

# **DIGITAL PROTECTION TECHNIQUES AND SUBSTATIONS FUNCTIONS**

**Working Group 01 of Study Committee 35 (Protection)**

**September 1989**



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## 1.0 ABSTRACT

This report summarizes the findings and recommendations of Working Group 34.01 of CIGRÉ Study Committee 34. The actual report is divided into six task reports. These deal with various aspects of digital computer techniques for protection of electric power systems, and the impact of an integrated hierarchical structure on all protection and control tasks. An important part of the report is defining the structure for collection and description of significant test cases for protection and control. Yet another significant activity is the proposed standard for common data format for exchange of fault data, and the development of a standard Engineering Dialog which may be common to all computer based protection systems. The last task continues the collection of Bibliography begun by the Working Group 34.02.

## 2.0 INTRODUCTION

### 2.1 *The Working Group Assignment*

This Working Group was formed in 1984. Its assignment is to study and evaluate the new technology of Digital Protection techniques and its relationship to the total integrated digital computer systems in the substation. The Working Group was directed to discuss the possibility of developing standards of various types that may be desirable in such an integrated system. Clearly, the main thrust of the Working Group investigations is in the field of protection. However, it is realized that in an integrated system many other functions, such as monitoring, control etc. may become inextricably linked with protection. That being the case, the Working Group must deal with these other issues as well — since they all may affect protection, and in turn be influenced by protection related matters.

### 2.2 *Related Activities*

The activities of this Working Group follow the reports of earlier Working Groups on digital protection: 34.02 (Convener: Phadke, 1984) and 34.02 (Convener: Dräger, 1980). Within CIGRÉ, other related Working Groups are 23.05, and 35.06. Outside CIGRÉ, the main activity seems to be in the Power System Relaying Committee of IEEE. Many of the members of the present Working Group also serve on the IEEE Working Groups, and thus were able to keep in close contact with those developments. Various ideas developed by this Working Group have been discussed at different technical meetings and conferences interested in digital technology in the substation. The report of this Working Group has benefited immeasurably from these associations.

### 2.3 *Membership*

The members of this Working Group are:

Members:

A. G. Phadke (Convener)	USA
C. H. Castro	USA
J. W. Chadwick	USA
L. L. Mankoff	USA
S. L. Nilsson	USA
A. Politis	USA
M. S. Sachdev	CANADA

J. S. Thorp	USA
E. A. Udren	USA
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Corresponding Members:

P. Bornard	FRANCE
W. J. Cheetham	ENGLAND
A. Kumar	WEST GERMANY
A. Ogorelec	YUGOSLAVIA
K. Suzuki	JAPAN
P. M. Van Miegroet	BELGIUM
C. W. Walker	AUSTRALIA
B. G. Andersson	SWEDEN
J. Szczupak	BRAZIL
M. Kezunovic	USA

*2.4 Meetings*

The Working Group met three times each year, twice in conjunction with the Winter and Spring Meetings of the Power System Relaying Committee of IEEE, and once at the time of the General Assembly Session of CIGRÉ in Paris or at the SC 34 Colloquia.

*2.5 Outline of Report*

Chapter 3 of the report defines each of the Working Group tasks in greater detail. Chapters 4 through 9 are dedicated to each of the 6 tasks. Chapter 10 gives the conclusions and recommendations of the Working Group. Chapter 11 contains references and Chapter 12 contains Appendixes which supplement the material of some of the earlier Chapters. In particular, a sample of the standard data file structure will be found in Chapter 12. Other Appendixes contain flow charts for control functions discussed in Chapter 5.

## 3.0 TASK DEFINITIONS

### 3.1 Introduction

As pointed out in Chapter 2, the assignment of Working Group 34.01 originated from the Final Report and recommendations made by the earlier (1984) Working Group 34.02. This earlier report took a comprehensive look at the substation computer environment, its hierarchical structures, and opportunities offered by this new technology for innovations in protection and control functions in a substation. It was felt that the earlier work had produced an overview of the entire field, and perhaps it would be appropriate to get into more specific aspects of Digital Protection Techniques and Substation Functions. In particular, it was felt that some attempt should be made to channelize the ongoing developments into uniform structures, so that many evolving concepts and systems could be evaluated and applied on an equal footing. Thus, the question before the Working Group was: *'Is it feasible to define substation protection and control environment on the one hand, and the computer systems on the other hand in order to create a uniform basis for comparing and specifying various substation devices on a functional level?'* It should be pointed out that the Working Group restricted this type of activity to three specific areas to be described below. It is hoped that the work on these tasks will lead to standards which will be acceptable and useful to the manufacturers as well as the users of substation computer equipment. Other tasks continue the work of consolidating the newly available information on substation computer systems developed since 1984.

In selecting the Working Group Tasks the Working Group repeatedly faced the problem brought on by the integration of substation functions in a hierarchical computer system. It is no longer possible to discuss protection functions by themselves. Integration means that protection, control, oscillography, sequence-of-event analyses, communications, all are part of the overall substation computer system. It is no longer possible — nor is it desirable — to discuss the protection tasks in a vacuum. One must take note of all the other functions mentioned above. Consequently, although the Working Group must confine itself to protection functions exclusively since it is a Working Group belonging to Study Committee 34, it has found it necessary to enter into areas which in the past have been the provinces of different study committees. This phenomenon is particularly noticeable in tasks described in Sections 3.3 and 3.6.

### 3.2 *Description of Tasks*

We now give a general definition of each of the tasks:

#### 3.2.1 Challenges in Protection:

This task attempts to create a catalog which identifies and describes those protection scenarios which constitute significant and critical tests of relays. The idea is to highlight each of these test cases in sufficient detail so that a designer of digital relays can use it as a check list against which the adequacy of a particular design can be confirmed. This catalog is also of special importance with digital relays due to the use of fast numerical Algorithms and fast fault locating techniques based on transient phenomenon, for instance travelling waves. It is realized that such a catalog is well known to both designers and users of conventional relays. However, the Working Group feels that with the advent of digital protection techniques it may well be that relays will be designed by engineers not completely familiar with all the fine points of particular relaying applications; and, for them, this task report should be of interest.

#### 3.2.2 Challenges in Control:

This task attempts to perform a task similar to the one above, for control functions in an integrated substation computer system. It is realized that not all control tasks are traditionally thought to be part of a protection system. Yet, in an integrated system, several peripheral tasks — such as input/output — may be common to protection and control functions. Thus it is necessary to catalog control tasks, which may have a significant influence on the architecture of the integrated system.

This task has collected flow-charts or logic diagrams of critical and significant control functions in the substation. It is felt that the level of detail provided in this task need not be as exhaustive as that in the previous task.

#### 3.2.3 Standard for Fault Data Exchange:

This task considers the needs of engineers interested in exchanging transient data records. The idea is to suggest standards for exchange media, file structures, and format of data in the files. Such a standard may be used by manufacturers of relays, substation computer systems and digital oscillographs. It is likely that each of these users and generators of transient data will provide translation programs for changing to and from the proposed standard format.

An important subtask is to simplify the task of conversion of data from one sampling rate to another. This leads to a list of compatible sampling rates, and suggested software techniques for sampling rate conversion.

#### 3.2.4 Standard Engineering Dialog for Protection:

In this task an attempt is made to standardize the engineering dialog that must take place between a computer based relay and the relay engineer who sets it, calibrates it, or monitors its performance. The motivation is that, with computer based relays it should be possible to adopt a common user interface for all the relays of a given type. It is felt that even though each relay may have features unique to its design, its adjustments should be related to power system data that the relay engineer would normally use in setting the relay. Thus, each relay may have a translator (interface) program which provides the linkage between the specifics of the relay — and the common engineering dialog designed to furnish the power system information. The work reported here is a modest start towards achieving this goal.

#### 3.2.5 Protection and System Wide Control:

This task will deal with certain system-wide applications to which relaying computers can make a contribution. Relaying computers may be viewed as highly sensitive and fast-responding measurement systems. Since the measurements can be communicated to a host computer rather easily, it is natural to inquire if some benefit may not accrue to many monitoring and control functions from making use of this measurement and communication capability. Conversely, the relays themselves may be influenced by decisions reached on a system-wide basis. This leads into the subject of adaptive protection — a field in which some research has already been started. This task explores these concepts, and point out considerations in system-wide control and its interaction with computer based relays.

#### 3.2.6 Bibliography:

The work begun by WG 34.02 is continued here. All reports and technical papers dealing with digital techniques in substations which came to the attention of WG members, have been listed.

## 4.0 CHALLENGES IN PROTECTION

### 4.1 *Introduction and Task Organization*

During fault conditions, it is very important that the characteristics and response of the complete protection system be known and understood. To properly design, engineer, and apply a protection system requires that the steady-state and transient response be known for all the individual components that make-up the system, e.g., generating plant equipment, transmission system equipment, protective relaying equipment, and associated equipment. This will assure predictable interaction between the power system, the protective relays, and the current transformers and voltage transformers interfacing the power system and the protective relays. The capabilities of the computer may be used inappropriately, leading to incorrect results, because of errors in the mathematical description of the power system phenomena. This underlines the necessity for the proper understanding and application of the characteristics and the response of the complete protection system to fault conditions.

The current and voltage transformer interface becomes very significant as the speed and sensitivity of protective relays increase. In EHV systems, the CTs and CVTs may not have ideal transient response, i.e., they may not correctly reproduce power system waveforms for faults occurring at arbitrary points on the wave. It then becomes important that, in digital relays, the sampling process must not exacerbate any deviations in transducer response.

With the advent of solid-state protective relays, and now digital relays, it became necessary that an additional component be added to the protective system, a power supply. This requires that consideration be given to the circuits and logic of the protective scheme to evaluate the effect of the additional component on the reliability (dependability and security) of the protective scheme. It is not only necessary to know the detailed characteristics required of the power supply output, but it is also necessary to know the response of the power supply to all expected variations in the power supply input. The power supply is deserving of particular attention and evaluation because it is one element in the protective scheme that is not present in electro-mechanical schemes. From the designer to the manufacturer, and the application engineer to the maintenance personnel, the power supply must command the respect due an element in a protective scheme.

The requirements for digital protection systems considered here very closely follow the requirements of other protection systems. CIGRÉ SC-34.04 Working Group has issued a report, "Guide on: Evaluation of Characteristics and

Performance of Power System Protection Relays and Protective Systems" (1986). This document can be referred to for details on suggested tests to evaluate characteristics and performance. To provide a bridge between the SC-34.04 report and the digital protection requirements, a copy of "Chapter 1 - Test Methods and Procedures" is included as Appendix I of this report.

Electric Power Research Institute (EPRI) of the United States has a project (RP 1359-1) that involves the design and implementation of a microprocessor-based, integrated protection and control system for transmission-class substations. EPRI report EL-1813, "Substation Control and Protection Project - System Requirements Specification" (1981) covers Phase I of this project. To define the scope of the system, the authors of that report generated a list of possible functions and the requirements of each function. A list of general system requirements and design criteria was also generated. While the EPRI report is not all-inclusive, it does contain many items that are worthy of consideration.

Tests on any protective relay should simulate conditions on a power system. It is assumed that the protection will be installed on a normally balanced three-phase system. The types of faults are generally unbalanced. For this document, they will be divided into three categories.

- (1) **Short Circuit:** Short circuit assumes that there is no impedance in the fault. This is equivalent to a "bolted" fault. The category is used to approximate the maximum current flow for the particular type of fault.
- (2) **Fault Through Impedance:** Fault through impedance assumes that there is impedance in the fault. This is equivalent to an arcing fault or a conductor arcing to a tree or structure that is not well-grounded. The category is used to approximate the minimum current for a particular type of fault and therefore the minimum sensitivity of a relay to a particular type of fault.
- (3) **Open Conductor:** Open conductor assumes that there is infinite impedance in the fault. This is equivalent to a conductor breaking and the ends of the conductor are "in the clear" or not in contact with anything that will conduct current.

In the remainder of this Chapter, we list system conditions and relaying considerations that are important to all relay designs. It is the intent of the Working Group that the following discussion be viewed as a check list for capabilities by designers and users of digital relaying systems.

#### *4.2 Design Features and Testing*

The following sections present a fairly comprehensive listing and explanation of the design features and requirements which might apply to digital protective relaying systems for lines, buses, and transformers. Both conventional and novel microprocessor-oriented approaches are covered.

Some comments on testing approaches are offered. In general, those functions aimed at high-speed fault protection are tested for performance in the presence of all types of balanced and unbalanced faults. The testing methods may be the same as those used with conventional relays (see Appendix I). In addition, the performance of computer programs to be use in on-line relaying applications can be verified with digitally-simulated power-system data. That data can come from :

- Simple Analytic Model— for example, analytically-generated samples of sinusoidal waveforms with selected added distortion components. All parameters for these cases are chosen by hand at time of the test case generation.
- Complex Physical Model — The behavior of real power-system elements are modeled via equations, and the samples of signals are computed from initial state variables, modeling equations, and equations describing the interconnection of elements. The best-known example is the widely-used Electro-Magnetic Transients Program (EMTP).
- Recordings of Real Test Cases — Digital fault recorders or digital relays can save samples of actual fault or other cases on power systems; these cases can be played back for testing of protection programs. The same approach can be used for saving test cases which have been set up on an analog model power system, so that they can be easily used at other locations.

Many of the relaying methods call for testing of security as well as reliable fault tripping. Security sometimes must be demonstrated in the presence of specific, unfavorable power-system conditions and input signals as specified in the sections below.

#### *4.3 Transmission Line Protection:*

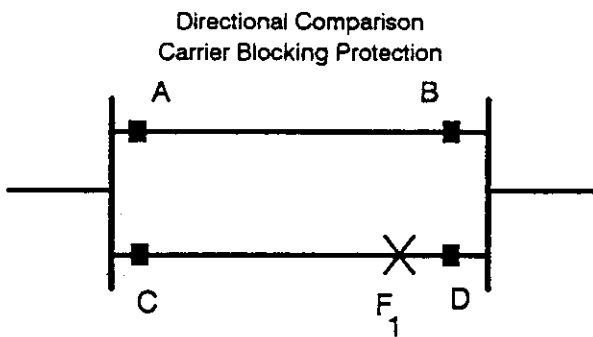
Just because a designer's logic may lead you to not see the need for a test that is required for electro-mechanical relays, does not mean that the test can be omitted for digital relays. The test should reflect an operating condition. Test omissions can come later, after the relay has proven not to be susceptible to the operating condition.

The following is a list, but not an all-inclusive list, of system conditions that transmission line protection might expect to experience within a reasonable number of installations.

The list covers a number of the operating conditions which reflect on the operation of digital (or conventional) transmission line protection. The protection must distinguish these conditions and trip or restrain as required.

#### 4.3.1 Current Reversals for Clearing of External Faults

Figure 4.1 shows the commonly-occurring situation of two parallel trans-



- \* Fault at F<sub>1</sub>
- \* A set up to trip but blocked by carrier from B
- \* D trips instantaneously
- \* Current reverses in AB
- \* B must not trip before time to receive A carrier
- \* B carrier must continue until A trip is reset
- \* C trips sequentially or by time

**Figure 4.1 Protection of Parallel Lines**

mission lines tied to the same buses at both ends. Assume we focus on the performance of the pilot (communications-based) directional-comparison protection scheme for the upper line. If a fault occurs anywhere along the lower line, the upper-line protection should restrain. Consider the case of a fault at location F<sub>1</sub> on the lower line. At fault inception, current in the upper line flows from left to right, and into the fault through the right breaker D. Direction-sensing relays on the upper line operate so that the

protection scheme at Breaker A attempts to trip, but is blocked by the apparent reverse direction indication communicated by relays at Breaker B.

Relays on the lower line operate correctly to clear the fault, but in general the breaker tripping commands and fault clearings at breakers C and D do not occur at the exact same instant. If breaker D clears first, the fault can only be fed from the left end. Fault current flow in the upper line reverses, as the right source feeds the fault through Breaker C. Upper-line relays must sense the reversal in a coordinated way – for example, if the upper right reverse-fault sensing relays drop out faster than the forward-fault sensing relays on the left, the upper left terminal will trip breaker A incorrectly.

The solution to this problem generally lies in a combination of logic and timing to detect the possibility of this condition. While the particular solution may depend on the manufacturer of the equipment and the directional-comparison scheme in use, the approach involves detecting the external fault condition, and providing some delay of tripping for an immediately-following directional change. This is called Transient Blocking Logic. When loaded signalling cables are used,

there may be some delays introduced in this scheme for long transmission distances. (CIGRÉ Teleprotection, March 1969, page 139). Since a genuine internal fault may occur on the parallel line, especially on double-circuit towers, additional logic may be incorporated to remove the delay for a more direct internal-fault indication. This addition is referred to as Transient Unblocking Logic.

At least one scheme has been proposed to handle two parallel lines as a unified protection problem [8]; this takes care of transient blocking problems, and cross-country (interline) faults as well. Other equivalent solutions to this problem are also possible.

This case is among the more difficult for testing; it requires demonstrating proper interaction of relay response and pilot tripping logic. A sophisticated analog model system, or digital simulation with coordinated signals to the two or more line terminals under test, is required. An extensive real-time simulation of fault-condition changes must be produced.

#### 4.3.2 Line Charging Current

The distributed capacitive shunt-admittance element of any transmission line conducts a purely reactive charging current which depends on circuit voltage, and its magnitude is directly proportional to line length. For long EHV lines, the charging current may be a significant part of the load, or even of the external-fault through current. Phase comparison or line current differential relays see the charging current as a net inflow to the zone, and may trip incorrectly unless suitable restraining measures are taken in the logic or measurements.

When a long high-voltage line is first energized, the shunt admittance may interact with inductive elements of the system to produce a substantial high-frequency ringing. The ringing current may cause operation of any relaying elements which do not have specific design features to block the high frequencies — unfiltered phasor-comparison circuits in conventional high-speed distance relays, for example. Ground overcurrent relays have also presented a particular problem of responding to these line-energization currents, and must be designed with high-frequency filtering to avoid this problem. In digital relays, the combination of analog antialiasing filters and a properly-selective algorithm transfer function will prevent operation on these transients.

Testing is easiest, and most accurately done, with a digital (EMTP) simulation of the line energization case. Steady-state high-frequency signals superimposed on power-frequency sinusoids are a crude but acceptable alternative. Only an exceptionally-refined analog model system will produce accurate signals.

Since EMTP output is in the form of data samples of relay inputs, digital

relay algorithms could be tested with no additional interfaced to the relay software. However, if a complete relay must be tested, then the EMTP output must be played back through D/A converters and suitable amplifiers to furnish the required levels of currents and voltages for the relay input circuits. Alternatively, the complete relay could be modelled as an EMTP device, and the entire test performed within EMTP framework. Both approaches are feasible. Progress is being made at present in developing systems which can be used for playing back sampled data through relay hardware at realistic levels of currents and voltages. A research effort sponsored by the Development Coordination Group (DCG) is developing relay and transducer models and incorporating them within EMTP.

#### 4.3.3 Transformer—Core Saturation Currents

Section 4.5 below discusses phenomena which may cause misoperation of transformer protection schemes. In particular, if the core saturates, the exciting impedance drops and large magnetizing currents may flow. The best-known core-saturation problems are magnetizing inrush on bank energization, and over-excitation currents in the presence of high voltages and/or low frequency. These magnetizing currents flow mainly during the actual instants of saturation, which occur only during certain portions of the power frequency cycle; therefore the currents tend to be not at all sinusoidal and can be distinguished by their harmonic signatures.

While transformer protection security measures are discussed below, line relays may also need to be designed to be immune from tripping on these distorted currents. The problem may be observed if the transformer is connected to a bus behind the line relay or at the remote line terminal; it may be even more acute if a transformer is connected to serve a tapped load along the transmission line itself. Magnetizing currents are mainly reactive, and may cause operation of overcurrent or distance relays. Minimizing sensitivity to harmonic currents is an effective way to prevent undesired operations.

Testing may be done by using harmonic currents or superimposing them on the power-frequency fault currents. More accurate testing would require the actual simulation of the waveforms. A half-wave rectified current is sometimes used as a crude simulation of inrush. An EMTP model, or actual saturating elements on an analog model power system, are far closer to reality. Since digital protection algorithms can be designed to be quite insensitive to harmonics, elaborate testing is not always needed.

#### 4.3.4 System Swings

Stable or unstable swings may produce large balanced currents on the

protected line, or may cause the apparent impedance to enter the protection zone and appear as an internal three-phase fault.

The designer may, in some cases, need to present the user with a choice of strategies. Tripping in response to the swing is easiest, but may often be unacceptable — the trip occurs when the sources are out of phase, and the large transient recovery voltage may destroy the circuit breaker. To block tripping altogether or to trip at a more favorable time, the swing must be detected and considered in the tripping logic. Detection is usually performed with multiple impedance circles or blinder elements, although other methods have been proposed. Faults are distinguished by the near-simultaneous operation of the nested impedance-measuring elements, as compared to the sequenced operation which occurs as a swing gradually enters the protection zone. Only the relaying elements which actually respond to the swing need to be supervised — some fault protection methods which respond only to unbalanced faults will not see the swing and can be permitted to trip at all times.

A realistic test of this measurement and logic scheme involves a computer simulation of system dynamics, or use of an analog model system with multiple machines. However, the logic may be verified by the simple use of a sequence of discrete apparent-impedance values, with times of change adjusted to exercise the particular logic scheme.

#### 4.3.5 Unbalanced Load Currents Due To Single Phase Tripping

Intentional single-phase tripping of a transmission line to clear a ground fault will cause negative-sequence and zero-sequence current flow in both the protected line and adjacent lines. Protection schemes applied on these lines should be tested for correct restraint during these intervals, and during the subsequent reclosing of the tripped phase. The simulation requires only development of the steady-state current flows on the lines in the vicinity with the one phase of one line open.

A related concern is the security of line relays, especially directional ground relaying functions, when an external fault is cleared via a three-pole trip, but one of the poles is sluggish in opening. The resulting current flow might not be distinguishable from an internal ground fault, and the only solution in either conventional or digital relays is to use a combination of reverse-direction fault sensing with trip blocking to ride through the interval of confusing input signals. A realistic simulation of the sequence of events can be attempted, but a relay design can usually be satisfactorily tested with an artificial sequence of signals which test the functioning of the logic.

#### 4.3.6 System Harmonics

Harmonics in voltages and currents are presenting an increasing problem on modern power systems. Harmonics are most noticeable at the distribution level, but some sources are tied directly into the transmission network. Examples of these sources are arc furnaces, frequency converters, dc transmission converter stations, and static VAR generators. Harmonics up through tenth order or higher may be observed, with total distortion of several percent or worse. The analog antialiasing filters of digital relays will attenuate higher-order harmonics.

The result of harmonics, if any, is errors in the results from ac signal measuring elements in the digital or conventional relay. The testing involves the straightforward superposition of harmonics on the power-frequency waveforms for which the protection must operate or restrain. It should be noted that, in general, the response of digital line relaying algorithms to harmonics is well understood and documented in the literature – much more so than for conventional designs which preceded them. It is a more straightforward task to design a harmonic-immune digital relay today.

#### 4.3.7 Oscillating Charge Due to Shunt Reactors

Long high-voltage lines with substantial shunt admittance may develop excessive voltages during light loading, and are compensated with shunt reactors at the line terminals. The reactors and the line capacitance form a resonant circuit which will show a decaying oscillation when the line is deenergized. The reactive compensation is usually less than 100%, and the result is oscillation at a frequency which is below but not far removed from the power frequency. The frequency of the oscillatory signal can be estimated from the total reactor inductance and distributed line shunt admittance across the reactor terminals or

$$\text{frequency of oscillations} = \text{power frequency} \sqrt{\frac{\text{MVA Shunt Reactor}}{\text{MVA Line Charging}}}$$

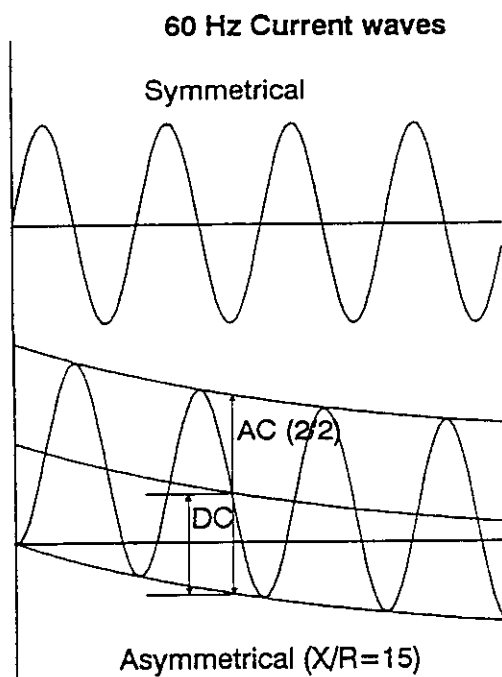
Differential, impedance, or overcurrent relaying functions applied to the reactors themselves must be immune to tripping on this oscillatory signal, since this tripping usually locks out the line breakers and imposes a needless, long outage. Intervention by maintenance personnel is required before the line can be restored. In addition, line relays connected to line-side potential devices will receive the oscillating voltage, and the designer must insure that line relays do not issue spurious trips after nonfault tripping of the line.

Digital relay designers should note that while many of the widely-publicized algorithms have response nulls at harmonic frequencies, they may or may not have

significant response lobes at adjacent non-harmonic frequencies. Additional checks or logic may be needed, along with the algorithm, to insure security in the presence of shunt reactor ringdown voltages.

#### 4.3.8 Dc Offsets

Because of the inductive nature of a faulted transmission network, a fault is often accompanied by a decaying-exponential transient current (dc offset) imposed by trapped flux. The magnitude of the offset depends on the inception angle of the fault with respect to the voltage wave, and varies at random from none to full initial offset. The time constant of the decay depends on the  $X/R$  value for the affected



**Figure 4.2 Single Phase Short Circuit Current Waves**

network lines or apparatus — values of from one-half to two power frequency periods for the time constant are typical in high-voltage transmission systems.

These dc offset transients have been a chronic source of overreach since the inception of relaying; digital methods provide some tools for approaching the problem, but do not provide an easy or automatic solution. Note in particular that, even though many relaying algorithms have attenuated response or a response null at dc, the dc offset transient is actually a decaying exponential and has frequency components which are distributed throughout the spectrum. There is significant energy around the power

frequency and even a selective algorithm will have errors. Minimizing overreach generally requires a specific ancillary computation which estimates and removes the transient, or modeling the inductive behavior of the network with a hardware or software "mimic burden" which shunts away or subtracts out the offset.

Dc offsets are easy to develop for testing purposes. For simulated-data programs, a decaying exponential is added to the sinusoidal fault current; the magnitude and inception angle are adjusted to yield no instantaneous change of current at the instant of the fault. Any system-modeling program, such as EMTP,

will generate realistic offsets. Also any analog power system model with control of fault inception angle will produce offsets. All protection computations should be tested with various degrees of offset to insure security.

#### 4.3.9 Source Impedance Ratio (SIR)

Large power systems generally have low source impedances at important buses, so that relay voltage is substantial for all but nearby, bolted faults. However, at some locations, strong sources may not be present or may be out of service. A very short line with moderately high source impedance, or any line with a high source impedance, will suffer a severe voltage collapse on the faulted phase(s)

regardless of fault location. It is then difficult for any line relay to accurately determine how far away the fault is.

The effect of SIR on fault current levels for a 380 kV network has been documented in the CIGRÉ report of Working Group 34.01, 1980. Figure 4.3 is taken from that report, and similar plots for other voltage class can also be generated.

Many contemporary line relays are rated for SIR of 30 to 60 (i.e. source impedance 30 to 60 times set reach). This means that

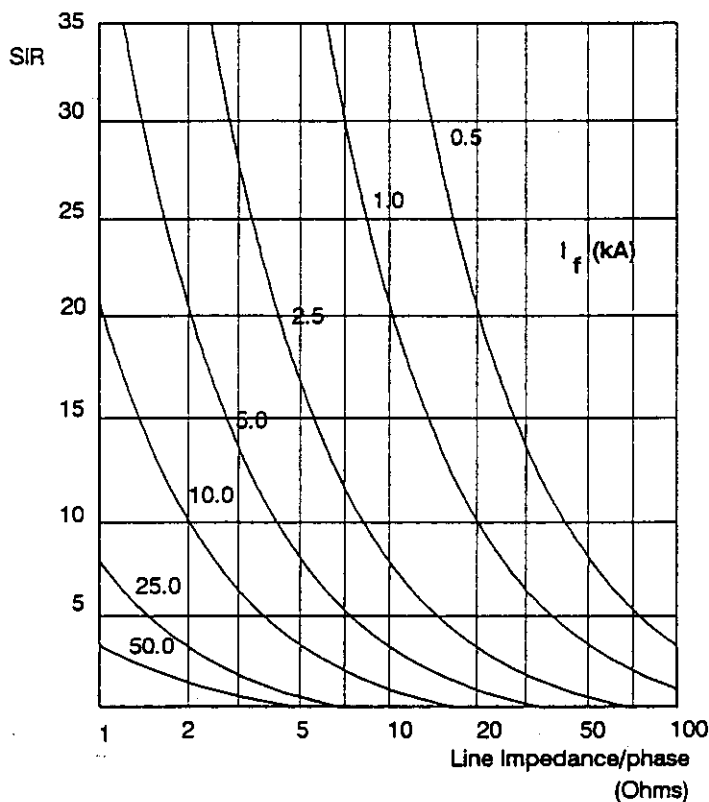


Figure 4.3 SIR as a function of line reactance and fault current.

the voltage collapses to 1% to 3% of normal even for far-end faults. These relays will generally yield high reach accuracy only for ideal, zero-fault-impedance conditions. As explained under 4.13.14 Double-End Fault Current Infeed below, errors with load flow may exceed 100%. The relay serves mainly as a directional unit, with only limited local-backup capability.

Polarizing must not be strictly dependent on faulted-phase voltage. Alternate polarizing voltages, such as sound-phase voltages or memory signals, may cause extreme dynamic shifts of the operating characteristics of distance relays;

these shifts can be helpful or hurtful and should be tested by the designer or user. Proper phase selection for single pole tripping on single line to ground faults should also be ensured under heavy infeed conditions (Low Source Impedance). High-SIR testing is realistic only if certain power-system features are accurately modeled. When the voltage collapses badly, important waveform influences are proper positive and zero sequence complex impedance values of the source and line, arc characteristics, and CCVT transient response. These are all described below.

#### 4.3.10 Characteristics of the Source System

The distortion of signals to the relay during faults or switching of the line is affected by the source parameters as well as those of the line. Faults near generating plants may induce dc offset transients of long duration in the voltage and current signals. Distributed capacitance in the source may produce ringing signals which may affect relay computations. Only sophisticated analog models of power systems, or detailed computer modeling will simulate these subtle effects.

#### 4.3.11 Fault and Arc Resistance

Fault resistance may be large for line faults where no overhead ground wires are used or where an arc is struck from a conductor directly to a tree or other nearby, poorly-grounded object. The term is also used to describe arc-path impedance for multiphase faults or from a phase conductor to a grounded metallic conductor.

High-resistance ground faults are difficult to detect because of low current, and because the fault current looks like load or stable-swing current. The fault current may lag faulted-phase voltage by only  $0^\circ$  to  $30^\circ$ . It is desirable for the relay to properly sense fault currents down to 10% or 20% of normal rated (load) current. Distinguishing such a fault from load flow can be done only by focusing on zero-sequence current magnitude and/or by using reach characteristic shapes which distinguish the fault and load (this is not always possible). As explained below, fault resistance greatly magnifies reactance measurement errors from load-flow and remote-end infeed.

Arc resistance becomes significant for close-in faults or faults with large SIR. The arc tends to limit the voltage drop at the fault to a maximum level of about 1kV per meter, yielding a clipped arc voltage when sinusoidal current flows. The resulting harmonics in the voltage may be as large as the fundamental, or worse. The relay must ignore large harmonic voltages, or suffer serious errors.

#### 4.3.12 Mutual Coupling Between Lines

Voltage induced in a protected line from zero-sequence current flow in a parallel line may oppose or assist the flow of fault current, causing sensitivity

problems, directionality problems, or serious reach errors in ground distance relays.

The ground distance relay may be compensated, using zero-sequence current signals from mutually-coupled lines entering the station. Unfortunately, lines with partial parallel runs frequently terminate at different stations so that no correction is feasible. A large number of parallel lines leads to many correction terms and makes compensation unwieldy. In many present-day installations, mutual compensation is neglected and ground-distance relays are set with increased reach (pilot relays) or reduced reach (direct-trip relays) to handle the worst case. The problem awaits clever solutions, perhaps using unique computational or communications abilities of digital relays.

Accurate simulation for testing requires an elaborate and extensive system model, either analog or digital. This is rarely justified — it is usually acceptable to show that mutual-compensation (furnished through hardware or software) causes the proper amount of change in reach when a calibrated amount of current is applied to the parallel-line zero-sequence input.

#### 4.3.13 Ratio of Zero- to Positive-Sequence Impedance

Variation of ground-fault current over the length of the line, and apparent impedance to the fault, is drastically affected by this parameter. The errors are readily eliminated, however, by compensating faulted-phase current according to zero-sequence current and the impedance ratio. Values of the ratio range typically from 1.5 to 7, with 2 or 3 being quite common values.

The ratio has traditionally been considered as real; i.e., the zero- and positive-sequence impedances have been assumed to have the same angle in most cases. Some European static relays have the ability to set and use complex ratios of  $Z_0/Z_1$ . However, some digital protection algorithms allow separate compensation of computed fault inductance and resistance values, so that  $X_0/X_1$  and  $R_0/R_1$  are considered separately; these need not be, and in general are not, the same value.

For testing purposes, realistic signals or transient performance are not issues. Calibrated steady-state signals, or analytically-derived values, usually suffice.

#### 4.3.14 Double-End Fault Current Infeed

For a zero-impedance (bolted) fault with infeed from both ends of the line, neither line-terminal fault-current contribution affects the other. For real faults with fault or arc resistance, however, each contribution produces a voltage drop in the ground path which modifies the current flow at the other terminal.

If no load had been flowing at the time of fault inception, the sources are in phase. If the fault path is a pure resistance, the remote infeed reduces current flow at the local terminal and moves the apparent fault impedance in the +R direction of

the impedance plane.

