quantitative accuracy in the individual case, it can be useful to develop and compare different strategies of autoreclosure.

3.3.5. Generator Protection

As outlined in Section 2.2., the delayed clearance of a close-in three-phase fault can endanger couplings and shaft line by the risk of plastic deformation and cause a considerable loss of fatigue life.

In some countries (Germany, Belgium, Netherlands, Switzerland, Denmark), a generator back-up protection is used to trip the TG-Unit in the case where the network protection has not cleared the fault within a set time of about 90 to 150 ms.

The measuring criteria are:

- high negative jump of active power
- high overcurrent
- low residual voltage at the high voltage busbar of the plant.

The setting is determined on the basis of torsional fatigue calculations. A typical setting may be:

$$\Delta P = 0.8 \text{ p.u.};\ U < 0.4 \text{ p.u.};\ I > 1.4\ I_N;\ t > 150 \text{ ms.}$$

A high loss of fatigue life must be expected (up to 20% according to page 7 when a TG-Unit falls out of step after a three-phase short-curcuit and goes into pole slipping operation /37/. Most manufacturers require the tripping of the unit in the first slip cycle.

For this purpose an out-of-step protection relay must be provided. The classical out-of-step relays trip, when the swing impedance locus crosses the unit step-up transformer.

In some countries (e.g. France) the TG-Unit is required to stand several pole slips and up to now tripping is initiated after a predetermined number of slip cycles.

Here a deviation of opinions about the withstand capability of TG-Units and of the acceptable risks of fatigue damage, should be clarified by further studies.

4. TORSIONAL STRESS MONITOR

Equipment using digital and analog computer techniques has been developed for permanent monitoring of the torsional duty of couplings and shafts of generating units.

A torsional stress monitor calculates on line the torsional stresses and the allied loss of fatigue due to faults, abnormal operating conditions and switching operations in the power system.

As mentioned in Paragraph 3.1, predictive estimation of the torsional duty of shaft lines of generating units during their service life is very difficult.

So the options differ about the necessity of protective measures and the setting of such protections.

With respect to the above mentioned problems, it could be of importance to equip, in general, large generating units with this equipment to gain experience about stressing of couplings and shafts by disturbances and to monitor the expenditure of fatigue life.

The output of this equipment could also be helpful:

- if a decision needs to be taken during the service life of a generating unit as to whether it is necessary to install a protective relay to cover an extreme expenditure of fatigue by the stress due to one disturbance.

Example: If, after say 12 years of service, the monitoring device indicates a loss of fatigue life of, for example, 60%, and a practical risk exists that a further 40% be lost by only one disturbance, should appropriate protection be provided ?

- in an attempt to compare the risk to both the shaft of the unit and the integrity of the power system by adapting the setting of the fatigue protection during the service life of the generating unit.

Example: If after, say, 12 years of service, the monitoring device indicates a loss of fatigue life of, for example, only 20%, while the protective relay against fatigue failure limits the loss of fatigue life to a maximum of about 10% per one secure disturbance and such a disturbance is considered to occur only seldom, then the setting of this protection could be made less restrictive. In this case the risk to the integrity of the power system decreases without an intolerable increase in the risk for the shaft.

5. CONCLUSION

GENERAL

World-wide attention is paid to the problem of the risk of occurrence of high torsional stresses in couplings and shafts of large generating units due to faults, abnormal operating conditions and switching operations in the power system.

These stresses can give rise to plastic deformation and fatigue. Computer programs are available for stress calculation, torsional monitoring equipment can record the stresses induced by disturbances and protective devices are developed to switch off generating units from the network if the risks to the units are too high.

Further, more restrictive three-phase autoreclosure policies can be adopted for lines directly connected with power plants.

BALANCE OF RISKS

Due to the above mentioned risks to the generating units and the consequent restrictive policy which applies to unit protection and reclosure, there is a growing trend toward decreased integrity of the power system. This is hardly acceptable.

To minimize this adverse effect of applying large generating units one should try to balance the risks of deformation and fatigue to the shaft and the risks to the integrity of the power system due to preventive and protective measures against deformation and fatigue.

Predictive estimation of the risks to the shaft is difficult for two reasons:

First: The torsional stresses depend strongly on the type of disturbance, on the moment of fault inception/fault clearing/autoreclosure, on the pre-fault load, etc.

Thus these stresses depend on events of largely stochastical nature. Also only statistical information is available for estimation of the number of each type of network disturbance applied to the shaft during the service life of the generating units.

Second: Computer programs to calculate the stresses during and after the disturbances are available but a sufficiently precise evaluation of these stress time functions into terms of shaft fatigue is still a problem. To make it more complicated, there is a significant scatter in the mechanical properties of couplings and shafts.

TORSIONAL STRESS MONITOR

Computer based torsional stress monitors containing assessment of stresses and fatigue are available on the market /38/.

These devices provide a complete history of the torsional duty of the monitored turbine generator as well as for high and low cycle duty, if installed before the beginning of operation of the generating unit.

The output of these equipments could be used to balance the risks to the generating units and to the integrity of the power system.

6. PROPOSAL OF WORKING GROUP 34.01

This Paper states the present state-of-the-art in a still evolving field.

However, in many countries an increasing number of large generating units are or will come into service.

With regard to high stresses in couplings and shafts most of these big units are susceptible to disturbances in the network. These units are often strongly interconnected.

At the occurrence of a three-phase short-circuit there is a risk of a simultaneous trip of a number of large units by their protection against deformation or fatigue of the shaft. This is a serious risk for the integrity of the power system.

Considering this, Working Group 34.01 proposes to form a Working Group with members of Study Committees 11, 32 and 34 to issue a joint Paper dealing with all the aspects of this topic.

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2 ND PART

"CRITERIA FOR ISOLATING POWER PLANTS AND EQUIPMENTS TO SEPARATE THE GENERATORS FROM THE NETWORK UNDER ABNORMAL CONDITIONS OF VOLTAGE, FREQUENCY OR OTHER"

CONTENTS

1. GENERAL

The continuity of supply to the consumers depends on the overall availability of both the generating units and the transmission and distribution system.

A fault occurring in one of the components of the overall system:
- causes damage to the component in question,
- may endanger outside adjacent equipment,
- may endanger the good operation of the system as a whole.

Elimination (or trip) of a faulted component from the overall system:
- stops further damage to the faulted component itself,
- relieves the danger from the fault to the overall system operation, but creates a new disturbance due to the functional elimination of the faulty component.

Elimination (or trip) of an endangered component from the system:
- relieves the equipment from the danger in question,
- causes an additional disturbance for the overall network operation, due to the functional elimination of a healthy component.

So the corrective actions in case of fault must establish a compromise between the positive consequences (minimize damage to equipment) and the negative consequences (danger for overall system operation).

This part of the report deals with the above mentioned considerations for the generating units with respect to the network.

Criteria for intervention on a generating unit are the following:

- faults in the generating unit itself, i.e. below the HV breaker connecting the generator to the network:
  . Electrical,
  . Other,

- disturbances in the outside system, endangering the genereting unit:
  . Faults,
  . Abnormal service conditions e.g. low frequency.

2. FAULTS INSIDE THE GENERATING UNIT ZONE

2.1. POLICY OF INTERVENTION

2.1.1. Direct consequences of fault itself

- Damage to equipment of the units is proportional to the severity of the event (e.g. fault current) and the duration. One should also note that, according to type and location of the fault, the repair and outage times can greatly vary (e.g. compare a phase-to-ground fault on overhead connection between step-up transformer and HV breaker with a stator earth fault in the unit).

- Damage to outside equipment

In general, only high current fault phenomena may affect the outside system, particularly faults at HV side of step-up transformer.

- Danger for the good operation of the overall system. Same remark as for damage to outside equipment.

2.1.2. Consequences of fault clearing by unit trip

- Unit trip stops further damage to the affected equipment and limits the repair and outage times.

- Unit trip also eliminates danger to adjacent equipment (provided there was some danger).

- Unit trip eliminates the danger for overall network operation due to the original fault, but at the same time creates a disturbance to the network due to the loss of unit production.

2.1.3. Basic considerations of intervention policy

- For high current unit faults, during which also adjacent equipment may be endangered and possibly also the overall network operation, one should proceed to immediately trip the unit, both for inside damage limitation and outside disturbance limitation (loss of production will be less severe than the possible damage caused by the original fault.

- For all other faults and conditions, the resulting damage (when not tripped immediately) should be weighed against the overall network consequences associated with the loss of unit production (when tripped).

- If an internal fault is fed by the generator, there is no point in islancing the unit with its auxiliaries as this would not eliminate the internal fault.

2.2. ENUMERATION OF INTERNAL DISTURBANCES AND USUAL METHODS OF DETECTION

2.2.1 Electrical disturbances

2.2.1.1. Phase-to-phase faults /1,3,4,5/

Phase-to-phase faults in generating units are typical high current faults, and may therefore also affect the HV network, particularly if the fault is situated at the HV side of the step-up transformer.

Possible consequences:
- high dynamic and thermal stresses,
- considerable damage at the fault location (particularly if fault situated inside the generator itself),
- network voltage drop (mainly for HV side faults) and associated problems.

Methods of detection:
- generator differential protection (for faults inside the generator),
- overall differential protection (faults in generator or step-up transformer),
- underimpedance relay connected at the MV side. A first zone of such relay, covering up to part of the step-up transformer, ensures back-up of the differential protection,
- HV side distance relay, looking into the step-up transformer, ensures back-up of the overall differential protection for HV side faults.

Protective actions:
- immediate trip of the unit, for limiting of the damage to the unit and disturbance to the network.

2.2.1.2. Stator earth faults /1,3,4,5,6/

With the quite generally adopted practice of unearthed generator neutral, single phase to ground faults in the stator produce only very low currents (≠10 A), far below sensitivity of the differential protection.

Possible consequences :

- although currents are low, they may considerably burn into the iron core of the generator if they are not cleared in a short time. Core damage causes substantial downtime and repair effort;

- there is a considerable risk for evolution into phase to phase fault.

Methods of detection :

- several principles exist, which may ensure protection from the terminals down to typical 80-90 % of the winding, the remaining 20-10 % to the neutral point not being covered. They rely on measurement of zero sequence quantities at rated frequency.

- 100 % protection is generally based on measurements at other than main frequency /6/.

Protective actions :

- immediate trip of the unit for limitation of the damage.

2.2.1.3. Faults in step-up transformer (and auxiliary transformer if not protected by a separate breaker) /1,5/

These may be high current faults or low current depending on type and location.

Possible consequences :

- for high current faults, refer to 2.2.1.1;

- for low current faults, there is a risk of evolution into high current faults.

