FAULT MANAGEMENT IN ELECTRICAL DISTRIBUTION SYSTEMS

Final report of the CIRED Working Group WG03 Fault Management

FOREWORD

This text comprises the final report of CIRED Working Group 03 "Fault Management". The working group was established in November 1995. The initiative came from Mr. Yves Harmand of Electricité de France, who was the convenor of the predecessor working group "Distribution Automation".

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In Espoo, Finland 22. December 1998
Matti Lehtonen

INTRODUCTION

In electrical distribution systems, fault management is one of the main functions to reduce outage times. For this purpose, various methods are used in different countries. This report is an attempt to estimate the current state of these functions and to give recommendation for improvement of the present solutions.

The approach of the report is to find the different technical and organisational solutions for fault management, depending on network structure, protection philosophy and other circumstances. Various methods are presented and compared for advantages and disadvantages, as well as for costs and benefits.

One of the main issues is the techniques for fault location and fault indication. For these, both different equipment and functions are considered. Of high importance also, are the various computer systems used in network operation. To analyse the state of art of these, also a detailed analysis of the properties of present SCADA-systems is given.

In the latter part of the report, two special issues are considered. One is the comparison of different solutions of fault statistics and fault indices. The second subject is the various approaches when assessing the economic feasibility of fault management solutions.

LIST OF ABBREVIATIONS

AM	Automatic mapping
DCC	Distribution control centre
DLC	Distribution line carrier
DMS	Distribution data management system
END	Energy not delivered
FM	Facilities management
GIS	Graphic information system
HV	High voltage (> 60 kV)
LV	Low voltage (< 1 kV)
LED	Light emitting diode
MMI	Man machine interface
MV	Medium voltage (1 kV …. 60 kV)
NCC	Network control centre
RTU	Remote terminal unit
SCADA	Supervisory control and data acquisition

1 NETWORK PROFILES

1.1 Distribution network structures

This section focus on the structure of MV (1 kV to 60 kV) and LV (1 – 999 V) networks. The distribution utilities that have been studied in this report are very heterogeneous in size (they operate from 1 to 100 distribution networks – HV/MV substations) and in structure. Nevertheless, the group has managed to produce a summary of network structures of all utilities that highlights the differences and the similarities between them. We will show only those characteristics that will be useful for the discussion of fault management.

There is one major issue that differentiate the characteristics of a network : its urban or rural nature. Urban networks are usually short and underground, rural networks are usually long (but not necessarily overhead : in some parts of Germany and in Electrabel they are mostly underground, and we see a trend in all utilities to increase the part of underground in rural networks). Many characteristics of networks can be explained when considering the urban or rural feature.

Two remarks should be made about this chapter:

- This document reflects the state of the art on network structures, and some changes might occur in the future.
- All the utilities contributing to this survey use MV networks without distribution of the neutral wire. Some conclusions don't apply to networks of the "distributed neutral" kind (very common in the United States and Canada).

1.1.1 Structure and operation

The structure of the MV networks is mainly meshable, so that feeders can be backfeed by adjacent lines. Urban networks are almost completely meshable, but that is not the case of rural networks for obvious reasons of cost. The percentage of rural networks that can be backfeed varies between 50% and 90% on the utilities studied.

LV networks are much less meshable than MV networks. Usually only some urban networks can be backfeed. The percentage varies between 0% and 30%.

MV and LV networks are almost always operated radially. No utility have plans to loop networks in the future.

1.1.2 Primary substations

Primary substations (HV/MV substations) have generally from 1 to 4 power transformers. 2 transformers is the most typical value.

The average number of MV feeders by substation varies between 4 and 20, most typical values being around 10. Usually we find differences in the typical numbers of feeders of rural and urban substations, but the trends are different from one utility to another.

The tendencies regarding the total number of primary substations are not same around Europe:

- In Finland the number is decreasing, in order to diminish the maintenance costs.
- In Austria the number is increasing in order to cope with new demand.
- In EDF and ENEL the number is increasing in order to improve the quality of supply.

1.1.3 MV feeder profile

Rural MV feeders are much longer than urban MV feeders. Average values vary from 10 to 35 km for rural feeders, and from 3 to 10 km for the urban ones.

Regarding the typical load of a MV feeder, there is no obvious trend to differentiate urban and rural lines. Some utilities design rural feeders more loaded than urban ones, other utilities do the contrary, and sometimes there is no significant difference. Typical loads of rural feeders vary from 1 to 8 MVA, typical loads of urban ones vary from 1 to 10 MVA.

MV networks are almost always 3-phased in the utilities that have contributed to this report. Some 2-phase branches (connected to a 3-phase backbone) are used by EDF to feed low-consumption rural areas.

1.1.4 Secondary substations

The average numbers of secondary substations (MV/LV) by MV feeder are different for rural and urban feeders :

- Averages from 5 to 15 secondary substations by urban MV feeder.
- Averages from 15 to 50 secondary substations by rural MV feeder.

The average number of LV customers by secondary substation varies from 40 to 100, the maximal number beingalways under 500.

1.1.5 Power generation

All the utilities reflect a step increase in the number of power generators that apply for connection in MV and LV networks.

The range of rated power of the dispersed generators connected to MV networks varies largely from one utility to another. The minimum rated power goes from 25 kW (ENSA) to 1 MW (Iberdrola), the maximum power allowed for connection at MV level goes from 1 MW (Finland) to 25 MW (Iberdrola).

1.2 PROTECTION PHILOSOPHIES

1.2.1 Short Circuit protections

Short Circuit Faults are usually the easiest to detect, as the fault current is important when compared to the load current. All the utilities studied use definite time current relays to detect this kind of faults: if the measured time is superior to a fixed threshold, the protection considers that a fault is present on the network. Time delays are used to co-ordinate the transformer, the busbar and the feeders protections.

Some utilities (Austria, Germany, ENSA) install distance protections that measure the current and the voltage at the time of a fault, and calculate the impedance of the fault that is a good indicator of the fault distance to the substation. This information is very useful to locate the fault. Sometimes the protection directly calculates the distance.

1.2.2 Earth Fault protections

Neutral grounding

The type of neutral grounding has important consequences over the earth fault protection scheme and the types of faults encountered by each company. Throughout the European utilities studied, we can find three main types of neutral grounding :

- Systems with **isolated neutral**, in which the neutrals of transformers and generators are not intentionally connected to earth, except for high impedance connections for signalling, measuring or protection purposes. Mainly used in ENEL and Finland, with some networks also in ENSA, Austria and Electrabel.

- System with **resonant earthing**, in which at least one neutral of a transformer or earthing transformer is earthed via an arc suppression coil and the combined inductance of all arc suppression coils is essentially tuned to the earth capacitance of the system for the operating frequency. Mainly used in Austria, Germany, some Swiss companies, and to some extent in Finland. EDF and ENEL are studying the conversion of part of their rural networks to compensated grounding.

- System with **low-impedance neutral earthing**, in which at least one neutral of a transformer is earthed directly or via an impedance designed such, that due to an earth fault at any location the magnitude of the fault current leads to a reliable automatic tripping due to the magnitude of the fault current. Mainly used in Electrabel, EDF, EDP and Iberdrola.

  NOTE: Systems with isolated neutral or resonant earthing, whose neutral is earthed within a short time at each occurrence of an earth fault, are included. This is the case of some networks in Austria and Germany.

Types of protections

All the utilities use definite time current relays to detect high-current faults (short circuits and some ground faults with low-impedance earthing). Concerning higher impedance faults (up to a few kΩ), several techniques are used :

- Inverse-time current relays
- zero-sequence relays (wattmetric, voltmetric or ampermetric)
- Distance protections
- Neutral voltage relays

Sometimes a combination of these three types is used.

Also, as stated previously, EDF and ENEL use the protection called “ shunt ” to eliminate non permanent earth faults without opening the feeder.

Sustained operation with fault

The compensated grounding technique permits a very interesting practice called sustained operation with fault. As the earth faults don’t produce a significant fault current, it is possible to search for the fault without opening the feeder.

Among the utilities that use compensated grounding, Austria and Germany use this technique.

1.2.3 Reclosing schemes

Reclosing philosophies

All the utilities contributing to this survey use reclosers at the head of MV overhead feeders in order to eliminate non-permanent faults without a long power cut. The reclosing schemes are basically of three types :

- Substation reclosers alone (Germany, ENSA, Finland, Iberdrola).
- Substation reclosers and on-network devices, located somewhere in the middle of the MV feeders. They are mainly automatic sectionalisers (Austria, Electrabel, EDF, ENEL, EDP), and sometimes automatic reclosers (Electrabel, EDF).
- Substation reclosers, on-network devices substation “ shunt ” - EDF, ENEL.

Substation reclosers

The principle of operation of the substation recloser automatism is as follows :

If a fault is detected by the feeder protection (short circuit or earth fault), the circuit breakers of the faulted lines open.

As sometimes faults are automatically cleared after the disappearance of the phase voltage, the recloser automatism serves to restore service as quickly as possible. It usually has two cycles :

- First, a “ fast ” cycle : some time after the opening (usually 0.3 to 1 second) the recloser forces the closing of the circuit breaker.
- If the fault has not been cleared, we have the “ slow ” cycle : the recloser waits between 20 seconds and 3 minutes, and orders the closing of the circuit breaker.

If the fault is always there (permanent fault), the protection opens definitively.

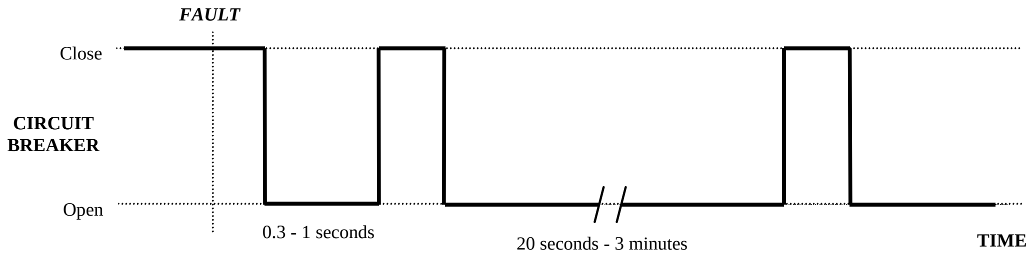

Fig. 1.1 The reclosing cycle for a permanent fault.

Reclosers and on-network devices

Besides the substation reclosers, there are on-network devices. These can be of two types :

- Automatic sectionalisers. They will open only if two conditions are met : the fault is seen beyond the sectionaliser, and after two openings of the feeder (they open during the slow cycle of the substation recloser). This device reduces the portion of the network that is de-energised in case of a permanent fault.
- On-network reclosers. They act just like the substation reclosers, with a fast and a slow cycle. Their advantage in comparison with the sectionalisers is that they act faster, as they don’t have to wait for the slow cycle of the substation recloser. They need some kind of co-ordination with the other automatism.

Sometimes if there are automatic sectionalisers the substation recloser will have a second slow cycle. This allows a first slow cycle before opening the sectionalisers, or permits the use of several sectionalisers in series along a feeder.

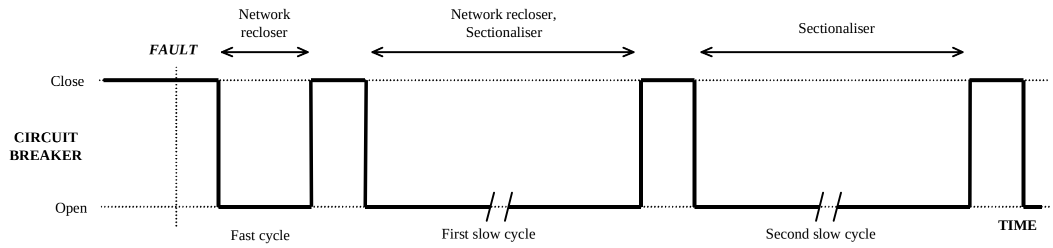

Fig. 1.2 The automatic sectionaliser reclosing cycle in a permanent faut.

Reclosers, shunt and on-network devices

Some utilities use also an automatism called “ shunt ”. This technique is mainly used in networks with high impedance or isolated grounding. The shunt is just a circuit breaker between each phase and the earth, that is normally open but that closes in case of an earth fault. By closing only the faulted phase, it allows for the disappearing of temporary earth faults without cutting the feeder. The co-ordination of the shunt with the reclosing sequence is achieved by an order of retard sent by the shunt to the recloser if it detects an earth fault. The following graphic describes the functioning of the system for permanent faults :

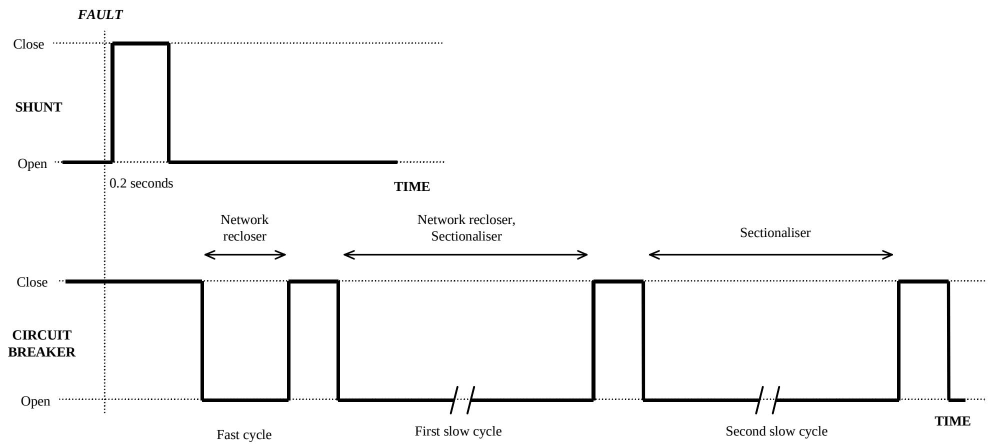

Fig. 1.3 The sectionaliser reclosing cycle with a shunt.

1.3 DEGREE OF REMOTE CONTROL

1.3.1HV/MV Substation

HV/MV substations are always remotely controlled in the distribution utilities that have participated to this survey.

We can distinguish between remote signals (binary values associated to an event) and remote measurements (numeric values associated to a measurement device at the substation or at counting devices).

Remote signals

The remote signals associated to switch position, circuit breaker position, fault detection and relay operation are found in almost all substations.

Sometimes other types of signals are sent to the Distribution Control Centres (DCC), as cause of event, recloser and automatism operations, and type of fault.

The remote signals sent to the DCC form the set of events to be interpreted by operators or by alarm processing software. Differences from one utility to another may explain the need or the difficulty for alarm processing software.

Remote measurements

Remote measurements can be obtained by several different ways, such as cyclic polling, polling on demand, or threshold trespassing. There are some differences about the type of measures sent to DCCs and the frequency of the polling.

The two measures that we can find in most of the substations are the MV feeders current and the MV busbar voltage. We usually find also a measure of active and reactive power (sometimes at the MV side, sometimes at the HV side, sometimes both of them).

Other kinds of remote measurements found in some utilities are :

- HV busbar voltage.
- Measures associated to the resonant system.
- Counting for billing purposes.
- Position of the tap changers.
- Transformer temperature.
- Fault current (the value of the current during a fault). This is the most important issue in fault management, because this measurement may allow fault distance calculations. Sometimes the electric distance is calculated locally and directly sent to the DCC.

No utility sends today to the DMS the time recording of the current pattern after a fault, that would be much richer to made fault distance calculations. Some utilities are nevertheless studying the issue: the technology to record and send this pattern exists, and is becoming standard for most of the new digital protections. Nevertheless, the frequencies of those protections range between 600 Hz and 2 kHz; those frequencies are not sufficient for the analysis of the current pattern – studies show that 10 kHz should be needed for the analysis of ground faults.

1.3.2 MV Network

The situation regarding the degree of remote control for MV networks is very different from one utility to another. We can distinguish the following items :

- Remotely controlled switches : some utilities have none, some have very few, and some have between zero and four by feeder ; usually there are much more in rural networks than in urban networks. Some utilities have today an active policy to increase the number of remotely controlled switches.
- Remotely controlled fault detectors : most utilities link them to the remotely controlled switches in overhead networks (whenever they install one, they install also the other to take full profit from the communication link).

- Power producers : about half the utilities monitor some of the power producers connected in MV. The usual measures are active power, reactive power, voltage, current and switch state. Some other utilities announce plans to monitor them. Only IBERDROLA sends tripping orders to power producers.
- Power quality monitoring : few utilities monitor power quality at all, and even in this case the monitoring is not directly linked to the SCADA system. The only exception is EDF, with a program aimed to monitor the quality of the entire MV network (but not linked to SCADA neither).