If real load was flowing between the sources, the two contributions are not in phase. Relays at each terminal will see a fault voltage drop which is out of phase with the local current contribution, giving the appearance of lowered fault reactance at the power sending terminal and raised reactance at the receiving terminal. The results are overreach and underreach, respectively.

Measuring units associated with different phases in distance relays tend to underreach or overreach under double-line to ground faults with fault resistance. Whether the measuring system underreaches or overreaches depends upon the phases involved in the fault. The logic used should ensure proper operation for example through the use of block-leading phase techniques.

Error estimates depend on source impedances, fault resistance, and source angle, which could be 45 degrees or more. Adaptive schemes have been tried for digital relays which remember prefault load conditions, and make an approximate correction to the computed reactance.

Many distance-measuring equations or elements, in use for years, inherently adapt their reach characteristics to these varying conditions using cross-polarizing or alternate polarizing sources. Reach errors are much reduced from those using raw apparent impedance values derived only from voltages and currents on the faulted phases.

#### 4.3.15 Nonlinear Components in Power System

Nonlinear apparatus produce distorted waveforms during fault or nonfault conditions. The designer must estimate or measure the appearance of the waveform, or its spectral composition, for the particular nonlinear element. The distortion must be compared to vulnerability of any particular relay design. Nonlinear components include:

- Any situation in which an arc is produced – arcing fault, arc furnace, etc.
- Surge arrestors.
- Protective gaps.
- Varistors (e.g. zinc-oxide arresters or overvoltage protectors which clip voltages above a threshold).
- Converter stations for interface to dc transmission or loads.
- Any ferromagnetic device which may operate near or at saturation of the iron core, including power transformers, reactors, CTs, CCVTs, and VTs.
- Motors .
- Phase-controlled static switching devices – static VAR generators, motor speed or power-factor controls, etc.

- Rectifiers supplying capacitive filters.

#### 4.3.16 Time Discrepancy Among Phases During Circuit Breaker Operation

A sluggish pole of an independent-pole circuit breaker, or delayed interruption in one or more poles, may produce relaying signals which are inconsistent on a transient basis. Any relay which performs measurements based on multiple-phase inputs may be vulnerable – for example, lack of line-side potential from one phase, combined with fault or load current in another, could cause an undesired operation. Zero-sequence or negative-sequence measurements may also be improper.

The poles of a properly-functioning breaker should show 1/4 to 1/2 cycle time discrepancy in operation. When problems arise, the skew can be several cycles. Many conventional relays will trip incorrectly for this skew. In particular, it has been shown that directional ground relays may misoperate for reverse faults when the breaker behind the relay trips with a lagging pole.

The designer must be especially careful with single-pole trip schemes, where one phase is intentionally opened for a fraction of a second.

#### 4.3.17 Current Transformer Saturation and Inaccuracy

CT accuracy classes are defined by standards. The relay user must select CTs which have accuracy and burden-carrying abilities according to worst fault conditions and accuracy needs. The relay designer makes the job of the user easier by keeping the relay burden as low as possible. Some digital relays perform multiple functions using a single current input; this further reduces burden so that CT-winding and switchyard-wiring resistances become the main burden.

Even high-quality CTs may saturate for severe dc offsets, especially when the dc offsets have long time constants. The output is a highly-distorted waveform with a relatively small power-frequency component. This saturation may occur in as little as 2 to 6 ms. Therefore, the relay must be very fast, and/or be able to ride through the saturation period until the CT recovers without misoperating. There may be new opportunities for analyzing the distorted output of a saturated CT using microprocessors.

When linearized current transformer (Air-gap CTs) are used, one should reckon with an angle error up to 3°. The secondary current lags the primary as a consequence. This lag results in an exponentially decaying direct current subsequent to breaker opening. When no special measures are taken in the relaying logic, the relay drop-out time is considerably affected which in turn might trip bus breakers through breaker failure protection.

For accurate testing, a good computer-based simulation of core saturation is

needed. It is difficult to try to get a real CT to saturate consistently for testing purposes unless elaborate laboratory facilities are available.

#### 4.3.18 Coupling—Capacitor Voltage Transformer (CCVT) Transient Errors

CCVTs use a tuned—transformer scheme to step down the high—voltage output of a large capacitive divider -- this is done to accommodate large burdens. The CCVT components store energy which is trapped when a fault causes the primary voltage to collapse. The stored energy is released as a long time—constant decaying exponential, or as a low—frequency oscillation. These waveform tails may be at 25% of normal just after the fault and may remain substantial for a cycle or more.

The relay must use filtering, pre-fault—memory, waveform check, or other methods to avoid misoperation on these non—sinusoidal transients.

Testing can be done with the output record from a detailed digital simulation (e.g., using the EMTP) or an analog network which is similar to the transformation circuit of a particular CCVT.

#### 4.3.19 Size and Location of Series Capacitor Banks

A series capacitor bank between the relay and the fault can overwhelm the inductive reactance of the unfaulted line portion, producing net capacitive reactance and a reversal of voltage phase. A distance or directional relay may trip for a reverse fault, or ignore an internal one.

Normally, 70% or less of the line reactance is compensated. The compensating capacitors may be lumped near either terminal, or divided between the two ends. The user has to be concerned about whether a given relay will see a voltage inversion, but the designer must provide a way to deal with it. Many successful schemes have been based on pre-fault voltage memory. Current—wave or current—phase comparison has also been successfully applied.

An additional complication is the use of parallel gaps or varistors across the capacitor bank to suppress series overvoltages. These protective devices switch the capacitors in and out in transient time frames, producing badly distorted waveforms and further confusing the relay. Also, capacitors interact with system inductance to promote subsynchronous—oscillation currents, and the relay must not misoperate when this occurs.

Testing must be done using a model power system, or a digital simulation, which models not only the capacitors themselves but the overvoltage protective devices — gaps or varistors, and shorting switches with their control logic for removal and reinsertion of the capacitor bank.

#### 4.3.20 Overexcitation of Transformers Due to Overvoltage:

Overvoltage can exist on EHV circuits due to inadequate reactive compensation or load rejection. This overvoltage can saturate power transformers and provide substantially increased exciting currents. The transformer protective relay should not operate for this condition. It is felt that this overvoltage condition is inimical to the power system equipment, an overvoltage relay can be used to disconnect certain elements from the power system.

#### 4.4 Bus Protection

This section discusses the protection of power buses. The following uses the term bus protection, although the preferred description is busbar protection at many locations.

Most, but not all, bus protection schemes use the current summation or differential approach. Current signals for a given phase, taken from each CT around the bus, are added. Since the bus has insignificant energy storage (shunt capacitance or series inductance), the sum is zero unless the bus is faulted. A number of well-known practical problems arise, however, along with a number of schemes to deal with them. Most of these are summarized in the following list of issues.

##### 4.4.1 Saturation of CT by DC Offset

DC-offset or decaying-exponential transients generally appear in fault-current signals, as a function of inception angle. They occur both for faults on the bus, and faults on adjacent apparatus which produce heavy fault current flow in the protected bus.

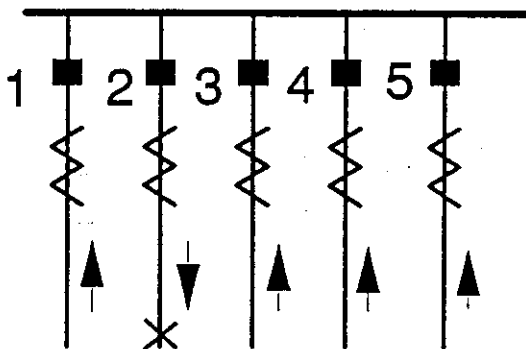


Figure 4.4 CT Saturation on Bus fault

Iron-cored CTs may saturate when subjected to such offsets. There is always time before saturation, but perhaps as little as a few milliseconds from fault inception for an unfavorable combination of remnant flux, severe offset, and CT quality or capability.

The saturation is a possible cause of misoperation of bus protection on external faults, or it can delay clearing of internal faults. Refer to Figure 4.4. The bus CT nearest the fault receives contributions from all other feeders, and is most likely to saturate. If it fails to reproduce primary current, the bus summation is substantially non-zero and a differential trip may occur. A host of schemes for circumventing the problem are

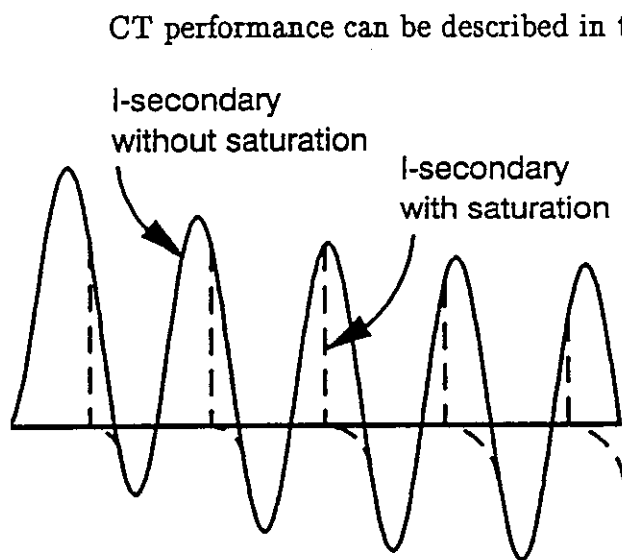
summarized below.

#### 4.4.2 Saturation of CT by AC Fault Current

Even without DC offset, the CT can saturate on the peaks of the ac fault current, causing the same type of problem. For transmission networks, maximum fault currents are well known and the user can install a CT of adequate quality. At lower voltages, however, wide variations of source impedance may arise from system switching or long-term growth. In these cases, tremendous fault currents, beyond CT capability, could result. Even if this is not the case, remnant flux after fault clearing can cause a temporary saturation problem after reclosing.

AC saturation problems may also arise if additional burdens, such as those of a line protection system for an adjacent zone, are connected in series with the bus protection CT circuit. Such additional burdens should be avoided if possible. AC Fault Currents may lead to steady state saturation due to large difference in CT ratios between the coupling bay CTs which have the highest primary current rating and CTs in station auxiliaries which have the lowest CT ratio.

#### 4.4.3 Waveform Considerations



*Figure 4.5 CT Saturation waveform*

CT performance can be described in terms of ratio error, which reflects what ammeters in the primary versus secondary circuits might show. This characterization implies a quasi-steady-state response and does not specify the frequency spectrum or transient response associated with the measurement.

If both the ratio and phase delay errors are available, one can estimate transient performance as long as the CT does not saturate. However, even this isn't adequate for predicting how connected relays

may behave under all realistic conditions.

A saturated CT may produce a grossly distorted secondary current, in which substantial fraction of half-cycles of either or both polarities are simply truncated. Figure 4.5 shows an example. In extreme cases, only short spikes of current are produced. Measuring this output wave with an ammeter may give a misleading

indication of relay response.

If the relay uses high-speed (sub-cycle) or short-window measurements, its behavior in the face of specific example waveforms must be carefully checked. This checking is also necessary if specific filtering algorithms or hardware is used. Estimating tendency to operate from ratio-error data is valid only for relay designs which respond like the instruments used to find the CT error data.

#### 4.4.4 Dynamic Range of Currents

Because of a possibly large number of bus feeders and the variety of switching states possible, fault currents in a given CT may vary from a small contribution to an internal or remote fault, to an overwhelmingly large current supplied from all the bus-feeders to a nearby external fault. This impacts not only CT selection, but also input-circuit design in the relay. For example, fault currents may vary from one tenth of rated load to 60 or 80 times that load. The A/D conversion systems must be capable of linear conversion of currents ranging from 0.1 to 100 times rated current. A 16 bit dynamic range would be able to cope with this range. Either one could use a 16-Bit A/D converter or combine a 12-Bit A/D converter with dynamic ranging amplifiers. This requirement is true for all protection systems.

#### 4.4.5 Methods for Bus Protection

Some existing techniques for handling these problems are as follows:

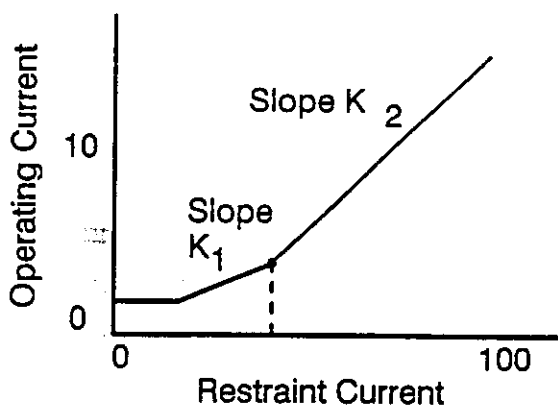


Figure 4.6 Variable slope Characteristic

For a heavy-current fault, a very large differential current is needed and tripping from saturation error is unlikely.

The CT signals must be matched in amplitude, or else scaling adjustments may be made within the relay. The CT secondary time constants must also be reasonably matched — they need not be identical for all CTs, but misoperations are likely if the signals from CTs having closed iron cores are compared to or combined with those of air-gap or air-core transformers.

#### Percentage-Differential Relay

An approximation of power-frequency differential current is compared to a restraint quantity developed from the magnitudes of the feeder currents. The comparison criterion shown in the example of Figure 4.6 is a fixed or curved (variable-slope) limit for required differential current to trip, as a function of restraint. For a heavy-

### High-Impedance Relay

All feeder CTs are wired in parallel, with carefully balanced lead and winding resistance. To the junction point is connected a relay consisting of an overvoltage unit and a parallel nonlinear varistor burden.

Discrimination of internal faults versus the external faults with saturation is accomplished using the low secondary exciting impedance of a saturated CT. If a CT is saturated, the false differential current causes a moderate voltage to appear at the overvoltage unit terminals. This voltage forces most of the false current through the low exciting impedance of the saturated-CT secondary, so the voltage does not grow large and no relay action occurs. If there is an internal fault, a large differential current flows and is forced mostly or entirely through the relay. A large voltage is developed, which picks up the overvoltage unit. The varistor conducts some current around the overvoltage unit, to protect the relay and associated wiring from dangerous voltages well above operating level.

### Linear-Coupler Differential

Saturation problems are banished by eliminating the iron CT core. The linear coupler (lc), an air-coupled transformer, develops a secondary voltage which is proportional to primary current. The lc secondaries around the bus are connected in series to a simple, low-burden voltage-sensing relay. The lc's are expensive, and have not been used in the past for other relaying or measurement purposes.

### Directional Comparison

If only current spikes are available from the CT, their polarity can be compared with a voltage polarization source, or the sum of all currents as a polarizing quantity, to determine if each breaker current is flowing into or out of the bus. If all currents flow in, the fault is internal.

### Instantaneous Differential

The instantaneous value of the differential current is evaluated in the brief interval between fault inception and possible CT saturation. Logic must be able to select a suitable time window, and avoid checking after the onset of saturation. This method may be supplemented by another which is able to operate at all times, for backup in case of an evolving fault.

### Differential Overcurrent

For non-critical installations where clearing times can be long, an inverse-time overcurrent relay can be set to ignore false differential currents. Since the CT recovers after decay of the offset, the relay can wait long enough for the easy-to-check, post-fault steady-state condition.

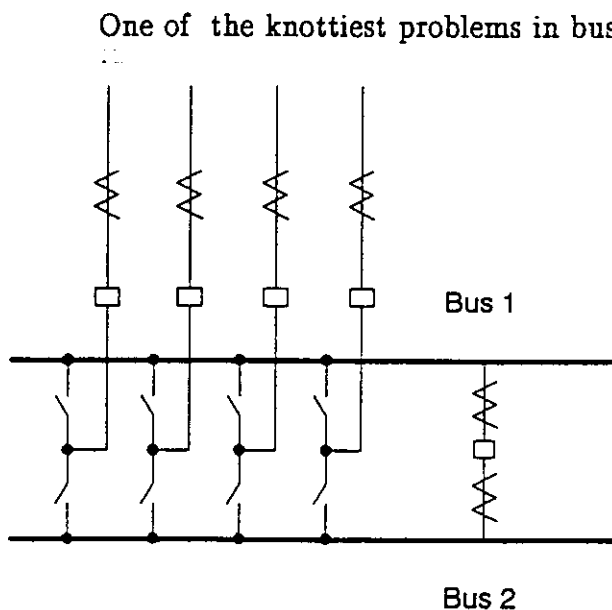
These are just some of the popular schemes — the list is not exhaustive.

With the most fundamental problems and solutions summarized, we can look at a few additional situations and requirements which the relay designer can consider.

#### 4.4.6 Large Feeder Count

At moderate or low voltages, a large number of feeders, perhaps 10 to 20, can be connected to one bus system. The relay engineer then needs a relay with many input channels. While the differential value is a summation, the restraint is developed from individual feeder magnitudes – the computational burden for a microprocessor may be high. An alternative compromise is to combine pairs or triplets of feeders in parallel. If this is done, the reduced restraint information must be considered in the design or setting.

#### 4.4.7 Bus Reconfiguration



**Figure 4.7 Main and Transfer Bus**

One of the knottiest problems in bus protection is the variable configuration of the main-and-transfer bus, double-bus schemes and related schemes. Figure 4.7 shows two bus configuration with feeders which are connected arbitrarily through isolating disconnect switches to one bus or the other.

It is normal to connect the secondaries of current transformers in the protection circuit in its new configuration before the feeder itself is connected to a bus and, conversely, the CT secondary must be disconnected from the

protection circuit after the feeder is removed from the bus. Also a short circuit between the circuit breaker and the CT remains a bus fault for the bus protection system even after the circuit breaker has tripped, and is cleared by the operation of the breaker at the remote end of the feeder.

The fault protection function for each bus must have access to all feeder currents, and sometimes a tie breaker current. Each relay function must also have access to inputs that indicate which feeders are connected to which bus at each instant of time. Only the connected feeder currents are analyzed for differential versus restraint checks of a given bus.

The switch states might be indicated from auxiliary contacts, perhaps backed up by manual operator inputs. Many utilities consider auxiliary contacts to be unreliable indicators. Checking the flow of ac currents during non-fault times might be used to confirm the bus configuration in use, so that the correct currents will be used for protection. In a microprocessor-based relay, it is easy to switch current inputs to one differential computation or the other by logical operations or sampled data – no actual switching of CT secondary currents is required.

A backup overall checking zone can be included for the whole bus system, using all feeder currents, in case of a state indication error or a fault during a switch operation.

#### 4.4.8 Cost Justification

The cost of bus protection includes that of CTs, wiring, and the relays. For straightforward applications, the bus relay itself may be quite simple. The designer of a new relay must consider the cost benefit to the user for any sophisticated equipment he considers supplying. Additional protection functions, flexible characteristics, data output, or operation as part of an integrated relaying and control system, may all help to justify the potentially higher cost of a microprocessor device. It should be noted that some bus protection schemes used in Europe can be quite expensive, and the microcomputer based relay is expected to be economical under such circumstances.

#### 4.4.9 Backup Needs

In addition to the primary individual phase protection schemes, the bus protection package may include backup. This might be a ground differential overcurrent function, in which an inverse-time overcurrent function is applied to the residual or neutral-return CT current. Beyond this, an elaborate relay might employ two different, redundant primary methods to cover any blind spots or either.

#### 4.4.10 Reclosing Possibility

There are a very few utilities which attempt automatic reclosing of bus breakers after a fault. The bus protection microprocessor could easily absorb such a task.

#### 4.4.11 Surge Arrester in Bus Zone

A gapped surge arrester may conduct up to one-half cycle of follow current once it conducts. If the arrester is inside the bus zone, the follow current looks like fault current and may cause a high-speed differential relay to trip. The solutions are to avoid fast-tripping relays, to add a CT to the arrester connection, or to move the arrester.

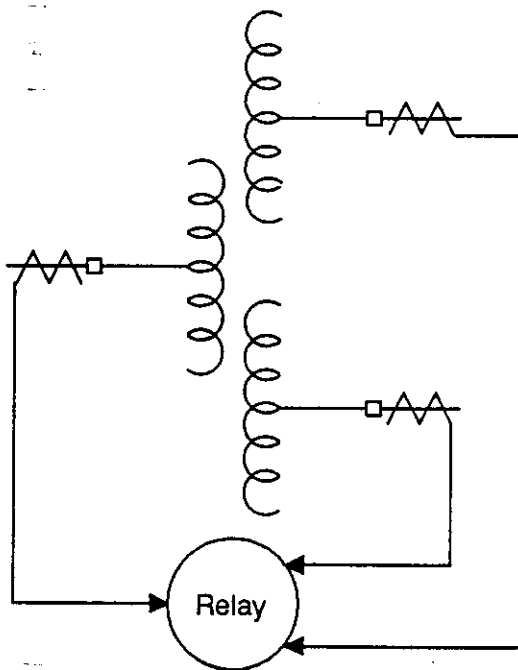
Metal-oxide arresters conduct only while an overvoltage condition exists.

The user must determine if the highest arrester current magnitude and duration can pick up the bus relaying.

#### 4.4.12 Breaker Backup Protection

Local breaker back-up (breaker failure) protection, and some other functions, may rely on some of the same ac measurements and bus-configuration logic as the bus protection. Accordingly, these functions might be included in the bus relaying equipment to achieve a considerable cost benefit. Of course, the designers and users must still determine how hardware redundancy or protection function segregation requirements are to be met.

#### *4.5 Transformer Protection*



**Figure 4.8 Transformer Differential Relay**

Windings of transformers are typically connected to the power system through multiple breakers. Relaying currents may be obtained from bushing CTs on the transformer itself, or from CTs at each of the circuit breakers. An example is shown in Figure 4.8.

In the Figure, note that the currents from the two CTs in the two secondary breakers are combined to obtain a winding current for differential or other transformer relaying functions. However, the bus sections within the transformer zone must also be pro-

tected, and in fact present most of the same protection requirements as for the bus relaying described in the previous Section. For example, a fault just outside the zone as shown may produce heavy through fault current and CT saturation; the same counter-measures as were suggested above are required and effective here, and must be included along with the specialized transformer functions discussed below. Accordingly, many of the same testing procedures will apply.

Other issues for transformer protection are as follows:

#### 4.5.1 Inrush Currents

When the transformer bank is energized or the applied voltage suddenly increases, flux from the applied voltage combines with remnant flux. The summation may be unfavorable and may produce saturation of the power transformer core. The exciting impedance drops and a heavy current flows from the source(s) into the transformer. A differential relay sees the magnetizing current inflow as an internal fault and may trip.

Because the inrush current flows mostly near the peaks of one polarity of the applied flux, the current wave is highly distorted and can be distinguished by its rich harmonic content (largely even harmonics). Analyzing the percentage of various low-order harmonics in the differential current wave is a popular method of distinguishing inrush from fault current, but other methods are available.

The newest EHV transformers are the most difficult to deal with — the saturation characteristics of the iron are such that the harmonic content of the inrush wave may be low and harder to use for distinguishing from faults. At the same time, the remnant flux may decay very slowly and inrush currents may last for minutes rather than seconds.

Inrush current testing is most accurately performed with a digital simulation of core behavior — trying to use a real transformer involves luck in getting the remnant flux high enough. A half-wave rectified current is often a suitable substitute.

#### 4.5.2 Overexcitation Currents

If the applied flux is well above the symmetrical rating of the core, even without the added effect of residual flux, saturation will occur at every peak (both polarities) and a false differential current will flow. This current is also highly distorted, although it has a significant content of harmonics (notably fifth) which can be used to distinguish it from fault current. Fifth harmonic is a reliable index of overexcitation, however, only in the range of voltage of 1.2 to 1.6 per unit or so. In the unusual application where even higher excitation can occur, harmonics actually are less and a direct measurement of excitation (volts or volts per hertz) is needed. An example is the series transformer winding of a phase angle regulating (PAR) bank, which may be subjected to voltages of several times normal during faults.

Analog-model testing is easiest, since almost any transformer can be symmetrically overexcited with overvoltage. A digital simulation may give a more realistic waveform, corresponding to that of an actual EHV transformer.

#### 4.5.3 Methods for Transformer Protection

Some existing relaying techniques which correctly handle these problems are

as follows:

- Percentage Differential Relay:

A transformer differential relay includes with its requirements all those for a bus differential relay, as discussed in the last section. Accordingly, the operating principles for the main tripping differential unit tend to be the same as described there. However, additional supervision of tripping is needed to handle the additional problems just described.

Harmonic measurement by a separate element or computation is a popular and proven way to prevent tripping on inrush currents. The magnitude of a particular harmonic, such as the second, or of a group of harmonics in the differential current, is compared to the fundamental-frequency or total differential current. If the harmonic measurement exceeds a certain low percentage (e.g., 10% to 20%) of the fundamental, inrush is assumed and differential tripping is blocked.

Overexcitation blocking calls for use of a different harmonic, such as the fifth harmonic mentioned above, to block incorrect differential-unit operation. Some relay designs combine the measurement of the two or more harmonics in a single element; newer proposed digital implementations may use discrete calculations to handle overexcitation versus inrush.

- Instantaneous Differential Protection:

Most percentage-differential relays for transformers include an instantaneous differential element which trips on differential magnitude only, without any fundamental or harmonic restraint. It provides high-speed tripping for faults whose current magnitude is clearly beyond the range of core-saturation phenomena, and requires no supervision.

At least one digital transformer differential relaying system uses an instantaneous differential computation with an instantaneous restraint, plus supervision based on voltage magnitude and/or sudden voltage changes which might indicate false differential current. This element can be set sensitively, to provide tripping for most faults. It works in the short time window of a few milliseconds before any of the CTs might saturate for external faults. It is blocked by the voltage change of energization, so that a second higher threshold or a separate backup calculation must be relied upon to detect faults during energization.

- Sudden-Pressure Relay (SPR) or Buchholz Relay:

Low-level faults among windings in the transformer tank may produce so little differential current that they are difficult to detect with conventional electrical measurements. Those faults do produce, however, explosive forces which displace oil and cause a pressure shock in the gas space above the oil. A simple mechanical

relay consisting of a diaphragm connected to a switch contact can respond to the shock and initiate breaker tripping in milliseconds. The diaphragm and switch assembly are mounted in a chamber at the top of the transformer, with some means of equalizing the gradual pressure changes resulting from thermal and atmospheric changes.

Some of these relays have an undesirable tendency to operate for heavy faults external to the transformer zone, since such a severe and sudden flow of through-fault current may also produce mechanical shock of the transformer windings and core. A simple solution used at some utilities is to supervise the sudden-pressure relay with an overcurrent relay which blocks SPR tripping for currents above the set current threshold. In this way, the SPR trips for low-level faults which differential relays may not see, while high-current faults are securely classified as internal or external by the transformer differential protection scheme. Each type of relay operates in the regime where it is secure against false tripping.

- Flux Estimation Measurements:

Schemes have been proposed in which the flux in the transformer core is calculated in real time from ac electrical measurements to predict saturation, and resulting differential current waveforms which are not indicative of faults. Any fault will produce a differential current which departs from the predicted values, and can be used to provide sensitive differential tripping. Obviously, this method is computationally intensive, and is ideally suited to application via a powerful microprocessor.

The only drawback is in estimating the significant effects of remnant flux which can change unpredictably from external faults, and which is generally unknown at the time of energization in any case. However, it is possible to make conservative, worst-case estimates of the flux in the core along with measured ac excitation, to obtain a conservative, secure prediction of saturation inrush currents.

- Solution of Terminal Equations for Transformer:

Multiple schemes have been proposed over many years in which the measured ac voltages and currents flowing in the core of the transformer are used to solve differential equations which incorporate known physical parameters. Depending on the scheme, the solution may be used to match the ac values to a model of a normally-operating transformer, or a saturated core, or a faulted winding. As with the flux-tracking approach, these equation-solving methods are computationally intensive and are practical only for microprocessor-based relays. They offer the potential for very fast operation, since they do not necessarily involve extracting power-frequency or harmonic-frequency phasor measurements from the

signals as might be needed in some harmonically-restrained differential relays.

- **Partial-Discharge Detection:**

The partial electrical discharge associated with a winding location where the insulation is failing emits unique, audible noise and may give an indication of an incipient fault. Schemes have been proposed to measure and analyze sound waves inside the transformer tank, and even to initiate tripping based on clear-cut indication of a partial discharge. Such measurements would probably be performed independently of the electrical protection of the transformer.

- **Gas-in-Oil Analysis:**

Equipment has been developed which is able to automatically separate combustible gases from the transformer oil and detect their concentration by gas chromatography. These gases also provide an indication that insulation is failing and that a fault may be imminent. The technique is the same as has been used for many years as a manual procedure to look for trouble in the transformer, but the automatic analysis equipment can yield a result every few hours and has been proposed as yet another criterion for tripping on incipient faults. As with the partial-discharge detection, the gas-analysis equipment is largely separate from the electrical protection. However, there might be interesting possibilities in writing the electrical protection programs of a microprocessor-based transformer relay to adapt sensitivity versus security according to these incipient fault detection subsystems.

#### 4.5.4 Additional Transformer Protection Considerations

The following is a partial list of requirements and situations which require attention in the design of a digital or conventional transformer relaying system:

##### Zero-Sequence Differential Current Handling

Any wye-connected transformer winding can serve as a zero-sequence current source for a ground fault external to the transformer zone. The current flow in the ground connection of the wye neutral is not included in the differential comparison of the winding currents, and looks like current flow into a fault in the transformer.

The simple solution to this problem, which is widely used in conventional schemes, is to connect the three CT secondaries in a delta configuration. An alternative to this scheme would be to use auxiliary CTs in a delta connection to achieve the same result. The zero-sequence current flow in the primary circuit is transformed to a circulating current in the delta secondary, and never reaches the differential relay. In wye-delta banks, only the wye side has delta-connected CTs. In autotransformer banks, both sides have delta CT connections. The delta CT

connection introduces a 30 degree phase shift in the currents, which we will consider just below.

In a microprocessor-based relay, the same solution can be implemented in a more elegant way. The CT secondaries can be connected in the more conventional wye configuration, which makes them more useable with other relays which might be connected in the same circuits. These wye-connected CT inputs are sampled and the values brought into the relaying processor. In the software, the instantaneous sample values from adjacent phases can be subtracted to accomplish the same end result as the delta connection — the zero-sequence component is removed and the phase of the power-frequency component is shifted by 30 degrees.

If the phase shift is not desirable, the zero-sequence current can be computed from the three phase currents and then subtracted out from each of the phases. This program operation is somewhat analogous to the previously-used connection of auxiliary CTs which act as a zero-sequence current trap.

#### Compensating for Bank Phase Shift

For wye-delta transformer banks, differential relays have traditionally been connected with delta-connected CTs on the wye winding and wye-connected CTs on the delta winding. This removes external zero-sequence infeed to the wye bank winding as explained above; and it also introduces a 30 degree phase shift which compensates for the complementary shift in the transformer currents themselves. The relaying currents from the two sides match perfectly.

Just above we suggested the new, microprocessor-based approach of connecting all CT circuits in wye, on both sides of the bank, and performing the conversion of the currents from the wye side in software, by subtracting adjacent-phase samples or computed adjacent-phase current phasor values. This software manipulation has the same effect of introducing the complimentary 30 degree phase shift, so that the currents from the two sides can be differentially compared.

The advantage of the wye CT connection from both sides of the bank is that the resulting current samples and phasors are more useful for other functions besides differential protection. The measurements which a microprocessor-based relay might supply to an operator, or via data communications to a higher level of an integrated protection and control system, are most useful if given in phase current form.

The same strategy can be extended to zig-zag banks, which use multiple sets of windings and crossed connections to create hybrids with 15 degree phase shift; other intermediate values of shift can be obtained by adjusting winding ratios or

specific interconnection. The microprocessor-based transformer relay uses a sequence of addition and subtraction of samples which mimics the manipulation of the power currents by the bank itself, and still performs the differential function by use of wye-connected CT inputs only.

#### CT Ratio Matching and Tap Changer Effects

The current magnitudes from the two or more windings must be matched for differential comparison, even though the primary currents differ in magnitude in accordance with the winding ratio and connection of the transformer. Traditionally, this has been done by a complimentary selection of CT ratios on the windings to match the normal load currents. If the bank includes a tap changer for control of voltage or Var flow, operation of the tap changer changes the transformation ratio and can introduce an error in the CT matching of up to 10 or 15 percent. Conventional differential relays are set with reduced sensitivity, so that the worst combination of CT ratio errors and tap-changer position will not cause tripping. Coverage of turn-to-turn or low-level faults is severely compromised by the reduced sensitivity.

Once again, the computational ability of the microprocessor provides a path to improved performance. The CT ratios need not be coordinated with those of the main transformer windings – either or both of the incoming sample sets can be adjusted by a fixed multiplicative scale factor applied by the protection program. If the tap changer position indication is provided as an input to the microprocessor-based relay, then the differential protection program can select from a variety of fixed scaling factors which correspond to the tap positions. A major source of differential ratio error is eliminated and relay sensitivity is greatly enhanced.

#### 4.5.5 Supplementary Overcurrent Protection Needs

Overall transformer protection schemes usually include a number of time-overcurrent measurements to supplement the main differential or equivalent protection. These might include:

- Neutral time-overcurrent protection, with its curve and settings coordinated with those of the protection on adjacent lines for which the transformer might provide the zero-sequence current return path. If line relays fail to clear a ground fault, this relaying element will trip the transformer to protect its various windings. Especially vulnerable is a delta-connected tertiary winding, which will experience severe circulating currents for an external ground fault.
- A delta-connected tertiary may have a buried CT which is used specifically to protect against thermal damage from circulating overcurrent. An inverse time-overcurrent measurement is applied to this signal which is coordinated with

volts-per-hertz quotient, or directly in terms of a computed flux level determined from the voltage sample values.

#### 4.5.7 Frequency Variation Effects

Current-based protection algorithms are also affected by the extreme frequency excursions to which a GSU may be subjected. Instantaneous differential checks are valid for all waveforms, but measurements based on phasor measurements of power-frequency components or on frequency-dependent physical parameter measurement (e.g., inductive reactance looking into a selected winding) may suffer unacceptable errors.