Methods of detection :

- gas relay ;

- frame leakage relay ;

- differential relay and impedance relays (for high current faults) ;

Protective action :

- immediate trip of the units for limitation of the damage.

2.2.1.4. Motoring of generator /1,4,5,6/

Continuous active power reversal in the generator may accur in case of intentional or accidental prime mover trip while still connected to the network.

Periodic power reversals may indicate out of step operation, this item is covered in 2.2.1.1./1/

Another way of causing motoring is inadvertent closing of HV circuit-breaker or generator isolating switch while unit is at rest or on turning gear. Then the generator tries to start as an induction motor.

Possible consequences :

- after mechanical turbine protection trip, prolonged motoring could aggravate the turbine problems. Fast generator trip is therefore recommended;

- for normal shut-down procedures, there is a widespread practice to trip the turbine first and then to trip the generator by detecting of the motoring condition. This may avoid overspeed problems.

- prolonged motoring may overheat the turbine ;

- generator trying to start as an induction motor may break a shaft or winding.

Detection :

- Wattmetric relay ;

- temperature detectors (at the last stages).

Protective actions :

- motoring while unit previously at rest : immediate trip of the HV circuit-breaker ;

- power reversal following a turbine trip signal : immediate trip of the generator ;

- power reversal without turbine trip : time delayed trip ;

- if overheat : attemperater sprays and afterwards trip.

2.2.1.5. Short-circuit in auxiliaries at critical locations /3/

Faults inside the auxiliary electrical system are not likely to affect the generator or network directly electrically, however, the consequences on the auxiliaries may be detrimental.

Possible consequences :

- local damage at the fault location ;

- auxiliaries insufficiency with consequential unit trip.

Detection :

- various types of relays (differential, overcurrent).

Protective actions :

- fast elimination of the fault ;

- quick transfer of supply, if this may eliminate the fault.

2.2.1.6 Single rotor earth faults /1,4,5,12,13/

Although not so dangerous in general, cases have been reported where a single rotor earth fault was the only external sign of a very damaging internal arcing.

Possible consequences :

- risk of a double rotor earth and associated damage ;

- possibly symptom of other internal faults (winding shorts or interruptions with arcing). Damage to winding, rotor body or rotor end retaining rings may be substantial.

Detection :

- various types of detection exist, based on applying a test voltage between rotor winding and ground or between the rotor winding and the shaft through shaft brushes.

Protective actions :

- alarm to prepare a planned shutdown ;
- delayed or even direct trip (required by some manufacturers).

2.2.1.7. Overvoltage /1,4,5/

Generator output overvoltage generally indicates an abnormal situation in the generator excitation system, or a severe overspeed in case of hydraulic units.

Possible consequences :

- overfluxing ;
- risk of insulation damage or flashover.

Method of detection :

- voltage relay.

Protective actions :

- alarm;
- intervention in exciter (field reducing resistor for example) mainly for small units ;
- delayed trip for sustained overvoltage.

2.2.1.8. Overheating of transformers

Transformer overheating may be due to an overload or due to some disturbance in the transformer cooling system.

Possible consequences :

- excessive ageing of transformer insulation ;
- risk of internal faults at hot spots.

Method of detection :

- top oil temperature ;
- thermal replica ;
- direct measurement of winding temperature /14/

Protective actions :

- alarm with manual intervention on generator output ;
- possibly a delayed trip.

2.2.1.9. Overfluxing /7,8/

Overfluxing occurs when the ratio U/f is increased above the design value, due either to an excessive voltage for a given frequency or conversely a lower than required frequency for a given voltage.

Generator step-up transformer and auxiliary transformer are concerned.

Possible consequences :

- overheating of steel core due to saturation and of adjacent structural steel due to excessive stray flux.

Detection :

- overfluxing relay (possibly 2 levels).

Protective actions :

- voltage/frequency limiters associated with voltage regulators ;
- alarm ;
- delayed trip, co-ordinated with the generator and step-up transformer overfluxing capabilities.

2.2.1.10. Loss of field /2,4,5/

Considered here are (total) loss of field voltage and interruption of field current.

Both events result in asynchronous operation of the generator at speed higher than rated speed. The actual asynchronous operation point depends upon :

- machine constants and excitation circuit condition (defines torque-speed curve of the asynchronous operation mode) ;
- the prefault power output and governor characteristics (defines mechanical torque speed curve of the prime mover).

Possible consequences :

- severe voltage depression (due to the Mvar consumption of the asynchronous unit) and associated effects ;
- overheating of damper cage, field overvoltages if open circuited field or if rectifiers in the excitation circuit ;
- small pulsating torques (if $X_d \neq X_q$) may induce mechanical shaft oscillations ;
- overheating of stator parts due to increased currents and stray fluxes.

Method of detection :

- DC underpower relay, detects abnormal flow of power from exciter to field winding ;
- offset MHO relay, based on the machine impedance, seen from terminals, in asynchronous mode ;
- reactive power relay, detecting Mvar absorbed by the asynchronous unit ;
- internal angle relay, detects rotor pole slipping by comparing the rotor position with the network voltage phasor reference ;
- combination of offset MHO, directional and undervoltage relay;
- combination of machine impedance detection and low excitation voltage detection.

The last two detection methods not only detect loss of excitation voltage or interrupted field, but also exceeding of the underexcitation limit curve.

Protective actions :

- alarms ;
- (delayed) trip of the unit.

2.2.1.11. Out of step operation /1,2,4,5,6,8/

Out of step condition occurs when one part of a system (in this case one generator) runs at a different frequency from other part(s) of the same system. This operation is characterised by periodic fluctuations of current and voltage.

The point of the system where voltage momentarily falls to zero during each cycle is called the system centre.

The out of step operation may be caused by steady state instability (exceeding of the maximum limit of transmittable power) or by transient instability (non recovery after system disturbance). If the system centre during out of step operation is inside the step up transformer or below, it is likely that the unit is in out of step compared to the network. If the system centre is beyond the step-up transformer, the out of step condition is probably among several generators or areas.

Possible consequences :

- disturbance of unit auxiliaries and consumer loads, particularly those close to the system centre ;
- indiscriminate operation of some network protections ;
- mechanical and thermal stress to generator stator winding, increased stray flux losses and heating ;
- set up of shaft torsional oscillations due to pole slipping pulsating torques.

Methods of detection (for generator application)

- simple impedance protection ;
- detection of apparent impedance vector variation at generator terminals through crossing of two typical impedance loci.

Practical examples are :

. double blinder
. double circle or quadrilateral characteristic
. lenticular characteristic.

Distinction between inside and outside system centre is made through comparison of the crossing point (with the axis of the lens) to a preset value. Inside centre is considered first zone, outside centre is considered second zone. Trip order is issued after preset number of lens crossing (different for first and second zone).

- internal angle and reverse active power scheme.

Checks the internal angle with respect to a maximum value for counting of pole slip cycles.

The method detects only inside system centres. For external system centres, it is completed with reverse active power relay counting the active power cycles of the generator.

Protective actions :

- Policy one : wait for possible resynchronisation, and only island the unit when approaching the damage limit /1/ ;
- Policy two : fast islanding of the out of step generator to minimise damage to the generator and disturbance to the network. For hydro units only policy two is applicable due to their low damping torques.

2.2.2. Non electrical faults

Typical case : low level of turbine oil tank.

These faults have no direct (electrical) impact ; in case of trip however, loss of unit production has consequences for the system as a whole. The enumeration of these non electrical faults is beyond the scope of WG 34.01. However, if any breaker failure scheme is implemented at the HV substation, it should be designed so as to cope with generator breaker failure on trip order of mechanical (and other) origin (no local electrical fault criteria available).

2.3. EXTERNAL SYSTEM PROTECTIVE DEVICES SENSITIVE TO UNIT FAULTS, HARMONIZATION WITH UNIT PROTECTIONS

Direct electrical impact of unit faults on adjacent equipment or network behaviour as a whole is only possible in case of heavy current phenomena (currents > rated current of the unit).

Three practical cases are :

- high current faults in the unit : phase to phase faults and all types of HV side faults ;
- loss of field ;
- out of step operation.

In all these cases the unit is to be tripped, instantaneously or time delayed, for limiting damage to the unit as well as network interference.

2.3.1. High current faults in the unit

- For this phenomenon the proper unit protections provide instantaneous tripping.
- Network protections that might see the fault namely :
  . distance relays
  . overcurrent relays
  . undervoltage relays

should therefore be time delayed by a suitable grading interval to ensure selectivity.

2.3.2. Loss of field

- The loss of field condition in a unit might be felt by the following protection types in the network :
  . overcurrent relays
  . undervoltage relays
  . distance relays (higher zone reach)

- For a matter of co-ordination, the time delay of the loss of field trip should be co-ordinated with the time delay of any of the above mentioned relays if they may see this fault.

2.3.4. Out of step operation

Relays (undervoltage, overcurrent and distance relays), referred to in 2.3.2., are also sensitive to out of step conditions.

If instantaneous trip or time delayed trip is performed on the generators, selectivity for overcurrent and undervoltage can be ensured by adding an adequate selective interval.

The distance relays of the network will see an apparent impedance vector which may well enter their operate region, even in first zone when the relay is close to the system centre. A time delay co-ordination is therefore not practical and if one wants to avoid distance relay operation on prolonged out of step, an adequate out of step device should be provided. These devices are mainly based on the fact that network faults cause a sudden jump of the impedance vector into the relay operate area whereas out of step causes continuous motion of the impedance point from the normal load impedance into the relay sensitive area /4/.

3. FAULTS OR DISTURBANCES IN THE NETWORK

3.1. POLICY OF INTERVENTION ON GENERATING UNITS

3.1.1. Direct consequences of the fault itself

- Damage to the network equipment (not in the scope of WG 34.01) ;
- Damage or disturbed operation of generating units either directly or indirectly due to auxiliaries insufficiency ;
- Danger for the safety of the system as a whole, e.g. stability (not in scope of WG 34.01).

3.1.2. Consequences of separation of the endangered generating units

- The unit is safeguarded against adverse effects from the network fault ;
- Regarding overall network behaviour, the situation is deteriorated due to loss of production of the unit as well as loss of available short-circuit power.

3.1.3. Basic consideration for intervention on generating units

In any case the separation of a generator from the system will result in an additional constraint for the operation of the network as a whole. The consequence of non separation should be weighed against the consequence of separation of the unit from the network.

As the unit itself is not faulty, it is advantageous to try and island with the auxiliaries or with a partial system so as to be able to resume service quickly. It should be noted that some generating units may not be capable of islanding.

The following different types of separation of the generating units may be distinguished :

- trip of generating unit (protection against electrical adverse effects) ;
- trip of generating unit (auxiliaries insufficient no stable islanding operation is possible) ;
- islanding of generating unit with partial system (with view to rapid restoration) ;
- islanding of generating unit with auxiliaries only (with view to rapid restoration).