This issue is extremely important to fault management in Distribution Management Systems.

The ratio of remotely controlled MV/LV substations is low in general, and specially in rural areas. The main exception is ENEL, who is going towards a global ratio of 12.5% for all kind of areas.

No utility has today any kind of remote control for LV networks. Some utilities are working on remote metering and monitoring systems for LV customers

2 FAULT LOCATION FUNCTIONS AND PRACTICES

In this section the most important techniques and solutions for fault location are outlined. The items considered are fault indicators, computational fault location and the methods for the detection of high resistance earth faults. With respect to the last item, also the aspects of sustained operation with earth faults is considered.

2.1 FAULT INDICATORS

Short circuit indicators

Short circuit indicators are mainly used in Medium Voltage (MV) networks, either radial or open ring operated, for finding the fault location. They can be installed on the current conductors to be monitored, busbar, cable or overheadline.

1.3.3 LV Network

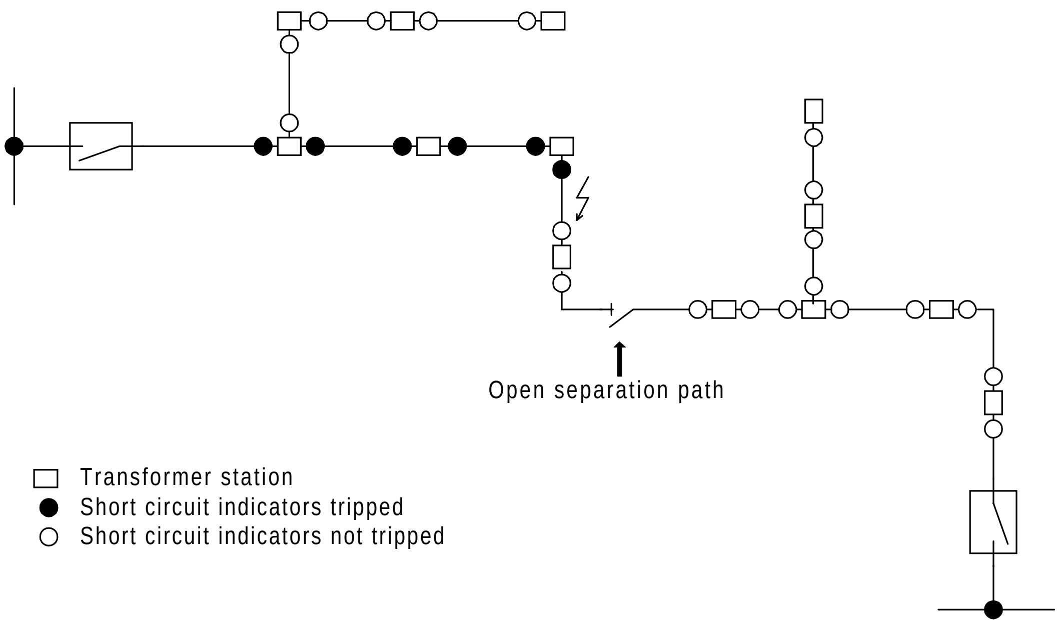

Fig. 2.1. A network with short circuit indicators .

The magnetic field of a conductor through which current flows triggers the short circuit indicator. The exceeding of the rated threshold current of the indicator results in a signal, either optical or electronical, thus marking the direction of the short circuit current from the feed in point to the fault location by tripped short circuit indicators. (See Figure 2.1)

The basic layout of a short circuit indicator consists of a yoke and an attached display system. The display system can be mechanical, e.g. a pivot bearing rotor for local indicating and/or a microcontact for remote signaling, or electronical processed for local indicating or remote signaling.

Every conductor through which current flows is surrounded by a magnetic field, see Fig. 2.2. The magnetic field strength H is used to discriminate between normal load conditions and overload or short circuit currents.

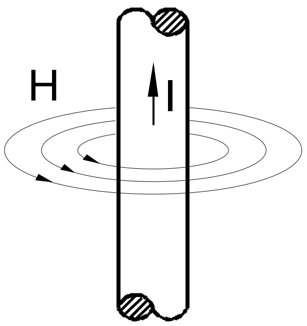

Fig. 2.2. Conductor surrounded by magnetic field strength H

Short circuit indicators with rotor system.

At currents higher than the threshold current the induced magnetic field strength H is sufficient to overcome the retaining force of a catch spring moving a rotor to the tripped position. The reset of this indication has to be done manually.

Typical technical data:

Threshold value:	200 … 2000 A, ±10%
Adjustment pulse:	100 ms
Clamping range:	Conductor diameter 8 - 80 mm for circular conductors 20x4 - 60x30 mm for rectangular conductors

Used on outgoing cable feeders or busbars in switchyards

Short circuit indicators with fluid system.

Another indication principle is based on fluids. They get along without moving parts. In the event of a short circuit a composite body is pulled up by the magnetic field stirring up red particles in a glass-clear fluid, see Fig. 2.3. The coloured particles remain in suspension in the fluid for approximately 4 - 8 hours indicating a short circuit. Due to the gravity they will sink and the display turns clear again.

Typical technical data:

Threshold value:	400, 600 or 1000 A, ±20%
Adjustment pulse:	200 ms
Clamping range:	Conductor diameter 8 - 80 mm for circular conductors 20x4 - 60x30 mm for rectangular conductors

Used on outgoing cable feeders or busbars in switchyards

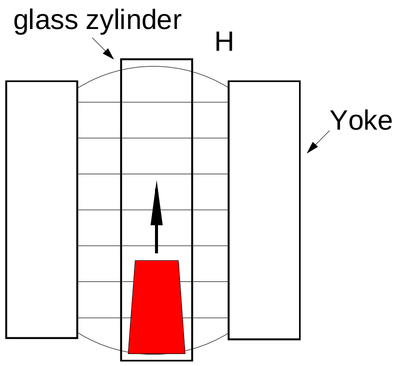

Fig. 2.3. Particles pulled up by magnetic field.

Electronic short circuit indicators with remote signaling system

In installations where the short circuit indicators cannot be easily read you apply indicators with remote signaling at the supervised conductor. The short circuit indicators consists of three sensors, a wiring equipment and a display unit. The sensors are mounted directly on the insulated cable and transmit their measured values to the display unit. To monitor bare cables or busbars the wiring harness has to consist of optocouplers and highly insulated fibre optical cable. The display unit is attached to an accessible location, e.g. on the front wall of a switchgear cubicle.

Typical technical data:

Threshold value:	200 … 2000 A, ±20%
Length of wiring:	1 … 6 m
Indication:	flashable led, rotor or fluid
Clamping range:	Conductor diameter 6 - 100 mm for circular conductors 20x4 - 60x10 mm for rectangular conductors

Mechanical overhead line short circuit indicator

These short circuit indicators may be attached to the overhead line. The indication of a short circuit is done by turning an all-round visible zylindrical flag indicator from neutral to red.
The indication has to be reseted manually by means of an actuation rod. The indicator can be installed and removed under power with a special actuation rod (max. 30 kV).

Typical technical data:

Threshold value:	300 / 400 A, ±10%
Adjustment pulse:	100 ms
Visibility:	up to 200 meter (depending on daylight brightness)
Clamping range:	Conductor diameter 8-25 mm

Electronic overhead line short circuit indicators with LED or strobe light

Here the indication is accomplished by extremely bright flashing LEDs. The indicator is excited by the short circuit current. Reset is done automatically after expiration of a previously set time. The indicator is also turned off when the line power is switched back on and the current flow is greater than 3 A. For powersupply a replaceable lithium battery with shelf life of approx. 15 years. The indicator can be installed and removed under power is acieved with a special actuation rod (max. 30 kV).

Typical technical data:

Threshold value:	100 … 2000 A, ±10%
Actuating time:	20 ms
Reset time:	2, 4 or 8 h
Visibility LED:	up to 200 meter (depending on daylight brightness)
Visibility strobe light:	300m (cloudy sky) up to 900m in dark
Clamping range:	Conductor diameter 8-mm

Combined short circuit and earth fault indicators

Fault indicator for cable networks.

A fault current indicator of medium voltage cable networks is shown in Figure 2.4. The indicator works both for short circuit and earth fault cases. The sensor for short circuit faults is based on a small coil, which energizes a light emitting diode (LED). The intensity of light varies with the magnetic field magnitude, which in turn depends on the current of the conductor. The light is transmitted to the detector unit via a fiber optic cable and the measured magnitude compared to the threshold value.

The sensor for earth faults is a simple sum current transformer, formed by a metal strip wound around the phases. Also the earth fault sensor is connected to the detector unit via a fiber optic cable. The remote reading of fault indicators speeds up the fault location and cuts the outage times especially in the urban networks, where the remote control of disconnecting switches is too expensive. In most utilities, the fault indicators already exist in the medium voltage / low voltage substation. The inclusion of these devices into the automation system only demands the data transmission system. This can be based on telecommunication cables, or leased telephone connections, for instance.

Fault indicator for overhead line networks.

A fault indicator for medium voltage overhead lines is shown in Figure 2.5. The device is based on the coil, which measures magnetic field and on a antenna to detect the electric field. There is no contact to the live parts of the line, but the indicator is mounted in the pole 3 to 5 meters below the conductors. The sensitivity of the device is tuned simply by altering this distance.

The indicator is able to detect both short circuit and earth faults. The earth fault detection is based on the measurement of magnetic field produced by the zero sequence current of the line.

Another restriction of the device is, that it can not be mounted at the line crossings. This is because of the interference of magnetic fields of the lines. If used in association of sectionalizer stations, for instance, the indicators must be mounted into the next poles, and wired to the station. This is costly and expensive, however. This kind of problems are not met, if the fault indication is based on the direct current measurement. For this purpose, small current transformers, built on the top of an insulator, are nowadays available. The corresponding fault indicator is actually a small relay, which can be set remotely. The currents can be recorded during the normal operation state too.

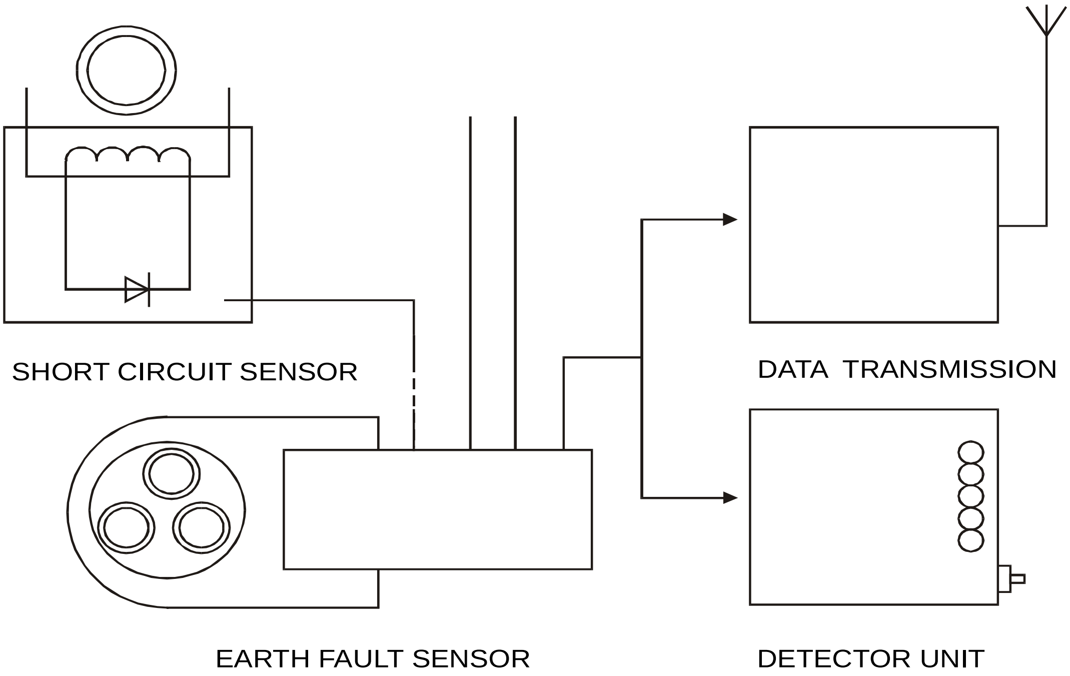

Fig. 2.4. An example of a fault indicator for cable networks.

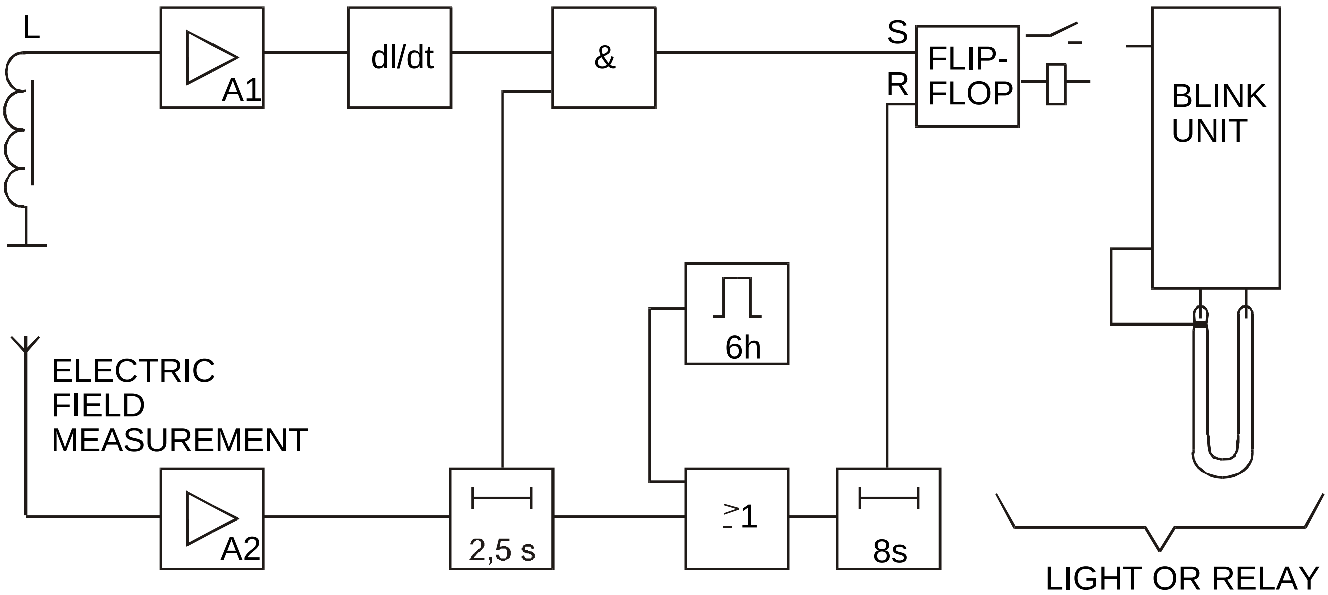

Fig. 2.5. An example of a fault indicator for overhead line networks.

Restrictions of present fault indicators

The main restriction of fault indicators in the present market is the lack of directional function. This would be of high importance in the case of earth faults in compensated networks. Another application is the networks with dispersed generation. Here the directional characteristics is needed also in the case of two or three phase faults.

The bottleneck when developing a directional fault indicator is the voltage measurement. This should be arranged using a technology cheaper than the present inductive voltage transformers typically used in the high voltage / medium voltage substations. A possible solution is a voltage divider based on resistive, capacitive or inductive principle. This kind of devices are not generally available in the market, however.

2.2 FAULT DISTANCE COMPUTATION TECHNIQUES

Especially in rural and suburban networks, where distances are long, a very good supplement to the fault indicators is the fault distance computation. In the case of short circuit faults, the distance estimate can be obtained by using distance relays. An alternative solution is to utilise the measured fault current only and to obtain the distance estimate by comparing the measured fault current to the results of network calculations.

Computational fault location techniques are now available for the case of short circuit faults. In the high impedance grounded systems, the single phase earth fault currents are so small that they do not allow for a reliable fault distance estimate. For these cases transient based solutions have been proposed instead.

2.2.1 Fault distance computation using distance relays

The method described here is part of the practical fault location process in the distribution network at OKA, an electricity utility of the state „Upper Austria“ of Austria [13]. It is in use in all HV/MV-substations of OKA and the practical experiences could be collected for more than five years.