The solutions are:

- Measure the frequency with any of a number of algorithms which have been proposed for this purpose. With many of the relaying algorithms, the computations can be modified to adapt the scheme to the abnormal operating frequency.
- Lock the sampling clock for the relay analog front-end to the power frequency, so that a fixed number of samples are taken per cycle regardless of variations in the length of a cycle. In this case, the protection algorithms in the microprocessor will not be aware of the frequency variation. The programmer must make sure that the microprocessor will have time to do all of its work between sample times for the highest power frequency (shortest sampling interval).

#### 4.5.8 Overload Monitoring

Utilities are finding great economic value in operating transformers close to their design limits, especially during system emergencies. A valuable feature in a microprocessor relay is the addition of a model for an overloaded transformer which yields information on actual available capacity at a given time, based on recent history, and on ambient conditions. If system conditions require that the transformer be operated beyond its normal capability, the model might also estimate loss of life or need for maintenance based on severity and duration of the overload.

Information to be used in such a modeling process includes steady-state voltage, currents, status of cooling fans and pumps, and ambient temperature. Actual temperature at various points inside the tank can improve the monitoring. Hottest-spot measuring devices have been developed which transmit temperatures from high-voltage points, without connecting wires, to a nearby transducer.

## 5.0 CHALLENGES IN CONTROL

### 5.1 *Introduction and Task Organization*

Generally, substation control functions can be divided into manual (open loop) or automatic (closed loop) controls. Some examples of manual control functions are circuit breaker control (local or supervisory), and the changing of set points for automatic control functions. Some examples of automatic controls are automatic reclosing, breaker failure protection, and voltage and VAR control.

The functioning of a power system is such that it would be difficult to divorce what are normally prescribed as control functions from protective functions. Many control functions are a direct adjunct of protection functions. Thus, when a transmission line protective relay system operates to clear a fault from a circuit it sets into motion a series of control commands. Normally these would be to test the circuit and restore it if the fault is cleared, or to lock it out if the fault is of a permanent nature. The control functions set into play may be high speed reclosing, single phase reclosing, time delayed three phase reclosing with or without synchronizing, supervisory closing, etc. Normally, these various control functions are closely related to the protective relay that has operated. Thus for a slow clearing fault, the control logic would normally be designed so that there would be no high speed reclose. For a detected three phase fault near a generating station the control logic may be biased to not permit a test into that fault from the generating station. Similarly, if a transformer fault is detected, switching would automatically be called into play to isolate that transformer while restoring other elements of the power system.

Station reconfiguration is a commonly employed control function. Thus at a station if it is required to take a bus or other system element out of service, it may be necessary to operate disconnect switches, circuit breakers, etc. to effect this. As the control functions take place the protective functions must also be reconfigured. Current transformers may be switched, relay potential may be transferred, trips from protective relays may be redirected. Thus in this instance the control functions strongly bias the protective functions.

In a non digital system, separate discrete elements are generally provided for the control functions which are separate from the protective system elements. In the digital environment, measurements and status information used by the protective systems are also used by the digital control systems. The dependability and security requirements of these control functions are important. While it might be said that the clearing of faults is of paramount importance, the proper restoration of

the system is not inconsequential. A prompt and correct restoration could make the difference between a minor and a major disturbance. A failure to properly restore could lead to extended blackouts and loss of revenue.

Manual control functions are those presently performed by human intervention, whether at the substation or through the supervisory control. In a digital control and protection system there is sometimes a need for operator intervention. The operator determines if the present power system conditions are acceptable and takes corrective action as needed. Manual control requires proper feedback to give the position of switches and breakers as well as measured voltage and current quantities. In some cases, operator actions are prevented if they would be undesirable. An example of this is an interlock to inhibit operator action such as reclosing a breaker into a faulted transformer. Where supervisory control is used, communication facilities provide the feedback to the operators for the decision making.

Where the substation control is part of a system control objective such as voltage control, the control system in the substation is likely to be merely a local control loop under the control of the system controller. Often this means following a setpoint that is set via telecommunication links to the station and reporting back key parameters to the central controller for its determination of the next step in the process. Set points are used for load tap changer control, static-var systems, hvdc converters, etc.

Local control systems are primarily related to equipment operation. The running of coolers on forced cooled transformers, compressors on pneumatic systems for breaker control, and heating and ventilating of buildings are examples of local control systems.

A major function of the instrumentation used in the substations is to support the control functions objectives. Another is to provide information for post mortem analysis in case there is a problem.

## 5.2 *Task Description*

This chapter enumerates critical and significant test cases for control functions. It is not readily apparent that these test cases can be as clearly defined as the protective functions. However, control functions are clearly dependent on a series of parameters to either enable or disable the specific function. It was felt that flow diagrams of various specific control functions might be an appropriate means of defining these parameters. In the case of high speed reclosing a check may be made to ensure that the pressure of an air blast breaker would be sufficient to retrip the

breaker if in reclosing it closes into a fault. Some of the pressure switches on these circuit breakers have been known to momentarily open (bobble) during the opening stroke even though there is sufficient pressure to enable a retrip. A significant test case in such a control circuit may be to determine the effect of the "bobble" on the reclosing sequence. Towards this end, flow charts, a single line diagram, a textual description, and where appropriate a timing diagram for the following control functions have been prepared and are included in this chapter.

- (a) Automatic Reclosing
- (b) Breaker Failure
- (c) Capacitor Bank Control
- (d) Motor Operated Air Break Switch Control
- (e) Single-Phase Pole Trip and Reclose
- (f) Phase Angle Regulator Control
- (g) Protection Against Accidental Energization of a  
Generator on Turning Gear
- (h) Bus Switchover
- (i) Bus Switching
- (j) SVC Voltage Control

#### 5.2.1 Fallback and Recovery Considerations

All control systems are built to handle a number of disturbances from external as well as internal sources. The system must be able to recover from these disturbances but in a safe and properly selective manner.

Assume a supervisory control system for a substation with local control and remote control options. Upon power up, it is necessary to have a method of establishing what devices are under local control, which ones are under remote control, which ones are prohibited from being operated because of some tags or lockout conditions, etc. An initialization routine which involves communication with operators, other computers with an up to date data base, default assumptions, or combinations of these may be needed. One may make the assumption that all breakers in the open position are locked out, all disconnects in the open position are tagged, etc. until the correct operating mode for these devices has been established. Assuming that the system goes through this initialization, it may be ordered to go into an operating mode.

There may be many different operating modes. Each one of these has its own specific fallback conditions. As an example, in the operating mode, the communication link to the remote control point may be lost. In this condition, the fallback may be to do nothing or to allow local control of all devices or systems.

Assume that there is a voltage control of all devices or systems. Assume that there is a voltage control routine that normally would get voltage control setpoints from the remote system. Without the setpoints, the local control loop may rely on a voltage profile depending on time of day or revert to minimizing reactive power flows within voltage limits and leave the voltage control task to adjacent stations. When the communication link is restored there may be an automatic resumption of the voltage control function but one must be careful not to bump the system if there is a large deviation between the local control point and the one received from the remote control system. A bumpless transfer may be programmed in for a soft recovery.

The test mode can be of different types depending on the function to be tested. It may be possible to test a line protection function while leaving the reporting function in an operating mode. This will allow for reporting of test results but the systems receiving the reports must know not to use the reports for any operating decision. The test mode may permit or inhibit outputs to controlled devices. Hence, the test of a protection function may allow for tripping of the breakers or it may inhibit the breaker trip as required for the test. It is equally clear that all test commands that may have been queued for output are erased before one allows a transition to an operating mode or test mode with outputs enabled. This has to be programmed into the system.

Power loss, either to the controller or to its input/output circuits is a frequently overlooked event. If the inputs are not readable because of loss of power to the inputs, this should not lead to any false operations of the system. Note that some operations may be required in this condition. Assuming that the outputs are functioning, an alarm output is an obvious one but it may also be necessary to allow setpoints to go to a default value or to be frozen at the present value. If the power to the output circuits is lost, the outputs should fail in a safe mode. One would not normally want to trip all of the breakers for a loss of control power but it may be desirable to freeze the setpoints in some nonvolatile memory. If the controller fails, it may be desirable to maintain the known state of the system in a nonvolatile memory to facilitate recovery. Some failsafe output such as a watchdog timer should be giving an output (e.g. close a contact) to report the failure through independent channels.

Recovery from power failure may be more intricate than the fallback. If there is a short glitch in the power supply, it would be desirable to allow the system to go right back to where it was operating. However, to allow for this, some measure of duration of the disturbance is needed. Lacking this, one has to assume

## Appendix II

### Programs for Sampling Frequency Conversion

## 6.0 UNIFORM METHOD FOR FAULT DATA EXCHANGE

### 6.1 *Introduction and Task Organization*

This section suggests a procedure for exchanging fault data between individual researchers and organization. The data to be transferred could be recorded from system faults, from laboratory experiments or simulated in computer programs. The objective is to suggest means that are commonly available to power system engineers for exchanging data. The availability of exchange mediums, types or files and organization of files are examined. A sample data file is also included.

The data is sampled at a selected rate. When the data is to be transferred to another person, two situations can arise. In the first situation, the recipient needs data sampled at the rate used at the time of acquiring it. The second situation (that will arise more often) requires that the data must have been sampled at a rate other than the rate used during sampling. This would require that the data be converted from one sampling rate to another. This subject is also addressed in this section.

### 6.2 *Exchange Medium*

Electric power utilities record fault data for post fault analysis, for determining the nature and location of the fault, and keeping the records for future use. The mediums generally used for keeping the data permanently are recording oscillographs and magnetic tapes in conjunction with computers. The oscillographs record voltage and current waveforms that can be examined and analyzed. The digital computers cannot record voltage and current waveforms. The voltages and currents are, therefore, digitized before recording on magnetic tapes with the aid of computers. More recently personal computers have been used to record fault data on diskettes and cassettes.

It is not convenient to transport magnetic tapes between utilities and individuals users. This is especially true if the users are separated by large distances located in different countries. Also the recipient of a magnetic tape must have a computer system compatible with the system on which the tape was prepared. Cassette tapes are more convenient to transport than the magnetic tapes. However, recording on and reading from cassettes are slow processes.

The most commonly used computer systems today are the personal computers equipped with drives for diskettes. Double-density double-sided diskettes can store approximately 360k bytes of text and data. High density diskettes with 1.2 Mbytes of text and data may also be used to store test data. They can be easily

placed in padded envelopes and sent by mail. Because of their wide use and the convenience with which they can be sent from one location to another by mail, the working group decided to recommend that diskettes be used for exchanging fault data. However, individuals exchanging data may use other mutually agreed mediums.

### *6.3 Files*

Computer files can be classified into several categories, such as, text files, command files, executable files, assembly language files and data files. The text files and data files are of interest for exchanging data; text files for exchanging system information, such as, time of the day on which the data was recorded, line parameters etc. The data files are suitable for recording the instantaneous values of the voltages and currents, and outputs of relays and communication channels.

The data files can be written as sequential files or random access files. Random access files are written in a packed binary format and, therefore, take less space than the space taken by sequential files for recording the same data. However, to write and use a random access file the user must have computer programs compatible with the programs used to record the sequential file. On the other hand, the writing and reading of sequential files is straight forward and requires fewer program steps.

A file of data from a power system fault contains numerals representing voltages and currents experienced at a selected location in the system. The user must receive system information to enable proper use of the data. This information can be provided in a separate document but separate description sheets can be lost, misplaced or can be considered to belong to files other than they were originally intended for. It is, therefore, advisable to include the description of a fault case on the medium on which the data is written. The description could be in the form of a header file that should precede the data file.

Files can be written in several codes. The use of ASCII would be easy to interpret and use, compared to binary or HEX files. Most software packages available for personal computer systems provide ASCII files and can interpret ASCII files. The working group, therefore, decided to recommend that data files prepared for exchanging information on system faults be prepared in ASCII.

The discussion presented in this section led the Working Group to conclude that:

1. data files be prepared in ASCII code.
2. data files be recorded on double-density and preferably double-sided

diskettes used for personal computers.

Since the IBM and IBM compatible computers are very often used by utility engineers, the working group recommends that:

3. an IBM PC (personal computer) or a computer compatible with the PC's be used for preparing data files.
4. MS DOS or PC DOS version 2 or higher be used for this purpose.
5. each data set be recorded in two files: the header file and the data file. The outline of the header and data files are suggested in the next section.

#### 6.4 *Organization of a Data File*

As outlined in the last section, information concerning each data set be recorded in two files, one containing the HEADER and the other containing the DATA. The organization of the header file is described first in this section. The organization of the data file is then suggested.

##### 6.4.1 The Header File:

The header should contain sufficient information for the user to interpret the system and the situation that provided the data contained in the corresponding data file. It is recommended that at least the following information be included in the header file.

1. The description should include information on the system and the operating conditions that existed just before the disturbance was experienced. The system information should include:
  - the name of the generating station or the substation at which the data was recorded.
  - the identity of the line, transformer, reactor, capacitor, or circuit breaker that experienced the fault.
  - the parameters of the system elements, such as the length of a faulted line, its positive and zero sequence resistances, reactances and capacitances, mutual coupling with parallel lines, and the locations and ratings of shunt reactors and series capacitors. In case of transformers, the nominal voltage ratings of its windings, their power ratings and the winding connections should be indicated.
  - the parameters of the system behind the nodes where the data was recorded, such as, the equivalent positive and zero sequence impedances of the sources.

- the operating conditions (such as, the real and reactive power flows at both nodes of a line before experiencing the fault) that existed just before the fault.
- the type of the fault, and resistance of the fault be specified.
- the time and date of recording the data.
- a single line diagram on a separate page be provided with the diskette.
- details of instrument transformers used for producing test data.

If a utility intends to keep any part of this information confidential, the information may be omitted from the header and a statement to this effect be included in the header.

2. The rate at which the data was sampled.

3. Classification of the data.

- It should be recorded how the data was obtained. For example, if the data was recorded at a utility substation, this should be stated; or if the data was prepared by simulating a system condition on a computer program, such as the EMTP, it should be identified as such.

4. Particulars of the antialiasing filters used.

Most digital devices used in power system protection and control use anti-aliasing analog filters. The particulars of the filters should be provided. This information could be in the form of a transfer function or frequency response.

5. Particulars of the mimic circuit, if used.

Some digital devices use analog mimic circuits for the purpose of, say, filtering the decaying dc components of currents. The purpose for which the mimic circuit was used should be specified and the transfer function of the mimic circuit should be included in the header.

6. Format in which the data is recorded.

It should be indicated if the data is recorded in the floating point format or the interger format. The working group recommends the use of the interger format.

7. Headings of the columns of the data table.

The data should be recorded in a table consisting of columns. The identity of each column should be included in the heading of the column. For example, the classification of the data in a column could be Phase A voltage, Phase A current etc. The real time of recording each row of data should be included in a column of the data table but the time skew of recording each data set be indicated in the header.

The scaling factors, such as, Volts per digit and Amps per digit for the data recorded in each column, should also be included in the heading.

#### 6.4.2 The Data File:

After considerable discussion the working group decided to recommend that the data be recorded in columns. The first column should be the serial number of the data set in that row. The second column should contain the real times at which the data were recorded. The third and remaining columns should contain data representing voltages, currents, status of switches, communication channels, etc.

It is quite conceivable that a value may be omitted while recording a data set. For proper use of the data, such incidents must be identified. Since the records would consist of numerical values, it would be advantageous to use a pre-specified value to represent missing data. A large number could be used for this purpose. For example, if the data is recorded in the floating point format, a missing data should be recorded as 0.9 E+99. If the data is recorded in the integer format of six digits, a missing value should be recorded as +999999.

#### *6.5 Preparing Data Medium*

Each fault data should be written on a medium, such as a diskette, as proposed in this section. A data set should consist of two parts, the header written in the alphanumeric code and the data written as numerals in the floating point or integer format. The header and data should be in two separate files.

The header file can be written using a word processing program, such as PC Write, Microsoft Word, etc. or using the EDLIN commands. Some word processing programs automatically include document format information at the start of the document. The format line can be deleted using the EDLIN program of the MS DOS. Some word processing programs, such as, Leading Edge, Symphony etc do not write files in ASCII. They can, however, be used to export the files on to a diskette in the ASCII format.

#### *6.6 Example Files*

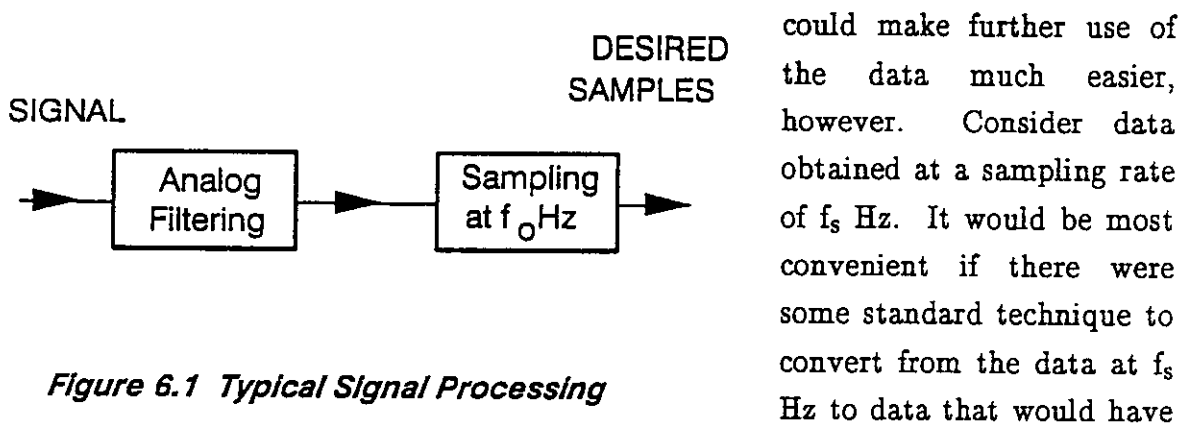
Sample files that contain data recorded by the Saskatchewan Power Corporation, Regina, Canada is given in Appendix IV as a sample for demonstrating the proposed data exchange format.

#### *6.7 Data Conversion for Different Sampling Rates*

The section is concerned with issues of sampling rates, filtering etc. in shared

data of standard test cases. Since it is difficult to anticipate all the future uses of such standard test cases (future algorithms, architectures, microprocessors) it seems clear that high accuracy and high sampling rates are desirable in the test cases. That is, although many existing digital relays use 12-bit accuracy, 16-bit or higher resolution A/D converters may be used in the near future. The sampling rate issue is similar. Samples obtained at a sampling frequency of 240 Hz, for example, must be obtained using a filter with a cut-off frequency of 120 Hz to avoid aliasing. It is straight forward to convert these samples to samples at higher sampling frequencies but the effect of the antialiasing filter cannot be removed. That is, it is possible to obtain equivalent samples at 960 Hz of the output of the 120 Hz anti-aliasing filter but it is not possible to obtain samples at 960 Hz of the original (unfiltered) signal.

It is therefore recommended that the original samples be obtained (after a proper anti-aliasing filter if it is necessary) at as high an accuracy and at as high a sampling rate as possible in a given installation. Specific choices of sampling rates



**Figure 6.1 Typical Signal Processing**

been obtained by the user's proposed system shown in Figure 6.1.

Recent developments in digital signal processing present an efficient solution to the problem if there are integers  $L$  and  $M$  such that

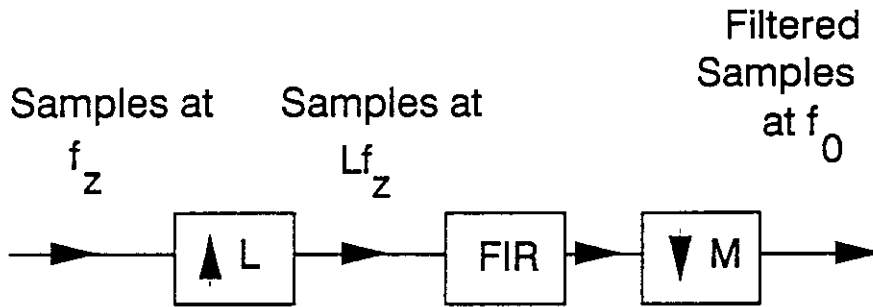
$$Lf_s = Mf_0 = f_{LCM} \quad (6.1)$$

where  $f_{LCM}$  represents the least common multiple. The solution is shown in Figure 6.2.

The box labeled FIR in Figure 6.2 is a finite impulse response equivalent of the analog filter shown in Figure 6.1 at a sampling rate of  $L f_s$  Hz. Equation (6.1) is the key to the solution and limits sampling rates to some extent.

The process of converting from samples at the frequency  $f_s$  to samples at frequency  $f_0$  is to first determine the frequency  $f_{LCM}$  such that (6.1) is satisfied, to provide a FIR (finite impulse response) description of the desired analog filter, and to implement Figure 6.2. The FIR description of the analog filter is a table of numbers corresponding to a digital filter description at the sampling frequency  $f_{LCM}$ .

A standard technique for the FIR design might be to use an impulse equivalent

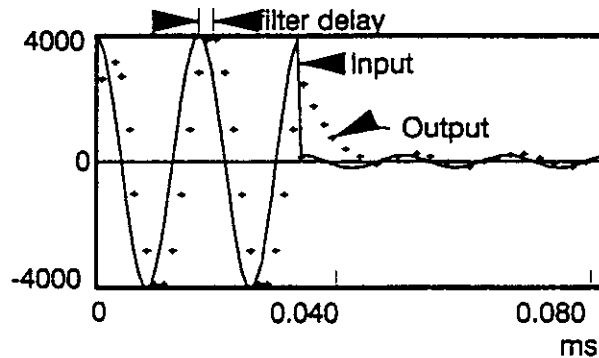


filter where the  $n^{\text{th}}$  entry in the table was the impulse response of the analog filter at the  $n^{\text{th}}$  sample time. Other FIR filter design

**Figure 6.2 DSP Solution**

programs are available in [1] along with a program which implements Figure 6.2. The transient response of the FIR filter at the beginning of the data must also be considered. If the FIR duration is a cycle then an additional cycle of pre-fault data should be included in the standard cases. Two cycles of pre-fault data should be adequate for all

reasonable cases. Artificial pre-fault data can be supplied if it is not present. The FORTRAN program CONVERT (Appendix II) is an implementation of Figure 6.2 which is an alternate to



**Figure 6.3 Example of Sample Rate Conversion**

the program in section 8.2 of [1]. The program is an illustration of the impulse invariant FIR filter for a second order low pass filter. Figure 6.3 shows the output samples at 720 Hz. with an input sampled at 4320 Hz.

A further simplification would result if a single  $f_{LCM}$  were specified. The simplification would be that the user would have to specify a single FIR representation of the desired analog filtering at the specified  $f_{LCM}$ . Unfortunately, a single  $f_{LCM}$  which will satisfy all the sampling rates known to the Working Group would be so large as to make the description of an FIR filter unwieldy. A solution is to use two different common multiple frequencies  $f_{LCM}^1$  and  $f_{LCM}^2$ . Each frequency would produce a short list of sampling frequencies corresponding to an integer

number of samples per cycle at the nominal power system frequency. Conversions between frequencies in a single list would be particularly simple. Conversions between frequencies that are not in a single list would require that the user determine the appropriate  $f_{\text{LCM}}$  for the application and then follow the same procedure. The two lists of recommended sampling frequencies are shown in Table 6.1 for both 50 Hz and 60 Hz fundamental frequencies. It is assumed that the sampling frequencies are independent of the actual power system frequency and that the columns "samples per cycle" in Table 6.1 are interpreted as the number of samples per cycle at the nominal power system frequency of 50 or 60 Hz. *The higher sampling frequencies in Table 6.1 are artifacts of the technique of sampling rate conversion and data sharing. It is not intended that the high sampling rates be used to capture traveling wave phenomena. The Working Group assumes that the lower frequencies in Table 6.1 will be the norm.*

The preceding is based on the assumption that the original data consists of the samples taken directly after a properly designed anti-aliasing filter. The possibility that the data to be shared has been processed digitally must also be considered. If the digital processing can be represented as a linear shift-invariant operation that preserves the original sampling rate of  $f_s$  Hz then it is straight forward to invert the digital processing. As an example, let the original samples be the sequence  $x(n)$  and assume that the average over the first four samples is used to produce the sequence  $y(n)$ , i.e.,

$$y(n) = \frac{1}{4} [x(n) + x(n-1) + x(n-2) + x(n-3)] \quad (6.2)$$

Given the sequence  $y(n)$  it is possible to recover  $x(n)$  with

$$x(n) = 4y(n) - x(n-1) - x(n-2) - x(n-3) \quad (6.3)$$

A more serious problem is encountered if decimation is involved in the digital processing. (i.e. samples are eliminated and data at a lower sampling rate produced). In the previous example this might correspond to sharing only every fourth sample of  $y(n)$  to form

$$z(n) = y(4n) \quad (6.4)$$

There is a program in [1] for least squares interpolation, i.e., to recover the missing samples from the sequence  $y(n)$ . It assumes however, that the sequence  $y(n)$  is band limited to a bandwidth consistent with the lower sampling rate. If the digital filtering has effectively reduced the bandwidth then the interpolation should be successful. The digital filtering (averaging) provided by equation (6.4) may in fact be acceptable; and in time-critical applications may be the only practical technique that can be used. In the absence of appropriate digital filtering however, decimation

introduces aliasing. In the previous example if every fourth sample of the original sequence  $x(n)$  is retained this corresponds to sampling the original signal at  $f_s/4$  Hz but with an anti-aliasing filter with too large a bandwidth. The nonfundamental frequencies present in the waveforms will be distorted by this aliasing. It is recommended that decimation be avoided if possible and only used after appropriate analog or digital filtering.

Table 6.1A Frequencies Corresponding to f <sub>LCM</sub> = 384 samples/cycle		
samples/cycle	f for 60 Hz.	f for 50 Hz.
384	23040	19200
192	11520	9600
128	7680	6400
96	5760	4800
64	3840	3200
48	2880	2400
32	1920	1600
24	1440	1200
16	960	800
12	720	600
8	480	400
6	360	300
4	240	200

Table 6.1B Frequencies Corresponding to f <sub>LCM</sub> = 3200 samples/cycle		
samples/cycle	f for 60 Hz.	f for 50 Hz.
3200	192000	160000
1600	96000	80000
800	48000	40000
640	38400	32000
400	24000	20000
320	19200	16000
200	12000	10000
160	9600	8000
128	7680	6400
100	6000	5000
80	4800	4000
64	3840	3200
50	3000	2500
40	2400	2000
32	1920	1600
20	1200	1000
16	960	800
10	600	500
8	480	400
4	240	200

## 7.0 PROPOSED STANDARD ENGINEERING DIALOG FOR PROTECTION

### 7.1 *Introduction and Task Organization*

This task proposes to develop a standardized engineering dialog language (EDL) to be used by protection engineers for entering settings into digital protective relays. When developed and implemented, the settings data required and the procedure for entering them will be identical among all protective relays that conform to the established language. As a result, the protection engineer will need to be familiar with and exercise only one method for setting all relays since the type or manufacturer of the relay becomes transparent to the settings process.

The ultimate objective would be to develop standard EDL for all protection functions. This is an ambitious goal. The Working Group does not plan to provide such a complete system. Rather, the intention is to provide sample dialogs for a few protection tasks, which may serve as a starting point for the development of a standard EDL in the future. The section below summarizes our development of an EDL for transmission line relaying. It should be realized that this is one of the most complex tasks to standardize, and consequently a success with this task is an encouraging development for future progress in this field.

#### 7.1.1 Steps to a Standardized Engineering Dialog Language

To initiate this task, Group 34.01 limited the language development to a digital line protection system. Specifically, the system contains and is limited to the functions listed in Table VII.1. The proposed steps to a standardized engineering dialogue are shown in Figure 7.1.

As a first step, each participating developer of digital line protection systems listed all the settings required by their digital line relays for the functions listed in Table VII.1. These lists are given in Appendix V. The lists were then simplified to a basic list of setting variables from which any setting listed in Appendix V may be obtained, directly or by derivation. The resulting simplified list is given in Table VII.2. This list of settings in Table VII.2 constitutes the STANDARDIZED LIST OF SETTINGS PARAMETERS. It is recognized that individual implementation of the digital relays may require special settings unique to that implementation; this would result in an additional settings list supplementary to Table VII.2. From Table VII.2 and the supplementary list, each manufacturer could satisfy his settings requirements for his implementation of Table VII.1 functions either by direct use of the information or by derivation from them.

**TABLE VII.1**  
**LIST OF LINE PROTECTION FUNCTIONS CONSIDERED FOR**  
**ENGINEERING DIALOG STANDARDIZATION STUDY**

- A. Phase and Ground Distance Protection for several zones (EPRI Westinghouse has three, AEP and EPRI-General Electric has two);
- B. Phase and Ground Pilot Protection using directional comparison blocking and unblocking, permissive overreaching and underreaching transfer trip, and hybrid schemes;
- C. Line Pick-up Protection;
- D. High-Set Phase Overcurrent Direct Trip;
- E. High-Set Ground Overcurrent Direct Trip;
- F. Fault Location.

Given the minimum settings data, the next step to the language standardization is the development of STANDARDIZED PROCEDURES FOR ENTERING/READING SETTINGS. This includes both the process of entering settings data into the relay and the process of reading the data back. As a first attempt to this language development, it was initially assumed the use of a CRT ASCII type interface for entering and reading the data into the protective relay. Consideration is also given to special dedicated types of MMI (Man-Machine Interface) such as those implemented in the EPRI-Westinghouse stand-alone digital line terminal and the hard-copy type ASCII terminal provided with the EPRI-General Electric stand-alone digital line terminal.

As shown on Figure 7.1, the items boxed in bold borders, STANDARDIZED LIST OF SETTINGS PARAMETERS (Table VII.1) and STANDARDIZED PROCEDURES FOR ENTERING/READING SETTINGS (Figures 7.2 and 7.3), are the main output of this task.

*7.2 Proposed Settings Procedures*

Given the minimum settings data, the proposed procedures for entering and reading the data are shown on Figures 7.2 and 7.3 respectively.

7.2.1 Entering Settings Data:

Figure 7.2 is a flow diagram of the procedure for entering settings into the

# Steps to a Standardized Engineering Dialog

FOR THE PROTECTION FUNCTIONS LISTED IN TABLE I,  
EACH MANUFACTURER WOULD HAVE A CORRESPONDING SETTINGS LIST  
(SEE APPENDIX)

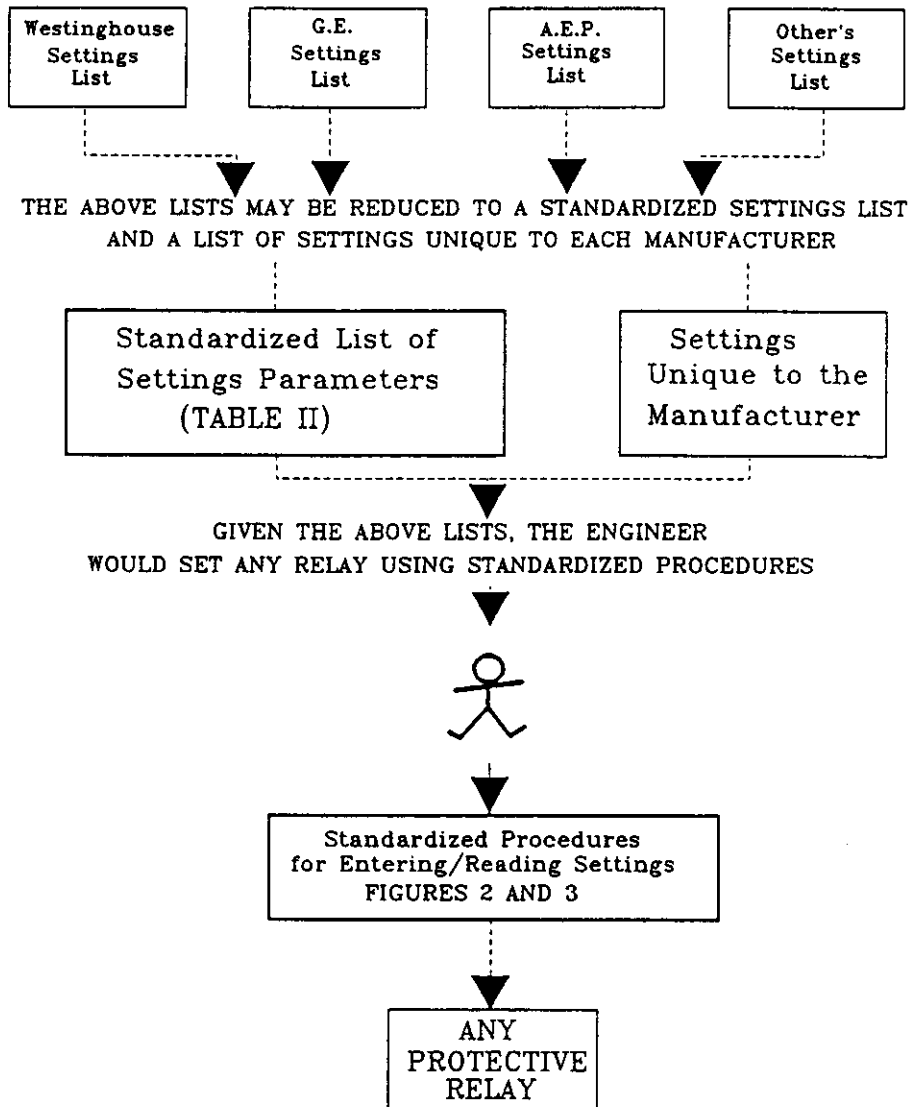


Figure 7.1  
Standard Engineering Dialog Language

relay system. This procedure is arrived at by some external selection process provided by the man-machine interface, such as a special function key for invoking the 'Enter Settings Data' man-machine interface function.