Tripping : no rapid restoration is contemplated.
Islanding : rapid restoration is kept in mind.

The success of an islanding operation is subject to adequate timing of the actions after fault inception.

3.2. ENUMERATION OF NETWORK FAULTS AND DISTURBANCES AS SEEN FROM THE GENERATING UNITS

3.2.1. Low level asymmetrical operation/1,2,3,4,5/

Possible consequences :

- presence of negative sequence currents and thus additional heating of the rotors. There is no immediate danger due to the heating time constant.

Detection methods :

- negative sequence relay matching $I_2^2 .t$ and I_2 continuous characteristic of the generator;
- other criteria e.g. step-up transformer neutral current and/or neutral voltage could be used to detect abnormally cleared network faults or situations.

Protective actions :

- for low level alarm ;
- at higher level islanding ;
- trip could normally be avoided for these external types of faults.

3.2.2. High level fault current /1,2,3,4,8/

Resulting from faults or erroneous operations.

Possible consequences :

- high transient torques (refer to 1st part of this report) ;
- voltage drops causing :
  . possible instability of the generator itself ;
  . possible drop-out of auxiliaries resulting in trip for internal reasons ;
- overcurrent conditions.

Methods of detection :

- transient torque detection (refer 1st part) ;
- generator instability detection (refer 2.2.1.11);
- undervoltage relays ;
- overcurrent relays ;
- impedance relays on HV and/or LV side of step-up transformer ;
- speed detection on critical auxiliaries e.g. primary pumps of nuclear plants.

Protective actions :

- transient torques (refer 1st part) ;
- generator instability (refer to 2.2.1.11) ;
- the other criteria (undervoltage, overcurrent, minimum impedance etc) are used to initiate islanding operation (with auxiliaries or with a partial system). The success of such islanding operation is subject to an adequate design of the power station auxiliaries, particularly the maximum acceptable voltage drop and duration. Also turbine governor and generator voltage control are important.

3.2.3. Disturbance of equilibrium generation-load

3.2.3.1. Active power deficiency /1,7,8,9,10/

Active power deficiency results from fault clearing, false tripping, network splitting and causes a frequency drop.

Possible consequences :

- loss of auxiliaries and then unit trip for internal reasons ;
- reduced cooling of autoventilated machines at continuous operation at low frequency ;
- turbine blade vibrations and fatigue damage ;
- saturation problems as (u/f) increases.

Methods of detection :

- frequency drops may be detected by under-frequency deviation relays ;

- auxiliaries' disturbance can be detected, for example by speed monitoring on critical drives (primary pump of PWR) ;
- saturation problems may be detected by appropriate relays (refer 2.2.1.9).

Protective actions :

- when during underfrequency conditions the unit auxiliaries become endangered, islanding may be initiated so that recovery is ensured ;
- for the turbine blading, it is considered now that the off-frequency operation fatigue is cumulative over the frequency deviation. In other words the damage at various off-frequencies is not occurring at the same locations and thus does not add up. From these considerations protective schemes have been derived totalling the off-frequency operation in various separate frequency bands, each of them having its own maximum acceptable time limit according to manufacturers data /7/.

3.2.3.2 Active power excess /1/

May result from load rejection or network splitting.

- Consequences : frequency rise.
- Detection and action is normally ensured by the turbine governor control. A mechanical overspeed protection is provided on the turbines (with fast valving). Electrical overfrequency protection can be used to anticipate mechanical trip by islanding.

3.2.3.3. Reactive power deficiency /2/

A typical case could occur in case of loss of field on a nearby generating unit.

Possible consequences : voltage drops, less severe than in the case of high level fault currents, but of possibly longer duration:

- risk of overload of generator ;
- risk of overload or unstability of auxiliaries leading to trip for internal reasons of the unit;

Methods of detection :

- undervoltage relays and/or overcurrent relays ;
- auxiliaries speed dection.

Protective actions :

- islanding of the unit (refer also 3.2.2)

3.2.3.4. Reactive power excess

A typical case may occur with load rejection on high Mvar consumers (e.g. HVDC link terminal)or with network splitting.

Consequences :

- voltage rise with mainly saturation problems (u/f rises).

Methods of detection :

- exciter control system ;
- overvoltage relays ;
- overfluxing relays.

Protective actions :

- normally the exciter control should intervene ;
- the other criteria could be used for alarm, islanding and even trip if the exciter cannot redress the situation.

3.2.4. Sustained oscillation of voltage and frequency

These oscillations (frequency range 1 Hz), of fairly large amplitude sometimes but without loss of synchronism, may occur in case of inappropriate exciter and governor regulator characteristics in relation with the typical network structure.

Consequences :

- high cycle fatigue
- flicker
- problems with auxiliaries.

Actions :

Protection should be sought rather than adaptation of control system parameters so as to stabilise the system as a whole (Power system stabilisers).

3.2.5. Out of step operation between network parts /2,4/

Out of step operation mostly occurs after faults in too weak a network structure.

Possible consequences :

- quite similar to those described in 2.2.1.11.

Methods of detection (at unit level)

- some types of out of step relays may also detect out of step operation with system centres outside the unit.

Protective action :

- refer to Part 3 for overall network protective actions ;
- at unit level a back-up islanding action can be performed.

3.2.6. Subsynchronous resonance /2,11/

Subsynchronous resonance conditions arise when electrical system interactions with turbine generator torsional oscillation modes result in negative damping of these modes.

Particular cases occur with series line compensation and predominantly HVDC interconnected generators.

Consequences : risk of high cycle fatigue of shaft.

Detection : detection relays are available (e.g. current relay with adequate filtering) /11/ ;

Action :

- subsynchronous resonance is a combined generating unit network problem and should be avoided by adequate design and system operation.
- in case of occurrence in practical situation, alarms and islanding (in second step) could be performed at unit level.

3.3. HARMONISATION OF UNIT PROTECTIONS AND NETWORK PROTECTIONS FOR NETWORK FAULTS

As a rule, normal network fault clearing should not necessitate islanding of units. Otherwise, major network protection improvement is required.

Of the faults mentioned in 3.2, the following are normally felt by generator protections and need thus harmonization of protective actions.

3.3.1. Asymmetrical operation

Normally, no problem should arise as elimination of fault conditions (leading to asymmetry) is fast compared to the operation time of relevant generator protections.

In case of abnormal clearing, units will be islanded. In order to avoid major loss of generation, it is sometimes advisable to introduce some network splitting before islanding the units. Some difficulties may arise due to the different measuring quantities at the splitting point (U_2, U_0) and the units (I_2 , I_0).

3.3.2. High fault currents

Generator protections that are sensitive to high current network faults (e.g. Imax or Zmin) should be time graded so as to allow first operation of the proper network protections. Systematic use of busbar differential protection may facilitate the overall coordination.

On the other hand, the time delay for initiating islanding should be compatible with the recovery capabilities of the auxiliaries (maximum limit on time delay) if one intends to island the unit.

3.3.3. Disturbance of equilibrium of active or reactive power (deviation of voltage or frequency).

Frequency deviations, high voltage and overfluxing are not felt by the classical network element protections (distance, differential, phase comparison ...) and need no coordination with them.

If there is an overall network protection scheme for such conditions (e.g. including network splitting and load shedding), it is essential that the protective actions on the individual generating units are in line and coordinated with the actions of this overall scheme (particularly for frequency and low voltage criteria) /7,9,10/.

In any case, if low voltage criteria are used for generating unit islanding, they should be time delayed for coordination with network protections (see also 3.3.2). The time delay should be compatible with safe unit recovery after islanding.

3.3.4. Oscillation

No specific protection exists in the network and no specific protection exists on the units.

3.3.5. Out of step operation between network parts

Network splitting should intervene before unit islanding, which only assures back-up for said condition (see also the 3rd part of the report).

3.3.6. Subsynchronous resonance

Some corrective actions are possible in the network, e.g. change of configuration, bypass of series capacitors.

Protective actions on the generators should be time graded with respect to the network actions.

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3 RD PART

" WARNING CRITERIA OF AN EVOLVING DANGEROUS SITUATION "

CONTENTS

1. INTRODUCTION

Utilities operating large networks are very preoccupied with the events that can lead to a collapse, more or less dramatic, of their systems.

These problems are more and more critical since :

- electric supply has a leading part in the life of a country (it is not difficult to imagine what can arise if a large area is short of electric power during several hours) ;
- electric systems become more and more intricate :
  - . the rated power of the units and the short circuit capacity of the network are increasing ;
  - . the transmission lines are more numerous with a larger power transmitted and a higher voltage level ;
  - . some particular components of network (series capacitors for instance) are more widely used ;
- operation of network can be more risky, due to some delays in commissioning primary plant ;
- the adverse effects of disturbances in modern high voltage networks with large generating units are more severe ;
- interconnection between networks being now applied very often, there is a risk that the collapse of a network leads to a black-out in the neighbouring networks (if no special care is taken) ;
- network collapses involve very large money expenditures :
  - . for the country : interruption of any activity;
  - . for the utility : large amounts of energy not sold, costs of restart of thermal units shut down during the collapse, and probably damages to some generating units and network components.

So it is obvious that the utilities try to decrease as far as possible the risk of having a network collapse.

They are mainly acting in three ways, regarding:

- measures that can be taken to minimise the occurrence of a dangerous situation (for instance fast clearing of network short-circuit) ;
- actions that can be performed, if possible automatically, to prevent a critical situation from evolving to a dangerous one ;
- actions that can minimize adverse effect of black-out (for instance network splitting,load shedding, fast restoration).

In this Paper, we are mainly dealing with the two last types of actions. So we analyse :

- which warning criteria (frequency, voltage value ...) can be used to detect a critical situation ;
- how these criteria can be reached, theoretically and practically ;
- how these criteria can be used to avoid a black-out or minimise its effect.

Some examples of integrated techniques for system stabilisation are also given.

It is necessary to point out that, during the evolution of a critical situation, several phenomena are generally occurring at the same time (for instance voltage drop and low frequency) ; so, studies are carriedout to try and identify in the aggregate critical situations. A short chapter gives some information about such a global approach to the problem.

2. ANALYTICAL APPROACH

Several phenomena can initiate an evolving dangerous situation on a network.

Generally a black-out can be due to :

- incorrect balance of load and generation leading to an incorrect value of frequency and/or voltage ;
- incorrect voltage profile on network leading to a voltage collapse ;
- incorrect power exchanges between areas, this phenomenon can be either static or dynamic (following a network incident) and can lead to :
  - . an overload (and then tripping of network items) ;
  - . electromechanical oscillations ;
  - . a less secure network (risk of instability in case of tripping or if a short-circuit occurs) ;
  - . out of step conditions.