In addition to distance computation fault detectors and telecontrol of MV-stations are in operation. In combination with the local staff a complete system has been established to speed up the fault location process and to reduce the duration of supply interruptions. Because the MV-network of OKA is compensated, the method is first of all designed for multi-phase faults.

Network characteristics

The MV-network has a nominal voltage of 30 kV with a portion of 11 % cables. It supplies mainly rural regions. The feeders are principally radial. Few meshed feeders are split up automatically in case of a fault. After the customary autoreclose (0,5 s) the conditions of radial feeders are fulfilled.

All the feeders are protected by distance relays, approximately 40 % of them are of digital type, the rest is electromechanically. In substations with electromechanical relays the backup protection relays at the infeeding transformer have been replaced by digital relays. The fault reactance measured by the relays is telemetered by the SCADA-system to the control centre. The reactance is transferred from the relay to the SCADA-system partially by analogue signals or by digital protocols.

Method

The basis of the method is a MV-network analysis model, that is kept and maintained for planing purposes by the network analysis group. Every feeder is split up into segments, that are physically defined by MV-stations and branching points. The segments have a length between 50 and 500 m, in few special cases longer.

With this network model an off-line short-circuit calculation is performed for every segment automatically by a standard power system analysis software. The short-circuit calculation is updated once a year. This results in a static reactance list for every feeder, that contains the fault reactance at the beginning and the end of every segment as well as long names for the stations or branching points.

If a fault occurs, the telemetered fault reactance is transferred automatically from the SCADA-system to a selection program on a PC or a SCADA-computer, that selects the suitable segments. There is no on-line analysis to compute the fault location, just a segment selection. These segments are presented to the operator as probable fault locations in form of a small list (1 to 5 segments) on the screen.

The practical experiences of the last years are excellent. There is a considerably reduction in time for locating faults as well as in the requirement for local staff. The accuracy is better than 5 %. Inaccuracy of the metering is compensated by the knowledge of the local staff about frequently faulted sections. This led to the fact, that fault distance metering became an integrated part of the fault location process and it was accepted by the staff in a very short time. The assumption of a standard topology without on-line analysis is largely acceptable.

Reactance measurements by the backup relays of in-feeding transformers are less accurate than direct feeder measurement, especially if the transformers are highly loaded. Nevertheless the results are still an important aim in fault locating.

Permanent single-phase-to-ground faults

Location of permanent single-phase-to-ground faults in compensated networks is sometimes difficult. If sustained operation is not wanted, there is no point of keeping the compensation. Therefore in two substations the Peterson coil is by-passed by a low resistive impedance in case of a permanent earth fault after 3 s. This leads to a short-circuit current that is detected by the distance relay and switched off by the circuit breaker of the faulted feeder.

The intention is to use from now on the same fault location devices as for multi-phase faults (reactance metering, fault detectors, telecontrol). Presently two problems are investigated:

- fault detectors for single-phase-to-ground currents less than load current
- adaptation of the fault reactance value given by the relay according to earth-fault currents

If these problems are solved, short term grounding will become standard at OKA-substations.

Further aspects

The present method of fault distance computation with distance relays allows still some improvements:

- automatic incorporation of telemetered fault detectors
- graphic display in the control centre (GIS)
- consideration of transformer and line loading
- consideration of generation and network topology
- extension to single-phase-to-ground faults (short term grounding)

Because of the good experiences so far, there is not much pressure to start these improvements

2.2.2 Short circuit fault location based on fault current measurement

In this section, the use of measured fault currents to the location of short circuit faults is discussed. A practical implementation of this automation function is first presented. The factors affecting the fault location accuracy are then outlined, and some practical results are given based on the experience with existing fault location systems.

The practical implementation of a fault location system

A modern short circuit fault location system is based on the integration of distribution data management system (DMS), substation telecontrol system (SCADA) and the relay protection. The main idea is the comparison of the measured and the computed fault currents. The computation is made on-line, assuming the same network topology as it was when the fault occurred. As a result, the estimated distance of the fault from the substation is obtained. This distance is then, in turn, compared to the network diagram, and the possible fault locations are shown on a graphical display of the distribution network in the DMS system.

When a fault happens, the operation of the fault location system is as follows [3]:

1) the protective relays store the fault information (currents, fault type, phases involved, feeder involved, information on reclosing steps)
2) the recorded information is transmitted to the SCADA central unit
3) the SCADA system adds some more information to the received fault data. This information includes the measured load current of the feeder concerned and the active and reactive load flows of the substation main transformer
4) the information is transferred to the DMS system
5) the DMS computes the corresponding fault currents of the feeder concerned and compares the measured data to the computation results. Before the comparison, the load currents, superposed on the measured currents during the fault, are compensated for

All the data needed for fault location computation is stored in the working memory of the DMS system. The purpose of this arrangement is to make the processing fast enough to meet the practical requirements. Each fault case data is stored in a separate record, which can be picked up by the operators for processing. Hence, phase 5 of the above procedure is not initiated automatically, but must be trigged manually. This arrangement makes it possible, that several fault cases can be studied simultaneously, and in an organized manner, by a number of power system operators.

Performance of the fault location system

The main factors affecting the accuracy of short circuit fault location are the errors of measurement transformers and other measurement equipment, the variation of network component impedances, the load current superposed on the measured fault current and the fault resistance [4].

The errors due to the measurement transformers are usually small, only a few per cent of the actual fault distance. The most difficult is the case where the fault is close to the substation. Because of the high fault levels, the current transformers may become saturated, which deteriorates their accuracy. If the voltage falls below 2 % of the nominal value, the performance of voltage transformers may also collapse.

When the fault location is based on an analysis of the current measurement solely, the result is also sensitive to a variation of network impedances. In addition to the variation of the resistance and reactance of the line concerned, the variation of short circuit level in the medium voltage busbar may also cause problems. The last one depends, in addition to the changes in the grid impedance, mostly on the position of the on-load tap changer of the substation transformer. For accurate fault location, the on load tap changer position should be telemetered.

The problem with the superposed load current is, that its magnitude is changed dynamically with the voltage change during the fault. For the load behavior, theoretical models have been developed, which can be used for load current compensation [4].
The largest errors are usually caused by the fault resistance, however. In the case of power arc, this can be calculated as follows [8]:

$$R = \frac{8750}{I^{1.4}} \frac{l}{0.305} \ (ohm) \qquad 2.1$$

where l is the arc length (m) and I the fault current (A). Resistance is increased when the fault current is decreased. Hence it is of importance especially in weak systems and for faults distant from the substation.

The fault current is known by the measurement and the maximum arc length can be deduced from the line geometry. Consequently, it is possible to estimate the maximum value of the fault resistance. In practice however the fault location computation is made with the assumption of zero fault resistance. This gives the estimated maximum fault distance. Because of the fault resistance, the actual fault point must then be closer to the substation.

The best statement on fault location accuracy is based on practical experience. An automatic fault location system, described in this section, is in active use in several distribution companies in Finland. According to the practical experience in rural overhead line networks, the average error in fault distance estimation has been about 1.2 km. For comparison, the corresponding average fault distance is 13 km. For close faults the absolute errors are smaller, whereas for distant faults they are larger, respectively. This degree of performance is good enough for defining the faulty line section between two isolating disconnectors.

The computational means however give only the fault distance. If there are several branches or laterals in the line concerned, several possible fault locations are also obtained. Among these the actual fault point must be distinguished by some other means. One possible solution is the remote monitored fault current indicators in the line branching nodes.

2.2.3 Earth fault distance computation based on transient signals

In networks with an isolated or a compensated neutral, the fundamental frequency earth fault currents usually are so small that no reasonable fault distance estimates can be based on them. Under these conditions some other techniques must be used. A very promising possibility is the utilization of earth fault initial transients. In this case the best results are obtained using the methods, which estimate the line impedance during the transient. These methods can be classified into differential-equation algorithms [7], Fourier-transform methods [2] and least squares fitting methods [5]. In the following, the theory of earth fault transients is first briefly discussed. The possible fault location methods are then presented.

Earth fault transients

When an earth fault happens, the voltage of the faulty phase falls and the charge stored in its earth capacitances is removed. This initiates the discharge transient. Because of the voltage rise of the two sound phases, another component, called charge transient, is created. The latter has a lower frequency and in most cases also a higher amplitude. Hence, it is the component best suitable for fault location purposes.

The maximum amplitude of charge transient, compared to the capacitive steady state fault current, approximately varies with angular frequency. Since it is not unusual for this to be 5000 rad/s, the maximum amplitudes can be even 10-15 times that of the uncompensated fundamental frequency fault current.

In real systems there is always some damping, which is mostly due to the fault resistance and resistive loads. Damping affects both frequencies and amplitudes of the transients. The critical fault resistance, at which the circuit becomes overdamped, is in overhead line networks typically 50...200 Ω, depending on the size of the network and also on the fault distance. If the resistive part of the load is large, damping is increased, and the critical resistances are shifted into a lower range.

The earth fault transients have also been examined by field tests in real systems. According to the results, in the case of the discharge component the amplitude was typically 5 to 10 % that of the charge component. The frequencies varied through a range of 500-2500 Hz and 100-800 Hz for discharge and charge components respectively.

Methods for earth fault distance estimation

Differential-equation algorithms solve the line inductance directly in time domain. Consider the first order model, which includes the series connection of the line resistance R and inductance L. The voltage and current of the faulty phase have the following relation:

$$u(t) = Ri(t) + L\frac{di(t)}{dt} \qquad 2.2$$

which can be solved for inductance L, if three equally spaced pairs of samples are available. Since differentiation is sensitive to higher frequency noise, the solution is usually obtained by integrating the above. Differential-equation algorithms work in theory for all the voltage and current components which satisfy equation (2.2). The best result is, however, obtained if all the other frequencies are first filtered out, except the charge transient.

Fourier-transform methods solve the line impedance in the frequency domain. In the case of the first order model, the reactance of the faulty line length is obtained directly as the imaginary part of the impedance calculated from the corresponding Fourier frequency spectrum components of voltage and current.

In the prototype system described in reference [2], the fault distance is calculated as a weighted average of the estimates made for the n dominating frequencies in the spectrum. Also a higher order model, which allows for the phase to earth capacitances, is presented.

The least squares fitting methods solve first the parameters the voltage and current transients directly in time domain. This is done by fitting a function, that models the transient waveform, to the measured samples of phase voltage and phase current. In the case of earth fault transients, the function used is a damped sinusoid.

For proper computation, least square fitting methods require signal filtering and preprocessing similar to differential-equation algorithms. Once the amplitudes and phase angles of transient phase currents and voltages are known, the fault distance is solved as reactance of the faulty line length.

Accuracy of the fault distance estimation

The accuracy of the different methods is compared in Table 2.1. For the comparison, data recorded during staged faults in a Swedish 22 kV overhead line network was used. The network was with a 100 % compensated neutral, the rating of the suppression coil being 17 amperes. Altogether 60 fault cases were considered.

According to the results the least square methods have somewhat better accuracy compared to the others. The differential-equation algorithms and Fourier-transform methods are essentially impedance relay algorithms. Their main advantages are the numerical stability and relatively small computation burden, which makes them suitable for on-line calculations.

The highest fault resistance, that allows for reliable distance estimation, is about 50 Ω. With zero resistance, more than 95 % of the faults can be located reliably. According to the experience in field test, the average errors are 1.6 km for the first order line model and 1.2 km for the higher order line model .

The transient based algorithms require a measurement technique with a relatively high sampling frequency, preferably in the order of 10 kHz. This has been a limiting factor for a widespread use of these techniques so far.

Table 2.I Comparison of the accuracy of transient based fault location methods. Sixty faults with fault resistance 0 Ω. First order and higher order algorithms of Differential-equation methods (a and b) [7], Fourier-transform methods (c and d) [2] and curve fitting methods (e and f) [5] respectively.

	error class in kilometers: 0.0-0.6	0.6-1.2	1.2-1.8	1.8-2.4	>2.4
a	*15*	*11*	*3*	*5*	*26*
b	*7*	*11*	*8*	*3*	*31*
c	*14*	*11*	*14*	*2*	*19*
d	*9*	*14*	*8*	*7*	*22*
e	*24*	*19*	*7*	*1*	*9*
f	*21*	*20*	*5*	*7*	*7*

2.3 METHODS FOR THE DETECTION OF EARTH FAULTS

This chapter gives a short overview of earth fault location methods presently in use. Conventional methods which use the zero sequence voltage or wattmetric relays have severe problems in detecting high impedance earth faults. This is the case especially in compensated neutral systems. To mitigate this problem, several techniques have been under research. Of these some examples are given.

2.3.1 The most important earth fault detection methods [11]

Transient residual voltage and current

Transient earth fault identification

During the ignition of an earth fault the faulted phase unloads itself with a current impulse and a following transient oscillation ("ignition oscillation"), while the fault-free phases load themselves at the same time. The amplitude of the ignition oscillation depends thereby on the phase angles of the earth fault entrance. During these high frequency procedures the petersen coil is ineffective by their high inductance. Therefore direction of the earth fault is determined outlet from the phase position between residual-current and -voltage.

Advantage:
- large, however variable amplitudes of the ignition current

disadvantage:
- if the earth fault accurse nearby the voltage zero (e.g. by foreign influences) the ignition oscillation is very small
- the measurement is only unique (with the ignition oscillation)
- after disconnection of one base point during a double ground fault the detection of the remaining earth fault is not possible

important parameters:
- ignition amplitude
- L/C distribution in the network

remarks:
- depends on the phase angel of the earth fault appearance
- determines the ignition frequency and damping

Residual voltage

Earth fault detection relay

Based on the unsymmetrical phase to earth voltage the residual voltage is not longer zeroed. An overvoltage relay observes the residual voltage. The threshold is set to approximately 30% of the nominal voltage. If the residual voltage exceeds this level a status signal is set

Advantage:
- The detection of the earth fault is independent of the fault location. Therefore earth faults in the whole network could be detected.

disadvantage:
- no feeder selective earth fault detection is possible; there are problems with high-resistance faults

important parameters:
- capacitive asymmetry of the network
- earth fault resistance

remarks:
- huge capacitive asymmetry combined with low network damping or resonance tuning of the petersen coil lead to high residual voltage during normal operation
- the residual voltage at a high-resistance earth fault is low

Residual current

Variation of compensation by switching of capacitors (pulse method)

The working method of this equipment is described at the beginning of this chapter

Advantage:
- the magnitude of the measured residual current is free dimensional

disadvantage:
- A central auxiliary equipment is necessary.
- the dimension of the switching capacitor depends on the network size

Residual voltage and current

Wattmetric earth-fault detection

The residual current at the fault location consists of a resistive– and a reactive-component. In resonant earth networks the reactive-component depends on the compensation level. Therefore in this networks only the resistive-component is being used for the fault location with a wattmetric earth-fault relay. The quantity of the resistive-component depends approximately to two thirds of the losses of the petersen coil and to one third on the line losses in the ground fault path. The small resistive-component has the same magnitude as the transducer errors. Therefore after the occurrence of an earth fault a resistance at the auxiliary winding is switched on. That rises the resistive-component and improves the operation of the relay.

Advantage:
- the resistive-component is constant

disadvantage:
- false indication in meshed networks based on current splitting or at parallel lines based on phase splitting are possible
- huge requirements on the phase accuracy of the current transducers are needed
- cable-type current transformers should be used instead of the three single phase current transformers

important parameters:
- losses of the petersen coil
- maximum current loading of the auxiliary winding for earth-fault detection of the petersen coil

remarks:
- determines the useful signal level
- limits the signal level

Reactive-power relay

In isolated networks the reactive-component is used for the earth-fault detection. The relays work with the so-called sin ρ arrangement.

Advantage
- independent from central auxiliary installations
- normal a high signal level

disadvantage:
- the signal level of the reactive-component depends on the part of the network without earth-fault

important parameters
- capacitive earth-fault-current

Harmonic components

In compensated network the harmonics of the residual current and voltage have the same characteristics than the fundamental signals in isolated networks. The petersen coil is ineffective by their high inductance to the harmonics. An audio-frequency remote control system (AF remote control) can also be used in state of the natural 5. Harmonic. This system is switched on during the earth fault. The frequency of this AF remote control system should nearby 250 Hz. The evaluation of the residual current and voltage preferably takes place either with ampere-metric relays or directional relays, which are adjusted, to the AF remote control system frequency.

advantage:
- Independence from central installations on use of the 5. Harmonic. Particular in cable systems are strong currents and therefor good results with this relays

disadvantage:
- Fluctuations in the level of the 5. Harmonic causes adjusting problems in some networks with ampere-metric relays (less with ground fault directional relays).
- there are wrong direction decisions possible by unfavourable distribution of the capacities and inductivity of the zero system, e.g. in expanded overhead line nets with central arranged capacities (cable system parts)

important parameters:
- level of the harmonics
- unbalanced residual current
- number of branches
- L/C distribution in the network

remarks:
- the level of the harmonics is e.g. dependent on the load
- the signal level of the harmonics is proportional to the unbalanced residual current
- the sensitivity of the ampermetric relays increases with the number of branches
- determines the ignition frequency and damping

5. harmonic magnitude of feeder residual magnetic and electric field

Operational principle similar to 5. Harmonic relays. The measured signals processed by the equipment are not directly the residual current and voltage, but the caused electromagnetic fields. These are the magnetic field of the residual current and the electrical field of the residual voltage. There are only clear field conditions at overhead line, however not in switchgear bays or at underground cables.