1. After the special function key 'Enter Settings Data' is depressed, the relay prompts for the setting name whose value the engineer may want to change.
2. The engineer enters a setting name from the list in Table VII.2. (The name may be a setting name unique to the relay and, therefore, is not included in minimum settings data list, Table VII.2. A supplementary settings list would then be provided by the manufacturer for settings unique to his protective relay.) Since we assumed the use of an ASCII terminal for entering the setting name, the engineer must provide a terminator (e.g. Carriage Return) to input the name.
3. The relay checks if the entered information is a correct settings name. If the setting name entered is valid, the sequence proceeds to step 7.
4. Else, if an invalid setting name is entered, the relay responds with an ERROR message.
5. On detecting an error, the relay must wait for the engineer's acknowledgement to assure his awareness of the error.
6. After acknowledging the error, relay queries the engineer whether he wishes to terminate the settings process or continue to select another setting to change. Selection to continue returns the user to step 1.
7. This step provides the engineer the facility to set a specific setting out of sequence from Table VII.2. It also provides an option to end the settings process through step 6.
8. If selected settings name is valid, the relay displays this name, the current setting, and waits for input.
9. At this point, the engineer has the opportunity to review the existing setting and either chooses not to alter the setting (in which case he keys in the terminator) or to enter a new setting followed by the terminator.
10. As in step 3, the relay checks for valid input by only accepting numerical input within the acceptable range for the particular setting.
- 11.,12.,13. Upon detecting an error in settings value, an identical ERROR display and ACKNOWLEDGEMENT sequence as described in steps 4, 5, and 6 is followed.

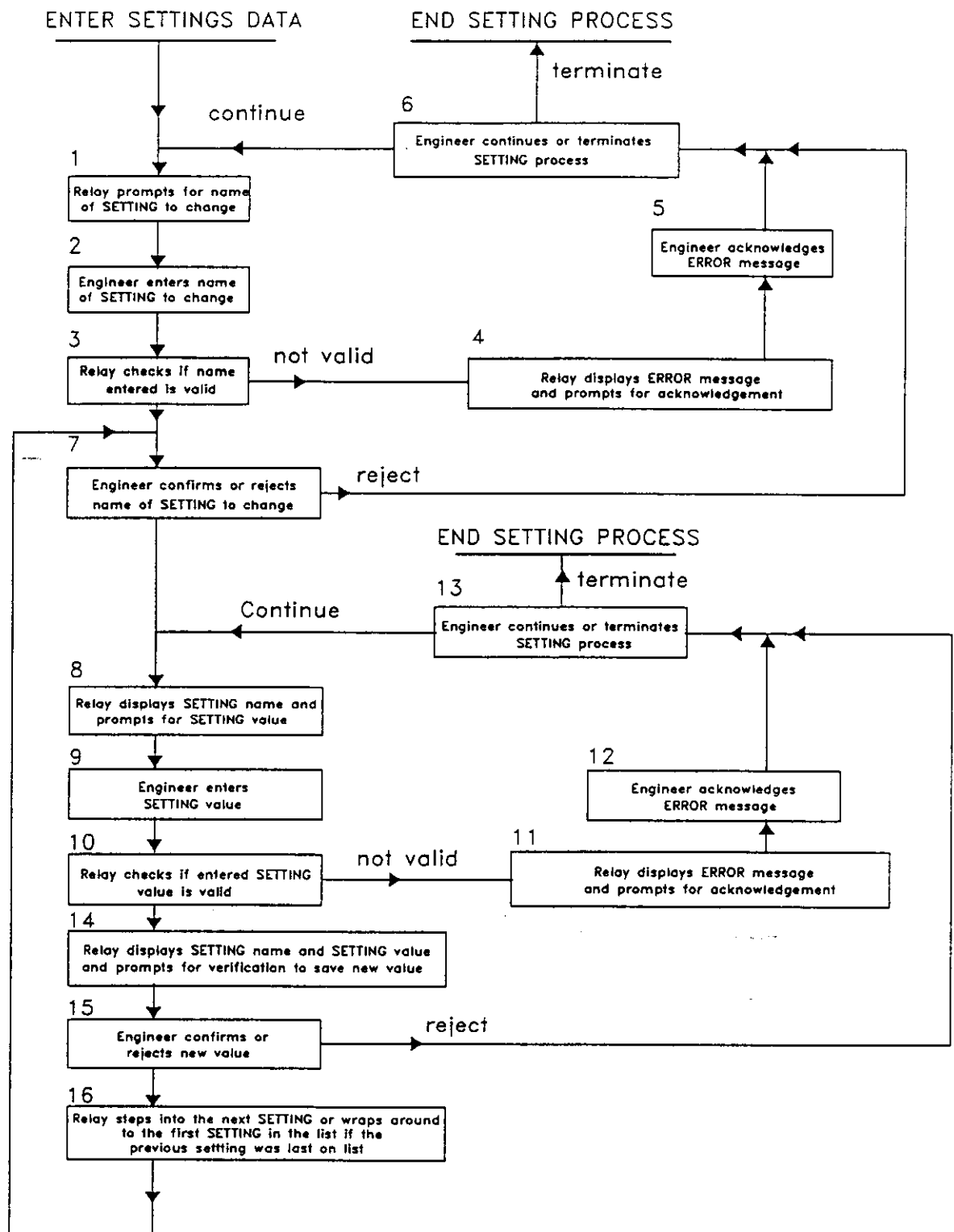


Figure 7.2

Standardized Procedure for Engineering Setting Data

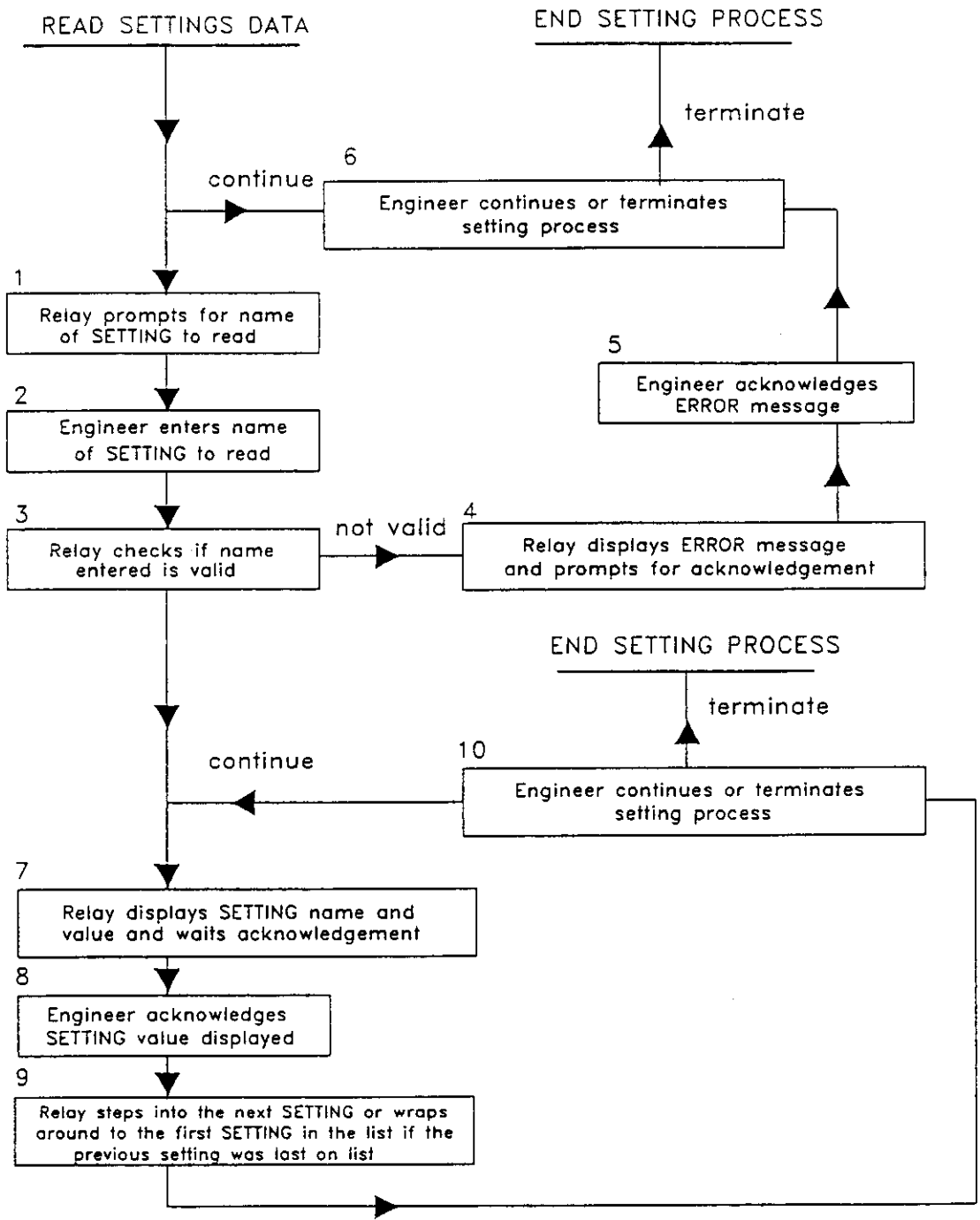


Figure 7.3  
Standardized Procedure for Reading Settings Data

TABLE VII.2

STANDARDIZED LIST OF SETTINGS PARAMETERS  
FOR DIGITAL LINE RELAYS

1. Line R1, X1, R0, X0
2. First Source R1, X1, R0, X0
3. Second Source R1, X1, R0, X0
4. Mutual Coupling R0, X0
5. R1, X1 for phase distance Zone 1 reach
6. R1, X1 for phase distance Zone 2 reach
7. R1, X1 for phase distance Zone 3 reach
8. R1, X1 for phase distance Reverse Blocking Zone
9. Maximum phase-to-phase resistance accommodation
10. R1, X1 for ground distance Zone 1 reach
11. R1, X1 for ground distance Zone 2 reach
12. R1, X1 for ground distance Zone 3 reach
13. R1, X1 for ground distance Reverse Blocking Zone
14. Maximum ground resistance accommodation
15. Zone 2 trip time delay
16. Zone 3 trip time delay
17. Pilot trip channel coordination time
18. Pilot blocking turn-off delay time
19. Line Pick-up delay time
20. Line Pick-up overcurrent trip level
21. Zone trip and Pilot trip phase overcurrent supervision level
22. High-Set Phase Direct Trip overcurrent level
23. Line Length
24. CT ratio (set equal to 1 if secondary impedances are used)
25. PT ratio (set equal to 1 if secondary impedances are used)
26. Ground distance carrier start overcurrent pick-up level
27. Ground distance carrier stop overcurrent pick-up level
28. High-Set Ground Direct Trip overcurrent level

14. If the settings value entered by the engineer is acceptable, the relay proceeds to display both the settings name and the entered value and prompts for verification to save the new value in the relay.
15. The engineer confirms (by simply inputting the terminator character) or rejects (by inputting a 'reject' code such as 'N' and followed by the terminator) the new value.

If the settings name and value displayed are not acceptable, the sequence reverts through steps 13 and 8 where a new value is requested for

the selected settings name.

16. If the settings name and value displayed are acceptable, the relay will assume that the engineer will want to input the setting value for the next setting by incrementing to the next setting parameter in the list (Table 7.2) and proceeding to step 7. If the value just accepted was for the last setting in the list (of Table 7.2), the program will wrap around to the first setting in the list.

#### 7.2.2 Read Settings Data:

This procedure is similar to the 'Enter Settings Data' and assumptions regarding range checking, terminator keys, etc. also apply. The flow diagram is self-explanatory.

This procedure merely provides the engineer a quick method to examine installed settings without going through many of the steps in the ENTER DATA SETTINGS process. It may be desirable to combine both Enter and Read procedures into one program.

#### *7.3 Standard Dialogs for Other Tasks*

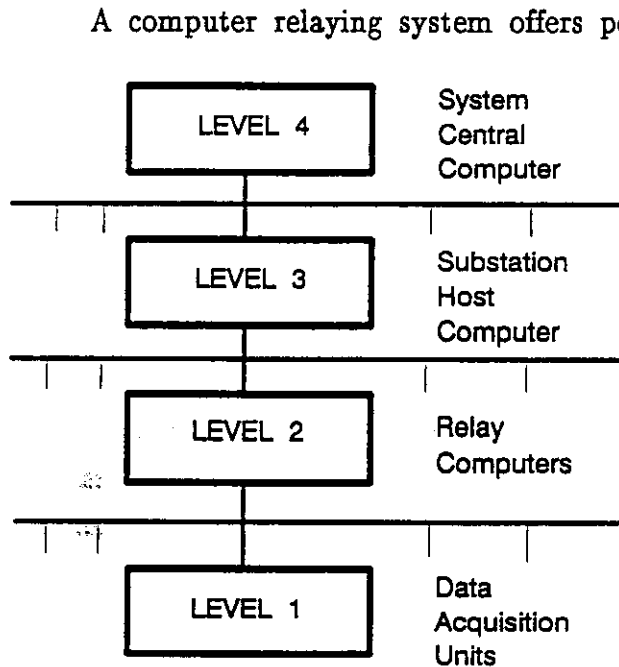
At this point, two major items that impact the development of a standardized language for relay setting have been presented for consideration: the MINIMUM SETTINGS DATA list and the PROCEDURES FOR ENTERING AND READING SETTINGS DATA. It should be apparent that if these two items were agreed upon by various developers of line relays, then the process of setting a digital line relay containing functions listed in Table 7.1 becomes uniform among all relays; i.e., a standardized language will have been developed.

It is the hope of the Working Group that through discussion among interested engineers, either this EDL proposal, or one developed from it, will become an industry standard.

## 8.0 PROTECTION AND SYSTEM-WIDE CONTROL

### 8.1. Organization of Hierarchical Systems

It is essential for the sake of reliability of protection that relays be able to perform their tasks independently, i.e. without any participation from other devices or relays. This is to assure that if any of these other devices fail, their failure does not affect the relay in question. It is realized that for economic reasons as well as for functional needs of certain relays, complete independence of a relay is not possible. It would be prohibitively expensive to have independent transducers, (CTs and CVTs), battery, or breaker trip coil for each relay. Similarly, functional dependence is built into some relays: a pilot relay depends upon the relay at the other end of a transmission line for its proper operation. It is thus an accepted fact that to a certain extent, existing protection systems consist of a hierarchy of equipment as well as of functions. The relay engineer designs maximum reliability into this hierarchical system.



**Figure 8.1 Functional Hierarchy of Substation Computer Systems**

stem from this ability to communicate and share data. Organization of a hierarchical system within the substation as well as on a system-wide basis to facilitate data sharing will be discussed in this section.

Functionally, one may identify four levels in the hierarchy (See Figure 8.1).

#### 8.1.1 Level 1: Data Acquisition Units:

These units obtain the sampled data from analog signals (voltages and currents), and status information of breakers, switches and alarm points in digital form. The Data Acquisition Units (DAU) may contain processors as subsystems [2] or may interface directly to Level 2 computers through their I/O ports [3]. In some cases, the DAU's may be installed in the substation yard, in which case they must be designed to withstand greater levels of electromagnetic interference and environmental stresses. Level 1 units must transmit data (such as signal samples) to level 2 computers at very high rates. Assuming an analog signal sampling rate of 20 times per cycle (only as an order of magnitude; the actual rates used may differ from this), a transmission line relay DAU may be called upon to transmit 3 voltage signals and 6 current signals assuming a breaker-and-half arrangement. If zero sequence current is also available as an analog quantity and if bus potential is also being read, the total number of analog samples per second becomes  $60 \times (3+6+1+1) \times 20 = 13200$  words per second. If each word consists of 16 bits, this is a transmission rate of 210 kilobits per second. This allows for no contact status inputs or communication protocol overhead, which may be accommodated by a factor of 2, and leads to a data transmission rate of about 400 kilobits per second.

Some level 1 units use fiber-optic links and multiplex data from several components in the switchyard [4]. The data rates then become proportionately higher. In many cases, this calls for direct access to computers at Level 2 through bus interfaces or Direct Memory Access (DMA) ports.

#### 8.1.2 Level 2: Protection Computers:

These are the relaying computers. Processing of acquired data from level 1 DAU's is done in real-time. The algorithms discussed in earlier chapters are executed at this level. The highest relay operating speeds of the order of a quarter cycle are possible, requiring instruction times of the order of 200 nanoseconds. In several implementations, multiple processors are used at this level [5], while others use single processors [6,7,8]. These computers, along with the appropriate DAU's form a single relaying function, and as such are designed to perform independently of any other computer within the hierarchy. It may be acceptable that the independent operation mode is not optimum for a given system condition, although it is adequate for the protection needs at hand. The optimum performance mode may depend upon other computers in the hierarchy. This will be discussed at greater length in the section dealing with Adaptive Protection.

The protection computers may also perform numerous other functions when fault-related tasks are not active. Measurement of current, voltage, and active and reactive power can be carried out. A later section will deal with the uses of these measurements for such applications as state estimation at control centers. Station oscillography can be performed by storing relevant waveform data for later processing. However, the frequency response of these recordings are limited by the sampling rate used in the relaying computer. The communication link to Level 3 computer (substation host) is a relatively low speed communication link as long as real time data for station protection functions is not involved. Serial links with data transmission rates of several kilobits per second are adequate. Through these links, the host computer can communicate control commands to the switchgear supervised by the relaying computer. The link may also be used for a user access terminal which may be connected to the host computer — one terminal serving the needs of the entire substation [9]. Alternatively, each relaying computer may be furnished with its own man-machine interface. The link to the substation host computer could also be used to communicate status change information of contacts, relays, switches and circuit breakers, so that a coordinated sequence-of-event log can be constructed in the substation host.

#### 8.1.3 Level 3: Substation Host Computer:

The substation host computer acts as a data concentrator, and as a conduit for communication between relaying computers and the system center. It handles all tasks requiring coordination of information from various relaying computers. This may include adaptive protection tasks, and construction of validated (partially processed) sequence-of-events records. Communication to lower level computers is local, i.e. within the control house. Communication to system control center is likely to be over a switched telephone network or over microwave links. In some systems [10] the host computer may be eliminated. Some of its tasks can then be absorbed by the relaying computers at the lower level, and by the central computer at the upper level.

#### 8.1.4 Level 4: System Center Computer:

This computer is primarily responsible for initiating supervisory control commands to be transmitted to the various substation host computers. It also collects measurements from substations which may be used for system-wide monitoring and contingency evaluation. As mentioned earlier, the primary mode of communication being considered at present is through a switched telephone network or over a microwave system. On the other hand, some of the functions being

considered for adaptive protection anticipate the use of high speed data links through fiber optic channels. The central computer is also responsible for keeping various historical records relating sequence-of-events, equipment health monitoring, maintenance schedules, system and component capability limits, etc.

## *8.2. Functions in an Integrated System*

Functions of an integrated system have been discussed in the context of various hierarchical levels in the previous section. These functions will now be described in greater detail and without regard to hierarchical level at which each function resides. It should be noted that these functions have been discussed by many researchers as the goals of an integrated system, although not all of these functions have been implemented in any given system.

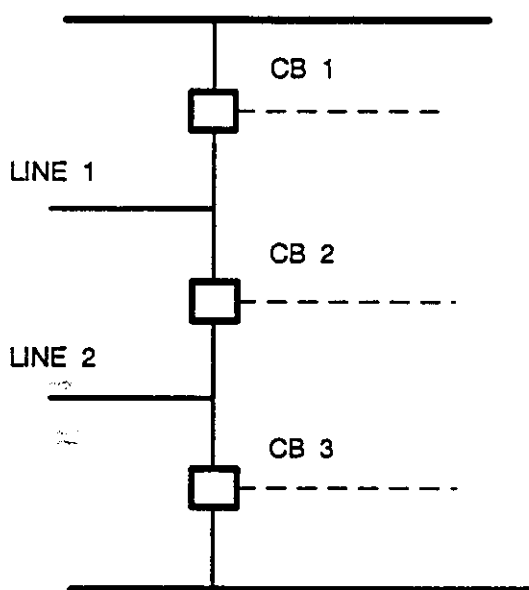
### 8.2.1 Protection:

Protection functions include the usual tasks associated with protection of equipment: transmission lines, transformers, buses, generators, capacitors, reactors etc. Both primary and back-up protection functions are included, as are the various timing functions, interlocks, fault detection, and other auxiliary functions. A significant part of the protection functions is the signal pre-processing required by digital relays. First among these is the anti-aliasing filter, which must cut off frequencies above half the sampling frequency used by the sampling system. The general practice is to use analog (R-C) filters with appropriate characteristics, [11] although data could be obtained at a much higher sampling rate and digitally processed to simulate the effect of analog anti-aliasing filters.

Back-up functions may be provided by computers that are physically distinct from the primary relaying computers. Perhaps one level of back-up may be justified in this manner. However, when a back-up is being provided through an alternate relaying principle — e.g. step distance being backed up by overcurrent relays or by directional comparison relays — it may be sufficient to provide these alternate relaying principles within the same hardware. Thus a functional back-up will be provided without the cost of additional hardware. Since the back-up functions are generally called upon to perform at times that are different from the operating times of primary relays, such a concept of shared hardware should not increase the computational burden on the relaying computer.

Another aspect of back-up relaying in a computer based protection system originates from the ability to share input data among processors. This could be accomplished in conventional relays with duplicate wiring of secondary leads and

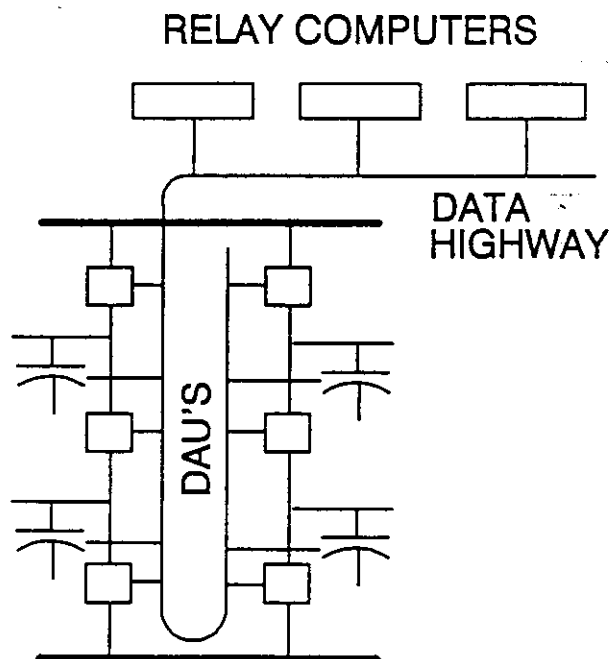
some form of switching arrangement for providing the back-up — neither of these practices are appealing in the relaying context. Consider a breaker-and-half



**Figure 8.2 Shared Inputs in a breaker-and-half scheme.**

arrangement shown in Figure 8.2. Since the current in CB2 is needed by relays of line 1 and line 2, it would be possible to bring in the CB2 current signal from its DAU and share it between the relaying computers for line 1 and line 2. If all three circuit breaker currents can be shared between the two computers, each one can be made to back-up the other in case of a failure. This leads to the ultimate in data sharing where all analog signals may be made available to all relaying computers in the substation. One of the suggested arrangements [12] calls for a

data highway upon which each DAU loads its own data samples with a proper identification tag. (See Figure 8.3) A scheme such as this would not be possible without a fiber-optic data highway because of the high data rate involved. Even then, there seem to be bottlenecks in handling the communication protocols and the related hardware at this time. However, this concept of back-up through programmed change-over with common data highway is sound and attractive; it may become practical in



**Figure 8.3 Data Highway for Shared Inputs**

the future.

### 8.2.2. Control:

Control functions in an integrated system may be divided into two categories: local control and central control. The local control functions need to respond quickly, and only locally available information is sufficient to determine what control action needs to be taken. This type of control is exercised in existing systems, and the only novel feature of an integrated system in this regard is the utilization of equipment and communication paths that are used for all other tasks. Thus all breaker control functions within a substation — high speed reclosing, automatic reclosing, synchronization checks, bus re-configuration etc. — are initiated through the host computer and are communicated to the appropriate circuit breakers through the relaying computers.

Several of the local control functions in use at present can be made more fitting to the prevailing system conditions with the availability of information from remote stations in an integrated control system. For example, the VAR control through capacitor switching may be based upon voltage information obtained from several buses in one area instead of depending upon local bus voltage magnitude alone. Bus re-configuration may also be influenced by the configuration of remote buses — or indeed of the entire system. Thus these control sequences need not be pre-determined to cover a wide range of system conditions — they can be made on the basis of prevailing system needs; and thus be more beneficial to the system as a whole.

The centrally directed control functions use system data as obtained from state-estimation. These functions will also benefit from the integrated computer system. The subject of dynamic and static state estimation and contingency analysis (and control) is covered in greater detail in a later section.

### 8.2.3. Diagnostics and Monitoring:

It is in the area of diagnostics and monitoring that an integrated control and protection system is expected to make its greatest contribution. First, the ability for self-diagnostic functions is an entirely new feature. It is true that to a certain extent existing protective devices can provide self diagnostic capability. However, the computer based devices can extend this ability to far greater heights. The relays can test themselves with respect to their ability to respond to external and internal faults of varying severity. This can be done through execution of pre-programmed test sequences from stored fault data. They can also be tested to check their behavior by re-playing saved data files of faults for which their response

is not as expected. This can be done from a remote location — or from within the substation. Thus periodic functional tests become possible with computer based systems.

The computer based devices can check for deterioration or outright failure of most of their subsystems. Thus Input—Output systems can be checked for linearity, offsets, phase shifts or catastrophic failures. These self—diagnostic functions can extend to signal conditioning units in the input and output circuits. In this fashion check the output diodes, even the continuity of the breaker trip coils, fuses in the input potential circuits, etc. Much of this type of testing implies additional equipment which may not be justifiable in many instances. However, the capability exists in the integrated system.

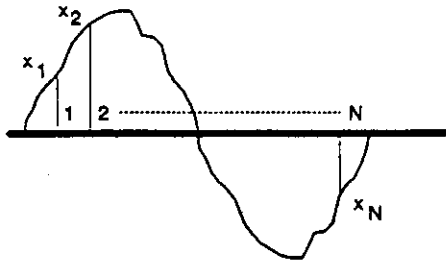
Integrity of the software can be checked by various techniques, such as the use of dead—man timers, and redundancy checks on program memory. The signal inputs can be checked for reasonableness: for example the currents around a bus could be checked for continuity; they could be checked for balance between phases. The voltages from all potential devices can be checked for equality for the same phases and balance between phases. Upon detection of an anomaly, an alarm would be logged, and in many instances a corrective strategy could be invoked to replace bad data.

The integrated system can also participate in monitoring the health of power apparatus. Severity of fault currents interrupted by a breaker could be used to determine its maintenance needs. The breakers could also be monitored for unusual arcing times or re— and pre—strikes. Transformer loading can be monitored and logged. Instances of through faults could be logged in order to assess the need for scheduling inspection of transformer windings and bracings. Negative sequence current distribution near a generating station could be monitored — both to identify the source of unbalance as well as for its cumulative effect on rotor heating. Operating times of primary relays, fault clearing times, reclosing relays, and back—up relays could be logged to check against their design values.

#### 8.2.4. Oscillography:

This capability of an integrated system is a by—product of its ability to store samples of analog quantities and status of contacts obtained at every sampling instant. A major limitation comes about from the relatively low sampling rates employed in present relaying algorithms, which require that analog signals be pre—filtered for limiting their frequency content to below a few hundred Hz. The oscillographs generated are thus unable to reproduce some system phenomena such

as switching surges, traveling waves or other high frequency components in voltages or currents. Even so, there is substantial information that can be obtained from the low frequency-response oscillography, and this may be adequate for most uses of oscillographs. With the steady improvement in the capability of microcomputers and A/D converters, it seems probable that the sampling rate in use in computer relaying may increase significantly. The frequency response limit on the



**Figure 8.4** *Sampled data from a non-sinusoidal waveform*

oscillography function in an integrated system may thus be eliminated in the near future.

It is of course understood that the oscillographs can be reproduced at the substations or at the center. Since no real-time data transfers are contemplated for this task, a modest data rate communication link would serve its needs adequately. Data

compression techniques could be used to transmit waveform information once they reach essentially steady-state values.

### 8.3. *Contributions to Central Monitoring and Protection Functions*

A relay is primarily a measuring instrument. All relaying capabilities of the device result from its ability to measure such system quantities as currents, voltages, frequency and power. An analog type of relay — a distance relay for example — may carry out the measurement in an indirect fashion: it may make a comparison at the zone boundary between the actual voltage-current signals, and the values these signals would take in the presence of a fault. On the other hand, with a few exceptions, the digital relays make true measurements of the input quantities — for example, an impedance relay actually measures the voltage and current phasors and then calculates their ratio in order to perform its function as an impedance relay.

As a measuring instrument, a computer relay has some unique properties. It is extremely reliable — high reliability is built into the protection system through various redundancies. The computer relay is free to perform measurement tasks almost all the time — fault related tasks occupy a minuscule (although a very important) fraction of its time. A measuring function is thus an ideal complement of the relaying function — the two tasks should be mutually exclusive functionally

— one should not be taking a measurement while a fault related transient is in progress, and conversely no relaying tasks should be active when the power system is in its normal quasi-steady state condition. The two tasks can coexist in a relaying computer as long as their relative priorities — higher for the protection function — are handled correctly.

The question of measurement accuracy needs some elaboration. A relaying measurement is not as accurate as obtained through a normal measurement channel. This is not a limitation of the hardware involved. Rather, it is related to the speed with which relaying measurements are obtained. The error made in a measurement is inversely proportional to the square root of the time period (data window) over which the measurement is obtained — provided that the errors in individual sample measurements conform to certain reasonable assumptions. This being the case, it is possible to obtain measurements of higher accuracy simply by waiting for a longer period. Thus a measurement made using a four-cycle data window has one fourth the error of a high speed relaying measurement made in a quarter cycle.

Errors made by instrument transformers are an integral part of the total error made by the phasor measurement system. However, these errors can be accounted for by using calibration curves stored in the measurement computer. There is some evidence that, as long as the burdens and transducers remain fixed, the calibrations will remain valid. Thus the transducer generated errors — significant though they may be — need not affect the accuracy of the final measurement.

### 8.3.1. Phasor and Frequency Measurements:

Before proceeding with the uses of measurements made by computer relays, it would be well to review the phasor calculation procedure from sampled data. It is assumed that an input analog signal has been sampled at a sampling frequency  $f_s$  where  $f_s$  is a multiple of the fundamental power system frequency. Typically,  $f_s$  is 4, 8, 12 or 16 times the power system frequency. The input analog signal is assumed to be band-limited to frequencies lower than  $1/2 f_s$  to avoid anti-aliasing errors. Although it is possible to achieve effective anti-aliasing filtering digitally by pre-processing data samples obtained at higher sampling rates, the most common procedure is to use analog type anti-aliasing errors.

If  $N$  samples of an input signal  $[x_k; k=1, \dots, N]$  are used in a phasor calculation, the phasor is given by

$$X = (AX_s + BX_c) + j(CX_s + DX_c) \quad (8.1)$$

where

$$X_s = \frac{2}{\sqrt{2N}} \sum_{k=1}^N x_k \sin k\theta \quad (8.2)$$

$$X_c = \frac{2}{\sqrt{2N}} \sum_{k=1}^N x_k \cos k\theta \quad (8.3)$$

and  $\theta$  is the sampling interval angle, with the understanding that the period of fundamental power system frequency is  $2\pi$  radians. A, B, C, D are constants which depend only on the data window specified by N. The factor  $\sqrt{2}$  is used to express the phasor as the rms value of the fundamental frequency component.

When the data window is a multiple of half cycle of the fundamental frequency, the constants A, B, C, D become particularly simple: (A = D = 1 and B = C = 0) [13]. The phasor calculation then becomes the familiar Discrete Fourier Transform relationship.

The phasor calculation is best handled recursively. As new samples become available, they are used to update the old phasor by the formula

$$X^{N+1} = X^N + K_{N+1} (x_{N+1} - x_1) \quad (8.4)$$

where the constant  $K_{N+1}$  is the complex number

$$K_{N+1} = \frac{2}{\sqrt{2N}} [\sin (N+1)\theta + j \cos (N+1)\theta]$$

if N spans a multiple of the fundamental frequency period. Although recursive formulas can be written for any data window, it is best to concentrate on the case of N being a multiple of fundamental frequency period for the measurement task. In relaying tasks, it is of course necessary to deal with fractional cycle data windows to achieve high speed of response to faults.

An alternate method of computing the phasor would be to measure the peak value of the input waveform, and find the location of the peak (or — equivalently, the location of zero-crossing) with respect to the instant at which the measurement is made. However, such a procedure is subject to uncertainties in determining the peak value and its location in the presence of non-fundamental frequency components.

In practice, the symmetrical components of three phase voltages and currents are far more useful than the phase quantities. Certainly all steady state analysis programs at a power system control center use positive sequence quantities and

system representation. It is a simple matter to calculate symmetrical components from the phasor representation of three phase quantities. For example, the positive sequence quantity  $X_1$  may be obtained from phasors  $X_a$ ,  $X_b$  and  $X_c$  (where  $X$  may stand for voltage or current)

$$X_1 = \frac{1}{2} [X_a + (\cos \frac{2\pi}{3} + j \sin \frac{2\pi}{3}) X_b + (\cos \frac{4\pi}{3} + j \sin \frac{4\pi}{3}) X_c] \quad (8.6)$$

When each of the phasors is calculated by a recursion relation such as equation (4), the positive sequence component can also be computed by a recursion relation:

$$\begin{aligned} X_1^{N+1} &= X_1^N + \frac{1\sqrt{2}}{3^N} K_{N+1}(x_{a,N+1} - x_{a,1}) \\ &+ \frac{1\sqrt{2}}{3^N} K_{N+1}(\cos \frac{2\pi}{3} + j \sin \frac{2\pi}{3})(x_{b,N+1} - x_{b,1}) \\ &+ \frac{1\sqrt{2}}{3^N} K_{N+1}(\cos \frac{4\pi}{3} + j \sin \frac{4\pi}{3})(x_{c,N+1} - x_{c,1}) \end{aligned} \quad (8.7)$$

If the sampling frequency  $f_s$  is a multiple of 3 times the fundamental power system frequency, the computation becomes even simpler, owing to the fact that the entire complex term multiplying the  $b$  and  $c$  phase quantities in equation (8.7) become one of the  $K_i$  with a different index. That is to say, the rotation for symmetrical component transformation falls at one of the sampling instants of the sampling process itself. For example, with a sampling rate of 12 times per cycle, the recursion relation (8.7) becomes

$$\begin{aligned} X_1^{12+1} &= X_1 + \frac{1}{18\sqrt{2}} \left[ K_1(x_{a,13} - x_{a,1}) \right. \\ &\quad \left. + K_9(x_{b,13} - x_{b,1}) \right. \\ &\quad \left. + K_5(x_{c,13} - x_{c,1}) \right] \end{aligned} \quad (8.8)$$

Recursion relations such as equations (8.4) or (8.7) have an interesting property: if the sampling frequency  $f_s$  is a fixed multiple of the fundamental power system frequency, the recursion formula gives a phasor which is stationary in the complex plane when the input signal is an unchanging sinusoid. If it is assumed that the sampling frequency remains constant while the power system frequency changes by  $\Delta f$ , the phasor calculated by the recursion relation begins to rotate in the complex plane with an angular velocity

$$\omega = 2 \pi \Delta f \quad (8.9)$$

Note that the direction of rotation depends upon the sign of  $\Delta f$ ; if the power system frequency is greater than its nominal value, the phasor rotates in a counter-clockwise direction.