2.1. FREQUENCY

2.1.1. Basic phenomenon

An incorrect value of frequency (too low or too high value) is due to an incorrect load-generation balance. This unbalance is normally automatically corrected by the governors of the generating units and by the load frequency control (LFC). But in case of a large disturbance, these actions on generation can be not large and not fast enough, so further actions are to be performed rapidly.

Significant unbalance can be due mainly to :

- . very bad forecasting of the load or very bad scheduling of the units ;
- . tripping of important generating units, substations or transmission lines ;
- . sectioning of systems into several parts ;
- . tripping of tie-lines.

In case of a frequency very different from the rated value, there are, of course, constraints on the customers loads but there are also important risks for the system itself, for instance :

- . islanding or even tripping of a lot of units (mainly due to incorrect auxiliary supply and actual limits of the turbine itself) ;
- . misoperation (non tripping or, on the contrary, unwanted tripping) of equipment protecting lines against short circuits.

2.1.2. Preventive actions

According to the risks mentioned above, utilities usually perform preventive actions, mainly :

- by improving methods for system planning, defining system parameters (for instance units characteristics), load forecasting, generation scheduling and for achieving automatic generation control (AGC) ;
- by preventing extension of network faults ; to fulfil this, several utilities have improved their protective system (high speed protections, duplicated functions, back up system, high speed

signal transmission between substations ...) and use more widely automatic reclosing (single and/ or three-phase) ;

- by improving the protections of the units in order to keep them connected to the network as far as possible, and to avoid a larger disturbance on the system due to a sudden and large lack of generation ;
- by improving, in the same way, the devices that can trip the tie-lines, in order to isolate the disturbed system from the neighbouring systems only when the risk of disturbance spreading is too great.

2.1.3. Corrective actions

a) Criteria used

In almost all the networks, automatic actions are based on a frequency measurement. But some utilities think that the use of this criterion only can be dangerous in some cases, mainly :

- actions performed can be insufficient or, on the contrary, too harsh (for instance in case of a frequency drop, shedding a too large amount of load can lead to a too high frequency with transient phenomena) ; to improve the actions performed in such a case, it is interesting to take into account the derivative of the frequency and then "calibrate" the action to the disturbance ;
- actions can be performed too early, meaning that unnecessary actions can take place during a transient evolution of the frequency ; to avoid such a case, it is possible to take into account the derivative of the frequency, or to introduce a time lag before performing the action, (but then, there is a risk to react too late in some cases).

Electronic frequency relays are now widely used because they are more accurate and fast. So it is possible to have many different settings in order to perform actions more specific and less harsh.

Previously the measurement of df/dt was not so easy to achieve with accuracy and reliability. Now it is easier with electronic and even digital devices, so this criterion begins to be used more widely.

b) Actions performed

In case of too high a frequency, actions are performed mainly on generation. But generally they consist only of islanding the unit when the frequency is too high regarding the security of the power plant.

It is necessary to point out that such a solution is risky, because it can lead to the tripping of a very large amount of generation and then to a frequency drop.

Some utilities begin to take into account such a risk and to implement devices able to rapidly decrease generation and/or to trip only a few units according to the level of frequency.

In case of frequency drop, some utilities usually increase rapidly and automatically the generation mainly by :

- starting fast units such as hydro power plants or gas turbines ;
- changing of hydro units mode from pump or synchronous compensator to generator ;
- increasing the power transmitted by HVDC links.

But the general rule in almost all the utilities is to decrease the load by :

- tripping the hydro pumped storage plants ;
- performing load shedding.

Some utilities usually perform preliminary or complementary splitting of the network, in order to correctly operate the sound regional networks, to confine the risk of black-out within a small area and to avoid any additional trouble due to incorrect power exchanges between areas.

One way of decreasing the load could be to decrease the voltage value, but such a solution seems to be used nowhere probably because it is easy to achieve such an action and also because it is difficult to calibrate the load shed by this method.

Regarding the load shedding some important remarks can be made :

- the amount of load shed must be as far as possible in accordance with the frequency drop ; to achieve that goal, it is possible to take into account the frequency derivative* (Italy,Brazil), or to have a lot of small load shedding steps (Canada,Australia, Portugal), or to compute predictively the generation deficiency that correspond to a combination of rate-of-change of frequency and frequency deviation (Australia), (see Chapter 3) ;
- if tie lines are not tripped before performing load shedding, it is necessary to coordinate the load shedding policies of the linked networks ;
- the load shedding relays must be set and must have response time coordinated in order to let the turbine governors react to the frequency drop before starting load shedding and also in order to have finished load shedding before tripping of the units ; however, on specific system conditions and in the case of a large generation deficit, the frequency rate of decrease is very fast and thus it can be necessary to perform load shedding without waiting for the governors actions.

Load shedding must not introduce constraints on the network, for instance :

. it can be necessary to trip shunt capacitances to avoid overvoltages ;
. load shedding relays are blocked (or time delayed) on generating areas, in order to perform load shedding first in consumption areas and then to avoid overload on transmission lines.

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* Since the frequency derivative is approximately : $\frac{df}{dt} = \frac{f}{T}\frac{\Delta P}{P}$ where f is the frequency before the disturbance, ΔP the amount of power unbalance, P the spinning capacity and T the average assumed system inertia constant.

. the load shedding relays must not operate in case of power oscillations, out-of-step operation or low voltage conditions.

Automatic reloading is generally not used. The reason is probably that the frequency return to the nominal value is not a valuable criterion since it is necessary, before performing reloading, to have a sufficient power margin on generating units and to check that reloading will not lead to dangerous situations on network (low voltage, overload ...).

However, Sweden is reported to perform successfully automatic restoration after load shedding. Automatic restoration following load shedding is also used in the USA by AEP and Pacific Gas & Electric /14/.

c) The future

In case of a large disturbance (for instance tripping of several large units due to a busbar fault), first the frequency is pretty steady thanks to the help from the other networks through the tie-lines; but after a few seconds the tie-lines can trip (due to overload, out-of-step operation...) and then the frequency decreases very quickly, so that the load shedding relays, based on a frequency measurement, can operate too late.

So, some studies are performed to get a valuable criterion directly from the load frequency control in order to shed the load, split up the network... before the frequency collapse and tie-lines tripping.

2.2. VOLTAGE

2.2.1. Basic phenomenon

The phenomenon feared by utilities is mainly a voltage collapse which is at first gradual but rapid after few minutes. This problem worries people operating networks, because:

. gradual decrease of voltage has initiated black-out in several systems or, at least, has led to very critical situations /1/;

. the problem being mainly a local one, it is not easy to find a simple and valuable criterion warning of an evolving dangerous situation.

This phenomenon of voltage collapse appears when the power to be transmitted is very near to the maximum possible according to voltage values at power plants and impedance value between generation and load. When this critical point is exceeded, any increase of load involves a voltage drop and a large increase of the reactive power lost in the network impedance. This phenomenon is accelerated (and becomes non reversing if no care is taken) because of the automatic operation of the transformer tap-changers which assess that the voltage is decreasing and so on.../2/.

In some networks, mainly networks around large cities including many underground cables, some sudden changes on system conditions can lead to a dangerous increase of voltage value.

In case of a voltage value very different from the rated one, there are constraints on the consumers loads but there are also important risks for the system itself (for instance islanding or even tripping of units, misoperation of protections...).

2.2.2. Preventive actions

Voltage collapse can be avoided by:

- Adequate planning of reactive power generation and absorption (location of power plants, rated cos of the units, compensation of the network, compensation of the load...),

- Improving the performances of the units.

- Helping the system operators to maintain automatically a right voltage profile: for instance, improvement of the automatic voltage regulators of the units, implementation of secondary voltage regulation (the reactive power generated by the units of an area is automatically controlled according to the voltage measured on the busbars of the main substations of the area), and even of tertiary voltage regulations.

2.2.3. Corrective actions

The problem of voltage collapse is not, at the present time, very well controlled and very few utilities usually perform automatic actions in such a case.

This can be understood, since the easiest criterion to reach (voltage value) is a local one (peculiar to each substation) and is not sufficient to evaluate correctly the proximity of the critical point /2/.

On the other hand it is not convenient to take into account, at substation level, values of active and reactive powers transmitted in the surrounding network, in order to evaluate the critical point (it would roughly consist of performing load flow calculation). One utility (France) is reported to intend to control some shunt capacitors located on high voltage network according to such a calculation performed automatically at substation level.

It is also possible to get an estimate of the reactive losses in the network by measuring voltage phase angles between substations /3/ (*).

(*) The sensitivity $\partial Q_{ij}/\partial \Phi_{ij}$ increases rapidly as a function of Φ_{ij}, according to $\sin(\Phi_{ij} - \theta_{ij})$, with Q_{ij} reactive power flowing into a line from the end i, Φ_{ij} voltage phase angle between the ends i and j, θ_{ij} line angle.

Another criterion that can be used to perform automatic action, is related to the secondary voltage regulation (if any). For instance France intends to energize some capacitors located on high voltage network when the reserve of reactive power of generating units available through the secondary voltage regulation becomes too low.

Actions performed in case of critical evolution of the voltage value are mainly the following:

- Change of the reactive power generated by the units:

  * automatically by the primary regulation (AVR) and, in few utilities, by the secondary voltage regulation (which is maintaining the voltage profile of a whole regional area),

  * manually in case of emergency;

- Switching on/off reactors, capacitors, synchronous compensators (this is done manually by a large number of utilities);

- Remote controlling, in some utilities, of the transformer tap-changer regulation in order to block them or to decrease their setting point (with the purpose to inhibit the unstabilizing action of the tap-changers in case of voltage collapse);

- Local load shedding and/or local network splitting (in very few utilities and in few cases very critical);

- Very rarely, changing the parameters of the voltage regulations (for instance, in France, in case of emergency, it is possible, only manually at the present time, to increase the gain of the secondary voltage regulation);

- Use of the units of the other areas: decreasing the generation of active power and increasing the generation of reactive power in the area with lack of reactive power so that generating units at large electrical distances can cooperate as efficiently as possible with the units in the area with low voltage.

2.3. INCORRECT EXCHANGES BETWEEN AREAS

2.3.1. Basic phenomenon

Power exchanged between areas of the same system can, in some cases, lead to critical situations. There can be:

- thermal overload of power lines or transformers, this overload can reach a lot of other lines or transformers by sequential trippings (trippings due to overload protection or to some damage caused to overloaded network components) (See the French black-out in 1978) /1/;

- instability (loss of steady state stability when the synchronizing torque is too weak regarding the power transmitted) /4/ /5/;

- dangerous operation of the system with the risk of losing the dynamic stability (mainly if a polyphase fault occurs).