Advantage:
Independence from central installations on use of the 5. Harmonic

disadvantage:
- Fluctuations in the level of the 5. harmonic causes adjusting problems in some networks
- there are wrong direction decisions possible, by unfavourable distribution of the capacities and inductivity of the zero system, e.g. in expanded overhead line nets with central arranged capacities (cable system parts)

important parameters:
- harmonics
- unbalanced residual current
- L/C distribution in the network

remarks:
- the level of the harmonics is e.g. dependent on the load
- the signal level of the harmonics is proportional to the unbalanced residual current
- determines the ignition frequency and damping

Phase current

Current magnitude relay

In impedance earthed networks the magnitude of the earth fault current is in order of the nominal current of the line. Therefore it is possible to use the normal short current selective protection technology. These are for example time relays, permission- and blocking-systems or current differential protection systems. Protective relays, which evaluate only the residual current, can be attached to the cable-type current transformers. A set of three pole current transformers is necessary for distance protection relays. Since the fault current can be lower then the nominal current of the line, suitable starting schemas are necessary.

Advantage:
- earth fault detection with existing short current protection systems

disadvantage:
- interruption of the electrical power supply
- with temporary impedance earthed networks the interruption could be avoided.

Important parameters:
- magnitude of the earthing impedance
- small earth-fault-current
- big earth-fault-current

remarks:
- determines the magnitude of the earth-fault current
- starting problems

problems with EMC and voltage dips

Short circuit fault indicator

The working method of this equipment is described at the beginning of this chapter

Advantage:
- shorten the time of the earth fault detection

disadvantage:
- the registration of the fault indicator decision is only detectable directly or by remote control

important parameters:
- magnitude of the earthing impedance
- network structure

remarks:
- Starting problems with small short circuit currents.
- only in radial networks the decision of the fault indicators are clear

Analysis

earth fault distance protection

The numerical distance protection device reports the measured fault distance. If also the distance protection device records single-phase earth faults, the faulted section can be easily and fast determined.

There is some research programs to determine the fault location in an isolated or resonant earthed network by the evaluation of the fault distance with the transient signals of the earth fault

Advantage:
- very fast fault location

disadvantage:
- a centralised fault location in the power system control station is possible

important parameters:
- zero sequence impedance

remarks:
- this impedance is often unknown

The different earth fault detection methods have been summarized in Table 2.2.

Table 2.2. Overview on earth fault location methods (based on Verband der Elektrizitätswerke Österreichs : Sternpunktbehandlung in MittelspannungsnetzenWorking Group Report, 1996, ISBN3-901411-19-4 Authors: Fickert L., Tenschert W., and others) [11].

Method	faulty feeder select.	Faulty section locat.	Iso-lated	Treatment of neutral point: reson. Earthed	imped. earthed	temp. Imped. Earthed
Residual voltage						
Permanent earth fault identification	No	No	Yes	Yes	No	Yes
Automatic feeder interruption (OFF and ON)	Yes	No	Yes	Yes	No	No
Manual feeder interruption (OFF and ON)	Yes	No	Yes	Yes	No	No
Two-Transformer-Method (no interruption)	Yes	No	Yes	Yes	No	No
Earth fault indicators (residual voltage field)	Yes	No	Yes	Yes	No	Yes
Transient residual voltage						
Transient earth fault identification	Yes	No	Yes	Yes	No	Yes
Residual current						
Magnitude	Yes	No	No	No	Yes	Yes
Active component	Yes	No	Yes	Yes	Yes	No
Variation of compensation by Peterson coil	Yes	No	No	Yes	No	No
Variation of compens. by capacitor switching	Yes	No	No	Yes	No	No
Phase current						
Magnitude	Yes	Yes	No	No	Yes	Yes
Reactance computation (feeder I and U)	Yes	Yes	No	No	Yes	Yes
Short circuit indicator	Yes	Yes	No	No	Yes	Yes
Harmonic components						
5. harmonic magn. of feeder residual U and I	Yes	No	Yes	Yes	No	No
5. harmonic magn. of magn. and electric field	Yes	No	Yes	Yes	No	No
5. harmonic phase comparison of residual I	Yes	No	Yes	Yes	No	No
Analysis						
Numerical analysis of feeder residual I and U	Yes	Yes	Yes	Yes	No	No

2.3.2 New Methods

To improve the detection of high ohmic earth faults new methods have been developed. The main features are:

- relative measurement of signals
- centralised signal processing

Admittance Method

The admittance method developed in Austria determines the unbalance of the zero sequence admittances of every feeder. The unbalance of the zero sequence admittance can be caused by the unbalanced network impedances or by high ohmic earth faults. The unbalance for feeders with symmetrical impedances under no fault conditions is zero [10].

The calculation of the unbalance takes place every 20 ms. If the unbalances of all the feeders are below a pre-set value, these unbalance values are stored as reference values for every feeder.

The behaviour of the admittance unbalance of every feeder is continuously monitored. If the difference of the magnitude of the unbalance compared to its reference value exceeds a threshold value, an earth fault is detected. Because of the relative measurement this threshold value can be set very sensitive.

Current Method (DESIR-Method by EdF)

If the zero sequence voltage is not available, the vectorial position of the zero sequence currents relative to a computed reference voltage can be monitored. The direction of the in phase component of an earth fault current is opposite to the direction of unfaulted feeders.
This method can be applied for steady state signals (static DESIR-method) as well as on steady state relative measurements (dynamic DESIR-method).

Practical Experiences

Field tests and practical experiences show excellent results. With DESIR-method and admittance method earth faults up to 50 kohms can be detected. The sensitivity of the admittance method can be set for earth fault detection up to 100 kohms (proved by field tests). The practical experiences with the admittance method at OKA confirm the reliability and sensitivity of the device.

2.4 SUSTAINED OPERATION WITH EARTH FAULTS

Because of the increasing demand of decreasing the supply interruptions experienced by the customers, there is a rising interest in sustained operation with earth faults also in public medium voltage distribution networks. Sustained operation has so far been used in Austria and in some utilities in Germany. In this section, the sustained operation is discussed according to the Austrian experience.

2.4.1 Austrian MV-networks

The neutral treatment of the MV-networks of the public supply in Austria is quite unique:

6,0	**%**	isolated
93,3	**%**	compensated
0,03	**%**	low impedance grounded
0,7	**%**	short term low impedance grounded

Except some smaller networks that are operated isolated, almost all the MV-networks are compensated with Peterson coils. In isolated and compensated networks sustained operation with permanent earth faults is usual. Few rural compensated MV-networks are equipped with short term low impedance grounding in case of an earth fault. In these networks no sustained operation with earth faults is performed.

Table 2.3. Neutral treatment of public MV network in Austria.

	Voltage		
neutral treatment	10 kV	20 kV	30 kV
isolated	2.824 km	249 km	98 km
compensated	7.871 km	27.733 km	14.111 km
low impedance grounded	15 km	-	-
short term low impedance grounded	-	151 km	237 km

2.4.2 Range of application, restrictions, limits

A sustained operation with a permanent earth fault is allowed only under some conditions that are further explained. The following chapters are valid for compensated MV-networks only. The values given here correspond to the present Austrian standards. Values defined in the new European Standard prEN50179, presently in final discussion, are given in parenthesis
.

Touch and step voltages

All earthing systems must be designed so, that the earth potential rise is less than 125 V (150 V). In this case no special proof of the touch voltages is required.

If 125 V (150 V) cannot be kept, explicit measurements are allowed, to prove that the touch voltages are below 65 V (75 V). Alternatively equivalent means (building, fences) are required to prevent too high touch voltages. The requirement for step voltages is not defined explicitly.

Common earthing system for high voltage and low voltage systems

For TN-type LV-systems the earth potential rise must be less than 65 V (75 V, 150 V if the PEN conductor of the LV-system is grounded at several points outside the common earthing system). For TT-type LV-systems the earth potential rise must be less than 125 V (250 V).

Influence on communication networks

Communication networks may be affected by capacitive, inductive or resistive influence. Capacitive influence has not to be investigated. Inductive influence has not to be investigated, if the resulting earth current is less than 60 A in MV-networks up to 20 kV or less than 67 A in 30-kV-networks. If these currents are exceeded, the inductive influence at double-earth faults must be investigated. Up to these currents temporary earth faults are considered as self-extinguishing. Resistive influence has only to be investigated, if the above current limits are exceeded.

Influence on pipe lines

Investigations on inductive or resistive influence on pipe lines have to be performed for networks with nominal voltages of 110 kV and higher.

Immediate start of fault locating

A sustained operation with permanent single-phase-to-ground faults is permitted, if the process of fault locating is started immediately. After locating the fault a sustained operation may be continued, if it is ensured, that no danger for persons can arise.

Duration of sustained operation

There are technical restrictions for the duration of a sustained operation with earth faults:

- Phase-to-ground voltage transformers may be destroyed by the increased voltage of the non-faulted phases after 8 hours.
- Peterson coils are usually designed to sustain the full earth fault voltage for 2 hours.
- Multiple faults. The increased voltage of the non-faulted phases is a stress on every phase-to-ground device. The probability of multiple faults is increasing with time and with the extension of the network.

Single phase interruption

Single phase interruption can cause a residual voltage similar to a single-phase-to-ground fault. Locating this type of fault by switching operations may become rather difficult, therefore the time of sustained operation is long. Single phase interruption in the MV-network unfortunately can cause unbalanced conditions in the LV-network with damage of consumer equipment.

2.4.3 Fault location

The process of locating a permanent earth fault in compensated networks is a four step sequence:

- detection of the fault
- detection of the faulted feeder
- locating the faulted section
- locating the fault

Detection of the fault

The detection of earth faults is usually done by monitoring the residual voltage by a relay. If the residual voltage exceeds e.g. 25 % of nominal phase-to-ground voltage an alarm signal is generated. The alarm signal is usually 5 s delayed to prohibit a signal for temporary self-extinguishing faults. High resistive earth faults cannot be detected by this simple relaying. Such faults can be recognised by analytical methods (e.g. controller of the Peterson coil).

Detection of the faulted feeder

The detection of the faulted feeder is performed by protection devices, by the controller of the Peterson coil or by switching operations in the HV/MV-substation.

Locating the faulted section

The faulted section of a long feeder is located usually by switching operations in the network outside the HV/MV-substation. If there are normally open rings to other HV/MV-substations or to sound feeders of the same substation, the location can be performed without interruption of supply.

Locating the fault

If further sectionalising of a feeder is no more suitable, the location of the direct fault point is done by patrolling the line. Present R&D tries to develop reliable methods for the detection of the fault and of the faulted feeder. Reliable and accurate methods in compensated networks for locating the faulted section are presently not known.

3 AUTOMATIC SWITCHING SYSTEMS

In this chapter, different solutions for automatic fault location, fault isolation and supply restoration are outlined. The alternatives considered are pause-switching, pause-switching complemeted by signalling and full automatic systems based on the integration of relays, SCADA and AM/FM/GIS systems.

3.1 Pause-switching

General

Pause-switch are commonly used in radial operated medium voltage (MV) networks. The circuit-breaker located at the feed-in of the spurline switchs off the overhead line or cable at overload or short circuit conditions. It is frequently also responsible for the protection of further transformer substations on this spurline, which are insufficiently or totally unprotected (Fig. 3.1).

Fitting out these substations with circuit-breakers and appropriate protection equipment to enable more selective disconnection fails often due to the lack of room or due to the high purchase costs. Therefore a fault leads always to the disconnection of the total spurline. Fault locating, disconneting the faulty line section and connecting the healthy parts is complicated and time intensive.

Function principle

The principle of pause-switching helps to achieve a selective disconnection of faulty lines in corresponding designed nets in an economical manner. Economical because the investment costs are low and no additional room, which may not be available at all, is required.

The occurrence of a fault in the net will lead to disconnection of the spurline by the circuit-breaker, located at the feed-in. Reclosure however can take place after a relatively short time period, there is no need to wait till the faulty part is located and disconnected by the staff. The reclosing of the circuit-breaker will be done automatically by a timing relay.

Within this settable intervall between tripping and reclosing all isolating points between the circuit-breaker and the fault location will open automatically. If the fault is located somewhere between the circuit-breaker, at the beginning of the spur line, and the paus-switch the reclosure will lead to another tripping of the circuit-breaker, comparable to an unsuccessfull autoreclosing.

The operation of the pause-switch take place under deenergized and off- circuit conditions. Nevertheless the pause-switch is build from an upgraded switch disconnector and therefore also capable of switching operations under normal load conditions.

The pause-switch is a loadbreaking capable device with direct overcurrent release. The tripping linkage of the direct release starts a settable time delay. Expiration of the setted time results in a tripping of the switch disconnector.

The faultless working depends on the correct setting of the dead time t_p of the circuit-breaker and the time delay t_v of the pause-switch, which both depend on the structure of the net.

Figure 3.1 shows an example: The tripping time t_{a2} of the overcurrent relay of the circuit-breaker ② at the feed-in of the spurline is usually fixed by the time grading schedule. As the starting condition of the direct overcurrent release of the paus-switch ③ cease to exist after the tripping of the circuit-breaker ② the tripping time t_{a3} has to be shorter than t_{a2} . The time delay t_v has to guarantee that the paus-switch trips not before the line is disconnected. As a failure of the circuit-breaker ② cannot be excluded it is wise to set the time delay t_v greater than the tripping time t_{a1} of the superior circuit- breaker ①.

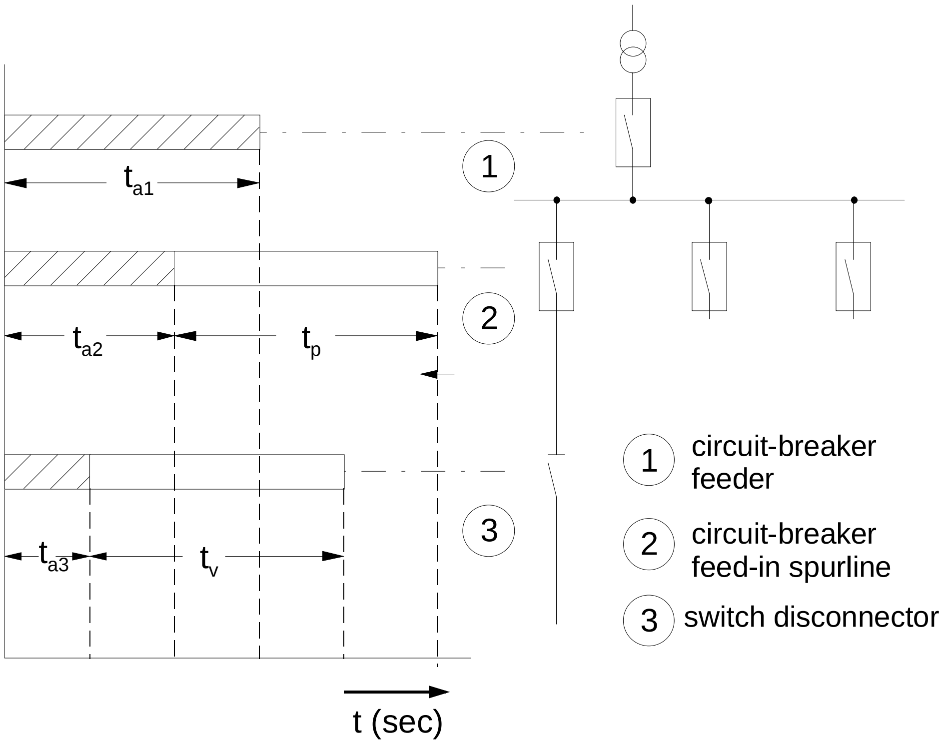

Fig. 3.1. Time grading scheme of a pause-switching system.