An additional interesting fact [14] is that although equation (8.9) is an approximation for large  $\Delta f$  when a single phase quantity is measured, it becomes exact for any value of  $\Delta f$  if the phasor in question is the positive sequence phasor calculated according to equation (8.7). Equation (8.9) represents a frequency measurement technique of high precision and resolution. This is one of the measurements that a computer relay can furnish to a control center. Frequency measurements are also needed for such tasks as load shedding and restoration.

### 8.3.2. Synchronization of Sampling Clocks:

The reference for the phasor calculations of equations (8.1) and (8.4) is determined by the instant of sampling of the input signal. If several phasors are being computed, it is necessary to have simultaneous sampling for each of those input signals. In particular, the identity of samples at a given instant  $k$  must be established for each signal, so that the multipliers  $\sin k\theta$  and  $\cos k\theta$  are applied with an identical value of  $k$  for all signals. This requires that in addition to having synchronized sampling clocks, a special pulse must be provided to start the  $k$  counters in each phasor computation. When the signals being measured are all located within a substation, this task is relatively easy to perform.

It turns out that the phasor measurements from different substations could be very useful in power system control centers if they were all measured with respect to a common reference. As seen above, this requires synchronization of sampling pulses at different substations, as well as a technique for identifying a specific pulse. The synchronization should be within a small tolerance in order for the phasors to be accurate — in fact the synchronization error is directly convertible into phase angle error of the phasors. An uncertainty of one microsecond corresponds to a phase angle uncertainty of 0.021 degree for a 60 Hz system. Thus synchronization to within a few microseconds would be adequate as far as 60 Hz phasor measurements are concerned. An auxiliary pulse used to mark the next occurring synchronizing pulse may be used to provide the necessary pulse identification. The identifying pulse may be provided every few seconds — it need not be at a uniform rate, as long as it reaches each substation at the same instant.

Technically, synchronization of clock pulses at different substations to within a few microseconds is feasible. Where fiber optic links exist between the stations,

these can be used to transmit a synchronizing pulse from a master station. Sufficient band-width should be available so that the necessary pulse definition is maintained. In particular, this may rule out using part of the frame of a multiplexed fiber optic channel, and a dedicated fiber may be called for. Optical fiber installation can not be justified for synchronization purposes; however, if it is in place for some other reason, it makes for a very convenient synchronization channel.

Another alternative — which may be the best practical one until fiber optic links between substations become commonplace — is to install receivers for Global Positioning System (GPS) satellite transmissions. These highly accurate systems can provide one microsecond accuracy of synchronization at any location within the country. There is some evidence that the cost of satellite receivers for clock synchronization is about to go down significantly as their potential for use in several applications is realized.

Some experience in synchronizing clock pulses already exists [15,16]. It is expected that following field confirmation of some of these concepts, common reference phasor measurements will be obtainable from any substation where a computer based measuring device (or relay) is installed.

### 8.3.3. Static State Estimation:

This is the first major application of phasor measurement technique introduced through computer relaying in the context of power system control centers. [17,18,19] In order to determine the security of a power system in real time, it is necessary to determine its current state. State of a power system is formally described by its state vector — the collection of positive sequence phasor voltages at all buses of the system. A measurement system that measures positive sequence voltage phasors thus constitutes a state vector measurement system. It should be clear that these measurements should be a great asset to the state estimation process at power system control centers.

At present, the state estimation problem is solved by measuring those quantities that do not depend upon the clock synchronization described earlier. Such quantities are active and reactive power flows in lines and transformers ( $S_{pq}$ ), active and reactive power injections at buses ( $S_p$ ) and voltage magnitudes at buses ( $V_p$ ). From these measurements (denoted by the vector  $Z$ )

$$Z = (S_{pq}, S_p, V_p)^t \quad (8.10)$$

the complex voltage vector

$$E = [E_1, \dots, E_n]^t \quad (8.11)$$

is estimated iteratively by the method of weighted least squares (WLS). Assuming that the standard deviations ( $\sigma_s$ ) of all measurement errors are known, this iterative technique can be described by [20]

$$E^{k+1} = E^k + G^{-1}A [Z^m - Z^c] \quad (8.12)$$

where the gain matrix  $G$  and the matrix  $A$  depend upon the system structure, the standard deviations, and the presently assumed state  $E^k$  of the system.  $Z^m$  and  $Z^c$  are the measurement vector and the calculated measurement vector based upon the assumed state  $E^k$ . When  $E^{k+1}$  is sufficiently close to  $E^k$ , the state estimation is complete, and  $E^{k+1}$  is the WLS estimate in the presence of error-prone measurements with known error covariances.  $G^{-1}$  is not a literal inverse — it stands for a solution of linear algebraic equations. Various approximations of  $G$  and  $A$  may be used in order to obtain fast and computationally efficient algorithms.

The complex power flows serve to make the estimate robust, and help identify data that are bad — i.e. data which fall outside the assumed error description. It is customary to use polar coordinates (magnitude and phase angles) in this technique in order to take advantage of decoupling between active and reactive power measurements.

Now consider the phasor measurements. Assume that positive sequence currents and voltages are measured:

$$Z = (E, I)^t \quad (8.13)$$

The WLS estimate is then given by

$$E = G^{-1} A Z \quad (8.14)$$

where, as before,  $G^{-1}$  represents a linear equation solution process. In contrast to the earlier technique, this procedure is non-iterative.  $G$  and  $A$  are constants — it is not necessary to make any approximations. If some current measurements are missing,  $G$  and  $A$  may become complex (otherwise they are real) — but that is the worst that can happen. If no currents are measured,  $G^{-1}A$  become the identity matrix: the measured voltage phasors are the WLS estimates.

The current measurements help make the estimate robust. In a way, they are the counterpart of the line flow ( $S_{pq}$ ) measurements of the present state estimation algorithms.

Bad data techniques with phasor measurements are somewhat different. It is possible to check for bad data at each substation independently. Thus all the

relaying computers in one substation may contribute a voltage phasor measurement; an averaging and voting procedure can then be used to improve the accuracy of the voltage measurement and eliminate any bad voltage measurement that may exist. Currents around a bus may be checked for continuity, and their accuracy could also be improved by distributing the mismatch equally among the various currents. Bad data, when present, would cause suspicion to fall on all currents; and they could all be flagged as candidates for bad data when used in the state estimation procedure. A further attempt at bad data identification can be made on suspect current measurements by comparing the measurement with computed current flow from measured voltage phasors.

A unique bad data case arises when the synchronizing clock pulse is lost. Now all local checks show consistency, but every phasor is wrong by an additive phase angle error. This fact can be used to estimate the missing reference angle. These and some other considerations have been described in a recent paper [20].

In conclusion, phasor measurements make the static state estimation problem linear; their bad data detection and identification properties are unique and somewhat better than conventional techniques, and they permit spot installations of phasor measuring systems so that the state estimation procedures can be begun or expanded in a modular fashion.

#### 8.3.4. Dynamic Estimation and Control:

This section is far more speculative — certain ideas will be explored and discussed, although it should be understood that experimentation and field work remains to be done in order to implement concepts discussed here. On the other hand, no concept is put forward which does not have a sound basis in the existing state of technological development.

Consider the broad class of problems described by the term "stability related". It spans the time frame of a few seconds — when transient stability is the main concern — to several minutes where energy balance consideration begin to dominate. In this section attention is restricted to the short term problem of transient stability. The longer term phenomena are considered in the next section on adaptive protection.

As with all other security related tasks in a control center, on-line real-time security assessment of the power system is preferred whenever it is possible to handle the analytical and computational problems involved. Thus, on-line static state estimation and contingency analysis is much more preferable as compared to predictive studies performed in an off-line mode. In case of the quasi-steady state

operating mode and the related security analysis, it is the practice in most modern control centers to use static state-estimation (discussed earlier) and perform contingency evaluation in real-time.

Similar techniques have not been developed as yet for the transient stability problem. The difficulties are two-fold: the analytical problem of dynamic contingency analysis (i.e. predicting the outcome of transient stability oscillations of the system starting from a given state for many alternative disturbance scenarios) has not been solved except for some simple types of power systems. Secondly, the problem of determining the dynamic state of a power system in a short enough time frame has been hampered by the need for data collection and transmission from distant substations.

With the technique of synchronized phasor measurement described in the earlier sections, much progress can be made in this field of study. First of all, consider the issue of data volume required. It is no longer necessary to find the voltage phasor at the terminals of a generator with respect to some common system reference. If the phasor angle with respect to a remote bus (such as a load bus) is needed, it is sufficient to measure the two phasor voltages directly. These are the only quantities of interest needed for performing such a fragmented state estimation. Consequently, data volumes to be communicated to the center where analysis and control computations are to be performed is reduced to the minimum, and a consequent increase in speed of response to dynamic changes in the system can be achieved.

The speed of response with which phasors can be measured has already been remarked upon. Since accurate phasors can be measured in a few cycles (or even in a fraction of a cycle), it then becomes possible to model the dynamic processes in a generating station and estimate these dynamic state variables in real time. [21, 22]. Either the 'observer theory' or Kalman filtering approach can be utilized. In any case, it seems clear that with fast measurement of phasors and frequency reliable dynamic models of machines and their control systems can be constructed in real-time. Building such models is the first step in a dynamic contingency program.

The second step is that of dynamic contingency analysis starting with the model developed above. As mentioned previously, a great deal of analytical work remains to be done to solve this problem. About the only system for which the dynamic contingency problem can be handled adequately at present is that of a system consisting of two synchronous machines.

This seems overly restrictive; yet many practical system configurations approach this condition. For example, the behavior of a generating plant (single or multiple unit) connected to a large system comes under this category. Similarly, low capacity interconnections between two strong systems also exhibit modes of behaviour similar to a two machine system. At least for these two important classes of problems, equal area concepts can be used to predict the stability (or instability) resulting from transients. Assuming fast phasor measurement scheme and a dynamic state estimator, it would be feasible to predict the outcome of a transient swing in about one-quarter period of the ensuing electro-mechanical oscillation. Of course, a longer decision period would allow a greater certainty of prediction.

There are some dynamic controls which would benefit from such an advance knowledge of a dynamic condition. Out-of-step blocking or tripping function could be supervised from a central location. Other drastic actions — such as dynamic brakes or fast-valving — could be applied more intelligently for an incipient dynamic contingency. Other related control actions will be discussed further in the following section on Adaptive Protection.

#### 8.4. *Adaptive Protection:*

Protective relays have always been adaptive. A time overcurrent relay adapts to changing fault location. An impedance relay adapts to changing source impedance of the network behind the relay location. In fact, one could say that to be totally adaptable to changing system conditions in order to keep the efficacy of protection functions constant is an ideal of all protection system designs. Until the advent of computer based relays, it has been difficult to make a protective system meet this ideal.

Adaptive protection is just now beginning to be discussed in technical literature, and it would be difficult to give anything but a very brief overview of ideas under consideration.

There are many types of relay settings that are based upon assumed extremes in some aspect of a power system. For example, pick-up values of over-current relays may be based upon assumed maximum loading in a line. Backup zones of distance relays may be based upon assumed conditions of cross-feed at intervening buses. On multi-terminal lines, certain assumptions about the taps may be made in determining protective zone settings. Other examples of stability related functions — out-of-step blocking and tripping relay settings have already been mentioned. Similarly, load shedding and restoration relays are set based upon

expected rates of frequency decline and rise. In a sense, these settings are in the same predicament as the off-line contingency analysis programs at a power system control center. Although on the whole they provide an adequate protection for expected power system behavior, in actual operating environment the assumed conditions almost never come to pass. Therefore, in most cases the relay settings are coarse compromises which will provide reasonable security under actual operating conditions. As a matter of fact, in a few cases, the actual system contingencies may be so uncommon that they can not be anticipated in planning the protection system — and may, in the event, lead to over-tripping or false-tripping of certain relays. This would of course compound an already bad operating condition. It is clear that to obtain an adaptive capability, it is necessary to have access to information not currently available, but which can be made possible through the communication channels of a computer relay. Further, it must be accepted that communication channels may fail, and therefore all adaptive capabilities must be nullified in the event of loss of communication; the fall-back position being the present one of conventional relaying. Account must also be taken of the fact that not all relays in a protective system can be adaptive, thus the co-existence of adaptive and non-adaptive relays should not lead to a degraded level of performance. All these are matters that must be — and are being addressed in various research studies. [23]

Adaptive capabilities can be predicated upon three types of activities which utilize communication to distant locations.

- (a) Techniques Based Upon Status Information: This technique requires the least amount of information from remote locations — that of the status (open or close) of various switches and circuit breakers. The information is not needed in real-time — in other words, this technique continuously updates the base case upon which the relay settings may be predicated. It provides a continuous relevance to the relay settings — and no compromises about various contingency conditions need be made, in fact few contingencies need be considered, as the system state at any time is correctly known. The data transmission needs of techniques based upon status feed back are very modest.
- (b) Techniques based upon Real-time data: These techniques require the transmission of actual fault data in real-time. Both analog (converted to digital samples) and status information would be transmitted. Extremely sensitive relaying functions can be provided

if real-time data were available. However, the data rates required are very high, and in all likelihood would call for such wide band communication links as fiber-optic channels. Although a few such schemes have been tried on an experimental basis, this technique is perhaps a long term proposition, awaiting wide spread use of fiberoptic links.

- (c) Techniques based upon static and dynamic state estimation: These techniques would use static and dynamic contingency analysis results to update or supervise certain relaying functions. Substantial data acquisition and computational capabilities are necessary for these techniques, and it is to be expected that they will be developed in conjunction with advances being made in power system control center activities.

As mentioned earlier, research in the area of adaptive protection is just beginning. Communication links and integrated computer based protection and control functions are two key components of adaptive protection systems. One of the most challenging aspects of adaptive protection systems is that they must operate in conjunction with the existing protection equipment which is not adaptive, neither does it belong to the integrated system.

## 9.0 BIBLIOGRAPHY

### 9.1 *Introduction*

The Working group has attempted to continue the work begun by WG 34.02 of collecting bibliography and reference listings of all projects involving application of digital techniques in substations. Instead of restricting our attention solely to protection projects, we decided to include projects involving monitoring and control as well. It was felt, that in keeping the objectives of this working group, it would be of interest to consider all aspects of substation functions, so that one could judge the interplay between the requirements and attributes of these other tasks with those of the protection tasks. As in the past, we decided to give particular attention to projects in which actual implementation in hardware and field trials played a significant role.

Section 9.2 below deals with descriptions of various projects, while section 9.3 provides the bibliography.

### 9.2 *Project Descriptions*

Additions to Project 17, Current Differential Carrier Relaying System for EHV Lines

17.3 Where Installed – 14 Transmission Lines of Tokyo Electric Power Company

17.4 Type Installation 2 Field Demonstrations and 12 Operating Installations

17.5 Actual Duration of Field Experience

2 Field Demonstrations at 275kV (July 1966 – April 1968, October 1982 – October 1963)

1st Operating Installations at 500 kV – January 1961 to date

12 line year cumulative experience

Additions to Project 20, Ground Relaying with Countermeasure Zero-Phase-Sequence Circulating Current

20.2 Participating Companies

Tokyo Electric Power Company – Japan  
Chuba Electric Power Company – Japan  
Meidensha Electric Manufacturing Company – Japan

20.3 Where Installed

66kV Hakone Lines at Nishi-Sagami Sub (Field Experiment)  
77kV Lines at Kita-Gifu Sub (Field Experiment)

66kV Higashii-Izu Lines at Tagata Sub (operating)

Additions to Project 22, Directional Comparison Line Relaying

22.3 Where Installed

Kansai Electric Company, Inc.

- Kitakata Switching Station
- Osaka Switching Station (Temporary Operating Installation)
- Matsuoka Switching Station
- Komaki Hydro Power Station
- Ohara Hydro Power Station (Operating Installation)
- Togani Hydro Power Station

22.4 Type Installation

- Temporary Operating Installation
- Operating Installation

22.5 Actual Duration of Field Experience

- June 1980 - August 1981 (Temporary Operating Installation)
- April 1985 to date (Operating Installation)

22.6 Synopsis of Project

22.6.1 Temporary Operating Installation

A microprocessor-based system for a two terminal directional comparison relaying was developed and installed at terminals of 154kV resistance grounded transmission line for field trial.

The system at each terminal is composed of four microprocessors, two of which are for the primary protection by a directional comparison blocking scheme and two for back-up protection by phase distance and ground directional relaying. The algorithm based on the relationships of the phasor quantities and their phase angle comparison is utilized. The sampling frequency used is 240 Hz, comparable to 90° of the power frequency. These selections result in the rational software organization and the memory size reduction.

This system includes such functions as the self-monitoring and automatic self-test, event recording and fault locating. Compactness to less than a half of the conventional equipment, easier maintenance and higher reliability is realized.

The system encountered 66 cases of transmission line faults and operated correctly for all these cases, which proved the security and dependability of both the hardware and software of the digital relaying system. The actual application of digital relaying will be considered by this test result.

The prospect of technical trend also shows the economical and technical advantage of the adoption of digital relaying system.

## 22.6.2 Operating Installation

We have studied the practical use of this system to enrich the technical experience about maintenance, operation, treatment to the system failure, software management, etc. The practical system is composed of two digital relay units, one of which is for primary protection and another is for back-up protection. In each digital relay unit, main protective functions are calculated by a high speed microprocessor, and fail-safe protective functions are calculated by a single chip micro-computer.

### Additions to Project 26, Integrated Control Equipment

#### 26.3 Where Installed

SSPB 220/70kV substation (July 1983).  
SSPB 400/220kV substation (Dec. 1985).  
Two substations in Netherlands, 110kV and 50kV respectively (1985).

#### 26.4 Type Installation

- Operating pilot installation, and
- Regular operating installation, respectively.

#### 26.5 Actual Duration of Field Experience

Service experience since July 1983 and Dec. 1985, respectively.

#### 26.6 Synopsis of Project

In a continuation of the project a second substation was equipped with the integrated control equipment. It is a 400/220kV substation in the Swedish main power grid. The substation and control system is bigger than the first installation, whereas the functions are about the same. Operators control facilities in the substation are extended, RTU-function is more integrated. Two installations are made in Netherlands and further installations are in progress in Norway.

#### 26.7 Published Papers

1. A. Gustafsson, N. Stockman, A. Dafgard, L-G. Malmqvist, "New Type of Control System for Transmission Substations" SSPB R & D Report, Main Area 3, Report No. 8, Jan. 1983.
2. K. P. Lau, S. L. Nilsson, D. F. Koenig, E. A. Udren, B. J. Allquren, "Pros and Cons of Integrating Protection and Control in Transmission Substa- tions", IEEE 84 SM 638-3 (Last part).

### Project 34

#### 34.1 Project Name - Microprocessor Fault Locator

#### 34.2 Participating Companies

ASEA  
Swedish State Power Board  
Sydkraft

34.3 Where Installed

Sydkraft, Nybro, 140kV substation, Sweden  
Texas Power and Light Co., 138 kV substation, Northwest Carrollton  
Swedish State Power Board, Horred 400 kV substation, and numerous other installations

34.4 Type Installation

Sweden: Field testing  
Texas: Staged Fault testing  
Commercially available product

34.5 Actual Duration of Field Experience

Sweden: June 1982 to present date  
Texas: October 25, 1983 (staged fault)

34.6 Synopsis of Project

This fault locator provides location of internal faults on a transmission line, using local quantities (currents, voltages and breaker trip signal) only. Microprocessor-based techniques provide the means to reduce the effects that have previously caused inaccuracies: fault resistance, variations in load flow and variations in source impedance angles.

Analog signals are digitized and stored in a 6-cycle circular file. Continued updating occurs until the start (breaker trip) signal freezes the data for the distance-to-fault computation, which requires about one minute. To provide improved accuracy of computation, pre-fault load currents are subtracted from total current after the fault.

Extensive laboratory tests, including tests using a power system simulator, have been performed. These tests, along with field results which include staged faults tests, have resulted in a typical accuracy deviation of approximately  $\pm 1$  km. of line length.

34.7 Published Papers

L. Eriksson, M. M. Saha, G. D. Rockefeller, "An Accurate Fault Locator with Compensation for Apparent Reactance in the Fault Resistance Resulting from Remote-End Infeed", IEEE 84 SM 624-3.

PROJECT 35

35.1 Project Name - Microprocessor Underimpedance Starter

35.2 Participating Companies

ASEA

35.3 Where Installed

Numerous Installations

35.4 Type Installation

Field testing and operating installations; commercially available product.

35.5 Actual Duration of Field Experience

Extended period following 1984 installation

35.6 Synopsis of Project

All single-measuring-element distance relays that utilize selective analog inputs require a starter. This starter must be responsive to all internal faults and must selectively determine which phase/phases is/are involved. Since the starting function necessarily precedes the measuring function, the starter must be fast. On the other hand, the starter does not have to be zone-selective. That is, the starter is allowed to overreach the protected line, in both the forward and reverse directions.

Microprocessor-based techniques lend themselves to meeting the above requirements. Using a single-chip microprocessor, with analog signals samples at the rate of 8 samples per cycle, a 10–25 ms under-impedance starter has been developed. Laboratory and power system simulator tests have demonstrated performance of the starter.

Project 36

36.1 Project Name – Out-of-step Prediction Protection

36.2 Participating Companies

Kyushu Electric Power Co.  
Hokuriku Electric Power Co.  
Toshiba Corporation

36.3 Where Installed

Transmission Lines of Kyushu Electric Power Co. and Hokuriku Electric Power Co.

36.4 Type Installation

Operating Installation

36.5 Actual Duration of Field Experience

3 Operating Installations at Kyushu Electric Co., June 1981 to date.

4 Operating Installations at Hokuriku Electric Co., May 1983 to date.

36.6 Synopsis of Project

Utilizing voltages and currents of a tie line, out-of-step condition is predicted. In the case of a failure to predict the out-of-step condition, it is detected by the conventional impedance method.

The out-of-step condition is predicted by two or three consecutive increases of power swing amplitudes or continuing change of apparent impedances within the specific impedance zone.

The out-of-step condition is also detected by a conventional scheme, which measures the time taken for the impedance locus to pass through the specific impedance zone.

In addition, the under frequency function for load shedding and the over frequency function for generator islanding are developed. Frequency is computed from digitized voltage data which are sampled 12 times per cycle.

### 36.7 Published Papers

S. Hashisaka, Y. Koda, M. Hori, T. Matsuhima, S. Mizuguchi, I. Shuto, "Development of Microcomputer-Based Increasing of Power Swing Relay", IEE of Japan 1982 National Conference Paper No. 983 (in Japanese).

### Project 37

#### 37.1 Project Name

Transformer Differential Protection

#### 37.2 Participating Companies

Toshiba Corporation  
Nihon Genshiryoku Laboratory

#### 37.3 Where Installed

Central substation of Nihon Genshiryoku Lab.

#### 37.4 Type Installation

3 Operating Installations

#### 37.5 Actual Duration of Field Experience

December 1983 to date

#### 37.6 Synopsis of Project

For each transformer bank, duplicate systems of microcomputer-based differential protection are installed to protect for faults within the bank. Each system has the same configuration and is composed of a main detection unit and a fault detection unit. The main detection unit is based on a 16-bit microcomputer and provides differential protection with 2nd harmonic blocking to prevent false tripping during magnetizing inrush periods. The fault detection unit is based on an 8-bit single chip microcomputer and

detects internal phase-to-phase faults, phase-to-ground faults and turn-to-turn faults by means of overcurrent or change of current.

### 37.7 Published Papers

J. Inagaki et al., "Development of Microcomputer-Based Transformer Differential Protection", IEE of Japan 1984 National Conference (in Japanese).

## Project 38

### 38.1 Project Name

Balance Protection Taking Measures for Zero-Sequence Circulating Current

### 38.2 Participating Companies

Chubu Electric Power Co.  
Toshiba Corporation

### 38.3 Where Installed

77kV Lines at Kita-Gifu Substation (Field Test)  
77kV Lines at Tohtohmi Substation (Operating)

### 38.4 Type Installation

Field Demonstration  
Operating Installation

### 38.5 Actual Duration of Field Experience

Field Demonstration – June 1982 to March 1983  
Operating Installation – June 1984

### 38.6 Synopsis of Project

To improve the sensitivity of balance ground relays against zero-sequence circulating current in double circuit transmission lines in 77kV neutral resistor grounded systems.

A system based on a 16-bit microcomputer provides balance protection for both ground and phase faults, distance protection for phase faults and directional protection for ground faults of a double circuit line on the same tower.

In the scheme of the balance ground relaying, the difference between during fault and before fault in negative sequence transverse differential current compensated with zero-sequence transverse differential current will decide the faulty line of the double circuit line with the help of voltage between healthy phases as the polarizing quantity. Other protection schemes are similar to conventional.

### 38.7 Published Papers

F. Andow, Y. Kurosawa, H. Fugii, T. Andow, M. Ando, "Microcomputer-Based Balance Protection Taking Measures for Zero-Sequence Circulating Current", IEE of Japan, 1983 National Conference, Paper No. 1222 (in Japanese).

### Project 39

#### 39.1 Project Name

Backup Distance Protection for EHV Systems

#### 39.2 Participating Companies

Kyushu Electric Power Co.  
Toshiba Corporation  
Mitsubishi Electric Corporation  
Hitachi Ltd.

#### 39.3 Where Installed

Kyushu Electric Power Co.

#### 39.4 Type Installation

1 Field Demonstration, 14 Operating Installations

#### 39.5 Actual Duration of Field Experience

Field Demonstration – July 1982 to June 1983  
25 Operating Installations – May 1984

#### 39.6 Synopsis of Project

A microcomputer-based protection system is installed on each tie between bus sections or each transmission line. The system is composed of a main detection unit and a fault detection unit. The main detection unit is based on a 16-bit microcomputer, and provides 4 or 5 zones of protection for phase-to-ground faults, phase-to-phase faults and three phase faults.

The fault detection unit is based on an 8-bit single chip microcomputer and detects faults by means of overcurrent or change of current.

#### 39.7 Published Papers

T. Nakamura, G. Iishi, G. Sawai, J. Inagaki, N. Watanabe, "Microcomputer-based Distance Relays for Bus Tie Separation", IEE of Japan 1983 National Conference, Paper No. 1224 (in Japanese).

### Project 40

#### 40.1 Project Name

Backup Digital Relaying for 154kv Line

#### 40.2 Participating Companies

Chubu Electric Power Company  
Mitsubishi Electric Corporation  
Hitachi Ltd. Japan

#### 40.3 Where Installed

Chubu Electric Power Company  
– Showacho Substation  
– Ogaki Substation

#### 40.4 Type Installation

Operating Installation

#### 40.5 Actual Duration of Field Experience

– at Showacho, February 1984 to date  
– at Ogaki, June 1984 to date

#### 40.6 Synopsis of Project

This digital relaying system was applied a backup protection for 154kV resistance ground transmission line, in which electromechanical relays are standardly used. The objectives of this project are saving the labor of maintenance, save the installation space and improving protective functions.

- i) Backup protective functions for double circuits are build in one panel
  - Protective scheme – Three zone directional distance relaying scheme for phase to phase fault detection. Directional overcurrent relaying scheme for phase to ground fault detection.
  - Concept of fail safe – This system has two digital relays which consist of main distance relays protecting one circuit and fault detectors for another circuit, therefore any single failure of digital relays cannot cause a misoperation.
- ii) Automatic inspection using a microprocessor is applied
  - Testing analog input circuits.
  - Testing operational functions of CPU.
  - Testing relay output circuits.

### Project 41

#### 41.1 Project Name

BPRS (Bus Protection Relaying System)

#### 41.2 Participating Companies

Electric Power Development Company, Japan  
Central Research Institute for Electric Power Industries, Japan  
Meidensha Electric Mfg. Co., Ltd., Japan

#### 41.3 Where Installed

Nagano 154kV Substation (field test)  
Nagayama 186kV Power Station (under operation)

#### 41.4 Type Installation

Field test  
Under operation

#### 41.5 Actual Duration of Field Experience

Field test, Dec. 1980 to Sept. 1981  
Under operation, Dec. 1983 to date

#### 41.6 Synopsis of Project

Because of the introduction of extra-high voltage cables and increase of system capacities, higher harmonics current caused by failures are being increased.

In this project, a bus protection relaying system which operates satisfactorily at a high speed under such conditions was developed by Meidensha. The performance of this system was verified by 22kV system model facilities and actual 154kV system. This relaying system has been in practical operation for 187kV bus protection since December, 1983.

##### 41.6.1 Power System

The system is composed of two generators, two parallel transmission lines and a mono-bus line.

##### 41.6.2 Functions

Protection                      Bus protection relaying system using current differential relaying, countermeasure in respect of undetectable fault points and countermeasure against CB trip failure by use of software sequence.

Automatic monitoring system: Automatic monitoring function to realize high reliability.

Others:                      Recording of voltage and current measurements for purposes of analysis of power line faults, information on faults of devices to keep track of their states and information on the states of associated equipment.

#### Project 42

42.1 Project Name

GRMT (A New Ground Relaying System for Multiple Three-Terminal Transmission Line)

42.2 Participating Companies

Shikoku Electric Power Co., Inc., Japan  
Meidensha Electric Mfg. Co., Ltd., Japan

42.3 Where Installed

66kV three-terminal parallel four line.

42.4 Type Installation

Field test

42.5 Actual Duration of Field Experience

Field test (March-December, 1983)

42.6 Synopsis of Project

In Japan, the layout of multiple transmission lines on common towers has been introduced due to difficulty in obtaining the right-of-way of towers. An example is parallel four transmission lines. It is very difficult to transpose multiple transmission lines on common towers. Thus the mutual inductances among the wires of lines become non-uniform, so that circulating currents are wires of lines become non-uniform, so that circulating currents are always induced in lines due to the load and/or fault currents. These currents contain zero-phase-sequence component, hereafter called the zero-phase-sequence circulating current.

In Japan, 66kV lines are neutral-grounded through high resistance (ground fault current is as low as hundreds amperes). It may happen that a zero-phase-sequence circulating current may exceed a zero-phase-sequence current caused by a single phase-to-ground fault. Therefore, it is difficult to protect the above-mentioned lines safely by using conventional ground relaying systems. On account of the above-mentioned circumstances, the Shikoku Electric Power Company and Meidensha Electric Mfg. Co., Ltd. have developed a digital ground relaying system via microprocessors for three-terminal parallel four lines with neutral-grounded high resistance.

In this system, the zero-phase sequence circulating current can be estimated exactly by referring to the measurable sound phase circulating current during a single phase-to-ground sequence circulating current component included in the ground relay input current, thus yielding a new ground relaying system with higher reliability.

These relaying systems were manufactured in December 1982. Tests with artificial transmission line were performed for many kinds of faults. The relaying systems operated correctly for all these faults. They are to be installed for field test at 66kV three-terminal parallel four lines with neutral-grounded high resistance in Shikoku Electric Power Co., during one

year from February 1983. After the field test, they will be used in service.

### Project 43

#### 43.1 Project Name

DRCD (Digital Relaying and Control System of Distribution Substation)

#### 43.2 Participating Companies

Tokyo Electric Power Co., Ltd., Japan  
Meidensha Electric Mfg. Co., Ltd., Japan  
Takaoka Electric Manufacturing Co., Ltd., Japan

#### 43.3 Where Installed

66/6.6kV Distribution Substation (Japan)

#### 43.4 Type Installation

Field test

#### 43.5 Actual Duration of Field Experience

Field test, April 1983 to March 1984

#### 43.6 Synopsis of Project

This system was developed in pursuit of an economical equipment using a microprocessor in the protective/control mechanism for automating collection of information on the distribution-line current, control of the distribution-line switch and confirmation of its response to save resources and labor and raise reliability for the protecting and controlling equipment at distribution substation for 66/6.6kV transformation. The principal system functions are as follows:

Protection:	66kV industrial power, 66/6.6kV transformer, 6.6kV bus line, 6.6kV distribution line.
Control:	Automatic power line change-over in case of an accident. Monitoring and controlling of the distribution line switch. Selection and cut-off of find ground-fault. Regulation of the voltage of LRT.
Measurement:	Collection of the distribution line current. Determining of a faulty section or locked section of the distribution line.
Transmission:	Transmission to and reception from the control stations of display and measurement data. High-speed data transmission using an optical fiber cable within the substation premises.

## Project 44

### 44.1 Project Name

Integrated Protection and Control System of Distributing Substation

### 44.2 Participating Companies

Hokkaido Electric Power Company, Japan  
Fuji Electric Company, Japan

### 44.3 Where Installed

Hokkaido Electric Power Company  
Chitose and Senpaku Substation

### 44.4 Type Installation

Field experiment and Regular Operating Installation

### 44.5 Actual Duration of Field Experience

March 1983 – February 1984 (Field Experience)  
August 1984 – (Operating Installation)

### 44.6 Synopsis of Project

We developed a digital protection and control system for 1 transformer bank with 8 feeders of a distributing substation.

This equipment uses two microprocessors. One of the microprocessors shares main protection and another one shares fail safe protection, control and measuring function. The instantaneous values of input voltages and currents which are introduced from the power system are picked up with sampling rate of twelve times of the system frequency. Sampled analog data are converted to 12-bits digital data and stored microprocessor system memory. Using these data, protection, control and measuring functions are processed. For example, over-current-relay is realized by comparison between a setting value and accumulated data of the sampled absolute values during every half cycle.