These exchanges between areas can reach dangerous limits:

- because of the system structure itself: generation by nature far from the main towns (for instance, hydro power plants located in the North of Sweden and Quebec);

- when the generating units scheduling is done mainly on least cost basis or limited by other constraints (meaning that the network security is not surely achieved);

- when the action of the automatic generation control (AGC is generally based only on economical constraints) is not manually corrected from time to time by the system operators, according to network security assumption;

- in case of casual tripping of generating units, transmission lines or transformers.

2.3.2. Preventive actions

Preventive actions must be considered at the system planning level (location of generating units, network impedance between generation and load...).

Scheduling of units and power lines must take care of the risk of incorrect exchanges between areas, mainly in case of tripping of a system component.

Improvements can be made at several levels:

- metering system delivering enough information to people operating the system and allowing security checks to be made by the computers of the control centres,

- automatic generation control including constraints related to network security,

- implementation of network stabilizers,

- fast clearance of network short-circuits thanks to a fast and reliable protective system,

- use of automatic reclosure (including single-phase one) on transmission lines,

- command of the transient behaviour of generating units (fast excitation, fast valving, generator braking...).

2.3.3. Corrective actions

a) Overload

In this case, the disturbance affects generally a small area: thus the easiest criterion used to detect an overload is the local measurement of power (of current) flowing through transmission lines and transformers. Some utilities usually improve the measurement by taking into account some additional information such as air temperature, oil temperature (for transformers), memory of the previous overloads and even wind speed.

Corrective actions, mainly local load shedding and change of local generation, are performed manually by almost all the utilities.

(*) The sensitivity $\delta Qij/\delta \Phi ij$ increases rapidly as a function of Φij, according to $\sin(\Phi ij - \Theta ij)$, with Qij reactive power flowing into a line from the end i, Φij voltage phase angle between the ends i and j, Θij line angle.

Nevertheless, it is possible to quote some interesting recent developments as an example where the constraints are checked automatically on transmission network and automatic systems control directly generation and even load shedding (see Chapter 3).

b) Stability limits proximity

Until recently, the proximity of the stability limits was checked only by the network operators by power measurements made on some main power lines and in some cases, with the help of on-line load flow calculation.

Now, a few utilities are reported to operate their system with the help of automatic systems acting directly on generation to overcome temporary stability constraints on network (see Chapter 3).

Some countries tried to reach directly a very valuable criterion to detect the proximity of the stability limits- phase angles between the voltages of the main busbars and angles between the generator shafts. This measurement can be achieved by modelling the transmission lines (USSR) /6/ or by checking the shift of the voltage angles referring to very accurate clocks (Canada - France) /7/. Such a criterion can be very useful since several control applications can be foreseen: excitation control of generators, dynamic braking, thyristor controlled phase shifting transformers, load shedding, generation rejection, system separation... /3/.

Of course, when there is a risk of losing stability, the most efficient way to come back to a secure state of the system is to control generation and, in case of emergency, to perform local load shedding. Except for the few examples stated in Chapter 3, all these actions are usually performed manually.

It is interesting to mention the TEPCO (Japan) practice: to prevent out-of-step operation: according to the large amount of power flowing through the main lines, some generators can be automatically allowed to trip preventively if a fault occurs on a neighbouring transmission line and if this fault is not cleared fast enough /8/.

c) Instability of the system

Until now, in almost all the systems, power oscillations, phase swinging and out-of-step operation are detected by operating people finding out cyclic changes in some measurements of power or of voltage.

Some utilities have developed policies to react in case of out-of-step operation between parts of network in order to prevent network collapse. The criteria mainly used are:

. Changing rate of impedance detecting relay (detect dR/dt or dX/dt) (Japan) /11/,

. Cyclic changes of voltage value (Rumania, France) /13/ or of $|U \cos \varphi|$,

. Cyclic changes or reversal of the phase angle between two substations: this detection can be done in the same way as stated in Chapter b) or directly by applying phase comparison method for voltages, (instead of currents as it is done for power lines protection) (Japan) /8/; it can be estimated that the most important improvements in the field of out-of-step detection will be reached by using phase measurements from several points of the system and a centralized protection able to decide the suitable actions (unit tripping, network splitting...).

In case of loss of stability between areas, there are two main policies:

- either to perform network splitting, in a controlled manner, in order to get segregated systems able to operate by themselves (*); these subsystems can be determined in advance (for instance, as it is done in France, by implementing out-of-step detectors on the lines linking subsystems), or these subsystems can be determined and controlled in real time (Japan) /11/;

- or to trip the line or the transformer being the centre of the out-of-step swing locus, this can be done by specific detectors (voltage phase comparison for instance) or by letting the distance relays operate (no anti-hunting device); but if such a method is applied there is a risk of sequential (and then too late) trippings due to this locus shifting from a tripped line to another not yet tripped.

In both cases, it is necessary to implement some out-of-step protections at power stations able to trip units (see 2nd part), at least as a back-up, when network splitting is not successful or done too late and when the constraints on units are too heavy.

Some studies can also be mentioned which aim at controlling very rapidly generation if an out-of-step operation is detected, but it seems that there is no actual application.

3. EXAMPLES OF INTEGRATED TECHNIQUES FOR SYSTEM STABILIZATION

At present there are some examples of systems where specific relaying practices are applied to prevent an evolving dangerous situation.

The application of such policies is generally done by implementing intricate systems with many electronic or computer based equipments linked by high speed telecommunication channels.

These stabilizing systems are generally able to react in case of frequency drop, overload, voltage phase angle shifting...

The main actions performed are generation control, load-shedding, network splitting.

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* That means:

- that each subsystem must remain stable: speed and voltage regulations of the units are to be designed according to such a goal;

- that load and generation must be balanced in each subsystem: load shedding and generation rejection must be automatically performed, if necessary, after system separation.

Some examples are given below:

3.1. AUSTRALIA /12/

We can point out three main automatic control features.

3.1.1. Automatic load shedding

This one acts to secure the Victorian system against loss of the interconnection with New South Wales under high transfer condition.

This centralized device:

- calculates the actual deficiency in megawatts according to the frequency drop, the frequency derivative, the system inertia constant and the frequency dependence of the load;
- compares the generation deficiency with telemetered values of the various load blocks available to be shed;
- transmits tripping signals to shed the appropriate number of blocks (at each substation, an underfrequency check relay prevents false tripping).

3.1.2. Automatic islanding

A control scheme has been installed to automatically isolate and stabilize Morwell Power Station generation and associated customer load as an island in the event of a severe system disturbance.

Formation of Morwell island can be initiated for:

- very low frequency condition

- system instability, the detection of approaching instability is achieved by measuring the accelerating power to which machines are subjected by a fault condition

- loss of the two main transmission lines between Morwell and the other part of the system.

After the formation of the island, this one is stabilized thanks to machine governing action and load shedding, if necessary.

3.1.3 Control scheme for braking resistor application

Most of the Gladstone station's output is transmitted 500km over a 275kV system. To improve the stability a 300 MW braking resistor has been installed at Gladstone. This one is energized for 0.4 seconds after a delay of 0.15 seconds from fault inception (detected by sudden power changes).

3.2. ITALY

In the ENEL network, due to its longitudinal structure, special care must be taken about power flows. Two automatic devices can be briefly described:

- Loads in appropriate substations are automatically disconnected following the loss of an important 380 kV line, if the previous power flow of that line was greater than a preset value or if the voltage value becomes too low;
- In some sections, when one or several circuits are lost, a device is able to trip generators in the exporting area and to shed load in the importing area: these devices are activated by the Area Control Center when the operator thinks that (n-1) security is not achieved.

3.3. JAPAN

3.3.1. The Chubu Electric Power Co.system stabilizing systems /11/

This utility has introduced fundamental technics to prevent large disturbance (improvement of relay reliability, sensitivity, speed...) and has developed system stabilizing control systems such as:

a) System segregation in case of out-of-step operation

Out-of-step detectors (directional impedance relay combined with changing rate of impedance relay) are installed in the main substations.

The second parts of these devices select the most suitable segregating point thanks to the output signals sent by their own detector and the ones located at the adjacent substations.

b) Emergency control

In case of a severe fault occurring in a subsystem, power swings, frequency fluctuations, difficulties to support power interconnection and even system collapse can take place.

Thanks to a hierarchical system of computers (central load dispatching centre, master-sets at 500kV substations, satellite-sets at 275 kV substations):

- the amount of power to be controlled in each subsystem is determined every 5 minutes (according to the power flow on the trunk lines),
- the corresponding power is allocated to the feeders and pumping stations (in case of underfrequency) or generators (in case of overfrequency),
- if a fault happens, the master set sends control signals in order to disconnect the controlled objects within 0.2 seconds.

c) Overload control

According to overload detected on transmission lines by high speed overcurrent relays, adjusting signals, or even tripping signal, (in case of emergency), are sent to the generating units.

3.3.2. Tokyo Electric Power Company's relaying practices for prevention of power system failure extension /8/

To further the improvements ofthe protective system for fault clearing, we can quote:

a) Out-of-step preventive relaying scheme

A microprocessor based device located at power station memorizes generated powers and power flows on the surrounding area (power flow data are sent every minute by the adjacent substations).

Whenever a protection relay of a substation operates and if the clearing time exceeds 100ms, a triggering signal is sent to the power station.

A calculation is effected (within 150ms) by the microprocessor of the station (according to fault mode and power flow condition before fault) and selected generators are automatically tripped.

b) Overload elimination relaying scheme

In case of overload on a transmission line, generating power increasing signals are automatically sent to power plants located at the importing end of the line and decreasing signals are sent to the stations located at the other end.

If the overload cannot be absorbed, load shedding signals are also transmitted to adequate substations.

3.4. POLAND /9/

To maintain power system stability in post-fault condition, Poland has installed, in the most exposed generating nodes, special automata which, just after fault clearing, perform a program of preventive controls.

Initiating events can be: short-circuits on busbars or near the power station, tripping of heavy loaded line or transformer, too large amount of power transmitted through the inter-system lines.

In case of disturbance, characteristics of this one are compared to previously determined situations where stability can be lost.

According to that identification, predetermined controls are sent to trip feeders and/or generating units.

In the future, it is intended to improve the system by:
- using microprocessors,
- replacing generators tripping orders by quick transient decrease of the turbines output.

3.5. QUEBEC

We can mention the system implemented by Hydro Quebec to prevent out-of-step operation and the spreading of a distrubance.