Conclusion

Pause-switching is an economical solution to improve the power supply reliability, where certain circumstances stay against the use of circuit-breakers instead.

Field of application

The pause-switch was put in action mostly during the 60's in Germany. Despite the economical advantages only a few electricity companies made use of them. Today new solutions are considered, e.g. signalling between the two stations in combination with modern compact relays.

3.2 PAUSE-SWITCHING COMPLEMETED BY SIGNALLING

In this section, the fault management practices in the medium voltage distribution networks of ENEL are presented. The items covered are the extension of a pause-switching system with signaling and an application where also fault indicators are integrated in the automatic fault management system.

In the case of overhead lines, the MV network fault management is based on secondary substations with SF_6 insulated motor driven switchgear and voltage detectors. The control of these is based on a combination of local logic similar to that described in the previous section and data transmission based on the distribution line carrier (DLC) technology.

The restriction of a DLC system is that the communication path can be blocked by the fault. To mitigate this problem, when there is a fault, all the switches of the faulty line are opened by the local logic after a certain time delay. The existence of a fault is noticed by the voltage detectors as a disappearance of the voltage. Next, the circuit breaker at the HV/MV substation is reclosed, and if the first line section is sound, communication up to the first line switch is possible. This switch is then closed by the DLC-system. If there is no fault in the corresponding line section, the procedure is repeated for the next line switch etc. When the faulty section is finally found, the voltage disappears again. The loss of voltage, immediately (less than 1 s) after the reclosing, is detected by a timer circuit and the last switch is opened again. Next, to complete the procedure, the circuit breaker is reclosed with a time delay longer than the previous one, but short enough to prevent the reopening of the other line switches.

In the case of underground cables, the MV network fault management is based on the secondary substation equipment similar to the above, but complemented with fault detectors. In this case, the procedure is somewhat different in order to avoid the reclosing of the faulty section. For the operation of the automation system, consider Figure 3.2:

When a fault happens, the circuit breaker of the supplying HV/MV substation is first opened. During the dead time of the line, the remote terminal unit at the substation 1 (RTU 1), sends a message downstream to check the status of the fault indicators at the second substation. Having received the message, RTU 2 responds to RTU 1 and sends a corresponding message to RTU 3 (Fig. 3.2 b). From RTU 3 there is no response, which means that either the fault indicators at substation 3 are not 'on', or that the communication path has been blocked by the fault. Now RTU 2 makes a conclusion, that the fault is in the following section, opens the corresponding switch and sets it in the 'blocked' mode (Fig. 3.2 c). Next, after a certain time delay, the circuit breaker is reclosed, and the substations are re-energized. The return of voltage for a sufficiently long period resets the fault indicators connected to the sound sections (Fig. 3.2 d).

The goal is to provide 10% of the secondary (MV/LV) substations by an automatism described above. For this a new generation of secondary substation equipment has been designed. In particular, ENEL has decided to use SF6 insulated motor driven switchgear, because the power of the motor and the capacity of the battery are reduced, due to the lighter masses of the moving parts.

As regards the injection of the transmission (DLC) signals, a new generation of MV/LV transformers have been developed, to allow the installation of the coupling device through a plu-in operation on the transformer case.

The automatic switching systems described here is a part of a more extensive automation system, the aim of which is:

- remote contol of distribution power network
- automation of metering service for MV and LV customers

The system is called SITRED.

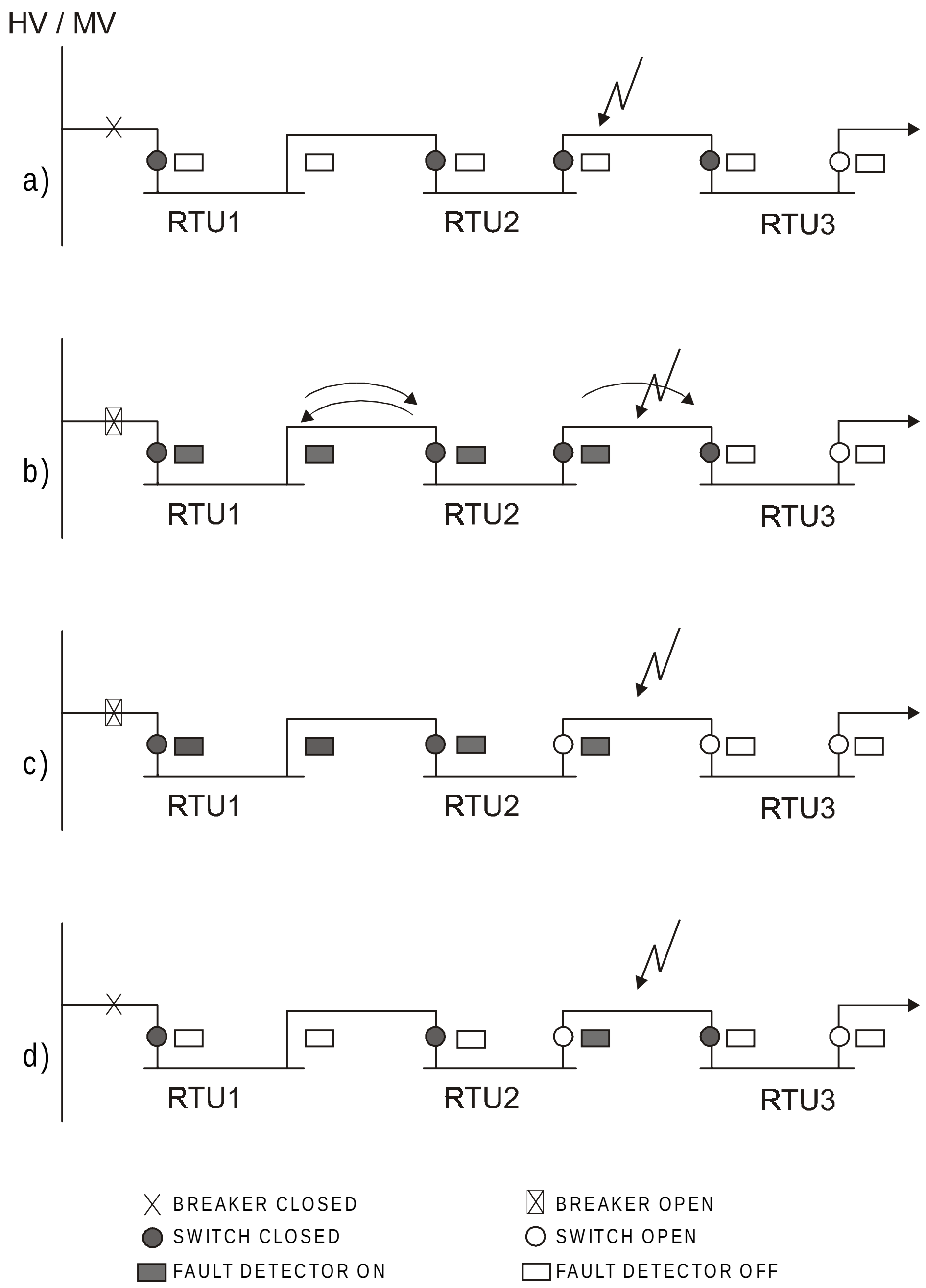

Fig. 3.2. The MV network fault management procedure of ENEL in the case of underground systems.

3.3 METHODS BASED ON THE INTEGRATION OF RELAYS, SCADA AND AM/FM/GIS

3.3.1 Introduction

An automatic computer model, called the FI/FL model, for fault location, fault isolation and supply restoration is presented. The model works as an integrated part of the substation SCADA and medium voltage distribution network automation systems.

In the model, three different techniques are used for fault location. First, by comparing the measured fault current to the computed one, an estimate for the fault distance is obtained. In the second phase, this information is combined, in order to find the actual fault point, to the data obtained from the fault indicators in the line branching points. As a third technique, in the absence of better fault location data, statistical information of line section fault frequencies can also be used.

Once the faulty section is identified, it is automatically isolated by remote control of line switches. Then the supply is restored to the remaining parts of the network. If needed, reserve connections from other adjacent feeders can also be used. During the restoration process, the technical constraints of the network are checked. Among these are the load carrying capacity of line sections, voltage drop and the settings of relay protection. If there are several possible network topologies, the model selects the technically best alternative.

3.3.2 System integration

The automatic switching system is based on a close integration of substation telecontrol (SCADA), network automation, protection relays and AM/FM/GIS systems. In the solution presented in this section, the integration of substation telecontrol and protection relays is based on the Inter Bay Bus (IBB), which enables spontaneous data transfer of events from bay level to station level (Figure 3.3).

The protective modules transmit the measured current and voltage values, and the additional fault information, via the serial bus to the station level unit (SC) of the SCADA system. The same data is transmitted through the communication gateway to the main SCADA computer in the network control center.

The main task of a SCADA system is to provide a real time interface to high voltage / medium voltage substations and to the remote controlled points in the medium voltage distribution system. The role of the AM/FM/GIS system is to form a data bank of the detailed network data. It is also used for real-time presentation of the network connections.

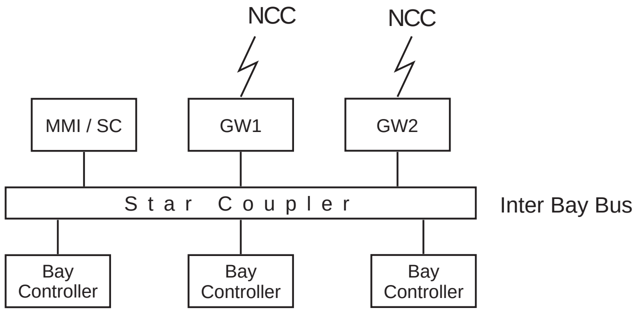

Fig. 3.3 The principle of the integrated station automation and relay protection. NCC is a network control center, SC is the station controller, MMI is the man-machine interface, GW is the communication gateway and the Bay Controller is the integrated protection and control unit.

The FI/FL module works as an integrated part of the substation telecontrol system. After the FI/FL module has been started, the communication is between SCADA system and the network controlled points only. In this phase the commands sent by the SCADA include the line switch close/open operations. At every step of the fault management process, the status of feeding circuit breaker at the substation is also checked, in order to detect possible closings against a faulty line section.

3.3.3 Fault location techniques

In the fault location part of the FI/FL model, three different sources of information are used:

1) the computed fault distance
2) the data from the fault indicators in the line crossings
3) the statistical fault frequencies of different line sections

For obtaining the computed fault distance, the measured and the computed fault currents are compared. As a result, the estimated distance of the fault from the substation is obtained. This distance is then, in turn, compared to the network diagram, and the possible fault locations are obtained.

When analyzing the readings of the fault indicators one has to take into account their possible misoperations. It is also often the case that only a part of the line sections concerned are equipped with fault indicators. These problems are mitigated by statistically combining the indicator readings.

The third source of information are the statistical fault frequencies of different line sections. This data is useful especially if the network is a mixture of overhead and underground line sections. In the latter ones the fault frequencies are substantially lower than in the former ones.

The final phase of the fault location procedure is to combine the information from different sources by fuzzy logic. The final result of the fault location module is the probability weights for each line section. These weights express the likelihood of the fault being located in the line section concerned. In the next step of the fault management procedure, this data is submitted to the fault isolation and supply restoration model.

3.3.4 Fault isolation and supply restoration

Once the fault location has been analyzed by the FL submodule, the automatic function for fault isolation and supply restoration (FI submodule) is executed. The control of the network switches is done in such a way, that the line is processed zone by zone in the smallest possible remote controlled sections. After every reclosing of a line switch, the status of the feeding circuit breaker is checked, and if there has been tripping, the line section concerned is regarded as a faulty one.

The operation of the FI model is optimized so that the number of outages experienced by the customers connected to the faulty line is minimized. For this, there are two alternative approaches, depending on whether the faulty line section will be verified by trial switching or not. In the trial switching mode, the FI model first tries the line sections with the highest fault probability. When the faulty line section is encountered, it is isolated, and the remaining sections are energized. The trial switching mode actually performs a delayed autoreclosing. This mode is recommended in the cases, where there is some degree of uncertainty in the fault location, or where it is desired that the traditional delayed reclosing by protection relays be replaced by a zone-by-zone reclosing.

In the second mode, the aim is to avoid the trial switchings. Here the line sections are energized starting from the smallest fault probability and when only one section is left, the procedure is stopped. This mode is usually used only if a full reclosing procedure is first performed by the relays. To be effective, this mode also requires a good knowledge of fault location. In practice this means, that there must be fault indicators mounted at the line crossing points where the remote controlled switches are.

The FI model first tries to energize the line section by section from the initial feeding direction. For those sections which can not be energized in this way, a reserve connection is used. Before the coupling, the capacity of the reserve connection is checked for thermal load carrying ability and for the maximum voltage drop. Also the settings of the protection relays of the feeding circuit breaker are checked in order to ensure relay coordination.

3.3.5 Other automatic models for fault isolation and supply restoration

SARA is a software package that aims at performing automatic switching experimented for several years on a EDF control center. When a fault occurs on a feeder, predefined restoration actions are recorded. After checking that the actual topology match the recorded one, switching orders are sent on circuit breakers. SARA is a package that is installed on the telecontrol system. The experiment was successful on the experiment done in several primary substation. Total amount for fault restoration was strongly reduced for the faulty situation where SARA was running. However, the system cannot easily be generalized since it supposes that the network is in a normal topology. So, EDF decided to put effort on a new tool, named AUSTRAL, that provide assistance rather than automatic switching applications (see chapter 4).

4 SOFTWARE FUNCTIONS FOR DISTRIBUTION NETWORK OPERATION

4.1 Introduction

4.1.1 The role of SCADA functions for fault management

This chapter discusses how the remote control system and associated software functions can provide assistance to operators for fault management.

Valuable assistance to network operation staff for fault management will be provided in the following main tasks:

- Incident management itself : **minimum power cut duration** (diagnosis, fault location, suggestion and implementation support for power resumption plans) ;
- **Improved customer information** ;
- **Preparation of network installation and repair operations** (new structure set up, maintenance shutdowns): operational network modelling and preparation for manoeuvre sequences enable to anticipate possible fault situation.

4.1.2 Major function categories

Software functions for fault management can be broken down into three main time-scale categories:

- <u>Real-time functions</u> address the current network situation, providing assistance in real-time network control, possibly including direct action on network structures. The main real-time functions are: event analysis and diagnosis; fault location; power resumption; field crew management; and trouble call analysis and customer information. Real-time function need a connection in real-time to up to date data from the SCADA system.

- <u>Preparatory functions</u> are provided to help operators study simulated network situations representing configurations which are liable to arise or be adopted in the future (e.g. incident or withdrawal configurations). With the kind of function, the operator is primarily seeking to determine baseline configurations which will be capable of handling future network situations. This kind of functions require from the SCADA system a copy of actual or forecasted network.

- Hindsight analysis functions are implemented to investigate actual-fact operating conditions over elapsed periods of a day or longer, usually by analysing records of network operation data. They generally output results in the form of statistics, quality indicators, or quantified reports on customer supply disturbances. This can be very valuable for fault management by enabling an adapted predictive maintenance.

Because of the variability in function location we do not attempt to specify a "standard" arrangement, and we do not use existing nomenclature (e.g. DMS, or AM/FM/GIS), which is often poorly defined and sometimes inconsistent.

The figure shows an global view of the telecontrol systems and the above three main set of functions.