To inspect the abilities as a system component of integrated digital systems, such as environment tolerance, relaying algorithm or handling facilities, we tested it in the field for a year and the result was satisfactory.

Based on this experience we reviewed the system, added some functions and now have a plan to introduce the system in the regular field operation from 1984.

#### i) Protection

Transformer and feeders' conventional protection, feeder reclosing and also back up protection for extremely high impedance earth fault with selective disclosing of feeders according to the magnitude of

- ii) zero-sequence current.  
Control

Transformer tap voltage regulating function with line drop compensation and program control of the voltage setting value.

- iii) Measurement

Measuring and indication of the voltages and currents of transformer, bus and feeders. Memory function of their maximum and minimum values and also zone-sequence voltage values of the last several earth faults.

#### 44.7 Published Papers

H. Fujita, T. Sakuragi, K. Iguchi, M. Matsumura, "on Development of Digital Type Protection Relay Equipment for Distributing Substations", Conference of the Institute of Electrical Engineers of Japan, 1984, No. 1129, pp.1446.

#### Project 45

##### 45.1 Project Name

Preventive Stepout System

##### 45.2 Participating Companies

Tokyo Electric Power Company  
Toshiba Corporation

##### 45.3 Where Installed

Sodegaura Power Station of Tokyo Electric Power Co.

##### 45.4 Type Installation

Operating installation after field demonstration

##### 45.5 Actual Duration of Field Experience

Field Demonstration: March 1980 to April 1981  
Operating installation: May 1981 to date

##### 45.6 Synopsis of Project

Information with regard to power transmitted before fault, type of faults and failure to trip are transmitted to the main processing equipment in the Sodegaura station from other substations via microwave links.

The main processing equipment will detect which generator unit should be shut down using the above information, pre-fault power of generators and required shutdown power calculated by off-line simulation.

#### 45.7 Published Papers

Y. Ohura, F. Andow, et al., "The Protective Relaying System for Preventing Power System Failure Extension in Bulk Power Systems", CIGRE 1982, Paper 82-03.

#### Project 46

##### 46.1 Project Name

Block System Emergency Prevention Control System (BSPC)

##### 46.2 Participating Companies

Tohoku Electric Power Company, Sendai Japan  
Hitachi, Ltd., Tokyo, Japan

##### 46.3 Where Installed

Miyagi Substation - Tohoku Electric Power Co.

##### 46.4 Type Installation

Operating Installation

##### 46.5 Actual Duration of Field Experience

Since July 1980

##### 46.6 Synopsis of Project

This system was developed to perform high-speed preventive control of power system disturbances using data from many power stations and substations. This system allows twice more power flow in the trunk lines than the conventional system does by monitoring dynamic instability such as power swing. As a result, stable and highly efficient system operation can be achieved.

Seven microcomputers and high-speed data transmission system are incorporated for emergency control, power swing monitoring, and event recording. In order to achieve high reliability, fan-less cooling, self-checking, and back-up functions are performed.

##### 46.7 Published Papers

J. Saita, S. Matsuoka, Y. Miki, Y. Sano, "Emergency Prevention Control System for Bulk Power Systems" HITACHI REVIEW, Vol. 31, No. 4, pp. 119-204, April 1982.

S. Matsuoka, Y. Ohura, H. Hashimoto, M. Yuki, Y. Miki, F. Andow, K. Suzuki, "The Protective Relaying System for Bulk Power Systems" CIGRE International Conference on Large High Voltage Electric Systems 1982, Session 34-03, September 1982.

## Project 47

### 47.1 Project Name

Intrastation Fiber-Optic Data Transmission System

### 47.2 Participating Companies

The Tokyo Electric Power Co., Inc., Tokyo, Japan  
Hitachi, Ltd., Tokyo, Japan

### 47.3 Where Installed

Shin-Tochigi Substation (500kV/275kV) - TEPCO

### 47.4 Type Installation

Field Experiment

### 47.5 Actual Duration of Field Experience

Digital Relay and Fault Locator, July 1977 - August 1978  
Total System, December 1978 - December 1979 (one year)

### 47.6 Synopsis of Project

This system is composed of data acquisition equipment in the switchyard, a digital processing panel in a control room and the fiber-optic transmission system between these two equipments. Three phase voltages and currents of a 275kv line are sampled by the synchronized clock of 1200 Hz at the data acquisition equipment. These sampled data are transmitted by the fiber-optic system at the transmission rate of 54 BPS. The optical components of this system are LEDs, pin-photodiodes and four fibers in a cable (600 m length). The digital processing panel is composed of a microprocessor-based digital relay, a digital fault locator, transmission data-error analyzer, and a fault recorder.

The noise simulation tests at the factory and the switching surge tests at the substation verified excellent noise immunity of the fiber-optic data transmission system and their preventive countermeasures for outdoor electronic circuits. The electrical fields of EMI noise and the induced noise on the power supply cable were also measured in the switching tests.

During the field experiment, no internal fault occurred. An external fault was located by the accuracy of +0.3%. No component failure as reported and the total bit-error-rate of the fiber-optic data transmission was 10-12.

### 47.7 Published Paper

T. Takagi, Y. Yamakoshi, H. Kudo, Y. Miki, M. Tanaka, K. Mikoshiba, "Development of Intrastation Optical-Fiber Data Transmission System for Electric Power Systems", IEEE Transaction, PAS-99, No. 1, pp. 318-327, Jan./Feb. 1980.

## Project 48

### 48.1 Project Name

Digital Distributed System for Measurement and Control

### 48.2 Participating Companies

CEPEL (Centro de Pesquisas de Energia Electrica)  
ELETROSUL (Centrais Eletricas do Sul do Brasil, S.A.)

### 48.3 Where Installed

To be installed in Palhoca Substation, Santa Catarina, Brazil.

### 48.4 Type Installation

Temporary Operating Installation to be completed in one and a half years.  
Laboratory demonstration prior to field demonstration (in course)

### 48.5 Planned Field Experience

One year

### 48.6 Synopsis of Project

Design and installation of a distributed digital system based on 16-bit micro-computers to measure voltage, current, frequency, active and reactive power, energy and status. The system also executes commands and has man-machine interface facilities. The digital processors are connected by an optical fiber network in a bus type of architecture.

### 48.7 Published Papers

Carlos Mauricio F. dos Santos, Jose Carlos N. Bianco, Jacques Szczupak, A. Tureli, "A Digital Distributed System for Measurement, Protection and Control", IFAC Symposium on Planning and Operation of Electric Energy Systems, July 22-25, 1985, Rio de Janeiro, Brazil.

## ABSTRACT

This paper describes a distributed digital system under development at CEPEL, integrating measurement, control and protection of an electric power substation. In this system the signals are digitalized and transmitted to the inputs of digital processors connected by a local network. This network, together with the application software developed, allows synchronization of the sampling processes at different nodes of the network. The data banks obtained by this procedure allow the distributed system to easily adapt to the substation topology.

This is the case, for instance, of power evaluated as a function of voltages and currents available at sometimes far apart terminals of CTs and VTs. The digital processors generate the measures of currents, voltages, active and reactive powers, frequency, etc., based on the received data banks. Results

of a laboratory prototype system are presented.

Although allowing only on-off commands in this first version, the distributed system is able to be transformed into an hierarchical distributed control network.

The paper also describes the principles by which microprocessor-based protection relays in a dedicated protection network would be connected to the first distributed system, using it for security purposes and for transmitting fault recording data whenever necessary.

## Project 49

### 49.1 Project Name

Alpha 765kV Substation Integrated Control System

### 49.2 Participating Companies

Brown Boveri and Company, Switzerland

### 49.3 Where Installed

Alpha Substation, South Africa

### 49.4 Type Installation

Regular Operating Installation

### 49.5 Actual Duration of Field Experience

Lifetime of equipment

### 49.6 Synopsis of Project

The system consists of a distributed and hierarchical computer based control system, providing the following functions:

- i) Interlocking for the 765kV GIS switchgear
- ii) Measurements viz.: voltage, current, frequency and calculation and logging of Megawatts, Megavars, MWHours, MVHours for both voltage levels.
- iii) Local control of isolators, breakers and tap changer controllers from a central control room via color VDU's. All controls are backed up by conventional protection panels.
- iv) Circuit breaker duty monitoring by measuring the current broken by the CB and the number of operations of the CB.
- v) Overview mimic board showing status of CB's, IS's and ES's.
- vi) Local alarming and logging.

- vii) Operator guidance to help in releasing interlocking conditions.
- viii) Expansion capabilities include: direct link to national SCADA system, protection functions, gas density monitoring of the SF<sub>6</sub> gas, fault arc detection within the GIS equipment and Sequence of Events functions.

#### 49.7 Published Papers

None to date.

The SICSUR is a modular system, which in turn is based on the modular construction of the substations. Each one of the ER modules of SICSUR is able to cope with:

- 2 HV lines (45 or 66kV)
- 1 HV/LV power transformer
- 5 LV liens (15kV generally)
- 1 two-step capacitor bank.

The system essentially comprises a series of remote stations, ER located in the substations to be managed, a fixed center of operation, CO, and a movable center of operation, CM. Both the fixed center and the movable center will be able to manage up to ten remote stations.

The communication is via radio with Voice-Data switching.

#### Project 50

##### 50.1 Project Name

Beta 765kV Substation Integrated Control System

##### 50.2 Participating Companies

Toshiba Corporation  
Camille Bauer  
Beta Products, Inc.

##### 50.3 Where Installed

Beta Substation, South Africa

##### 50.4 Type Installation

Regular Operating Installation

##### 50.5 Actual Duration of Field Experience

Lifetime of equipment

##### 50.6 Synopsis of Project

The system consists of a central computer system with distributed programmable logic controllers, providing the following functions:

- i) Interlocking of the 765kV GIS switchgear
- ii) Local control of isolators, breakers and tap changer controllers from a central control room via color VDU's. All controls are backed up by conventional protection panels.
- iii) Circuit breaker duty monitoring by measuring the current broken by the CB and the number of operations of the CB.
- iv) Local alarming and logging.
- v) Gas density monitoring of the SF<sub>6</sub> gas.
- vi) Fault arc detection with the GIS compartments.
- vii) Operator guidance to help in releasing interlocking conditions.
- viii) Overview mimic showing status of CB's, IS,s and ES's.
- ix) Interface communications to Digital Measurement Equipment from Camille Bauer and the logging of the measurements.
- x) Interface communications to the Sequence of Events Recorders from Beta Incorporated and the logging of sequences.

#### 50.7 Published Papers

None to date.

#### Project 51

##### 51.1 Project Name

SICSUR (Sistema Integrado de Control de Subestaciones Rurales)  
Integrated Control System of Rural Substation.

##### 51.2 Participating Companies

Union Electrica—FENOSA (Promoting Company)  
Siemens, S.A. (Manufacturer)  
OCIDE (Member through which all Electric Companies can partake)

##### 51.3 Where Installed

Remote equipment is going to be installed in the 45/15kV substation of "Collmenar de Oreja" (Toledo).  
Fixed operation center (CO) will be installed in Aranjuez (Madrid).  
Movable operation center (CM) will be installed on a vehicle of the Aranjuez agency.

##### 51.4 Type Installation

Field Experiment and Regular Operating Installation

### 51.5 Completion of Field Tests

Laboratory Tests have been already run and satisfactory results have been obtained.

Field tests are foreseen to be finally completed around the end of May 1986.

### 51.6 Synopsis of the Project

SICSUR is a system leading to the remote and local management of small size distribution rural substations. It has been designed following the philosophy of enclosing in itself all the automatic controls which until now were covered mainly based on relays. They are the following:

- Line reclosing
- Voltage regulation
- Capacitor banks On/Off operation
- Off load/On load operation due to low frequency

The project is based on the application of microprocessors. To be precise, it comprises two off CPU's, one of which is essentially devoted to the reclosing automatic control, and the other to the remaining functions: voltage regulation, capacitors automatic controls, communications, etc.

During the development of the first phase the protection functions will be covered by the relay chassis system, but such functions will be integrated in the system at a later stage.

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3. E. Buurman, B. Gortz, H. Westerholt, "Microprocessor-Based Control and Protection System for Switchgear, Designed with an Eye to the Future", Siemens Power Engineering and Automation, Vol. VII, No. 3, May/June 1985, pp. 164–168.
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Elektrizitätswirtschaft, Jg. 84 (1985) H.11, pp. 405–412.

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8. G. Koch, "A New Modern Microprocessor-Based HV Feeder Protection Package", IEE Conference on Power System Protection 1985, London, UK.
9. M. Mainka, K. Renz, G. Koch, "Design Aspects of a Fully Microcomputer-Based Feeder Protection System for HV Lines", CIGRE Conference, Paris, France, 1986.

### Project 30

#### Add to HIERARCHICAL SYSTEMS

A. G. Phadke, A. Politis, J. S. Thorp, "Improved Protection and Control of Power Systems", CIGRE 1986 Session, Paris, France, Sept. 1986.

#### Add to MEASUREMENT OF FREQUENCY AND PHASE

J. S. Thorp, A. G. Phadke, K. Karimi, "Real-Time Voltage Phasor Measurements for Static State Estimation", IEEE Transactions on PAS, Vol. PAS-104, No. 11, November 1985, pp. 3098–3116.

A. G. Phadke, J. S. Thorp, K. Karimi, "State Estimation with Phasor Measurements", PICA 1985, San Francisco, CA, May 1985.

A. G. Phadke, J. S. Thorp, K. Karimi, "Power System Monitoring with State Vector Measurements", IEE Second International Conference on Power System Monitoring and Control, University of Durham, England, July 1986.

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P. Muller, B. Kulendik, L. Bures, "A Programmable Test Unit for Line and Feeder Protection", Brown Boveri Review No. 2 -1985.

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H. F. VanLandingham, D. K. Lindner, A. G. Phadke, A. Jayakumar, "A Nonlinear observer applied to state estimation of a synchronous Generator", (short paper) IECON-84, Tokyo, October 1984.

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## 10.0 CONCLUSIONS AND RECOMMENDATIONS

1. The Working Group feels that the researchers and developers of computer relaying algorithms need to be aware of a host of complex power system phenomena which must be taken into consideration when digital relay systems are being developed. A selection of important protection issues is provided in Chapter 4. Similarly, in an integrated substation computer system, the development of monitoring, protection, and control functions must be done in such a way that each of these functions is performed in an optimum manner. The material in Chapter 5 provides an overview of control processes which are of particular significance in this respect, and should be taken into account when an integrated substation computer system is being developed.

2. The Working Group believes that computer relaying is a well established field. Development of various protection algorithms has progressed in a satisfactory manner, so that it can be said that the principles of computer relaying of all power apparatus and systems is well understood. It is likely that we have now passed into a phase of computer relaying development whereby issues of a more practical nature — e.g. service reliability, maintainability, necessary testing and training of personnel — have become more relevant. Prospects and opportunities for standardization are also acquiring greater importance. A start toward two such activities has been made in this report.

3. The Working Group has developed a standard for exchange of transient data. The details of the standard are described in Chapter 6. It seems certain that an almost identical standard will be developed and proposed as an ANSI standard by a working group of the Power System Relaying Committee of IEEE. It may well be that this standard will provide a much needed convenience for researchers who wish to exchange transient data records obtained from various sources.

4. The Working Group recognizes that personnel training for digital relays is of increasing concern to many utilities. It is felt that the digital relay offers a unique opportunity to ensure that the man-machine interface software is independent of the manufacturer of the equipment. Thus, the user interfaces to digital relaying systems could be made function-specific, rather than device-specific. This is a formidable task, and the work accomplished in Chapter 7 of the report is intended to be a guide for the development of future standards for the man-machine interface functions.

5. The digital relay has always been regarded as a measurement system. One would therefore expect to see future development of digital relaying systems which can provide high accurate and reliable measurements of all electrical variables of a power system. It is realized that one must take into account the errors introduced by the transducers. However, digital relays may compensate many of these errors, and remove other through digital filtering. We would expect to see some interesting developments in this direction in the coming years.

6. The new field of Adaptive Relaying has been introduced in recent years. The idea in adaptive relaying is to allow and to require changes to be made within the relays to respond to changes taking place on the power system. This is a serious departure from traditional relaying practices, and should not be taken lightly. A complete re-examination of current relaying practices should be made, to determine if any protection function may benefit from the use of Adaptive Relaying concepts. One must also provide for safe fall-back positions if the adaptive capabilities

become undesirable or unavailable for any reason. These, and other related questions may perhaps be a subject of a future CIGRÉ Working Group.

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## 12.0 APPENDIXES

## Appendix I

Final Report of CIGRÉ 34.04 – Chapter 1

## APPENDIX I

Excerpt from: Report by CIGRÉ—34.04 (January 1986)  
"Guide on: Evaluation of Characteristics and Performance  
of Power System Protection Relays and Protective Systems"

### 1.1 GENERAL

1. Tests for power system protection relays and protective systems can be divided into type tests and individual tests.  
Type tests are normally performed once on a given type of relay.  
Individual tests are performed on individual relays for acceptance, commissioning and routine maintenance.  
Acceptance tests are intended to verify the conformity of the individual relays with the type.  
Commissioning and maintenance tests are intended to verify the correct operation of the relays during their service life.  
This guide is not concerned with individual tests.
2. Type tests can be divided into functional tests and technological tests.  
Functional tests are intended to establish the declared characteristics and performance of the protection.  
Technological tests are intended to check the quality of the relay technology (e.g.: insulation tests, climatic tests, mechanical shocks and vibration tests, etc...) This guide is not concerned with technological tests.
3. Functional tests can be divided into steady—state tests and dynamic tests.  
Steady—state tests are intended to measure the accuracy, sensitivity and operating characteristics of the measuring functions of the relay when applying a.c. energizing quantities (without transients). Steady state tests are uncomplicated and appropriate to measure the overall operating characteristics of the measuring functions of the protection.  
  
Dynamic tests are intended to measure the operating times of the relay when simulating faults within the protected zones and the non—operation (security) of the relay when simulating faults outside the protection zones. Some accuracy and sensitivity measurements are also performed in dynamic conditions to enable a comparison with the steady—state test results. On dynamic tests, the transient phenomena due to fault and fault clearance sequences shall be correctly simulated.  
  
This guide is concerned with both steady—state and dynamic tests. The latter are subdivided into single—source dynamic tests (Figure 1—a) and double—source dynamic tests (Figure 1—b). Dynamic tests with load current and simulation of fault clearance sequences can be performed in a more realistic way by double source tests rather than by single—source tests.
4. Functional tests: are performed in reference conditions and within the ranges of the influencing quantities or factors.

Table 1.1—a indicates the nominal ranges of general influencing quantities or factors in accordance with IEC Publications. Reference values are given in

IEC Publication 255-6 (1978) – Table I.

Table 1.1-b indicates typical reference conditions and ranges for other influencing quantities or factors. Their inclusion is considered in accordance with the type of relay to be tested and the type of characteristics or performance to be established.

5. Functional test programs: in this report are divided into two parts (a and b):

Part a: to establish the basic characteristics and performance of the protection for basic types of faults and within the setting ranges. Dynamic tests are repeated for different values of the initial point-on-wave from 0 ... 180° in steps of less than 30°. Other influencing quantities or factors are set at their reference values.

Part b: some of the tests in part a are repeated to investigate the effects of varying the values of the influencing quantities or factors within their ranges. Influencing quantities or factors are normally varied one at a time. Part b tests can be subdivided as follows:

(b1): Tests to establish the relay's operations at the various extremities of its range of application (parametric tests).

(b2): Tests to establish the relay's operations for a particular case of application (specific tests).

Part a tests and part (b1) are basic tests.

Part (b2) tests should only be performed when required.

The block-diagram Figure 2 summarizes the general classification of tests and indicates the limited object of this report.

## 1.2 STEADY-STATE TESTS

### 1.2.1 Object

1. These tests are intended to measure the operating characteristics of the measuring functions of the relay. For single-input measuring functions (e.g. over-current function), the operating and resetting values are measured. For double-input measuring functions (e.g.: impedance functions), the operating characteristics depend on the magnitude (X, Y) and relative phase-angle ( $\varphi$ ) of both input energizing quantities, i.e. by vectors  $\bar{X}$  and  $\bar{Y}$ .

The operating characteristics are generally measured with constant values of one quantity:  $\varphi$  (X and Y variable), X ( $\varphi$  and Y variable) or Y ( $\varphi$  and X variable). For multi-input measuring functions, the operating characteristics are generally measured with constant values of several quantities.

2. These test are also intended to check the correct operation of internal logic

(starting, phase selection, tripping, etc...), indications, output contacts, etc... The returning values of starting functions, accuracy of timing functions and power consumption of a.c. current, a.c. voltage, and d.c. auxiliary voltage circuits are also measured.

3. The test procedures are uncomplicated and appropriate to the investigation of the effect on the protection of varying the basic influencing quantities or factors such as: ambient temperature, auxiliary voltage, H.F. disturbances, frequency, harmonics, etc.

#### 1.2.2 Test procedures

1. The steady state tests are performed by applying a.c. energizing quantities on the measuring inputs of the protection and varying some of these quantities slowly or in small steps without generating transients.
2. The number of measured points on each operating characteristic may vary in accordance with the type of characteristic to be measured: e.g. 1 point (over-current function), 12 points (impedance characteristic from 0 to 360° in steps of 30°), etc.
3. At least one point is measured several times (e.g. 10 times) to check the reproducibility of the measurements, according to IEC Publication 255-6 (1978 - Appendix B).
4. Information on the test equipment for steady-state tests is given in Appendix A (synthetic tests, including conventional steady-state tests).

#### 1.2.3 Test Programs

Examples of test programs are given in the following chapters for particular types of relays.

### 1.3 SINGLE-SOURCE DYNAMIC TESTS

#### 1.3.1 Object:

1. These tests are intended to measure the operating times and dynamic accuracy or sensitivity of the relay whilst simulating basic types of faults on a single-source, three-phase power system scheme as illustrated in Figure 1-a.
2. These tests are also intended to verify the correct operation of internal logic (starting, phase selection, tripping, etc.), indications, output contacts, etc. The resetting time after fault clearance is also measured.
3. The tests procedures are uncomplicated and are designed to establish the basic performance data of the protection and to investigate the effect of varying the influencing quantities or factors such as initial point on wave, fault type, d.c. time constant, etc.

### 1.3.2 Test Procedures

1. The single-source dynamic tests are performed by simulating basic types of faults (R-N; S-N; T-N; R-S; S-T; T-R; R-S-N; S-T-N; T-R-N; R-S-T; R-S-T-N) at different locations inside and outside the protected zones and measuring the operating times of the protection. The tests are repeated for different values of the initial point-on-wave (e.g.: from 0 to 180° in steps of less than 30°).
2. According to the type of protection to be tested, the dynamic characteristics can be measured with constant values of source impedance (variable line impedance and fault current) or fault current (variable line and source impedance), etc.
3. At least one point is measured several times (e.g.: 10 times) to investigate the reproducibility of the measurements, according to IEC Publication 255-6 (1978 - Appendix B).
4. Information on test equipment for dynamic tests is given in Appendix B. Some dynamic tests can also be performed by using synthetic methods of testing as indicated in Appendix A.

### 1.3.3 Test programs

Examples of test programs are given in the following chapters for particular types of relays.

## 1.4 DOUBLE-SOURCE DYNAMIC TESTS

### 1.4.1 Object

1. These tests are performed by simulating basic fault and fault clearance sequence on a double-source power system scheme as illustrated in figure 1-b, and are designed to establish:
  - the operating time and correct operation of the protection when simulating faults and fault clearance sequences on the protected line (e.g. on line L<sub>1</sub>)
  - the non-operation of the protection when simulating faults and fault clearance sequences on an adjacent line (e.g. on line L<sub>2</sub>).
2. These tests are performed on many types of relays and protective systems: especially distance relays, distance relays with autorecloser, line unit protection schemes, etc.
3. Double-source dynamic tests are also performed to check the correct behavior of distance relays with auxiliary blocking functions such as: power swing blocking, fuse failure unit, etc.

### 1.4.2 Test procedures

1. These tests are performed without load current and with load current flowing in both directional (from A to B and B to A).

2. The simulated fault clearance sequence operates according to the tripping and reclosing commands from the tested relays in an interactive way (the tripping and reclosing commands from the tested relays actuate the appropriate circuit breakers in real time during the simulated fault sequence) or in a pseudo— interactive way (the tripping and reclosing commands from the tested relays are only recorded).

#### 1.4.3 Test programs

Examples of test programs are given in the following chapters for given types of relays.

Fig 1-a  
Single-source  
dynamic  
tests

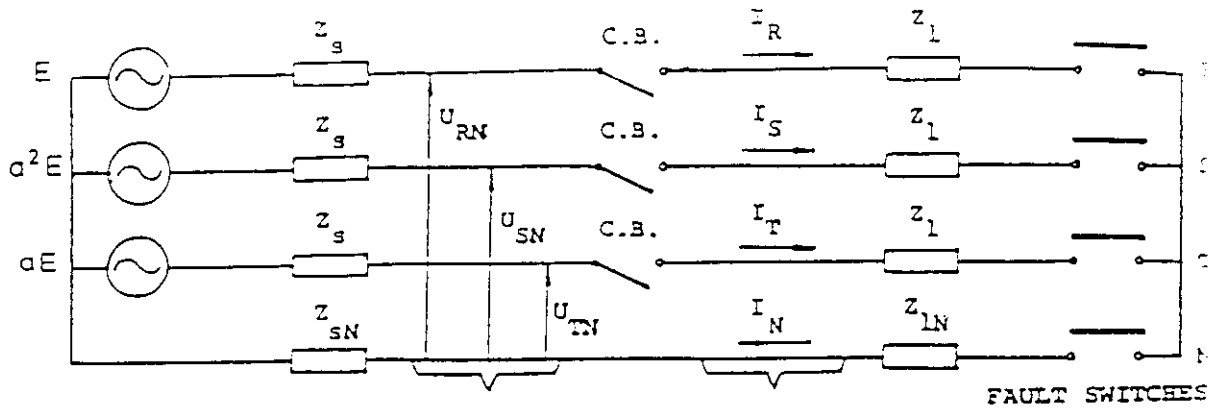


Fig 1-b  
Double-source  
dynamic  
tests

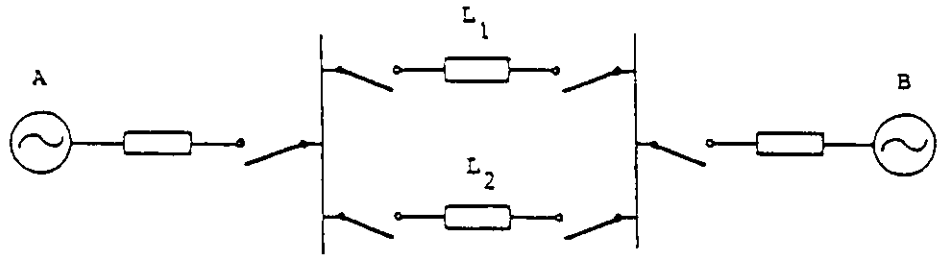


Fig 1-c  
Transmission  
line or ca-  
ble model

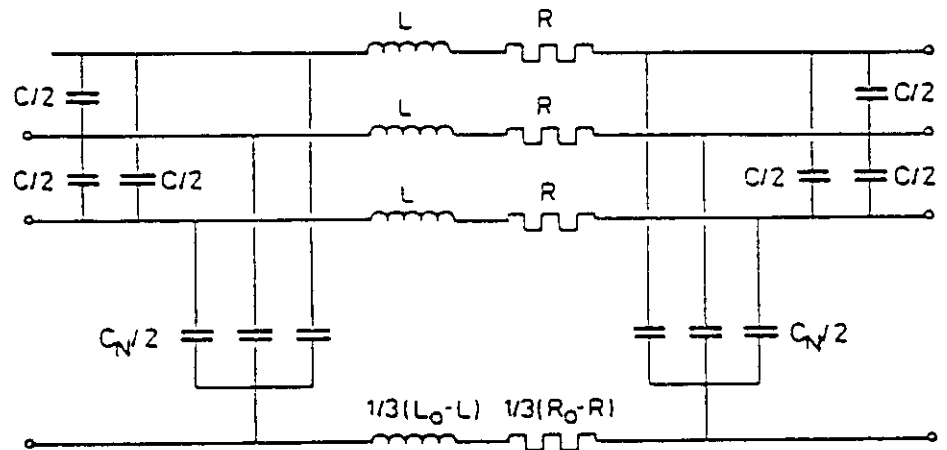


Fig 1-d  
CVT and burden  
models

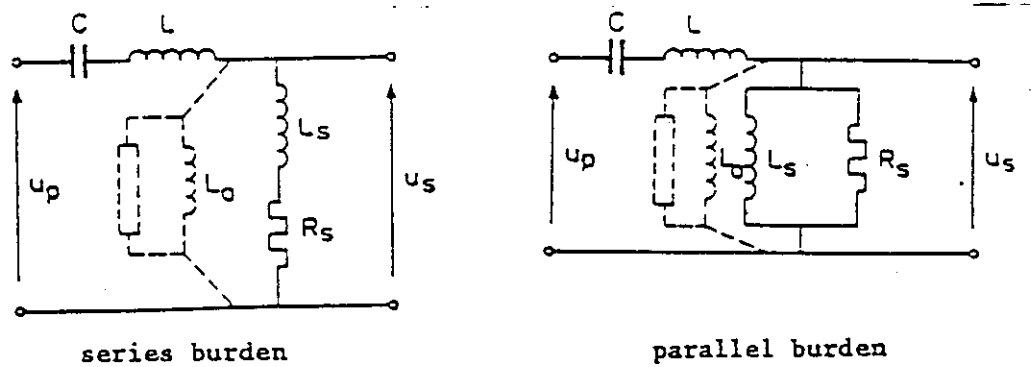
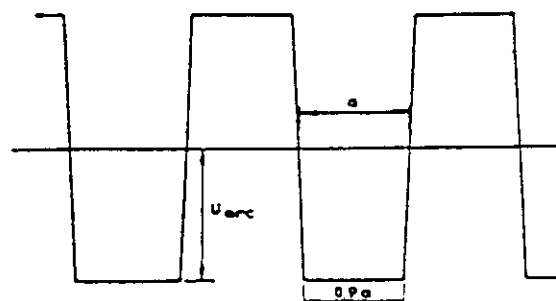


Fig 1-e  
Arc voltage  
waveform



Influencing quantities or factors	Typical ranges proposed by WG 04	IEC Publications	
Ambient temperature	- 5 °C to + 40 °C (+ 55 °C)	IEC 255-6 (1978) Table II	
d.c. auxiliary source	voltage	80 % ... 110 % $U_n$	IEC 255-6 (1978) Table V
	short interruptions	2 .... 200 ms	IEC 255-11(1979) - § 5
	ripple	max 12 % peak-to-peak	IEC 255-11(1979) Table III
H.F. disturbances on a.c. current, a.c. voltage and d.c. auxiliary voltage circuits (*)	1 MHz - 200 $\Omega$ Common mode : 2.5 kV Transverse mode : 1 kV	IEC 255-6 (1978) - Appendix C - Class III	
Relay setting	Setting range	IEC 255-6 (1978)	

(\*) electromagnetic fields as well as fast transients and electrostatic discharges are under consideration by IEC

Table 1.1-a : nominal ranges for general influencing quantities or factors

Influencing quantities or factors		Typical reference conditions proposed by WG 04	Typical ranges proposed by WG 04
Source e.m.f.'s	frequency	$f_N (\pm 0.5 \%)$	94 % .... 102 % $f_N$
	waveform	sinusoidal (total harmonic distortion $\leq 2 \%$ )	0 ... 5 % harmonics of different orders and phase positions
Source impedance	impedance	reference value	Min ... Max
	time constant	50 ms $\pm$ 5 ms	10 ... 500 ms
Line (or cable)	capacitance	Zero	$\pi$ cells representation (fig 1 -c)
	frequency of line oscillations	no oscillations	Max 1 ... 3 kHz
Current transformers	remenance factor (BR/BS)	Zero	0 ... 0.8 (*)
	knee-point voltage	no transient saturation	5 ... 1200 times internal e.m.f. at rated current
	secondary time constant	$> 10$ sec	unsaturated : 50 ms ... 10 fully saturated : 0.2 ...
Voltage transformers	remenance factor (BR/BS)	Zero	0 ... 0.8
	knee-point voltage	no transient saturation	$U_N \dots 2 U_N$
	capacitor voltage transformer	not represented	typical CVT model (fig 1
Faults	impedance	Zero	trapezoidal representation arc voltage (fig 1 -e)
	fault types	single-phase-to-ground two-phase two-phase-to-ground three-phase no fault	evolving faults (e.g. R - N $\rightarrow$ R - S - N)  complex faults
Initial conditions	initial voltage	$U_N$	0 ... $U_N$
	initial load current	Zero	0 ... $I_n$
	initial point-on-wave	0	0...180° in steps of less than
Circuit- breaker operation	at closing	simultaneous pole operation	0...10 ms between pole operation
	at tripping	current interruption at natural zero crossings	-
Shunt wires	resistance and capacitance	Zero	0 ... Max
Transmission links	attenuation and time delay	Zero	0 ... Max,

(\*) consecutive dynamic tests are performed with maximum current offset of the same polarity to obtain a maximum build up of remanence.

Table 1.1-b : typical reference values and ranges for influencing quantities or factors.