In case of disturbance (for instance tripping of lines transmitting a large amount of power or loss of several generating units) this system can control rapidly the generation and the load, for example:

- in case of tripping of some predetermined lines one or more shunt reactors (according to the power previously transmitted) are teletripped,
- in case of tripping of some predetermined lines, some generating units are teletripped,
- in case of loss of a large amount of generation, coming from the N.W. part of the system, thanks to a double microprocessor system, load shedding controls are sent, (in less than 200ms) to 24kV substations.

This system has been implemented to prevent loss of stability and/or voltage collapse due to a too large increase of the power generated and transmitted on the N.E. part of the system (that subsystem trying to compensate too much for the power lost in the other subsystem).

3.6. USSR /6/

USSR has developed and put into operation a number of multifunction automatic devices to control active power of thermal and hydropower plants, with the aim of maintaining steady-state and transient stability of the power system.

The main features are:

- device for the determination of:
  - . voltage phase difference between the power system parts,
  - . relative pole slipping between them,
  - . transmission line overload.
- device for the determination of:
  - . prefault and post fault load flow
  - . rate of power change on transmission lines.
- device for the calculation of emergency unloading of power plants for maintaining stability (this emergency unloading is calculated when a fault occurs and according to a polynominal dependence between unloading and prefault and postfault system parameters).
- device for the determination of generators to be tripped,
- device for controlling the output power of steam turbines.

Through the use of such devices, it has been estimated that the transfer capacity of some 15 main links has been increased by about 7GW.

3.7. YUGOSLAVIA /10/

We can also briefly describe the power system emergency control under study and development in Yugoslavia.

The automata organisation should be hierarchical with three levels:

- coordinating device which:
  - . detects the type of situation (deviation from the scheduled interchange on tie-lines, overload, main transmission lines or transformers or units tripping);
  - . delegates the execution to the device of the subsystem in which the outage occurred.
- subsystem devices which execute the following actions based on prior recognition of the disturbance pattern:
  - . activation of spinning reserve
  - . starting up of additional units (gas, hydro)
  - . load shedding
  - . voltage reduction at distribution level
  - . disconnection of preselected lines
  - . sectionalizing the network.
- local devices, located at power plants, substations and some main consumers, which carry out:
  - . changing of unit output power
  - . unit starting up
  - . injection of voice frequency controls into MV and LV networks
  - . transformer tap changing
  - . line disconnection.

4TH PART

AUTOMATIC RESTORATION AFTER A LARGE SCALE SHUT-DOWN

CONTENTS

1. GENERAL

Over the past years there have been small and large black-outs in many countries. The nature of their origin is rather varied: short-circuits in busbars not eliminated in time which let the whole system enter an unstable mode; unbalance between production and demand, etc. After a black-out, studies are made about the main reasons (e.g. weak points of equipment used in controlling and monitoring the system). Corrective action is taken as required, and increasing sophisticated systems are established for detection and correction of disturbances in the system.

However, should the measures adopted as described in the former parts of the report be insufficient or in the case of failures in cascade taking place (such as faults in terminals which were not correctly eliminated due to failure of protections), the security given by the (n-1) rule can be surpassed, falling then to a quick process of degradation of the network which can produce a black-out. Then it is necessary to minimize the effects of such a black out and then to have a "black start policy" with 2 steps.

a) Preparation of network for restoration
b) Voltage restoration

Such steps, in most countries, have been carried out for many years manually, by substation personnel and under the supervision of the dispatching center. The manual restoration can be satisfactory but it usually takes too long a time (4-6 hours) and there are serious difficulties.

Such difficulties are described practically in all reports on large black-outs (auxiliary supply, air pressure for control of breakers, failure in communications, overload of information in the dispatching center, and so forth). The problems are increasing with the time of disturbance, leading in many cases to a complete breakdown when the disturbance may persist for over 12 hours.

A black-out of such an extent, in addition to causing significant financial loss to the utilities and to other industries, also causes rather relevant social loss. Black-out over several hours may create a panic situation in large cities; so that any measures intended to reduce the time of black-out, are to be considered as high priority. For instance, E.D.F. estimate is $ 150,000,000 cost of the black-out of December 19, 1978* ; the total cost of the New York city black-out on July 13 and 14, 1977 was $ 350,000,000 (including a cost of $ 170,000,000 for looting and vandalism)**.

Probability of a black-out in a country or region depends greatly on its structure and interconnections of the network. A black-out situation occurs very seldom in strong networks with protection equipment to ensure quick and selective elimination of faults. Thus, it can be seen that countries which, due to geographic or other problems have a lower number of interconnection lines or a greater energy transmission distance from generation to demand, are the most affected ones.

* Investigation of French Black-out - RANSOM & CASAZZA Inc.

** Impact Assessment of NYC Black-out. Department of Energy

In quite a number of countries remote control of substations has been established over the past years, either through several low level control centers monitoring 4 or 6 substations each, or through a high level remote control center for the whole system. These extensive facilities give a complete view of the system and thus more resources available for decision-making; the measures taken to solve small incidents or to prevent dangerous situations in the system are far better than in the past. However, in case of a big disturbance, the dispatching center will receive an overload of information, able to produce real information chaos. But this information is indispensable in order to be able to assess the true state of the network and, depending on the result, be in a position to take the necessary corrective measures. In addition to this problem, which can be partly solved by technical means (e.g. filtering the information with the balance to be recorded for further evaluation during disturbance analysis), it is found that, with the means currently available to the operator, it is difficult for him to carry out satisfactorily all the operations required in order to restore the network, due to the large number of operations to be done. Even if the operator should not make any mistake due to the natural nervousness of the moment, the time required for restoration will be unacceptably long; because from having one operator at each substation, with all of them working in the same time,the change is that there are now only a few people (in the case of a low level remote control center).

To speed up voltage restoration and at the same time increase safety, there are several actions to be adopted, as e.g.:

a) to facilitate visualizing and operation of the primary system by active control boards;

b) to hurry up transit of information between remote stations and dispatching centers;

c) possibility of complex orders (one order only for several connections or disconnections in different substations);

d) computer-to-computer linkage between control centers for information exchange;

e) installation of automatic restoration equipment in the facilities.

In this report, only the last mentioned item will be described. This type of equipment cannot perform by itself the whole restoration of a network, but is is very helpful to network operators.

2. SYSTEM PREPARATION FOR RESTORATION

Practically all utilities have operational instructions available, specifying the actions to be effected by operators in case of system disturbance, without having to contact the dispatching center previously, and, of course, these instructions include also the possibility of black-out.

The first of the operations specified is to open almost all power line breakers, in case of zero voltage. Of course, automatic service restoration equipment (ARE) should carry out in the first place such trippings.

Therefore they are equipped with zero voltage tripping devices with adequate timing in order to avoid trips by undervoltage, due to fault. In order to get safety all three phase voltages are checked, or voltage testing is done both at line and busbar sides. Zero voltage causes the breakers to trip and at the same time ARE are started in order to proceed to restoration.

Of the two ways of acting in case of black-out, the first one, opening the breakers, is the most common and easy to carry out; however, there is the disadvantage of having to operate all network breakers, thus increasing the possibility of some incorrect action or failure, and in the case of operation with air breakers, there is an increased air consumption, this may cause serious delay in restoration.

In some utilities a second solution is used in order to leave prepared some paths between the points with hydro or gas turbine generation and the large thermal units, so as to ensure auxiliary power as soon as possible and to reduce the risk of total lack of this power.

This method is normally used when hydro plants are near by (passing through one or two substations) and the network is established in such a way that it can be assured that the voltage will appear always in the same place, as otherwise, leaving lines connected would only complicate restoration.

In order to avoid voltage increase at the time of energizing the network, reactors (if available) are connected; some utilities are reported to use banks of two transformers: regulation of one is set to the maximum and the other one to the minimum, in order to produce circulation of reactive current and then have these two transformers acting as a reactor.

3. VOLTAGE RESTORATION

After preparation of the network and voltage recovery at any point of it, it is required to proceed to its reconstruction. The goal is to get the network, if possible, in the same situation as before the disturbance, excluding however from operation all defective components or components the connection of which may lead to zero again. The possibility of carrying out these operations automatically will be very helpful, offering the following major advantages:

- the restoration will be much faster when using automatic equipment instead of manual restoration and can speed up the reconnection of islanded thermal units;
- personnel mistakes often appear during large disturbances because of the stress situation; ARE can partly eliminate these;
- the local equipment for automatic restoration can be designed in such a way that it is redundant to the remote control system;
- if there are stations which are not attended and have not remote control either, it seems to be of very good benefit to install automatic restoration in such stations.

In fact in most transmission lines there are different equipments installed for automatic reclosing mainly after a short-circuit.

Single-phase reclosing and high speed three-phase reclosing normally are installed not only for automatic restoration itself. It is also of great benefit for the stability of the network (since the majority of faults are not permanent).

Three-phase reclosing with synchronous check is normally programmed so that the line is energized from one end and synchronized at the other end. This reclosing is usually very slow and is not of any benefit for the stability of the network. Often power lines are equiped with both single phase reclosing and slow three-phase reclosing with synchronous check. The last one can be considered as the first stage of automatic restoration.

But there is a fundamental difference between the functions of auto-reclosure and of ARE. The reclosing equipment is started through operation of a protection (distance, phase comparison, etc). Automatic restoration is started through zero voltage detectors or by a manual control.

Restoration equipments, though designed with different technologies (electromechanical, electronic, microprocessor, etc) have in common that, either segregated or integrated, they are generally organized in such a way that a common unit controls priority and each terminal has an individual module. In this module all values and signals required are carried out, adjustments and setting are programmed, and the pertinent orders and signals are transmitted to the circuit-breaker.

The ARE is a local equipment and though in some instances it may be designed to operate with signals coming from the dispatching center or other substations, it has an internal logic system which in case of failure in communications is able to operate independently, just as an operator would, with the intent to restore the network in the same fashion.

For each terminal it is possible to program specific conditions to comply with, in order to enable zero voltage connection, reception, sending and closing of voltage.

It is also possible to program the order of priority between terminals and timing between two consecutive connections.

Where it is intended to close a circuit-breaker with voltage present at both sides, it is necessary to check synchronism. Generally, for this check, the same substation equipments are used as for manual connections and if there is no synchronism this is checked cyclically until synchronous conditions are met; during this time, information (e.g. phase angle) is generally sent to the remote control center to allow operators to perform corrective actions on generation.

If, when connecting a terminal there is a trip or zero voltage again, the respective terminal remains out of operation while restoration in other terminals continues. Should such terminal be the first one connected to the busbar, the whole restoration will be blocked.

The ARE allow general type blocking, so as to render inoperative all terminals at the same time. Besides, it allows individual blocking avoiding reconnection of a terminal (e.g. in order to allow inspection of equipment before connection, for instance if Buchholz or differential protection has been actuated).