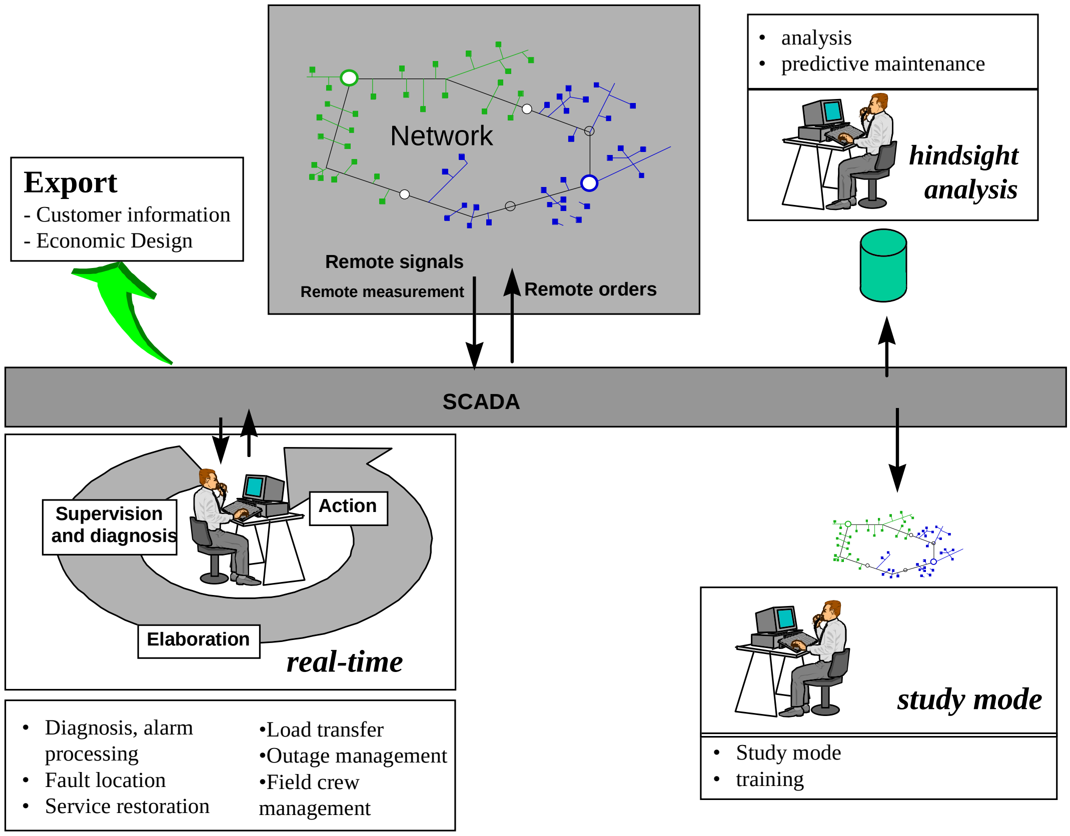

Figure 4.1 : Overview of functions

4.1.3 Open discussions

Centralized or decentralized

Should the new functions be installed on the SCADA system, in a centralized position or should be they decentralized inside every substation. We note that a compromise must be struck between improved functions for the network operating system and improved functions integrated in new generations of source substations. Specifically, steps should be taken toward greater complementarity.

The observed trend in primary substation is towards more and more intelligence, digital and computer-based technologies. Some functions that has to be previously implemented in the central control system cam be now partly implemented at the substation level. Coupled with improvement in information technologies and telecommunications, data exchange between the SCADA system and the primary substation will become in a near future a quite solved problem.

However, rather decided to implement a given function into the telecontrol system *or* into the primary substation, it seems to be more interesting to find complementarily. For instance, a diagnosis function based on event analysis is better implemented closer to the field (primary substation). But as soon as the topology is required, an implementation in the telecontrol system is best suited. A shared implementation based on data exchange is certainly the target for future developments.

Close the loop : decision support function or also active function?

Another point should be addressed. Until now, functions in the telecontrol system has been almost always specified as off-line functions. More precisely, they has been seen as function that inputs data from real time but don't perform any action directly on the network. The operator has always been included in the loop. Automatism that directly acts on real-time operation was implemented at the field level (protection, substation). Current developments observed now let predict that the loop will be closed "one level higher" in a near future. Some functions implemented at the telecontrol system level are specified to directly send order on the network (for instance, a fault restoration function). So, the strong distinction between automatism (necessarily on field) and analysis and decision support (necessarily on SCADA) is will certainly become less true in a near future. Both will be performed at any level.

4.2 SCADA SYSTEM, DATABASES AND BASIC SCADA FUNCTIONS

4.2.1 Definitions

The kernel of the telecontrol system is basically composed of the following modules :

- the **SCADA** system for data acquisition. The SCADA system is connected to **RTU** and manages a real-time **data base**.
- the **graphical display** that presents to the operator the interface for the complete telecontrol system (network representation, data visualisation, remote order, etc.).
- an **archiving system.**

Plugged on this kernel, we may find the various functions illustrated on Figure 4.1.

4.2.2 SCADA and platform

Hardware, operating systems and architecture

The majority of the current SCADA platforms are client server systems in a master/slave or master/hot-stand-by configuration. Most used operating system is UNIX on 64-bit machines but platforms running under Windows NT on powerful PC's are also used. This of course is a consequence of the evolution on the PC market (less and less limitations and more and more processor capacity). The use of an NT environment gives advantages on behalf of the user interface and on behalf of the connectivity with other software tools running in the different companies. A combination of both operating systems also exists : main server under UNIX and workstations with Windows NT.

The database used is mostly of an open standard type who can be easily accessed from other applications. This of course is a serious advantage if we consider using database information in fault management programs who are not developed by the SCADA constructor.

The upgrading of the systems can be divided in 2 types : upgrading of the energy control software and, upgrading with new data on the controlled network. Modern systems allow this upgrading actions during real-time operation. This is the result of both the client-server architecture and the fact that most systems work in a master/slave configuration.

All recent systems provide tools for self examination and self-control of the SCADA system.

Network monitoring, network control

The basic real-time functions can be divided in two major items : network monitoring and network remote control.

All modern systems allow monitoring of status's (switches, breakers, short-circuit indicators, etc.), analogue (current, voltage, temperature, etc.) and digital values and accumulators (pulse counting).

Alarm handling and alarm processing is available everywhere. Remote control is principally possible on every object (switch, set point, etc...) in the network (as far it is equipped to be controlled).

Front-end (FE)

Database

Two philosophies are used : FE's with particular database and FE's as client on the SCADA main server. Both systems have pro's and contra's.

FE's with particular database give the opportunity to connect to different central control systems. Normally generic data formats are used in this cases. Final format-translation is then done on the receiving SCADA platform. Biggest advantage of this method is the fact that transmission lines to the different controlled stations can be reduced and that data are shared after the FE. In case of failure of the central control devices, in most cases -reduced- control operations can be done from the FE consoles.
A disadvantage is that the data have to be placed and upgraded in at least two different databases (redundancy problem).

FE's as client on the main SCADA server get their network-configuration-data from the main SCADA server. Redundancy is not a problem in this case and the result is a more simple architecture. However if the main server fails no control actions are possible. In this case a hot-standby configuration is a must.

Exchanging network control with other SCADA platforms can be done with additional servers where the desired data is presented. Links can be made with point to point connections or over the Internet.

The FE as client on the SCADA server is the most common solution in the examined countries.

Protocols

Most recent FE-systems allow the standard exchange protocols. These protocols run mostly in a multi protocol mode.

Polling / Transmission to the control centre

The combination of cyclic polling and polling on demand is normally used. For the transmission both point to point lines and switched networks (private and public) are used.

4.2.3 Data and database

Most of the functions outlined above are based on the use of a fixed database storing data from the substations plus data on the power system structure. Configuration of this database will often prove long and fastidious. To ensure that the functions receive valid input data, it is nevertheless primordial to ensure that the data in the database is up to date and coherent. This task is not always easy, given the data models and technologies offered by most suppliers.

Moreover, some functions may need to access data stored in several databases, which might not even be operated by the same company (e.g. trouble call functions will need to merge data from network operation and customer information databases).

4.2.4 SCADA hook up and Open architecture

Most of the functions outlined above require fairly tight coupling to the control system (and to the SCADA in particular). This can be a very complex matter, because control systems often use outdated technologies, and there are no standardised data exchange methods. We should, however, note that international working groups are addressing the issue of standardised data exchanges between control centres. An EPRI working group has put forward a data exchange model, and there are two IEC working groups assigned to this subject.

Control application (control software)

Practically all new systems work with open utility standard control software. Tools as visual basic are commonly provided to give the customer the opportunity to tune the system. This is a very important feature for automatic fault detection and load restoration.

4.2.5 Basic SCADA functions

Graphic Interface

More and more functions display results on user interfaces featuring a graphical representation of the power system. There are many types of representation, ranging from schematics to geographical maps. Semi-geographical representations are highly appreciated by control centre operators, because they give clear analytical views of the power system, providing a good perception of the relative locations of different devices. Geographical representations are needed when the control centre is required to manage field crews (i.e. assess travelling distances and probable repair times). For this reason, control centres are experiencing an increasing need for hook-ups to the utility company's GIS; a single centralised point for geographical data entry avoids the risk of inconsistency between databases, and eliminates the need for duplicate data capture.

Strong visualisation ameliorates the knowledge of the status of the network. Schematic flow displays with dynamic coloration give an immediate view on the impact of a fault and the result of fault restoration efforts. This feature increases drastically the control capacities because it gives a global overview of the network structure. Graphical trending and digital trending are features that can be used in the development of a load forecast application. In the margin of the graphical tools the different operation modes are also to be mentioned. Study mode and dispatcher training mode are mostly graphically orientated. They give the opportunity to simulate faults and events on the network. The results of these simulations can be of great value for mathematical and logical models for fault restoration.

Archiving / Reports / Overviews / Study mode

All modern systems have these possibilities. The fact of the open database structure makes it possible for the user to customise his view on the events and alarms. Exporting these data from the SCADA database to other environments gives even more opportunities to examine these files.

Extra features as "net freeze" and "snapshot" give helpful hints and historic data.

State estimation, topology analysis

State estimation and topology analysis are basic features that can be provided to many functions.

Topology analysis involves inputting the static network model plus information on dynamic switching states in order to perform connectivity analysis and construct a real-time network model. This model may include load flow calculation (see Electrical System Computation below). As well as being a basic function of considerable value to operators in itself, topology analysis is also a prerequisite for most advanced functions. Results are presented to the operator as dynamic colouring on the user interface. Each feeder has its own colour, which is dynamically updated as switches change position. The function detects abnormal or erroneous switching states causing closed loop situations or de-energisation of line sections and substations. De-energised line sections and meshed feeders are displayed on screen to help the operator locate the switching state errors.

Topology analysis is based on graph analysis. Dynamic colouring suppose a efficient algorithm in order to provide real-time visualisation.

State estimation and topology analysis is becoming a standard function, offered by most remote control systems. A quite efficient algorithms are necessary in order to support real-time visualisation and real-time functions.

We must note, in addition, that the actual topology may differ from that recorded in the database because some devices on the network are not remote-controlled. If these are manual devices, the database can be updated with information received by the control centre, but if they are automatic devices it is much more difficult to ensure database accuracy.

Electrical system computation

Electrical system computation affords improved understanding of network behaviour, to help operators check compliance with technical constraints, supply quality requirements and protection schemes. The main computations likely to be of value to distribution network operators are as follows :

- power flow (to check device current limits)
- voltage drop (to check quality of supply of customers)

The main difficulty concerns data availability and accuracy. Load profiles are the weakest point, because loads can only be estimated from measurements on feeders. The actual load may differ considerably from the estimated value used for computation purposes.

In addition, electrical computation may require detailed technical data that might not always be available during real-time operation (e.g. : electrical features of lines and cables).

Most of the electrical system computation packages available for distribution networks assume a radial network configuration, but it may be useful to compute special meshed network situations (e.g. for load transfer).

Electrical system computation are needed to estimate the actual electrical features on the network and to perform simulations for forecasted situations. So, electrical system computation appear to become the basis of many new advanced functions. Many software packages are available from SCADA vendors and specialised software companies, **but they are not yet widely used for real-time operation**. However, most of the European utilities have plan to integrate a load-flow computation for real-time operation.

Load estimation and load control

Although not commonly introduced, these features are on the list of nearly every company. This is quit obvious because load forecast and load control can have a direct impact on the price of the energy.

Depending on the automation degree of the SCADA platform, load monitoring, load forecast, adaptive load forecast, automatic load switch-off and tariff applications are running on some SCADA platforms. In some cases these applications are running on a different platform.

Area of responsibility

All new systems give the opportunity to virtually divide the database so that the network can be monitored in isolated parts. This multi-control feature gives the customer the ability to split the controlled area in mini control centres. This can also be used to control several energy forms without interference (gas/electricity/data).

4.3 REAL TIME FUNCTIONS FOR FAULT MANAGEMENT

4.3.1 Diagnosis, alarm processing and event analysis

Technical description

Diagnosis, alarm processing and event analysis functions input a stream of events from the network (remote signalling data, mainly) in order to output diagnostic information and event-analysis messages, for real-time transmission to the operator (via the remote control system log or in a dedicated window).

The precise term for the function ("diagnostic", "event analysis" or "alarm processing") will depend on whether the system accommodates automatic device management and supports the notion of alarms.

Basically, this kind of function works by matching incoming signalling and alarm data against predetermined patterns that characterise the messages and diagnostic data to be output for the operator.

Difficulties

The main difficulties affecting this kind of function are as follows:

- real-time connection
- availability and validity of data (especially data describing the protection system)
- update of expert knowledge

Benefits

This type of function brings the following benefits:

- improved understanding of actual network conditions and incident situations, for faster and more appropriate remedial action.
- diagnosis of failings in protection system.

Existing and operational functions

The most common situation is that such functions are not yet operational in the utilities from our study. However, some advanced project can be mentioned. Several **EDF** control centres are about to be equipped with a real-time diagnosis function. Experiments with the diagnosis function from the EDF AUSTRAL package has started in two sites (1998).

4.3.2 Fault location function

Technical description

Networks use various devices for locating feeder faults (network fault detectors, fault distance estimation devices). Some of the information output from these devices is integrated in the remote control system, to facilitate the implementation of fault location functions of varying degrees of sophistication. Fault location will be used :

- by operator for fault isolation, using remote control devices,
- and by field crew management for fault repairing.

For the latest purpose, fault distance calculation is very useful to ensure a fast repairing. One method involves the use of detectors in the network. Location is simple, since faults are located between two adjacent detectors. The accuracy therefore depends on the number of detectors in the network..
A second method involves measuring the fault current (using digital protection systems or oscillographs) in order to calculate the distance to the fault. However, in a tree-structured network there will always ambiguity in determining the defective section. Greater accuracy and reliability will therefore be obtained by correlating calculated values with data from the fault detectors.

Difficulties

The first method requires a specially fitted network, which can represent substantial investment. The cost of the second solution is not exactly negligible either.
Another difficulty concerns the reliability of fault detectors and transmission systems.

Benefits

Precise fault location means faster remedial action by field crews and by operators.

If the network is fitted with remote-controlled switches, power can be resumed for customers on certain network sections without having to wait for action by field crews.

Existing and operational functions

- Several **Finnish utilities** are using since 1993 a fault location software that combine fault distance calculation and fault detectors information.
- An experiment has started (1998) in one **EDF** control center using the fault location function that is included in the AUSTRAL package. This function is based on fault detector on networks.
- Fault distance calculation is under experiment at EDF for several years in several distribution centres. Remote access to the fault distance calculation is performed. But connection to the DCC and integration into the DMS package is not yet realised
- In OKA (Austria) a "Fault Location Function" is used in a semi real time modus. After a fault in the distribution system the measured reactance of the tripping distance relay is sent to the DCC. A program is started and the probable fault locations (generally more than one) are presented to the operator on the screen in alphanumerical form. This procedure if performed automatically. Together with remote monitored fault detectors and fault detectors read by the field crew, the operator decides what tree of the feeder is most probable the faulted one. "
- In ENEL the STM system provides a function which is able , in case of fault, to detect the section affected by the fault between two automated substations: The faulted section is then isolated by opening the switches in the substations and the rest of the line can be re-supplied.

4.3.3 Power restoration

Technical description

Network reconfiguration may be required in the following situations:

- Permanent fault on a portion of the network: the defective portion will have to be isolated while power

is resumed on other fault-free portions that were blacked out when the protective device tripped.
- Preliminaries for work on a network section: the section will have to be isolated from the network, and load transferred to ensure uninterrupted customer supply.
- Overload on a MV/HV transformer: MV/HV transformers are designed to withstand only temporary overload, so when an overload situation arises, the controller will have to transfer load to another transformers.

Reconfiguration is possible because of the meshed arrangement of the distribution network. Load transfer plans seek solutions capable of resuming power or providing back-up to the largest number of customers, while complying with electrical engineering constraints.

Power resumption and load transfer functions involve optimisation problems that can be solved using a number of different techniques (classic optimisation methods, artificial intelligence, etc.).

Difficulties

These functions involve highly combinatory problems which require complex algorithms. To suggest valid plans, the software requires accurate estimations of loads and transits on the network, and this is always difficult to achieve on distribution networks.

Benefits

shorter service interruptions, if power resumption plans are developed promptly

implementation of optimum (or optimised) plans

network operation closer to permissible limits

Existing and operational functions

- In **Finland**, systems from various vendors are used in several utilities.
- In **France**, experiment has started in 1998. The fault restoration function of the AUSTRAL package (called RTP) is experimented on several EDF control centre.