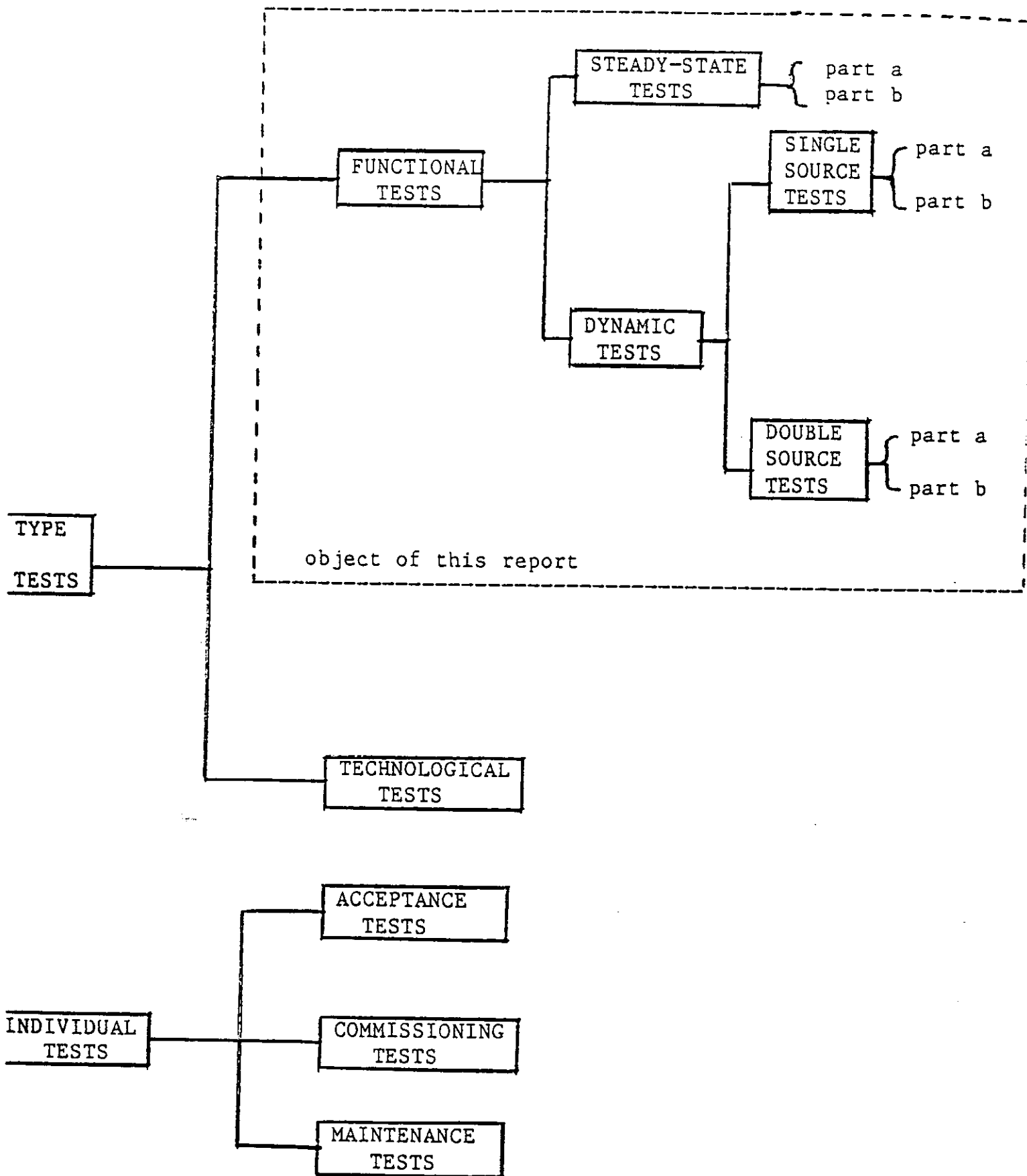


Figure 2: Classification of Tests Block-Diagram

## Appendix II

### Programs for Sampling Frequency Conversion

APPENDIX II  
PROGRAM FOR SAMPLING FREQUENCY CONVERSION

```

C   PROGRAM CONVERT
C   CONVERTS SAMPLES TAKEN AT ONE RATE TO A SECOND
C   RATE
C   USER SUPPLIED FILTER IS IN FOR020.DAT
C   DATA IS IN FOR021.DAT
C   OUTPUT IS IN FOR025.DAT
C
C   NFMAX = THE MAXIMUM LENGTH OF THE FILTER
C
C   PARAMETER NFMAX = 3600
C   3600 CORRESPONDS TO ONE CYCLE
C
C   LFAC = THE NUMBER OF TENTHS OF A DEGREE BETWEEN
C   SAMPLES IN INPUT
C   PARAMETER LFAC=50
C   FSAMP=THE INPUT SAMPLING FREQUENCY
C   PARAMETER FSAMP = 4320
C   NSIZE = THE MAXIMUM LENGTH OF THE INPUT DATA
C   STRING
C   PARAMETER NSIZE = 720
C   INTEGER*2 DBUF(NSIZE)
C   DIMENSION HFIL(NFMAX),ZTD1(NFMAX)
C
338  DATA N0/0/
C
C   GET FILTER RESPONSE
C   READ(20,*) NA,NB
C   IF(NB.LE.NFMAX) GO TO 6
C   WRITE(6,5)
5   FORMAT(3X,'DECIMATION FILTER IS TOO LONG')
C   STOP
C
6   NBF=NB/LFAC
C   IF(NB.EQ.NBF*LFAC) GO TO 10
C   WRITE(^,*) 'FILTER LENGTH INDIVISIBLE BY LFAC'
C   STOP
C
10  READ(20,*) (HFIL(JJ),JJ=1,NB)
C
C
C*****

```

```

C
C
C
C
18 WRITE(6,18)
   $ FORMAT(1H$, 'ENTER TOTAL NUMBER OF SAMPLES TO BE
   $ PROCESSED')
   $ READ(6,*)ITIME
C
   $ READ(21,*) (DBUF(JJ),JJ=1,ITIME)
   $ IPTR=1
C
30 WRITE(6,35)
35 FORMAT(1H$, 'ENTER THE DESIRED PROCESSING RATE')
   $ READ(6,*)DRATE
   $ MFAC=IFIX(FSAMP*LFAC/DRATE)
   $ IF(MFAC*DRATE.EQ.FSAMP*LFAC) GO TO 40
C
   $ WRITE(6,*) 'RATE IS UNACHIEVABLE - TRY AGAIN'
   $ GO TO 30
C
   $ WRITE(6,*) 'INTERPOLATION FACTOR =',LFAC
   $ WRITE(6,*) 'DECIMATION FACTOR =',MFAC
C*****
C
   $ DO 500 I=1,ITIME
   $ DT=(I-10)/4320
   $ X=FLOAT(DBUF(IPTR))
   $ WRITE(26,*) DT,X
C
C
   $ DO 120 J=1,NBF-1
   $ INDX=NBF+1-J
120 $ ZTD1(INDX)=ZTD1(INDX-1)
   $ ZTD1(1)=X
C
C
   $ N0=N0+LFAC
   $ IF(N0.LT.MFAC) GO TO 500
C
   $ N0=N0-MFAC
C
   $ ZOUT=0.
   $ DO 130 J=1,NBF
   $ INDX=J*LFAC-N0
130 $ ZOUT=ZOUT+HFIL(INDX)*ZTD1(J)
   $ ZOUT=ZOUT/FSAMP
   $ WRITE(25,*) DT,ZOUT
C
500 CONTINUE
   $ STOP
   $ END