Should the ARE detect any abnormal state of operation (autotest in case of micros) or in external circuits (low air pressure, voltage circuit fuses blown, etc), the terminal or the whole equipment, as the case may be are put out of service.

In addition to the functions described earlier, there are others, as the stand-by position in which the ARE stops; upon order of the operator operation is started again at the point where it had stopped.

The ARE function is also used for the case of voltage control being required before connecting a line, in order to avoid excess voltages or risks, or in order to allow connection of load, reactors, capacitor batteries, depending on current, voltage, cos φ, frequency, etc.

In the case of ARE removed from a terminal, if an attempt is made to connect it again either from the local or remote control, logically all the rest of the terminals should be locked so as to avoid automatic operations interfering with the manual ones.

4. EXPERIENCES

The ARE, as compared with other reclosing equipment, is so far not used in many countries, in spite of the increasingly complex electrical systems and in spite of control of substations through control centers, which are becoming more common.

As an example of such equipment, we may describe the most relevant characteristics of the equipment installed in Sweden, Spain and France.

SWEDEN

Almost all 400 and 220kV stations are equipped with local equipment for automatic restoration. At the present time, about one hundred equipments are installed on the 400-220kV network. If all voltage levels are taken into consideration, the total number of equipments is about 200. Some of these are electromechanical and some are of static types and others are computer based.

Normally all breakers in a substation can be operated by means of remote control system. The operator in the operating center, however, may have several stations to take care of. The local equipment used for restoration can be a great help to him in the case of a large scale shut-down.

The present policy is to install such equipment in all new substations. This equipment will not replace equipment for automatic high speed reclosing.

The motive for using automatic restoration is as follows: faster restoration; to eliminate personnel errors; redundancy to the remote control.

After a complete black-out, usually one station must start the restoration manually. As soon as voltage appears on one line or one busbar in a station, the automatic equipment will continue the restoration until all breakers in the station have been closed. If black-out covers only a part of the network the automatic restoration usually will be successful. The experiences from large disturbance are few.

In the equipment there are voltage relays which release the equipment if the voltage is higher than $\approx$ 80% of the normal voltage. In some cases there are voltage relays which will block the restoration if the voltage is higher $\approx$ 115% of the normal voltage. Normally there are under-frequency relays in the automatic restoration equipment for power lines feeding load centres. If the frequency is lower than 49.8Hz, the restoration will be blocked.

There is automatic restoration after load shedding. In this case the restoration is controlled by means of frequency relays. The load is split in small pieces. If too much load has been connected to the network, the frequency will drop below 49.8Hz. The restoration will be blocked until the frequency is higher than 49.8Hz. The experience from this equipment is good.

The automatic restoration equipment can be blocked from the operating centre. When the operator wants to continue with restoration it is possible to override the blocking.

Normally, hydro units and gas turbines are started and synchronized with the network by means of separate automatic devices and these can be initiated by ARE.

SPAIN

The equipment is unique for each substation, designed with microprocessor technique, and working together with the dispatching center. In addition to the conventional features of voltage restoration, it carries out a second reclosure of lines after three-phase tripping and unsuccessful autoreclosure, transmits the isolators position to the dispatching center, controls reloading of the system (reclosing of the distribution feeders is performed, step by step, only when receiving signals from the control center). Regarding voltage restoration, when there is a failure in communication with the dispatching center, after having received the blocking signal from dispatching, the ARE unblocks itself and continues restoring as required, blocking itself again after restoration of the communication link.

In order to avoid the avalanche of signals, produced in the event of a black-out, from masking the alarms which are indispensable to know the network situation and the possible cause of disturbance, the ARE of every substation block (from 200ms before the trip of the first circuit-breaker for zero voltage until after the last part of restoration) all alarms concerning this substation (overcoming of limit U.I., variation of circuit-breaker position, etc.) excepting those corresponding to mainly protections, communication failures, etc.

Nevertheless, all information is compiled in a magnetic tape for later study. During the blocking, the operator of the control center is informed of the real conditions by an active synoptic panel of 220 - 400kV networks and by the displays with telemeasurements and the circuit-breakers position of the 110 - 25 - 11kV networks.

FRANCE

1. - In case of a large scale shud-down it is necessary to have automatic devices which can help to restore quickly the network to a normal situation.

So it is necessary to:

. disconnect the loads,

. prepare the closing of a few breakers in order to supply the auxiliaries of thermal units as soon as hydro power plants are able to run again,

. reenergize the feeders avoiding excessive high voltage or self-excitation of generators,

. be able to reconnect easily two parts of the system,

. avoid unnecessary switching of breakers.

2. - To achieve such a goal, automatic devices are implemented on the French network.

. NO VOLTAGE TRIP AND RESTORATION

Generally feeders and transformers are fitted out with an automaton which can:

. trip the breaker in case of a lack of voltage (lasting more than 20sec),

. reclose the breaker after voltage recovery; this closing is performed, according to one or several preset programs:

- to reenergize the busbars from the feeder,
- to reenergize the feeder from the busbars,
- to reconnect the feeder to the busbars after synchrochecking.

. AUTOMATIC COUPLER

In the main substations, where it is necessary to reconnect two parts of the system, an automatic coupler can be switched on from the remote control center. This coupler delivers to the control center information relating to the differences of frequency, phase and voltage values between the two parts of the system.

When the differences are not too large, the coupler closes the breaker (when the beat due to the frequency difference is crossing zero).

ANALYSIS OF THE ANSWERS TO THE QUESTIONNAIRE

ISSUED BY WORKING GROUP

34.01

FOREWORD

In March 1981, WG 34.01 issued a questionnaire dealing with the general problem of harmonization

- of protection policies for power stations and generators,
- and of protection policies for high voltage networks.

This questionnaire comprised 6 parts:

- general questions about the network and the basic policies of protection and autoreclosure;
- questions related to the fatigue of generating units due to distrubances, switching operations and abnormal operating conditions in the network;
- questions about loss of field, out-of-step operation and anti-hunting policies;
- inquiry about criteria for isolating power plants and equipments to separate the generators from the network under abnormal conditions of voltage, frequency or other;
- questions investigating what can be done automatically to prevent a large scale shut-down;
- inquiry about the automatic operations that can help in a rapid restoration of the network after a black-out.

The questionnaire was sent to 27 countries and answers have been received from 41 utilities.

Detailed analysis of the answers has been carried out by the members of the Working Group (*), the purpose of this paper is to summarize this analysis and point out the most valuable information.

I. GENERAL QUESTIONS

1) The main point to note is that the electrical systems become more and more difficult to operate, since:

- short-circuit currents (both single and three-phase) are increasing (30-40 GVA are often mentioned);

- large generating units are numerous (13 countries have units rating more than 500 MVA, 10 countries will have in the near future units rating more then 1200 MVA);

- stability margins are decreasing (in many utilities, multiphase faults are to be cleared in less than 100-200 ms);

- many components of the system must be protected against high stresses and fatigue (metal-clad substations, nuclear units, turbine shafts...)

2) It appears that, according to such an evolution of the electrical systems, utilities have made many improvements regarding the protection of the EHV networks, mainly near the large generating units:

- redundancy is very often applied (32 utilities have two main protections on their EHV transmission lines)

- rapidity is increased, both on protective devices (2 cycles tripping time is often achieved) and on breakers (2 cycles operating time becomes more and more common);

- new protective schemes are applied very often (33 utilities use busbar protections, 36 utilities have implemented breaker failure protections).

3) Regarding autoreclosure policy, it seems that single-phase autoreclosure plus three-phase autoreclosure with synchrocheck is more and more often applied (26 utilities), since high speed three phase autoreclosure (used by 11 utilities) is reported to be risky for the large units.

II. THE EFFECTS OF H.V. NETWORK FAULTS AND SWITCHING OPERATIONS ON LARGE TURBINE GENERATORS

1) Regarding this problem, 26 utilities stated their concern; but if we do not take into account the utilities which have predominantly hydroplants or only generating units smaller than 300 MVA, the percentage of concerned utilities would increase to nearly 100%.

2) Among the utilities concerned by this problem, the events considered to be the cause of a significant life expenditure were distributed as follows:

Events considered the most preoccupying	"Yes" answered
- close in three phase short-circuits	17
- out-of-step operation of the unit	13
- subsynchronous resonance	4
- faulty synchronization	16
- autoreclosure	13
- cumulative fatigue effect of disturbances	18
- stability aids (such as braking resistor switching, fast valving)	4

3) Regarding the protective system, several utilities have introduced specific measures and improvements as a consequence of the shaft fatigue problem. It seems, however, that in most cases, this problem was not the only reason (the other being mainly transient stability).

Improvements or specific measures	Number of utilities where applied
- high speed protective relays	16
- faster circuit-breakers	14
- measures to increase the dependability	11
- fast busbar decoupling	6
- others	7

- 5 utilities are reported to use back-up protection to separate the turboset, if a fault is not cleared fast enough, these protections being applied mainly to reduce the shaft fatigue.

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* Corresponding papers are available if anyone is interested to have them.

4) Regarding the autoreclosure policies, it is obvious that many utilities have changed their mind and adopted restrictions near the large units in order to decrease the shaft fatigue. Corresponding answers are:

Restrictions adopted	Number of utilities concerned
- no autoreclosure at all	3
- only single pole autoreclosure	9
- ARC blocked if fault is near the power plant	1
- ARC blocked if three phase fault	9
- provision of synchrocheck relays	12
- reenergization only from the remote end	9
- changes in the settings	3
- check on current flow on parallel lines	1

5) On-line monitoring equipments, to evaluate the fatigue effects of electrical disturbances, were reported to be in operation in three cases; in six further cases an installation is planned.

6) Concerning information collected from system operation, it seems that most utilities have not made a final decision and are therefore reluctant to deliver information about damage noted in connection with electrical disturbances on the network or about actual tests performed on generators to evaluate the fatigue effects.

III. LOSS OF FIELD, OUT-OF-STEP OPERATION, ANTI-HUNTING

Almost all the utilities use loss of field relays. These relays are far more widely used than generator out-of-step relays.

Regarding out-of-step operation, there is no agreement on whether it is advisable to trip units as soon as possible or to allow the system to try resynchronizing. Nevertheless it can be stated that:

- many utilities have made a lot of improvements to prevent out-of-step operation (high speed protective equipments, autoreclosure policy, high performance excitation systems...), even some utilities consider that out-of-step operation is almost impossible in their system;

- less than half the utilities use dedicated generator out-of-step relays;

- less than half the utilities prefer to keep the units connected and split up the network; this network splitting is generally performed by the distance protections since they have no anti-hunting devices, only very few countries usually perform this network splitting in a controlled manner (using either phase comparison of the voltages of two substations, or changing the rate of impedance relays or cyclic changes of voltage value checking;

- in some countries, studies are carried out on automatic devices, using telecommunication links, able to prevent out-of-step operation (by fast changing of the generations set points for instance), to detect such a disturbance and to perform corrective actions (e.g. network splitting); some automata are even under operation but, at the present time, we cannot say that it exists in actual on-line centralized out-of-step protection.