4.3.4 Field crew management functions

Technical description

Field crews must be able to respond to incident situations as fast as possible, so fault identification and location are important factors in determining field crew performance. A basic version of the field crew management function would offer real-time location of field crew teams (by means of a GPS system, for example), so that repair operations could be assigned to the closest team. A more sophisticated version would seek to optimise team assignments

Existing and operational functions

- In ENEL, in case of fault the system gives automatically the list of the personnel to be called for intervention.
- A real-time positioning system on road map is used in Electrabel. The system works with beacons/transmitters placed on the Belgian border allowing to give the position and two-way data transmission. The crews give the status of the task they are working on (started, finished, etc.). This information is transferred to the positioning system, to give the control centre a real-time overview of where the crews are and what is the job situation.

4.3.5 Trouble call analysis and customer information

Technical description

Customer calls are usually managed using one of two methods.

The first method involves a voice server connected to the control system. When the control system detects an incident, it sets the voice server to issue a pre-recorded message covering the affected area. Incoming calls to the voice server can be recognised automatically (using the caller ID function), or callers can be asked to identify their locations by pressing keys on the telephone sets. The system can also be used to store customer voice messages for rapid examination by an operator. These messages may provide notification on incidents that have not yet been detected (for example, incidents can be detected by identifying calls originating from the same area), or additional information on incidents that have been detected but not yet located. Customers may have experienced abnormal events on the power system, and their reports may well accelerate the location process, thus accelerating service resumption as well.

The voice server system can also be used for calling specific clients automatically, to inform them on the extent or probable duration of an incident, if the operator has the necessary information to predict this. The main advantage of the voice server system is that it can handle large numbers of incoming calls following an incident. Servers are today offered by several suppliers, and are becoming fairly widespread among electric utility companies.

The second method consists in providing the operator in charge of handling customer calls with a tool for locating the caller on a map representing the power system and the electrical state thereof. Location might be performed by analysing the customer name, telephone number, etc. The map will give a clear indication of those areas that receive power and those that don't. If the customer is located in an incident-affected area, the operator can explain the extent of the incident and forecast how long the customer will have to wait for supply resumption. If the customer is located in an area not affected by a known incident condition, full customer details are stored. If there are several calls concerning the same area, a simple algorithm is applied to identify the branch most likely to contain the incident. This information is automatically supplied to the controllers. By providing automatic real-time information to the staff responsible for customer calls, the customer call management function ensures that customers are given relevant up-to-date information, and that information is conveyed efficiently and promptly among all concerned. Customer call management is offered by many suppliers of DMS functions, and is used by many utility companies, especially in the United States. The greatest difficulty (and the most significant cost factor) in setting up this type of function concerns hook up between the control system and the customer databases.

Difficulties

The main difficulty concerns hook up between the operations database and the customer database, for identifying and locating a given customer.

Benefits

- Service quality (customer information)
- Fast power resumption

Existing and operational functions

- **EDF** has started (1998) the experiment with its application called « Prevenance Incident ». Based on a service provided by France Telecom, this application provides to customers a phone number where information on fault that have occurred are available. This application relies the fault location and the customer identification to provide appropriate information to the customer. Direct connection to the real-time application is scheduled for 1999. The actual state of each load point, as known by the real-time operation, will be exported to the Audiotel system.
- ENEL has experimented both the approaches in different areas. The choice of the system that will be implemented is on the study.

4.4 ANALYSIS FUNCTIONS

4.4.1 Analytical functions

Technical description

In a distribution control centre, all available data can be stored for subsequent statistical analysis, in order to detect weak spots on the grid (as revealed, for example, by repeated incidents on the same substation feeder). Frequent statistical analysis thus provides operators with early warning of possible permanent fault conditions, allowing them to take prompt preventive action.

Analysis also helps the operator determine exactly what power cuts are experienced by what users. This can be useful for revealing, for example, whether priority customers are receiving the stipulated supply quality.

The operational diagram can be modified to improve the situation pending a more thorough examination of the problem. Customer-based determination of power cuts also enables the operator to identify weak areas within the power system. This can be followed up by field tests to determine sharply-focused improvement solutions.

Statistical analysis is also useful for detecting defective equipment. Data acquired at the substations can be processed to schedule sharply-focused preventive maintenance operations.

Most system suppliers offer functions for archiving data in databases, accessible via market-standard spreadsheet applications like Excel, which operators can use to run analysis operations as and when required. Unfortunately, most data storage software does not store control system configuration data, which means it is not always possible to recover stored data following power system upgrades.

Difficulties

Implementation of this kind of function relies to data archived from real-time operation. Some analysis require topology information that have to be recalculate from the archived data. This can be more or less complex to design, according to the type of data archived.

Benefits

Analysis are very profitable for predictive maintenance and for identifying weakness in the network and then decide further investment.

Existing and operational functions

Every utility has a more or less sophisticated analytical set of functions that can operate on data archived from real-time. The level of sophistication can range from simple data request (SQL request) to more complex computation based on request, sort and filters.

4.5 STUDY MODE AND TRAINING

Overview

Training is an important feature for fault management. It may enable a prompter reaction from operator when a fault occurs. Training software is usually based on a network simulator. Fault situation are simulated and the operator has to deal with this situation as he will do in real time operation.

Technical description

The kernel of the software is the simulator. This simulator can be more or less complex, according to the target of the training. It can range from simple state simulation (switches status) to a detailed simulation of the protection scheme

Most training simulator are disconnected from real-time operation and real-time SCADA. Training is often based on a specific network description designed for training purposes. Sometime, the training room is not located in the control centre. However, the trend is to provide integrated solutions where training is done on a copy of the actual network.

Difficulties

As for real time operation, load descriptions is an important and often complex problem.

Benefits
Benefits are obvious. Since fault situations become to be less frequent, it is important to train operator before these critical situations.

Existing and operational functions

Training simulators disconnected from SCADA are commonly available on utilities. Training simulator based on real-time SCADA are less frequent.

5 FAULT STATISTICS

In this chapter the statistics, associated with fault management functions, are discussed. First a general overview is given on the data collected in different countries. This overview is based on an inquiry made in different countries, and it is considered to give a general description how this data typically is arranged.

As special cases, two examples are given in more detail. These are the description of fault statistics in ENEL of Italy and the use of fault statistics in Electrabel of Belgium.

5.1. Main fault statistics indices

Fault statistics indices are computed in different ways in the company according to the different uses. In order to emphasize the influence on FAULT MANAGEMENT in distribution system, it seem suitable to suggest the following classification.

- Indices of availability of supply
- Indices of status of network
- Indices of availabilty of network components
- Indices of effectiveness of emergency teams

The first class deals with the quality of the service as it is perceived by the customer. The second one deals with the faults on the network, so they are useful to detect where to improve the service. The third investigates on the quality of the components. The last one can show us how efficient we are in case of trouble in finding the origin of the fault and in restoring. These indices can be useful computed also for operating areas in order to find how and where to improve the performance of the area itself.

Indices of availability of supply

These indices concern the quality of supply as percieved by LV and MV customers. A Distribution Study Committee (50,05 DISQUAL - Unipede) has produced the prescriptions to compute such indices. In particular the interruptions of supply are considered in respect of the effects on a customers.

First distinction is done between PLANNED interruptions and ACCIDENTAL interruptions. The planned interruption allow to inform in the most cases the customers in advance. The accidental interruptions are generally caused by PERMANENT or TRANSIENT FAULTS and usually are classified as LONG (if the duration is 3 min or over) or SHORT (if the duration is up 3 min). So far the following indices should be provided separately for planned and accidental interruptions:

- INTERRUPTION FREQUENCY: number of interruptions on average per year per customer (number of interruptions/year)
- SUPPLY UNAVALABLITY: number of minutes wthout supply on average per year per customer (minute/year)
- INTERRUPTION DURATION: average duration of customer interruptions (minutes/interruption)

Indices of the performance of the network

These indices concern the status of the network and the components; as they are related mainly to the faults (transient or permanent) only the accidental interruptions are considered. They should be provided for MV CIRCUITS, MV/LV SUBSTATIONS, LV CIRCUITS, namely

- INTERRUPTION FREQUENCY: number of interruptions per consumer per circuit or per substation
- FAULT RATE: number of interruptions per consumer per 100 km of circuit

Indices of availability of components

These indices concern the components of the network; and usually the fault rate for permanent faults is considered.

Effectiveness of emergency teams

These indices are related to the organization of company in case fault. In order to monitor the effectiveness o fthe emergency team commonly the follwing indices are considered.

- alert duration of emergency team
- travel duration of e.t.
- selection of the faul t part of the line ad resupply time
- restore time

5.2 FAULT STATISTICS IN ENEL

<u>From the SCADA systems</u>, which monitor the HV/MV substations, the following information is derived, taking into account that normally a short reclosure at 0.3 seconds and a long reclosure at 30 second are adopted on each MV feeder:

- data and time of each circuit breaker manoeuvre: opening, reclosing
- cause of manoeuvre: overload protection, short circuit protection, ground fault protection, manual
- duration of interruption: transient (≤ 1 second), short (1 second < and ≤ 3 minutes), long (> 3 minutes)
- value of the current immeditely before the opening
- number of manoeuvres on the circuit breaker for each interruption: typically 1 for transient, 2 for short, ≥ 3 for long interruption
- faulted section of the circuit in case of load switches on MV feeders locally automated or remote controlled

<u>From the forms</u> filled by the agents the following information is obtained:

- stage interrupted: HV or HV/MV, MV, MV customer or MV/LV, LV, LV customer
- type of interruption: only accidental interruptions > 3 minutes, prearranged interruptions
- node, branch of the node, date and time of each manoeuvre, performed automatically or manually by telecontrol or by emergency teams on site

<u>In real time</u> in each operational area can be desplayed all the events that have affected the network and equipements with all the information recorded by SCADA system

<u>The information system</u> provides monthly and yearly per each MV feeder and each organisational subdivision, statistical information in terms of:

- <u>average values</u> of main indices
- characteristic values (threshold and target values representative of the allowable range of the indices)
- number of customers beyond the target and beyond the threshold

The threshold and target values are established, according to the kind of index,taking into account:

- the subdivision of areas introduced by the Charts of Electrical Service for supply quality indices
- physical characteristics of the network (i.e. cable or overhead line, length of the circuit, etc:) for network performance indices
- physical characteristics of the environment (i.e. keraunic level, pollution, population density, etc.) for network perfomance indices

These target and threshold values allow to select the critical circuits (those with indices beyond the target or the threshold) to be considered for improvement interventions.

MAIN INDICES CONCERNING QUALITY OF SUPPLY

The main indices concerned with quality of supply to the customers are the following:

accidental interruptions > 3 minutes

- Total duration of accidental interruptions > 3 minutes
- Number of accidental interruptions> 3 minutes
- Duration of a single accidental interruption > 3 minutes

prearranged interruptions

- Total duration of prearranged interruptions
- Number of prearranged interruptions
- Duration of a single prearranged interruption

accidental interruptions < 3 minutes and voltage dips

- Number of accidental interruptions > 1 second and ≤ 3 minutes
- Number of accidental interruptions ≤ 1 second
- Number of voltage dips

5.3 FAULT STATISTICS : METHODS USED IN ELECTRABEL

Electrabel (Belgium) has created a standard way of making Fault Statistics which is to be used in the basic form by all the branches over the country. The branches themselves can add different items to this standard in order to give it more significance on behalf of the local situation and the used materials.

Keeping this kind of statistics makes it easier to have a view on both the state of the network and the equipment used. It also allows us to make better investments (a cable who has failed several times during a certain period may be used and better replaced).

Because of the fact that the basic form is standard for the whole company, it is very easy to compare the different regions on behalf of the number of power failures and the difference in intervention and restore times. This comparison on intervention and restoring times can for example be used as the base for investment in remote control and command (see example at the end) or as a base for refining the intervention methods.

Data collected in the basic form is as follows:

- Date of fault
- Time when fault occurred
- Total time in minutes until the last client had current again (T)
- Total number of switchings (remote/manual) necessary to restore power (S)
- Number of MV/LV stations involved (C)
- Cause of the fault
- On what material did the fault occur

- On what main item of the network was it (Cable, overhead, ...)
- Statistical information on the type of material
- A calculated value in order to evaluate the "weight" of a fault because an interruption time of 10 minutes for 10.000 clients is much more important than an interruption time of 1 hour for only 25 clients.

Formula : weight = C x T x (1+S)/(2*S) (MV/LV station minutes)
In the case of a fault which was restored immediately (for example with recloser) the "weight" is set to 0.

For example, comparison of the statistics for '96 of a specific region with the neighbour region, was the start of investments in extra remote control in the second region. Evaluation of the figures for '96 pointed out that the average total restoring time of region 1 (with 1400 remote controlled switches on MV) was exactly the half of the average time to restore in region 2 (with very few remote controlled stations on MV).

These figures made it easy to calculate the volume of the energy "not sold", which resulted on its turn in a cost due to power failure. Every lost kWh was calculated at a price of 2.5 €/kWh which is a very low price because loss of production due to power breakdown varies between 1.25 and 10 €/kWh depending on the kind of customer. This loss of production is the base of claims from the customer.

In this specific example it was shown that an investment for connecting some 500 crucial MV-feeders on the control network was profitable over max. 1 year. The cost/feeder to control it was around 840 €/feeder because the switches were already motorised and an RTU was almost everywhere available for the HV/MV side. The profit on saved crew cost was not taken into account. Faults with "weight" = 0 were also not taken into account because f. e. a successful automatic reclosing gives practically no interruption.

Most significant facts of the evaluation :

	Region 1	Region 2
faults on cable	319	203
1/ 100 km network	6,4	3 (factor 1/2)
faults on overhead	330	28
1/100 km network	19	21
faults in MV/LV stations	108	45
idem/1000 stations	10,5	3
Average time of intervention	1hO5'	1h58' (factor 2)
Fault frequency/MV-LV station	1,52	0,37
power shut-off/MV-LV station	23'20"	48'
restoring time	31'	1h03' (factor 2)

Although the restoring time of region 1 is the half, the area is much more spread (larger distances between clients and towns and the network is much older (average number of faults is higher). Region 2 is an area with denser population (larger towns).

Average number of stations/fault : 11,8
Total of faults : 276
Average unsold energy/station : 105 kVA
Price/lost kWh : 2.5 €/kWh
Time gain : 30 min
Profit : 11,8 x 105 x 276 x 0,5 x 2.5 = 427 000 €/year
Cost : 500 feeders x 840 €/feeder = 420 000

6 COST/BENEFIT ANALYSIS OF FAULT MANAGEMENT

This paper is an attempt to outline the most important factors, which will affect the future fault management applications. The benefits of various functions are first discussed and, as an example, results of a cost/benefit analysis are given. Finally two different approaches of dealing with investment selection and supply quality appreciation are given.

6.1 Benefits of fault management functions

The benefits of fault management applications can broadly be classified into two categories: 1) direct benefits to the distribution utility itself or to the customers, and 2) better adjustment of the utility to the changes in and to the new demands of the operation environment.

In the first benefit category we have:

- reduction of outage costs
- savings in network investments
- savings in labor costs

and in the second category:

- optimized voltage quality
- better competitiveness of the utility in the free power market

The basic difference between the two groups is, that the benefits in the second category are much more difficult to assess in monetary terms than those in the first one. It is clear, however, that they will in the longer run be of extremely high value. In what follows, the benefits in the first category only are discussed in more detail.

<u>The reduction in outage costs</u> has so far been the major benefit of network automation. With the remote control of line switches of overhead line networks solely, for instance, the distance between the controlled points being about 15 to 20 km, the outage costs have been cut by about a half. The outage costs can further be reduced by developing fault location techniques, i.e. fault indicators and computational fault location.

In the future, also part of the temporary faults and the faults with high fault resistances can be detected and located. In this case, the critical fault type is a single phase to earth fault in overhead lines. The fault often begins with a very high resistance, and evolves only gradually into a fully established earth leakage requiring protective actions.

The difficulty with outage cost reduction is, that the benefits mostly come to the customers, and only a minor share, corresponding the lost revenues, to the utility. Because of this reason, several alternative approaches exist for the appreciation of these costs:

1. The customers outage costs are fully taken into account as if they were hard costs
2. A certain price per kWh is used, less than the customers costs, but higher than the revenues.
3. They customers outage costs are ignored

<u>The savings in network investments</u> is the other major benefit class. Due to fault management, investments can be reduced mainly for three reasons:

1. better knowledge on load behavior, which allows smaller operation margins
2. more flexible use of the distribution capacity

Investment savings are made possible by line switch remote control and effective computerized tools for switching planning. This is of value especially in abnormal situations. Suppose, for instance, that the main transformer of a high voltage / medium voltage substation is temporarily out of operation. The automation system enables quick switching of outaged lines to the neighboring stations. Furthermore, the load of these stations can in turn be relieved by other adjacent substations. This reduces the investments needed for reserve connections in the medium voltage system.