IV. CRITERIA FOR ISOLATING POWER PLANTS

This part of the questionnaire covered criteria for isolating power plants and equipment to separate the generators from the network under abnormal conditions of voltage, frequency or others.

The answers received seem to represent a heterogeneous collection of opinions. However it was possible to focus the various items to principal blocks of statements. The percentage of the various meanings is indicated in the following comments.

1) Unbalanced load

Unbalanced load relays are mentioned in 75% of the answers. The greater part of the information indicates only one step, used for trip or isolating actions (65%). The types of relays used are either I_2^2t = constant (66%) or constant time negative sequence overcurrent. One reply mentions inhibition of the relay in case of low load of the generator. Another reply mentions cascaded elimination of unbalance, first islanding then trip.

2) Step-up transformer neutral current and voltage

Neutral current criterion is used in 40% of the answers, neutral voltage in nearly 16%. Actions are islanding or trip, in one answer cascaded action is mentioned. Another answer mentions a thermal type characteristic for the zero sequence relay.

3) High level fault currents

In 45% of the answers, the criterion used is trip of the generator, in 20% of the cases islanding is mentioned.

4) Distance relay on HV side of the step-up transformer

20% of the answers indicate network directed distance relay action for generator trip. Half of these use two distinct steps.

In 40% of the replies the same criterion is mentioned for islanding, also with roughly half of them distinguishing two steps.

Distance relay action in generator direction is used in 45% of the replies for generator trip (as back-up protection), only 10% attempt islanding for the same condition.

5) Distance relay on the generator side

Use of this criterion is mentioned in 50% of the answers. Of these roughly half use one single step.

Actions are trip (in the great majority) or islanding.

6) Low voltage

This criterion is used in 26% of the answers. Most users indicate islanding and cascade tripping. A minority goes for direct trip, probably through scram of reactor.

First remark: the criterion seems to be systematically applied to hydro and particularly pump storage units.

Secondly, one answer mentions the criterion to initiate transfer of auxiliaries to a source of safe supply (in nuclear stations).

7) High voltage

The criterion is used in 82% of the answers, mainly for direct trip. Two contributions mention a dual stage protection.

8) High frequency

This criterion is used in 47% of the answers; of these only a few consider only islanding, the others both islanding and trip.

Most of the protections mentioned are purely mechanical (overspeed).

One reply considers only for pumping storage, another reply uses the criterion for initiating transfer of auxiliaries to safe supply.

9) Low frequency (non nuclear units)

The low frequency criterion is used in 55% of the replies. A great majority initiate islanding (and cascade tripping), a minority goes for direct tripping. One reply indicates also the use of a df/dt criterion (with low frequency) for islanding purposes.

10) Low frequency (nuclear units)

The 15 replies (out of a total of 17) mention low frequency for nuclear units. Three of them go for direct trip, the others consider first an islanding step.

11) Overfluxing

55% of the replies indicate the overfluxing criterion. Most of them consider only the trip action. In 25% of the relay applications, a separate islanding step is considered and only one case performs only islanding and no tripping.

The criterion is sometimes disabled (3 cases mentioned), when the HV breaker is closed. The problem is mentioned particularly for big step-up transformers.

12) Oscillations

Oscillations are mentioned in 4 reports. It is not clear how the criterion is detected and used although the 4 reports mention trip and islanding actions.

60% of the answers consider that there is a reasonable risk for oscillations in their power systems. Nearly 44% of these companies apply power system stabilizers in this respect.

Are also mentioned angle deviation stabilizers as well as static shunt var systems. These can however not be considered as protection devices.

13) Subsynchronous resonance

No information can be drawn from the answers to the questionnaire, except for one contribution which mentions the problem without, however, referring to a protective measure.

14) Others

One answer mentions generator islanding relay based on ΔP, intended to limit torsional stresses on the generator (refer to Chapter 2).

V. WARNING CRITERIA OF AN EVOLVING DANGEROUS SITUATION

This part of the questionnaire investigated what can be done automatically to prevent a large scale shut-down.

Relevant information was collected regarding three main items: frequency drop, voltage drop and incorrect exchanges between areas.

1) Frequency drop

. Measurements

Most of the utilities use the frequency measurement. The frequency derivative measurement is adopted by nine utilities, seven of them using the derivative measurement as an additional criterion and two of them as a basic criterion.

. Actions

Load shedding is applied or is under consideration by all countries (at least in certain areas).

The number of steps generally varies from two to six. The four-step scheme seems to be the most popular.

The frequency setting for the first step varies from 48.2 to 49.6 Hz in 50 Hz systems and from 58.5 to 59.3 Hz in 60 Hz systems respectively. The first step is practically instantaneous in every case, and the amount of load to be shed in the first step varies from 3.5% to 30%. The frequency setting for the last step varies from 45.4 Hz to 48.5 Hz in the 50 Hz systems and from 57.5 Hz to 58.3 Hz in the 60 Hz systems, respectively.

The total amount of the automatic load shedding varies from 10 to 90%, the average being approximately 50%.

The tripping of pumped-storage power plants (in pumping mode) during the frequency decrease seems to be the normal practice since 15 answers have specified that kind of policy.

The automatic starting of fast units (gas turbines, pumped-storage power plants, diesel sets, hydro power plants) is a normal practice because more than half of the answers have specified this policy.

The tripping of tie lines is used in very rare cases, because only 10% of the answers specified this practice. The same applies to the splitting of the network.

2) Voltage drop

. Measurements

All utilities specify that they use the voltage measurement of the main busbars as a warning criterion as regards the voltage drop. Only in some cases the utilities take into account the active and reactive power transmitted by power transformers, power lines, etc.

The criteria

. Actions

Switching on/off capacitor banks, reactors, synchronous compensators or other compensation devices takes place automatically in half of the cases and manually for the other half.

The blocking of tap-changers of power transformers during a voltage drop is performed (mainly manually) in some countries (12%), but the normal practice is to have no blocking. The same applies to the local load shedding as regards the voltage decrease.

The decreasing of set point of tap changers of power transformers is not normal practice. This policy is adopted only in few countries.

The splitting of the network due to low voltage in the network is not performed automatically. The splitting is applied to a certain extent in very few subtransmission systems.

3) Incorrect power exchanges between areas

. Overload

The current measurement and the power measurement are approximately equal as regards their use as a warning criterion for overload. The same applies to the supervision of the oil temperature in power transformers. The air temperature, previous overloads and in some cases even the wind speed are taken into account in few countries when evaluating the overload situation.

Automatic actions due to the overload are not as usual as manual actions. Of course the items provided with an overload protection (e.g. power transformers, generators) are tripped automatically if an overload condition appears. But the overhead transmission lines are seldom provided with separate overload protection and therefore, the reduction of the overload on transmission lines requires manual action.

The local automatic load shedding due to the overload is applied in 4 countries and to a certain extent only. The automatic decreasing of local generation is executed in 6 countries.

. Proximity of stability limits

Almost all countries have specified that they use the measurement of power transmitted between areas as a warning criterion. On the other hand it can be noticed that the phase-angle measurement is very seldom appmied or under consideration.

The automatic local load shedding due to the proximity of stability limits is only adopted in 2 countries. Only in few utilities are automatic actions performed on local generation.

To a certain extent, changing of the tripping time of the generating units is applied in one country, in case of decrease of stability margin.

. Power oscillations between areas

Detecting a cyclic change of the voltage or of the active and/or reactive power (on lines, transformers) is the most common way to indicate the power oscillations between areas. Almost half of the answers received have specified this warning criterion.

The splitting of the network during power oscillations is performed automatically in very few cases.

The decreasing of transmitted power between areas (in order to get a better balance between the load and generation in each area) is performed manually, except in very few cases where automatic actions are applied.

VI. AUTOMATIC RESTORATION AFTER A BLACK-OUT

The last part of the questionnaire was dealing with the criterion and automatic restoration equipment for a rapid return to a normal situation after a large scale shut-down.

After general questions related to the ways of operating the network, 2 points were analysed in more detail: what to do automatically to help the operators prepare the network for the restoration and the voltage restoration itself.

1) Remote control of the system

Regarding hydro power plants, 55% of the countries have the possibility of controlling these plants from a Low Level Remote Control Center (L.L.R.C.C.) and 30% from a High Level Remote Control Center (H.L.R.C.C.).

As regards gas turbines and diesel sets, it seems that remote control (at least starting orders) is common practice.

As regards substations, most countries use the L.L.R.C.C. (75%) and local operation. Control from H.L.R.C.C. is gradually increasing and is used, at the present time, in 40% of the countries.

2) Preparation of the network

This paragraph inquired about the automatic actions following a loss of voltage.

Tripping of loads is performed by more or less the same countries which trip all circuit-breakers (35%).

Keeping some circuit-breakers connected (to prepare special network connections) affects only 25%. The replies for moving a tap changer to a predefined level are affirmative in 25% of the cases.

From the countries which have replied affirmatively that all breakers should be tripped, 22% can, from the remote control center, start, or stop temporarily the Automatic Restoration Equipment (A.R.E.) and 33% can change the program of these A.R.E.

3) Voltage restoration

For restoration of auxiliary supply to the principal generation blocks there is a clear preference for islanding on auxiliary load (65%); the internal standby generation is backed up (in 40% of the cases) with remote hydro-generation, requiring either the main transmission system (70%) or (30%) the subtransmission system only.

From the global analysis of all responses, it is assumed that only 25% of the countries use automatic equipments to perform restoration after a black-out whereas only 20% perform automatic restoration after a load shedding due to a low frequency.

This automatic restoration equipment (A.R.E.) effects mainly breaker reclosure after voltage recovery either on busbars or on feeders.

When A.R.E. is used, this is connected to the remote control center for

- start permission in 40% of the cases
- program changes in 40% of the cases
- information sent by A.R.E. in 100% of the cases
- temporary standby of the A.R.E. in 60% of the cases.

In more than 70% of the countries synchrocheck equipments exist in substations. In almost all cases of existing A.R.E., these can start checking synchronism. Likewise, we can state that almost all countries having control from a remote center, check of synchronism may be started from this control center.

Only 30% of the countries are using the synchrocheck equipment to send information (ΔU, $\Delta \varphi$, Δf) to a remote control center, although this information is sent to the remote control center by other equipments in many cases.

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