A necessary tool here is also the distribution load estimation. Since this functions gives a better knowledge on the load currents in different power system parts, it also allows for a more efficient use of distribution system capacity both in normal and in fault situations.

<u>Savings in labor costs</u> are expected in operation and planning of the power system. Examples are routine switching and trouble shooting in the case of network faults. In some cases the labor cost savings are the largest benefit factor of the function. Among this kind of functions is the processing of telephone calls of the customers experiencing an outage.

Table 6.1. The benefits of different fault management functions. The abbreviations used are: OC for outage costs, L for labor costs, INV for investments, M for competitiveness in power market and Q for supply quality.

Functions	*Benefits*
Medium voltage switch control and fault clearing	*OC,L,Q*
- *line switch remote control*	
- *fault indicator remote reading*	
- *fault distance computation*	
High resistance fault detection	*OC,L,Q*
Voltage and var control	*INV,M,Q*
Distribution load estimation	*INV,M,Q*
Switching planning	*INV, M,Q*
trouble call handling	*L, M,Q*
customer information	*L,M,Q*
fault statistics production	*L,M,Q*

6.2 RESULTS OF A COST/BENEFIT ANALYSIS

In this section, the results of a costs benefit analysis made for six Finnish distribution systems is summarized. The functions covered are all related to fault detection and fault clearing. The outage costs of the customers are fully taken into account as hard costs. Both the costs and the benefits of various fault management functions are partly overlapping. This makes their economic analysis complicated and tedious. The feasibility analysis can most conveniently be made using a computer program for assistance. In this section a software package for this purpose is briefly presented. The input data of the software package is divided into four classes:

- the utility specific data
- general calculation parameters
- the configuration of automation functions
- general cost parameters

The utility specific data includes the information which is applicable only for the distribution company concerned. In this file we have, for instance, statistical information of the utility and some average technical data of its network.

The general calculation parameters include such information that is common to all the utilities, like the parameters of outage costs to different customer classes. Another example is the parameters which control the efficiency of the fault management functions, like the per cent reduction of outage times due to remotely controlled switching stations. This data is often based on experience and must be collected from several sources.

The configuration of automation functions is simply a list of the functions that are taken into account in the analysis. The software package allows for any combination of the functions mentioned in the latter part of this section.

The general cost parameters include the data of the costs of the computer equipment, computer software packages, data transmission systems, automation related power equipment etc. The costs are further divided into purchase, installation, operation and maintenance costs.

The output data of the software system is correspondingly divided into two classes:
- intermediate results of technical computations
- results of cost/benefit analysis

The intermediate results of the technical computations are used for checking the consistency of the input data and for assessing the quality of the analysis in general. The final computation results are stored in a separate file. The results include the total costs and benefits for the given function configuration and their decomposition into various classes.

Benefits modeled in the software package include the savings in labor costs and the reduction in outage costs. Savings in labor costs are expected in the operation of the power system, like in trouble shooting during network faults. In some cases the labor cost savings are the largest benefit factor of the function. An example is the processing of telephone calls of the customers experiencing an outage.

According to the cost benefit analysis, the reduction in outage costs is the major benefit of fault management functions. With the remote control of line switches of overhead line networks solely, the distance between the controlled points being about 15 to 20 km, the outage costs can be cut by about a half. The outage costs can further be reduced by developing fault location techniques, i.e. fault indicators and computational fault location.

In the future, it will also be possible to detect and locate part of the temporary faults and the faults with high fault resistances. In this case, the critical fault type is a single phase to earth fault in overhead lines. The fault often begins with a very high resistance, and evolves only gradually into a fully established earth leakage requiring protective actions. This kind of fault can be detected well in advance by a careful analysis of neutral voltage, and in many cases the permanent fault and the corresponding outage can completely be avoided.

Typical costs of supply outages for different customer categories are given in Table 6.2. The values are taken from a recent Nordic study. The values for residential customers are based on the willingness to pay, whereas those for agricultural customers are defined according to the willingness to accept. The figures of the three other major classes are based on the direct evaluation of the costs and losses by the customers themselves. According to the study, the costs of short outages are relatively high. It should also be stressed that the short repetitive outages (3 outages of about 1 minute within a period of 15 minutes) usually cause high monetary losses. Thus, such solutions of network automation should be favored, which not only shorten the outage time, but also reduce the number of outages. An example is the use of fault current indicators in the switching stations in line locations. By the use of the indicators, it is possible to reduce the number of trial switching needed during the course of fault location.

Table 6.2 *Typical values for average outage costs in different customer classes in Finland (€/kW) .*

Outage duration	*1s*	*3x1min*	*1h*	*4h*	*8h*
Residential	-	-	*0.7*	*2.8*	*10*
Agricultural	-	-	*5.3*	-	*58*
Industrial	*2.2*	*4.3*	*11*	*32*	*58*
Commercial	*1.8*	*4.3*	*12*	*33*	*68*
Public	*0.5*	*1.2*	*4*	*11*	*23*

The above discussion applies to the rural networks with overhead construction. In the underground systems of urban areas the situation is somewhat different. According to the studies in Finland, the outage rates in underground cable networks usually are so low, that the remote control of line switches hardly is profitable. Some other solution must be found for medium voltage network automation in these cases. One of the most promising alternatives is the remote reading of fault current indicators, located in the MV/LV distribution transformer stations. This is a fairly inexpensive way to cut that part of the outage time, which is due to the location of the faulty line section.

The costs and benefits of different fault management functions are presented in more detail in Table 6.3. The results are given as present values per feeder of a HV/MV substation. The networks studied were two urban and four rural ones. The results can be summarized as follows:

- the remote control of line switches was justified for all the rural networks but not for the urban ones. The major part of the benefits, about 90 to 97 %, comes through the reduced outage costs of customers. In urban underground systems, the fault frequencies are substantially lower than in rural networks. Hence the outage cost reduction also is smaller.

- Fault indicators at remotely controlled line switches mainly reduce the costs of repetitive short outages due to trial switching. The function is economical in most of the rural systems.

- independent fault indicator stations, at locations in addition and separate from line switch remote control stations, are cost effective in all the four rural systems. The remote control of fault indicators at the secondary substations, or ring main units, was found to be very cost effective for both the urban systems. Here it was assumed, that 20% of the indicators are equipped with communication.

- computational fault location, based on the integration of protective relays, substation SCADA and the distribution data management system, is justified in all the rural systems and also for one of the urban utilities.

- For the high resistance earth faults (in high impedance grounded systems), it was assumed, that 10% of the faults can be detected by neutral voltage analysis and by partial discharge based techniques. This function was found to be very cost effective for all the utilities.

Table 6.3 Benefits and costs (B/C) of various fault management functions in two urban and four rural Finnish utilities. Sums as present values in 1000 € per feeder.

Function	*URB1*	*URB2*	*RUR1*	*RUR2*	*RUR3*	*RUR4*
line switch remote control	*-/-*	*-/-*	*34/20*	*57/23*	*46/17*	*94/20*
fault indicators at line switches	*-/-*	*-/-*	*-/-*	*4/4*	*7/3*	*13/3*
fault indicator stations	*9/2*	*19/3*	*7/5*	*12/5*	*11/4*	*23/4*
computational fault location	*-/-*	*6/3*	*8/4*	*15/4*	*9/3*	*18/3*
high resistance fault indication	*2/1*	*5/1*	*4/2*	*7/2*	*6/1*	*12/1*

6.3 WEIGHTING OF QUALITY IMPROVEMENT INVESTMENTS IN MEDIUM VOLTAGE DISTRIBUTION NETWORKS

Contrary to the cost/benefit analysis in the previous chapter, the outage costs of the customers usually are not fully accepted an argument when deciding on network automation or fault management investments. Some weighting procedures are often used instead.

As a first example of weighting the quality improvements when deciding on network investments, the procedure adopted by an Austrian power company, Oberösterreichische Kraftwerke AG (OKA), is presented.

Quality improvements

The MV-distribution network defines many parameters, that have direct influence on the quality of supply to the customer (number of short and long term interruptions, time of interruptions). While the situation in urban networks is usually acceptable, in rural regions the quality of supply is often bad. To raise the quality several improvements to network operation may be introduced:

- ring connections in the MV-network
- restructuring of historically grown networks
- mounting of additional circuit breakers with protection
- remotely controlled MV-stations

The aim of such improvements can be quite different:

- reduction of time of interruptions after disturbances or for maintenance
- reduction of staff costs
- reduction of not delivered energy
- improvement of customer satisfaction
- increase of technical attraction of rural business areas

Purpose of weighting

The weighting of necessity and gain of a quality improvement is subjective, depending on experiences and task of the person. To get an unique quality understanding in the company a unique weighting of improvement is required. The target of the weighting method is to get a reliable investment decision based on technical and economical aspects.

It is very important to see a target-value always in relation to the determination method of the value. The target-values may differ quite a lot, but if the determination methods of the values are different as well, the different target-values mean the same target. It is further important to set up a weighting method that is easy to use in practice. It should not require data, that are not available, and it should not require specialists, that the company does not have.

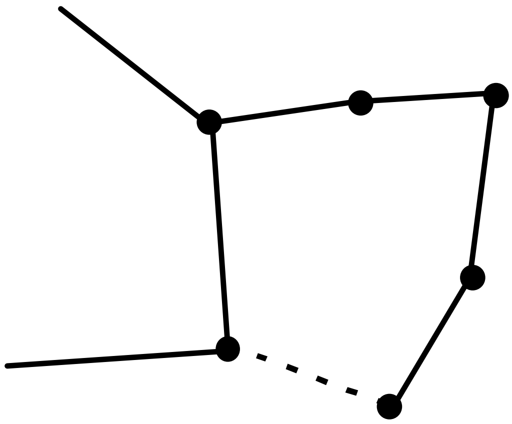

Fig. 6.1. A new ring connection in a distribution system.

Technical-Economical-Gain

As example for a weighting method the „Technical-Economical-Gain“ for ring-connections is explained, that is used at OKA. A ring-connection is considered, if several MV-stations are radially operated (see left side picture). In case of disturbances or for maintenance purposes in the first MV-station, all radial MV-stations must be switched off. An additional ring-connection could solve many problems (dotted line).

The gain of such an ring-connection depends on the length and type of the radial feeder as well as on the size of energy, that is supplied by the radial stations.

$$\boxed{TEG = \frac{NV_{ist}}{NV_{soll}} \cdot DB_{ist} \cdot DB_{\%} \cdot ND}$$

A simple formula to calculate a target value is shown on the left hand side:

TEG   Technical-Economical-Gain
Nv_{ist} Not-availability without ring-connection [hours/year]
Nv_{soll} Target-value for not-availability [hours/year]
Db_{ist} Proceeds of energy sale minus energy costs/yr of MV-stations [per year]
$DB_{\%}$ Target-value, % of DB_{ist}, that should be taken [e.g. 0,5 %/year]
ND   expected service life [e.g. 30 years]
This rather simple procedure gave good practical results for the decision, if this investment should be done. If the costs of the ring-connection are less than TEG, the ring-connection may be constructed.

6.4 DISTRIBUTION POWER QUALITY POLICY AT EDF

This section describes the policy and methods used by EDF regarding power quality for distribution customers. It also describes the method used to calculate the cost of the non-quality.

Customers quality needs

Today EDF observes two strong tendencies regarding their customers quality needs : a evolution of the exigency levels and an increasing differentiation of the wanted quality. In order to respond to this new context, EDF is offering a new relationship founded on :

- A Reference Level adequate for the great majority of the customers, with a contractual engagement concerning the quality performance.
- A case-by-case upgrade of this level to respond to the specific needs of certain customers.

A Reference Quality Agreement

The characteristics of EDF reference level have been designed to respond to the expectations of the great majority of customers, while keeping EDF amongst the most performing European distribution utilities in terms of report quality / cost and of customer services. This offer has been built on two main principles :

- A solidarity principle : to provide to all customers a quality superior to a base standard level.
- An economic optimum principle : to guarantee the best use of the financial resources of the company.

This Reference Offer is at the heart of the standard “ Emeraude ” Contract for MV and HV customers, that is adapted to local constraints depending on the geographical area and on the goals in quality levels. As for LV customers, this Offer is contained in the concession contracts signed with the French local authorities.

Three main action courses have been initiated in order to ameliorate this reference level at short and mid term :

- Improvement of the everyday quality (reduction of frequency and duration of customer cuts).
- Fight against the major incidents.
- Reduction of rms voltage variation margins and improvement of voltage quality.

The complementary offers

The complementary quality offer aims at responding to very specific needs from one part of the customers. It is based on the two following targeted offers :

- The personalised offer : for one or several customer precisely identified. The design of the offer must lead to an optimal global economic balance. EDF takes in charge the part of the cost justified by its contribution to the general interest.
- The “ high performance zone ” offer : the same as the personalised one, but offered to a whole zone.

Prospective goals

The quality goals that serve to define the threshold of the compensations paid to customers are the following:

From 1995 to 1998	**Rural areas**	**Small and middle-sized towns**	**Big cities**	**City Centres**
Maximum number of long cuts	6	3	3	2
Maximum number of short cuts	30	10	3	2

2005	**Rural areas**	**Small and middle-sized towns**	**Big cities**	**City Centres**
Maximum number of long cuts	2	1	1	<1
Maximum number of short cuts	5	2	1	<1

This values take into account all the faults perceived by the customers.

Putting this policy into practice

A common work of the commercial, customer and technical teams is necessary. The typical action plan is the following :

- First phase : meeting the customer.
- Second phase : analysis and agreement.

To put into practice the general technical orientations, a decision-help technical-economic approach is used ; this approach includes :

- A standard valorisation of the failure, calculated from the power cut and from the non-distributed energy (END), with a cost A (5F ~ 0.76 €) for kW cut, a cost B (60F ~ 9.1 €) for non-distributed kWh and a cost C (130F ~ 19.7 €) for kWh in case of incidents concerning more than 50 MWh of END.
- Taking into account the real prejudices of sensitive customers, when designing personalised solutions.

Distribution Centres conduct an internal feedback system and several indicators that allow them to evaluate the customer's perception of the personalised offers, and to act in the designing of these offers.

A great importance is given to clarity. The reference offer includes simple indicators measuring the global performance and its dispersion. This indicators are the same that are written in the standard Emeraude contract.

CONCLUSIONS

The fault management functions can be classified to fault identification, location and supply restoration, and to assisting functions, like statistics production and supply quality reporting and monitoring.

For the location of permanent faults, two different approaches exist, namely fault indicators and fault distance computation. Fault indicators are used both for the detection of short circuit and earth faults. The main restriction of the present fault indicators is the lack of directional function. This would be of high importance especially in compensated neutral systems.

For fault distance computation, two different techniques are being used. By comparing the measured fault current to the computed one, a rough estimate for the faulty line section is obtained. The other approach is to use impedance relays. However, these techniques work in the case of short circuit faults only. In unearthed or compensated neutral systems, the rated frequency earth fault currents are too small to allow for a reliable fault distance computation. A possible solution is the transient based techniques, but the bottleneck has so far been the lack of measuring technique with high enough sampling frequency.

In the case of supply restoration there are two development lines. One is the fully automatic switching systems. For these several solutions exist, spanning from simple predefined sequences to fully integrated systems, where the network topology is analysed and technical constraints are checked in real time. However, the latter ones are still in an experimental phase. The other development line is the assisting software, used for checking the technical constraints of the network, but leaving the decision on the switching actions to the operator. This development line seems to be more popular nowadays.

In the case of computer tools of fault management, there is strong development going on. New functions are developed both in the SCADA and in the DMS systems. Examples of these functions are tools for distribution system state estimation, alarm processing and event analysis, fault location and power restoration, field crew management and various types of analysis tools. A very promising possibility also is the automatic production of fault statistics.

When assessing the economic feasibility of fault management functions, the central issue is the outage costs. When they are reduced, the benefits mostly come to the customers, and only a minor share to the utility. Because of this reason, several alternative approaches exist for their appreciation: 1) The customers outage costs are fully taken into account as hard costs, 2) A certain price per kWh is used, less than the customers costs, but higher than the revenues, and 3) The customers outage costs are ignored. It is clear that the selection between these alternatives greatly affects the investments made, and consequently the techniques used for fault management applications.

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