```

```

C*****
C      PROGRAM FIR
C*****
C      IMPULSE INVARIANT DESIGN FOR SECOND ORDER
C      LOW PASS FILTER WITH REAL POLES AT -S1 AND -S2
C
C      TRANSFER FUNCTION =  $A*S1*S2/(S+S1)(S+S2)$ 
C
C      SAMPLING RATE OF 216000 AT 60 HZ
C      180000 AT 50 HZ
C
C      ONE CYCLE DURATION FINITE IMPULSE RESPONSE FILTER
C      OBTAINED BY WRITING THE PARTIAL FRACTION
C      EXPANSION OF THE TRANSFER FUNCTION AND FORMING
C      THE IMPULSE RESPONSE IN THE FORM
C       $H(T)=SUM\{CI*EXP(-SI*T)\}$ 
C*****
C
C      DIMENSION H(3600)
C      S1=394.
C      S2=2620.
C      MAKE GAIN AT 60 HZ = 1
C      G60=INVERSE OF THE 60 HZ GAIN
C
C       $G60=(SQRT((S1**2+(377)**2)*(S2**2+(377)**2)))/(S1*S2)$ 
C       $C1=G60*S1*S2/(-S1+S2)$ 
C       $C2=G60*S1*S2/(S1-S2)$ 
C      WRITE(20,*)H(I)
100 CONTINUE
STOP
END

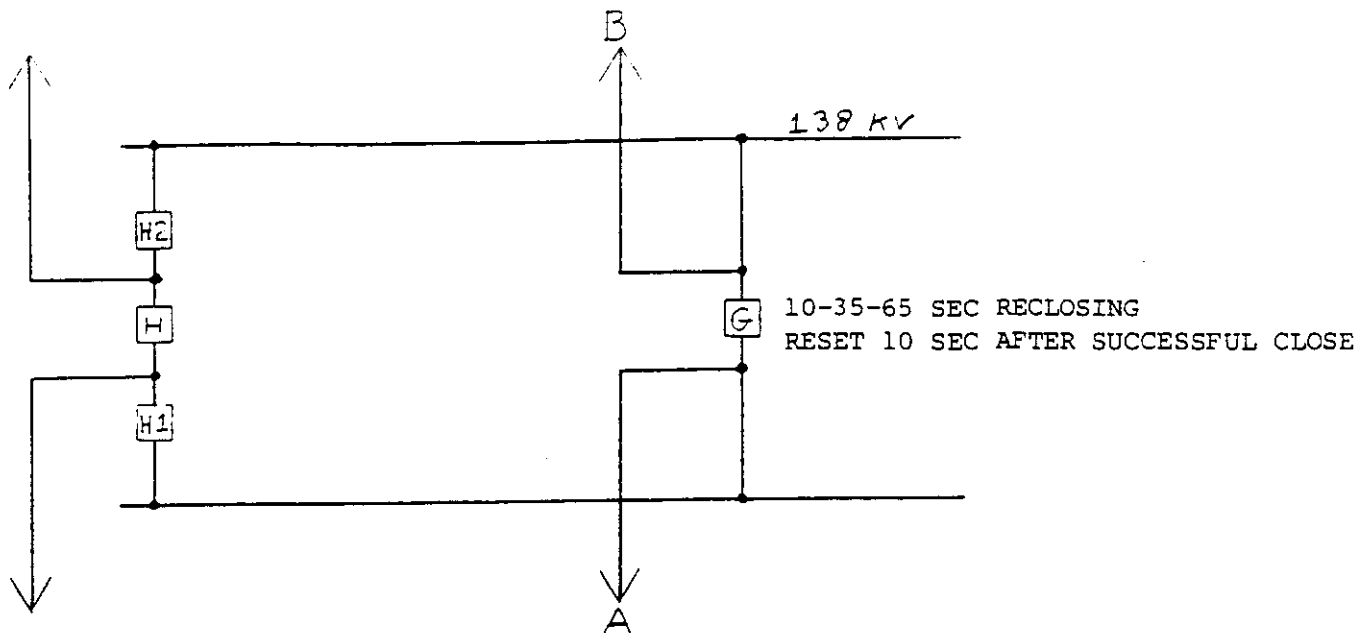
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## Appendix III

### Control Functions and Flow Charts

The acronyms used in this Appendix are explained below:

CB,	Bkr	-	Circuit breaker
	MDP	-	Minimum dielectric pressure
	MOAB	-	Motor operated air break (switch)
	RI	-	Reclose initiate
BF,	BFI	-	Breaker failure (initiate)
	PAR	-	Phase angle regulator
	TSC	-	Thyristor switched capacitor
	TCR	-	Thyristor controlled reactor
CAP	bank	-	Capacitor bank
	GSU	-	Generator step up (transformer)
	PT	-	Potential transformer
	Sync	-	Synchronous
	SW	-	Switch

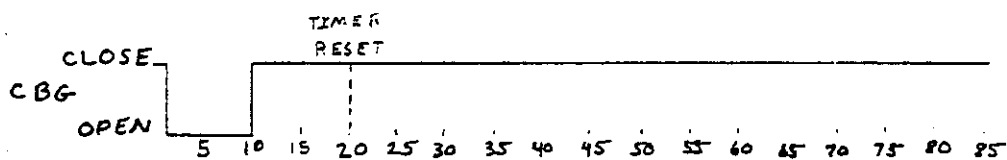


138KV Operating Notes for the Reclosing of Circuit Breaker G

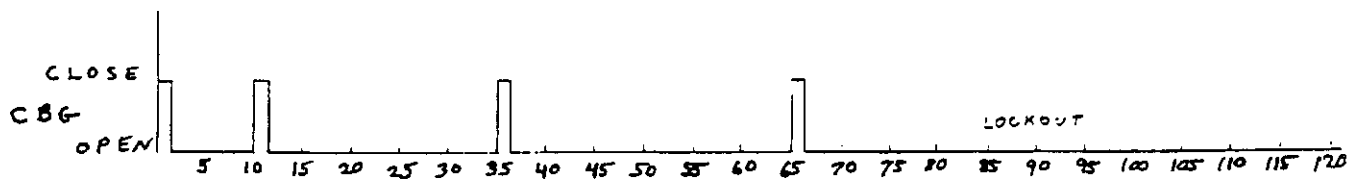
1. Circuit breaker G recloses as follows:
  - A. With check synchronizing if line A and line B are energized.
  - B. Switch provided for automatic reclosing when either line A or line B is deenergized.

CB G Reclosing Timing Chart for a Temporary Fault on Line B

CB G RECLOSING TIMING CHART FOR A TEMPORARY FAULT ON LINE B



CB G RECLOSING TIMING CHART FOR A PERMANENT FAULT ON LINE B



## Reclose Flow Chart Introduction

Notes:

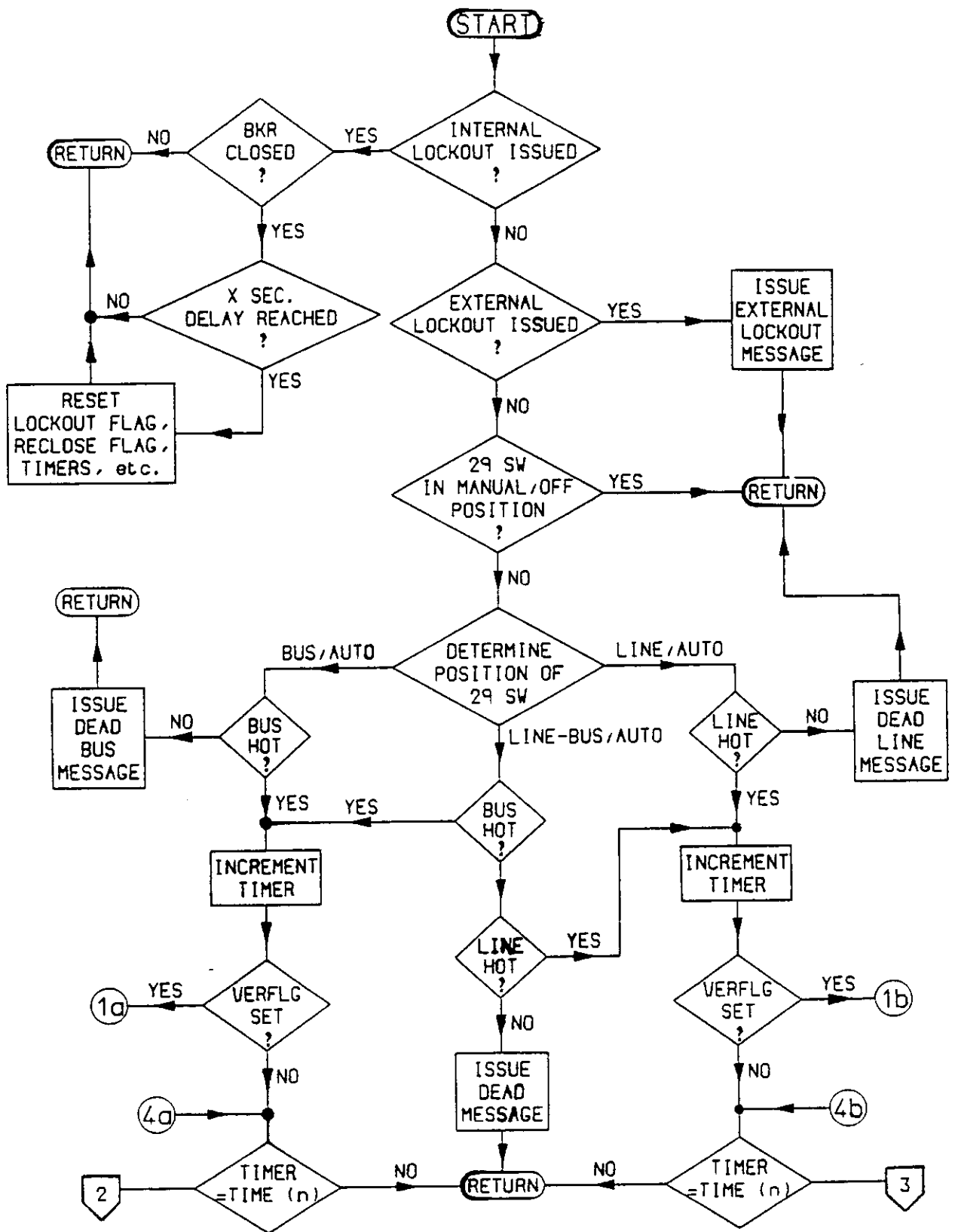
1. Routine is entered only if Breaker "n" is open.
2. All messages issued by this routine are done so only once.
3. Return means go back to the Calling Routine.
4. VERFLG is a Flag that is set once a reclose has been issued.
5. Decrement Timer – stops routines from timing.

Settable quantities

- Xsec. – Delay required to assure a breaker is close after a Lockout has been issued.
- Bus Hot – Voltage level of active bus.
- Line Hot – Voltage level of active Line.
- Reclose Limiter – The number and time span to Limit Reclosings.
- Y–Time – Amount of time necessary to allow a reclose after the reclose Limiter has stopped a reclose.
- Z–time – Maximum amount of time other timer can be stopped.

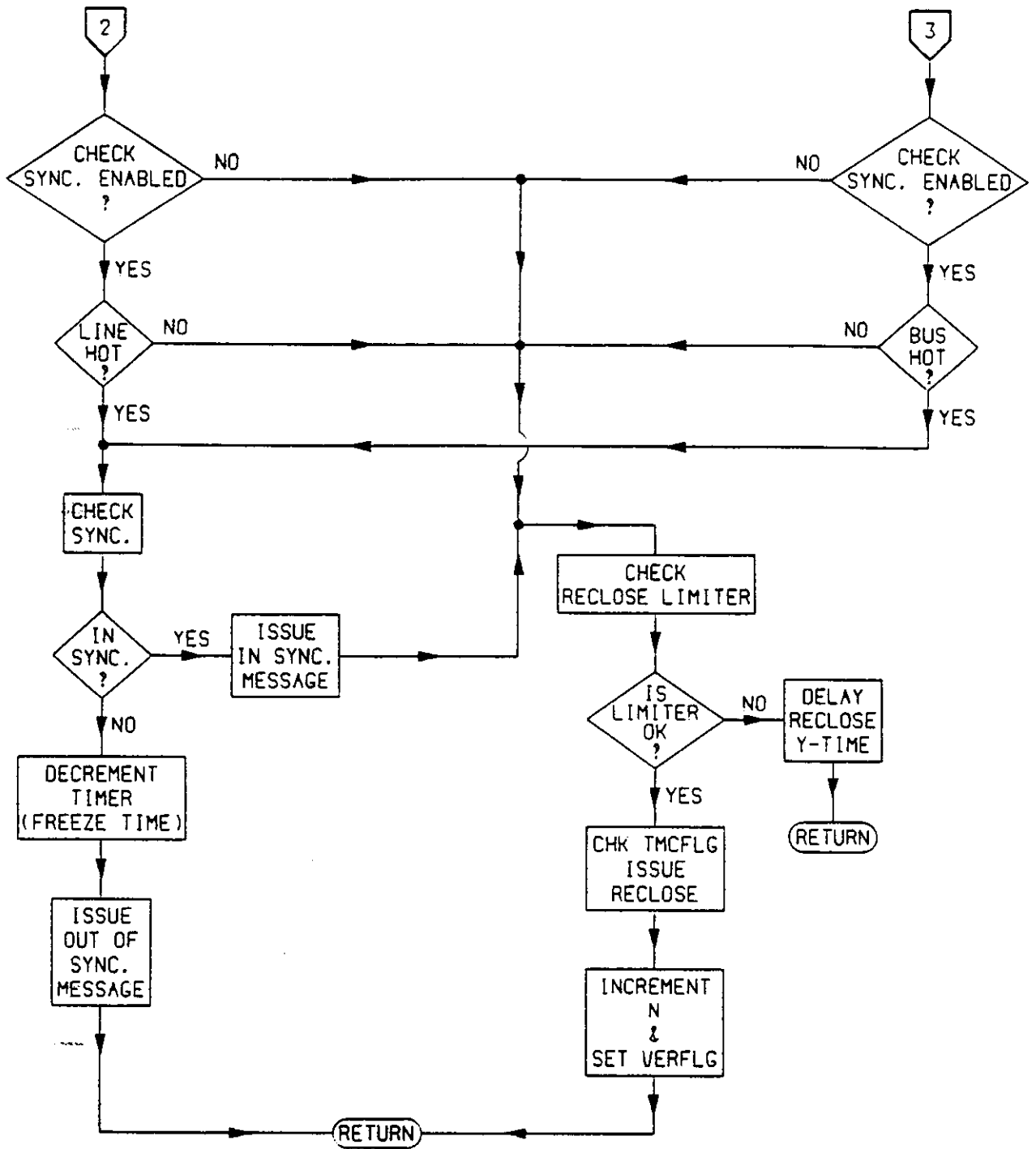
Reclose # N	Time ( n)	Reset Time (n)
1	10 sec	20 Sec
2	35	45
3	65	45
4	Lockout	—

All times are absolute and settable

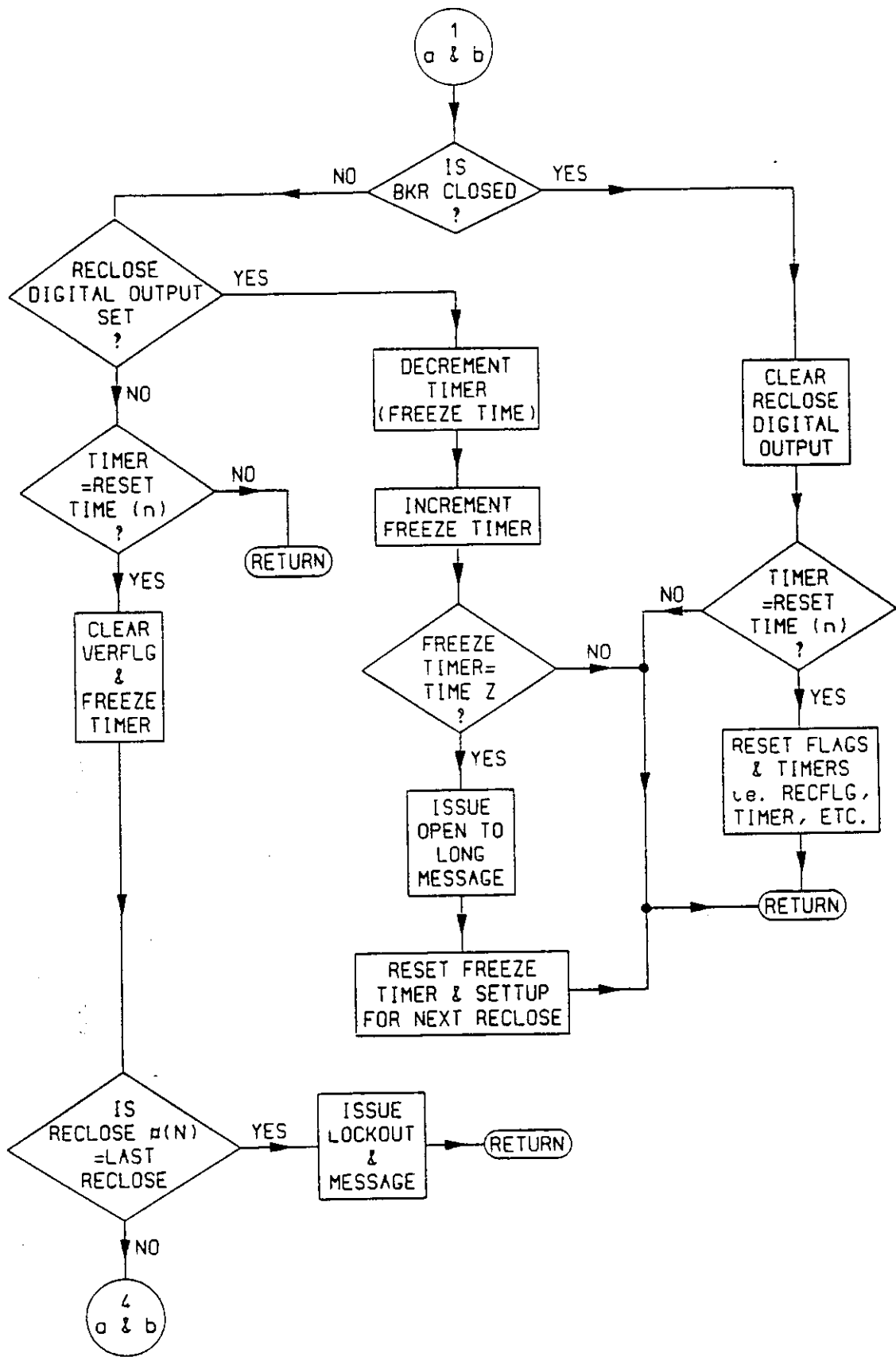


RECLOSE FLOW CHAR  
SH. 1 OF 3

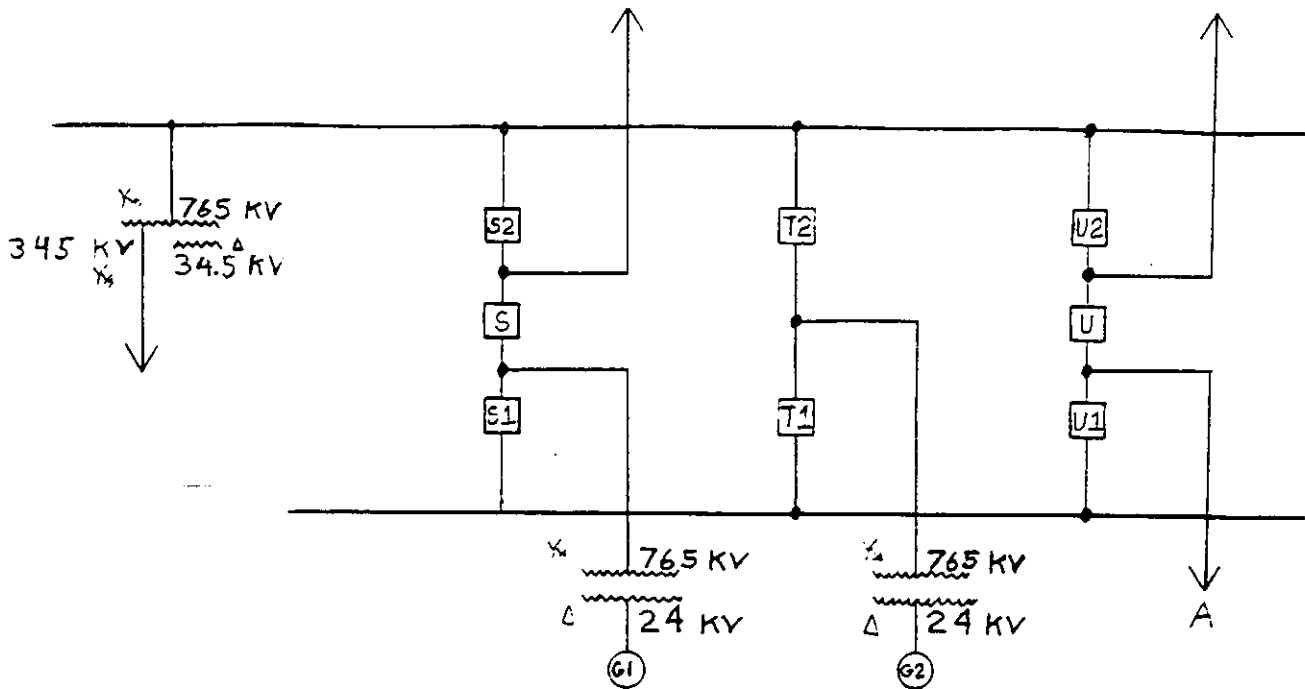
AP9



AP10

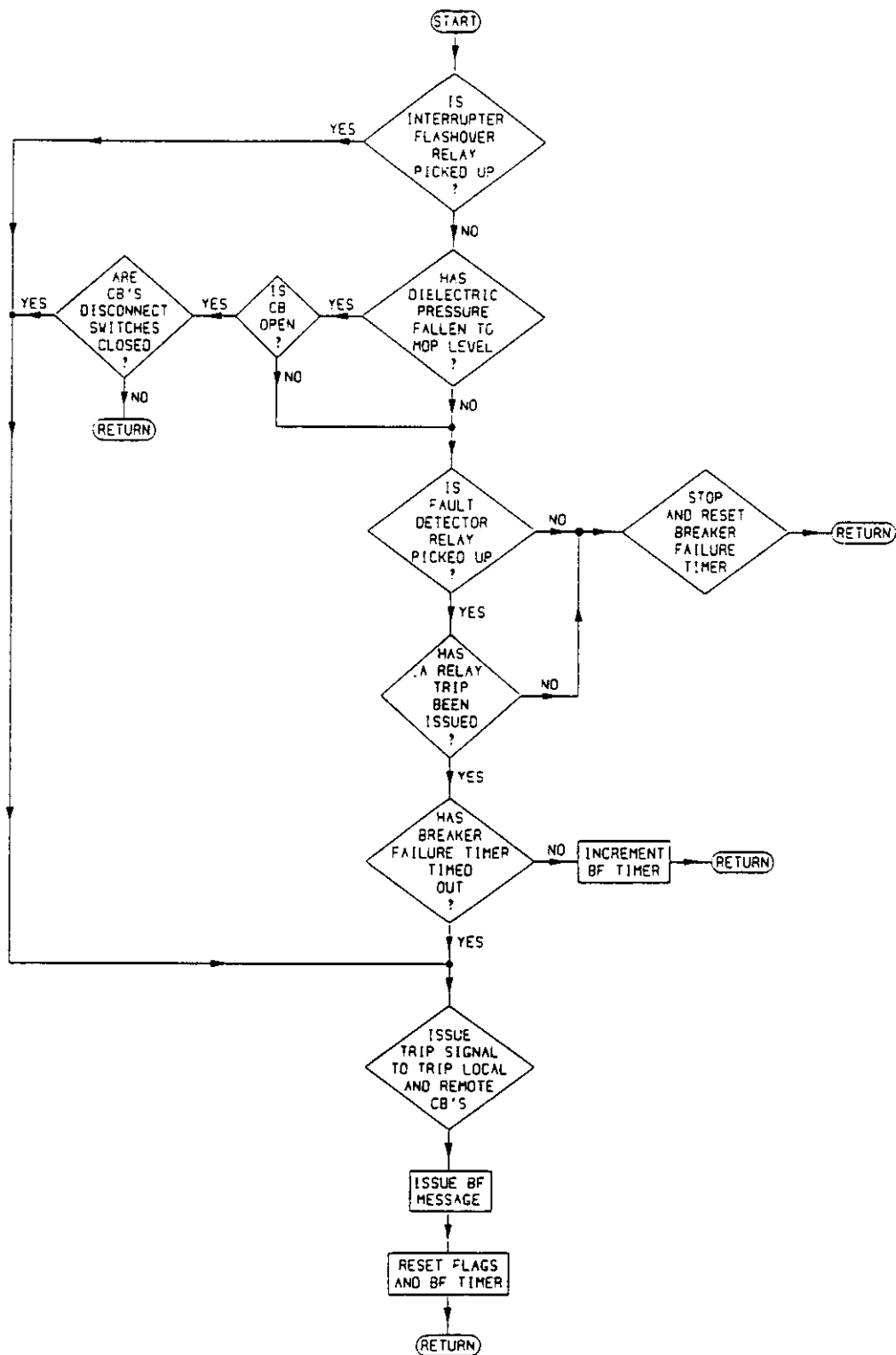


RECLOSE FLOW CHAR  
SH. 3 OF 3

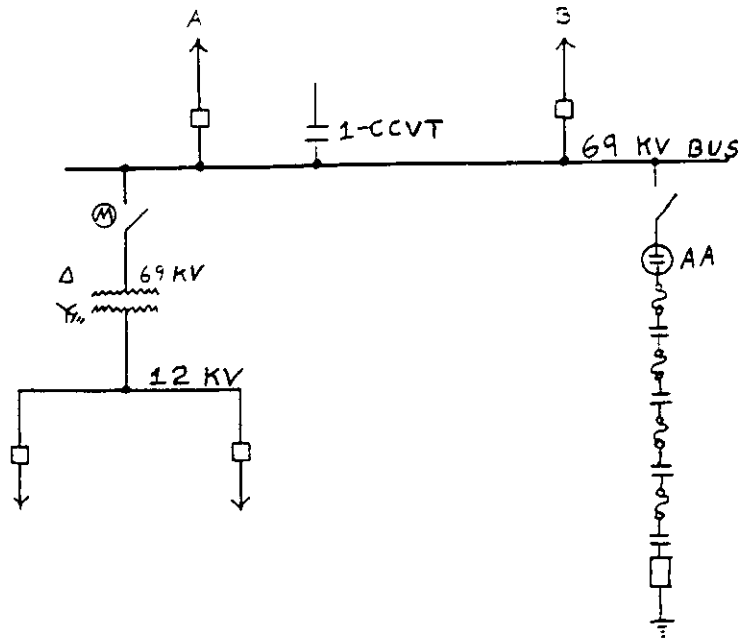


765kV Breaker Failure Operating Notes for CB U1

1. Interrupter flashover relay operates CB U1 breaker failure lockout relay.
2. The breaker failure lockout relay for CB U1 operates if the dielectric pressure has fallen to the MDP level, and the circuit breaker is open and the circuit breaker's disconnect switches are closed.
3. The breaker failure lockout relay for CB U1 operates if the fault detector relay picks up, and a relay trip has been issued and the breaker failure timer has timed out.
4. Circuit breaker U1 breaker failure lockout relay operates to perform the following:
  - A. Trip and lockout CB's U, T1 and S1.
  - B. Lockout CB U1.
  - C. Stop carrier current transmission on line A.
  - D. Operate carrier tone line and equipment transfer trip, to trip and lockout line A CB's at the remote end.

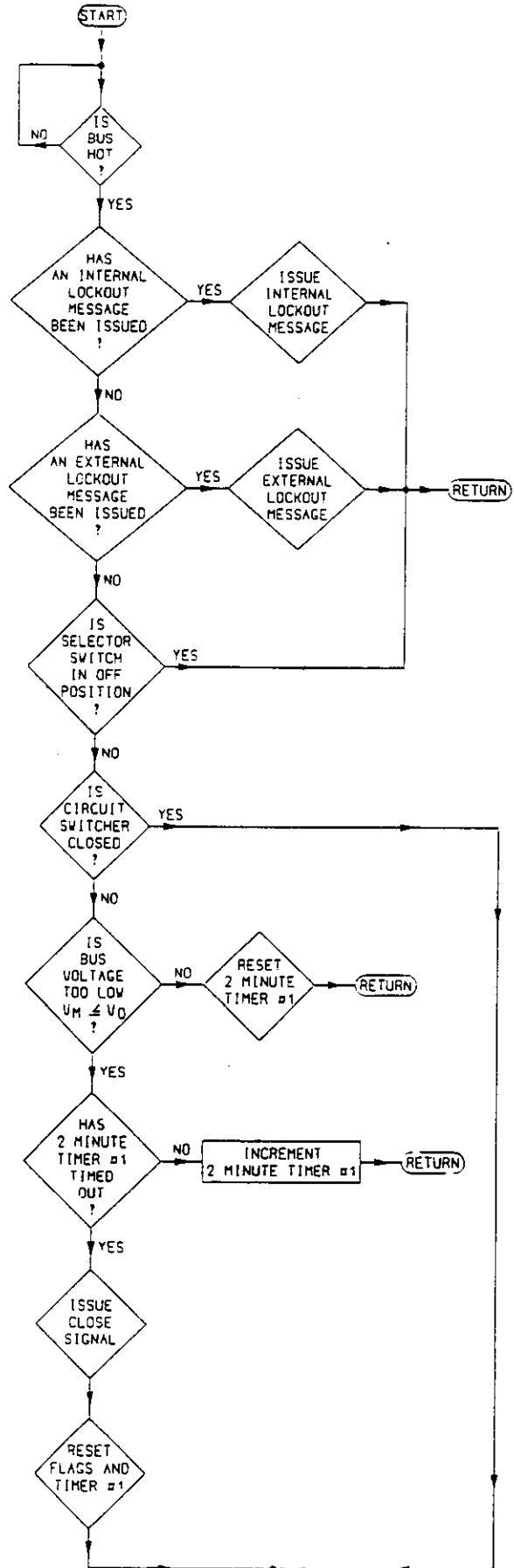
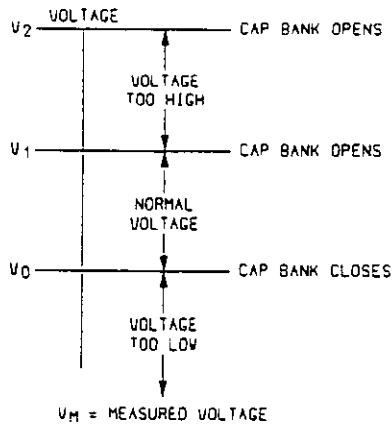


765KV BREAKER FAILURE  
FLOW CHART  
FOR ONE CIRCUIT BREAKER



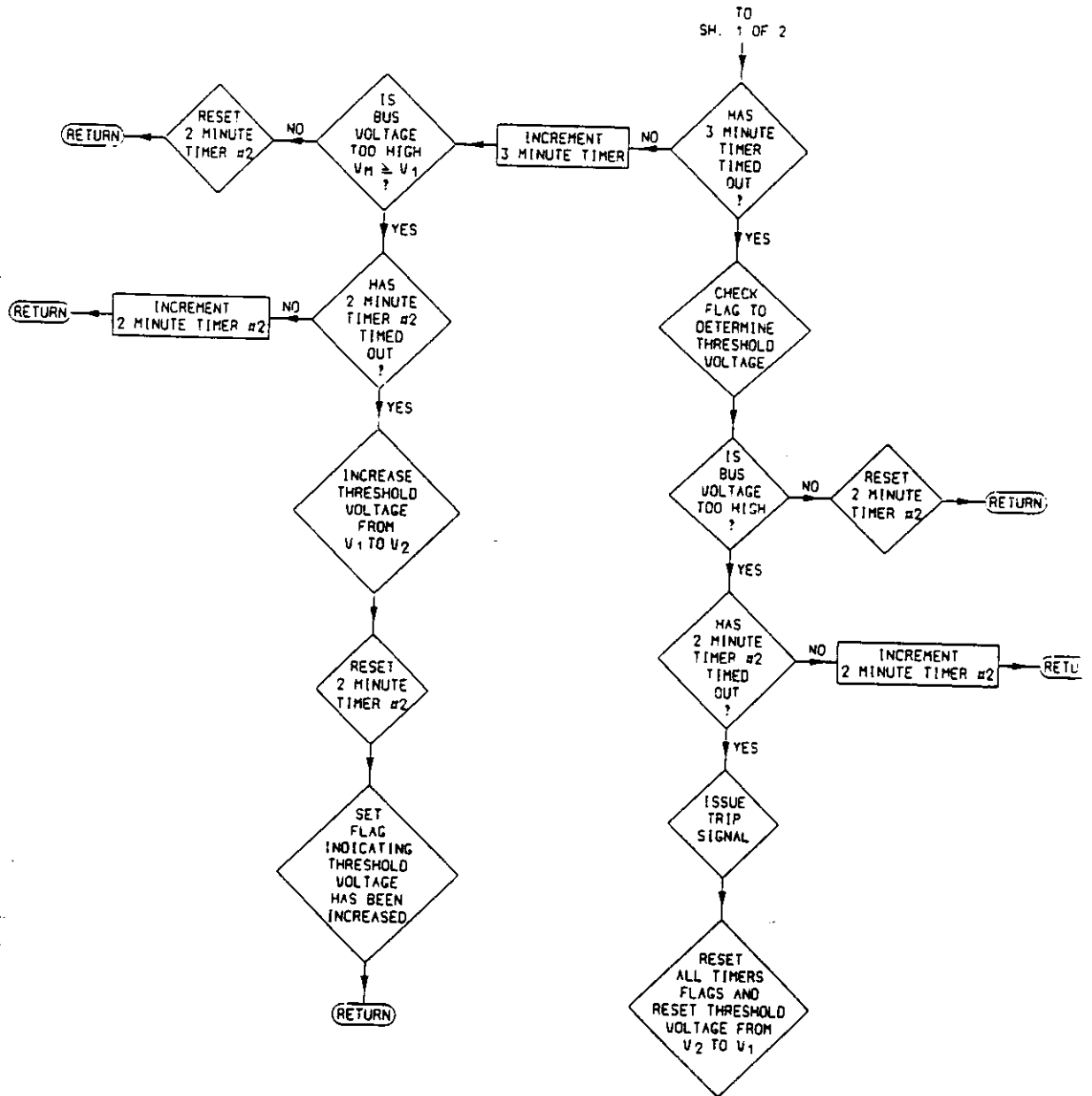
### 69KV BUS CAPACITOR BANK OPERATING NOTES

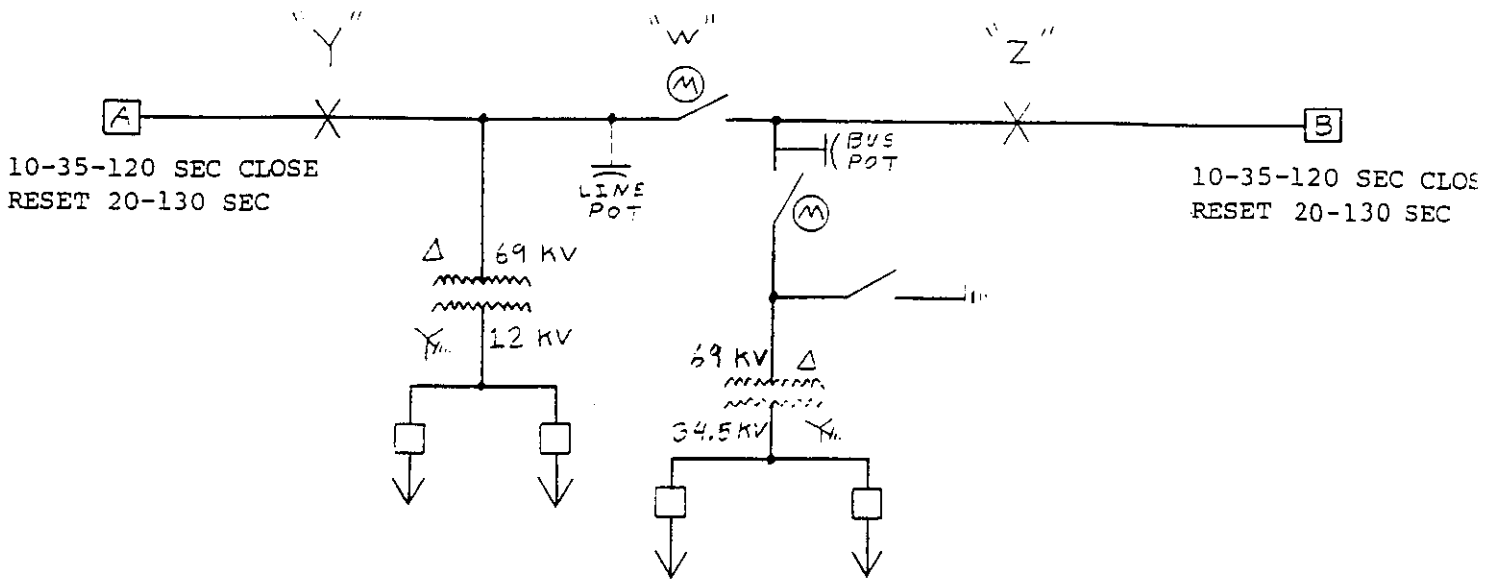
1. Vacuum switch AA is controlled by a contact making voltmeter on the 69kV bus potential.
2. Vacuum switch AA closes after a 2 minute time delay on occurrence of a low voltage (116.3 volts) provided the 69kV bus is energized.
3. Vacuum switch AA opens on occurrence of a high voltage after a 2 minute time delay as follows:
  - A. At 118.3 volts provided bus voltage does not rise to this level within 3 minutes of vacuum switch AA closing.
  - B. At 120 volts if bus voltage rises to 118.3 volts within 3 minutes of vacuum switch AA closing.
4. Automatic and manual closing circuit of vacuum switch AA is interlocked so that this switch cannot be closed unless 69KV bus is energized.
5. Overvoltage relay, set at 126 volts, trips capacitor bank lockout relay.
6. Capacitor bank lockout relay trips and locs out vacuum switch AA.



TO  
SH. 2 OF 2

BUS CAPACITOR BANK  
CONTROL FLOW CHART  
SH. 1 OF 2

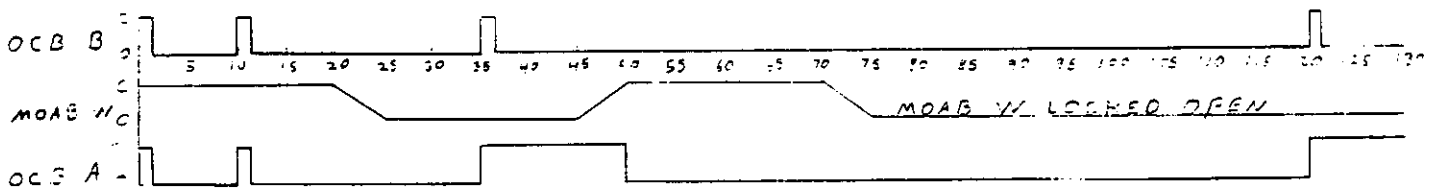




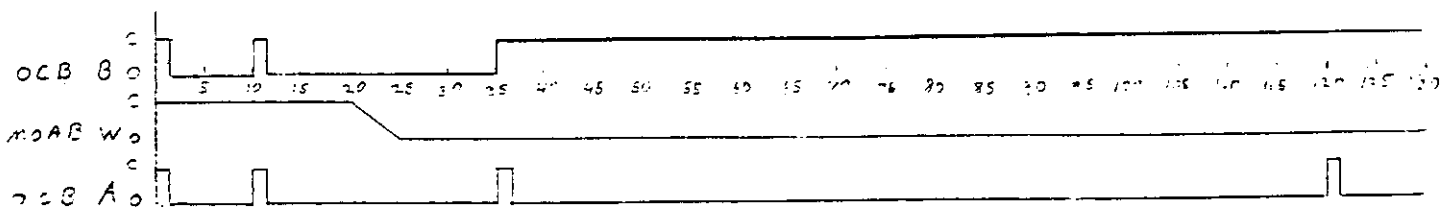
Line Sectionalizing Automatic Motor Operated  
Air Break Switch Control Operating Notes

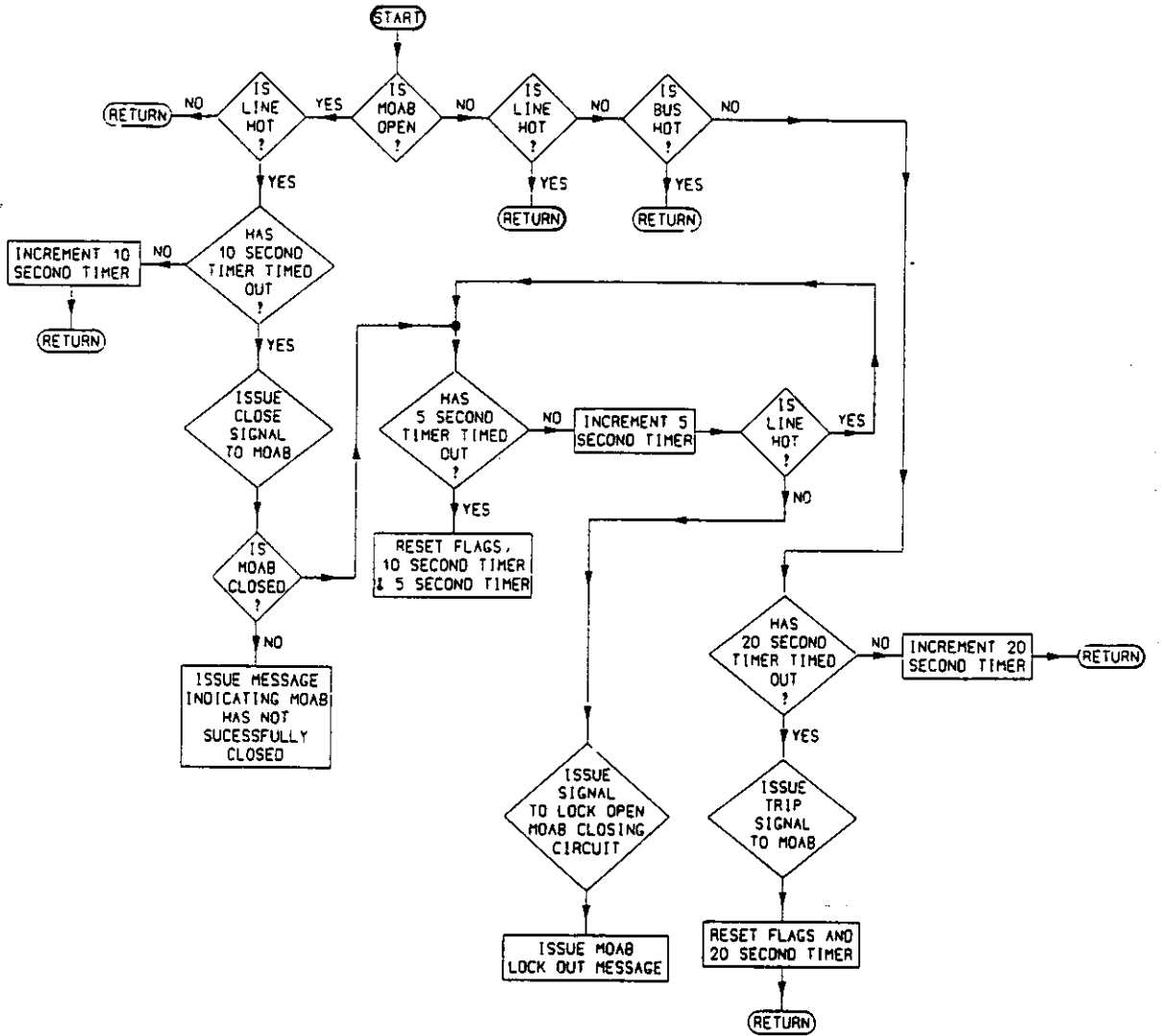
1. Air break switch W opens automatically after both line and bus have been deenergized for 20 seconds.
2. Air break switch W closes automatically after the associated line has been energized for 10 seconds.
3. Automatic closing circuit of air break switch W is locked out if associated line potential is deenergized within 5 seconds after closing automatically.

MOAB TIMING CHART FOR A PERMANENT FAULT AT "Z"



MOAB TIMING CHART FOR A PERMANENT FAULT AT "Y"





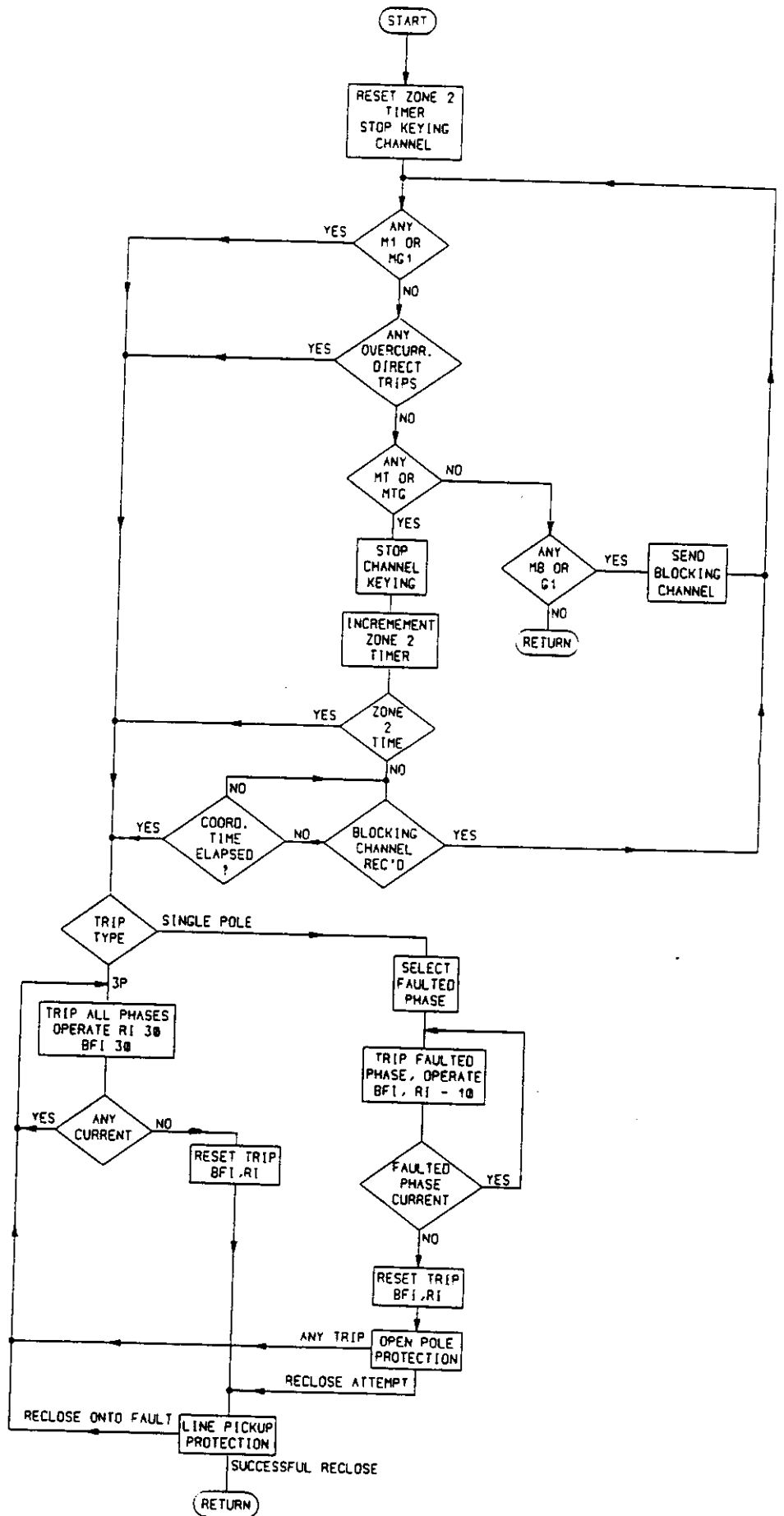
### Single Pole Trip and Reclose Flowchart Scheme Outline

The scheme depicted on the flow chart is a directional comparison blocking scheme using Type CS26 AM carrier. Two zones of phase and ground distance protection (M1, MT, MG1, MTG) are provided in the tripping direction. The blocking units for carrier starting consist of mho distance units (MB) for inter-phase faults and a sensitive, non-directional, ground overcurrent unit (G1) for ground faults. In addition, overcurrent units are used for direct tripping (high set) and trip bus seal-in (low set).

In standby, the scheme will first check for any direct trip operations. If any have operated, the scheme branches to the trip type selection (single pole or three pole). If none have operated, the overreaching distance units (MT, MTG) are then checked. If any of the overreaching units have operated, channel keying is blocked, the Zone 2 timer is initiated, and the scheme checks for a received blocking signal. If a blocking signal is not received by the time the channel coordination time has elapsed, then the scheme branches to the trip type selection logic. If a blocking signal is received, the scheme remains in the loop until the trip units reset, the blocking carrier resets, or the Zone 2 time is satisfied.

If the trip units have not operated, the blocking units are checked after the overreaching distance units. If a blocking unit has operated, then blocking carrier is sent to the remote terminal until the blocking unit resets or a local tripping unit operates. If no blocking unit has operated then the scheme resets and starts over.

The trip type logic determines if the scheme should produce a three pole trip or a single pole trip. For inter-phase faults or Zone 2 time trips all three poles are tripped, a three pole reclose is initiated, and the breaker failure scheme is energized. The scheme remains in this state as long as any current is detected in any phase. When the current units reset, the scheme enters the line pickup protection loop until the line is reclosed successfully at which time the scheme resets and starts over. If a single phase to ground fault is detected, the scheme trips only the pole associated with the faulted phase, initiates a single pole reclose, and energizes the breaker failure scheme. These remain energized until the current unit associated with the faulted phase resets. The scheme then proceeds to the "open pole period" protection loop until a reclose is attempted, at which time the scheme branches to the line pickup protection loop.



## Phase Angle Regulator Control

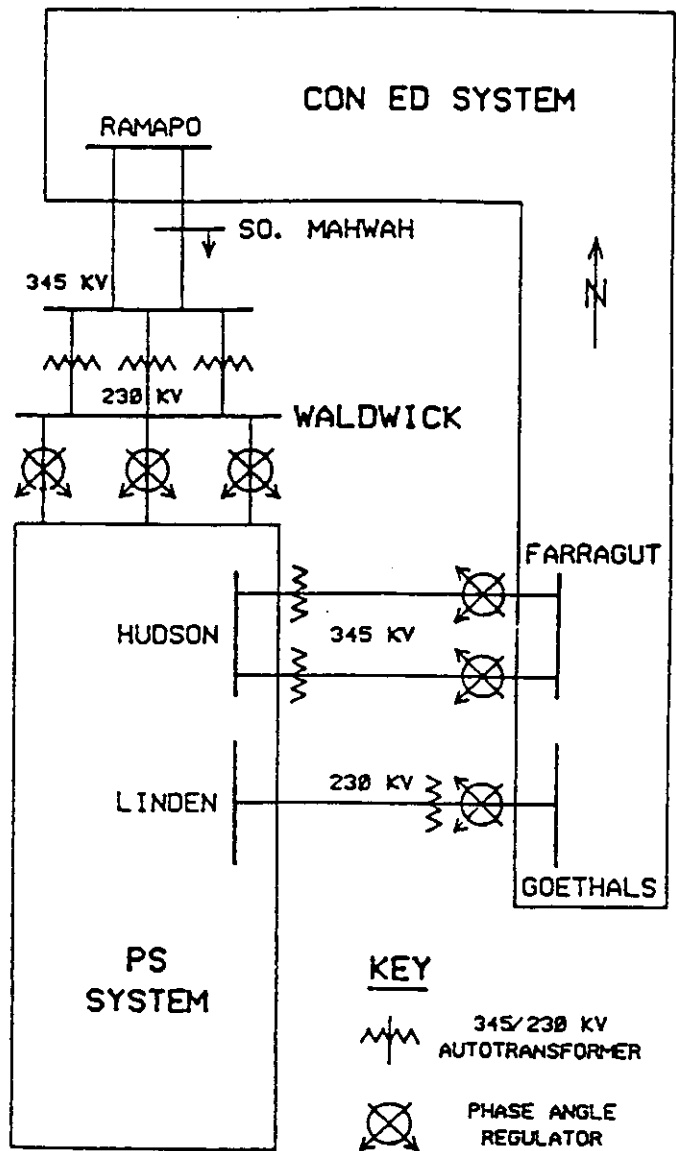
In order to provide positive control at all times on a 345kV underground cable interface designed to transfer up to 1000MW, a Programmable Controller (PC) has been installed at PSE&G's Waldwick Switching Station. This PC will independently take corrective action by moving phase angle regulator transformer (PAR) load tap changers (LTC) upon recognition of local flows exceeding emergency ratings after a time delay of five minutes.

The control log of the PC is shown in the flow diagram. The PC detects an overload on a facility and reduces it below the long-time emergency rating of that facility by operation of the PAR's LTC. An overload is present any time the current through a monitored facility exceeds its long-time emergency rating. Stated another way, an overload exists when the flow to rating ratio on any facility exceeds one (1.0). Upon first detection of the overload, the PC initiates a 5 minute alarm to the ESOC and starts a 5 minute timer.

At the end of 5 minutes the PC checks to see if an overload still exists. If the overload is gone, the PC takes no action. If the overload persists, the PC begins its control.

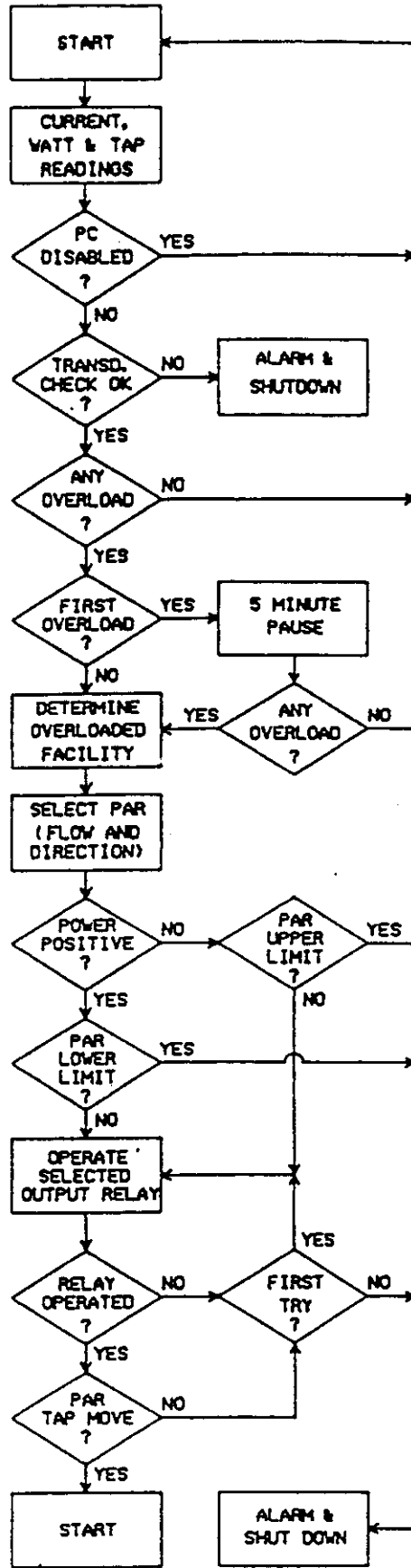
To reduce the overload, the PC selects the PAR with the highest ratio of flow to rating and a power flow in the same direction as the overloaded facility. If the flow of the overloaded facility is in the negative direction (north), the PC raises the tap of the selected PAR. If the flow is in the positive direction (south), the tap of the selected PAR is lowered. This scheme relieves the most severe overload while reducing the possibility of creating an overload in another facility.

To effect a tap change, the PC checks the tap position of the selected PAR. If the PAR is at the limit of its tap movement, the PC goes into an alarm state. Once in an alarm state, the PC takes no further action other than displaying in code, on its LED display, the reason it stopped and signaling the ESOC that a failure has occurred. The PC remains in that state until manually reset by a substation operator. If the PAR is not at its limit, the PC initiates a tap move by operating of one of its control relays. The PC pauses six seconds to allow the PAR time to change tap position. Should the attempted move be unsuccessful, the PC immediately retries the same PAR. Two consecutive failures cause the PC to go into the alarm state. After any successful tap move, the PC returns to the start of its control logic. If an overload still exists, the PC bypasses the 5 minute timer and continues to attempt to move taps until all overloads are relieved.



PS-CON ED INTERFACE

# PHASE ANGLE REGULATOR CONTROL

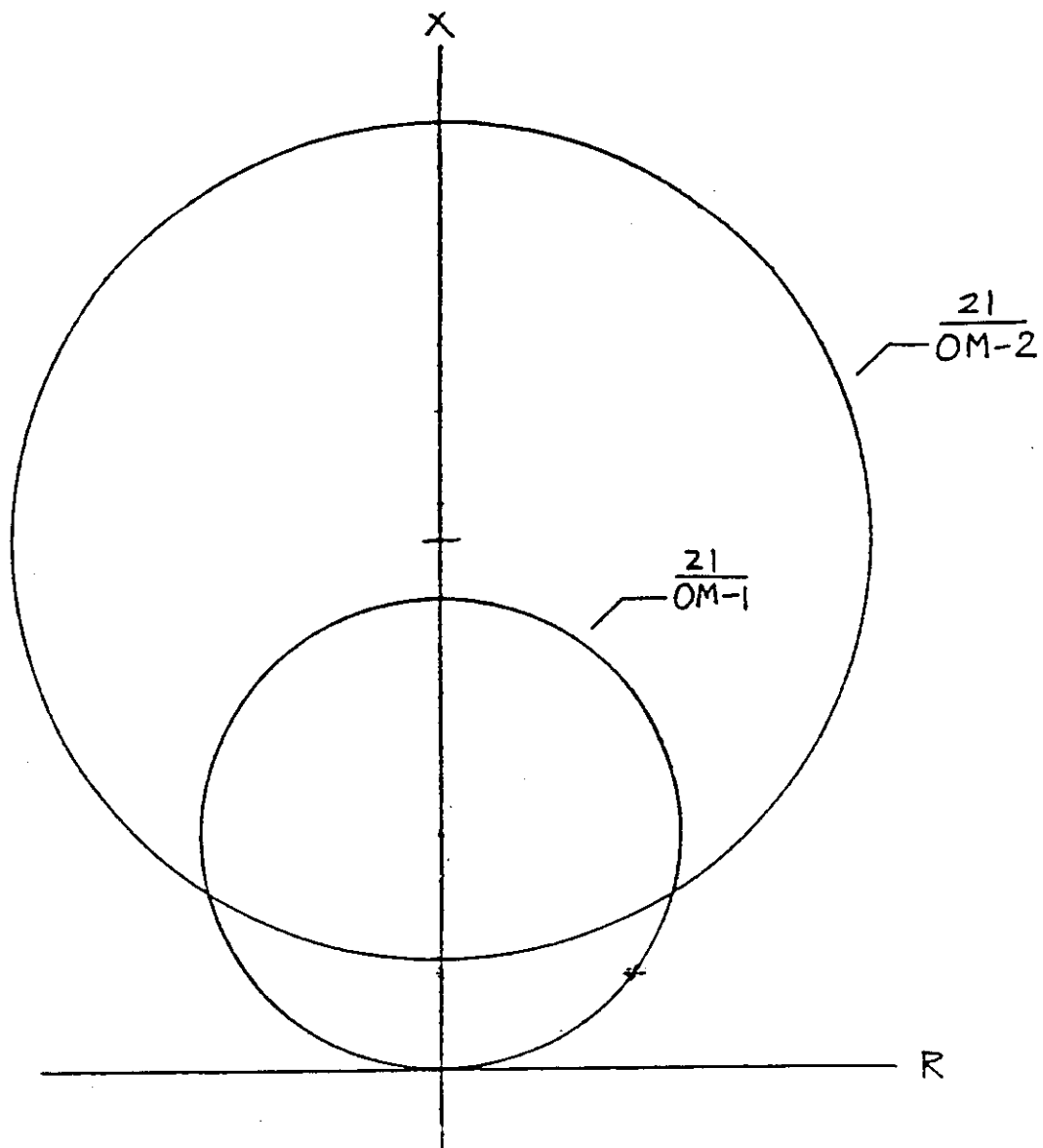


BASIC CONTROL LOGIC

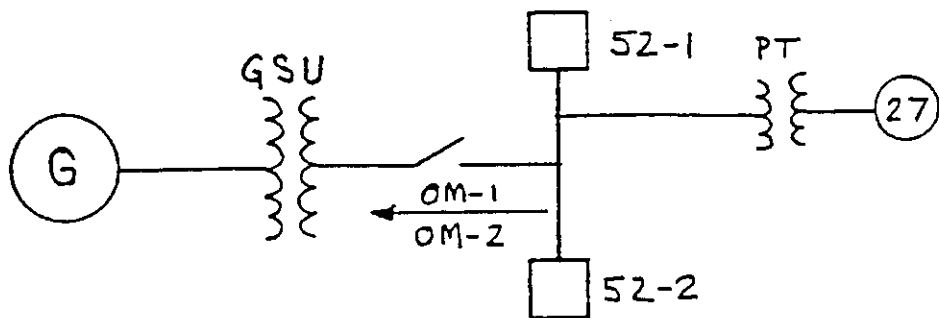
Protection Against Accidental Energization  
Of a Generator on Turning Gear

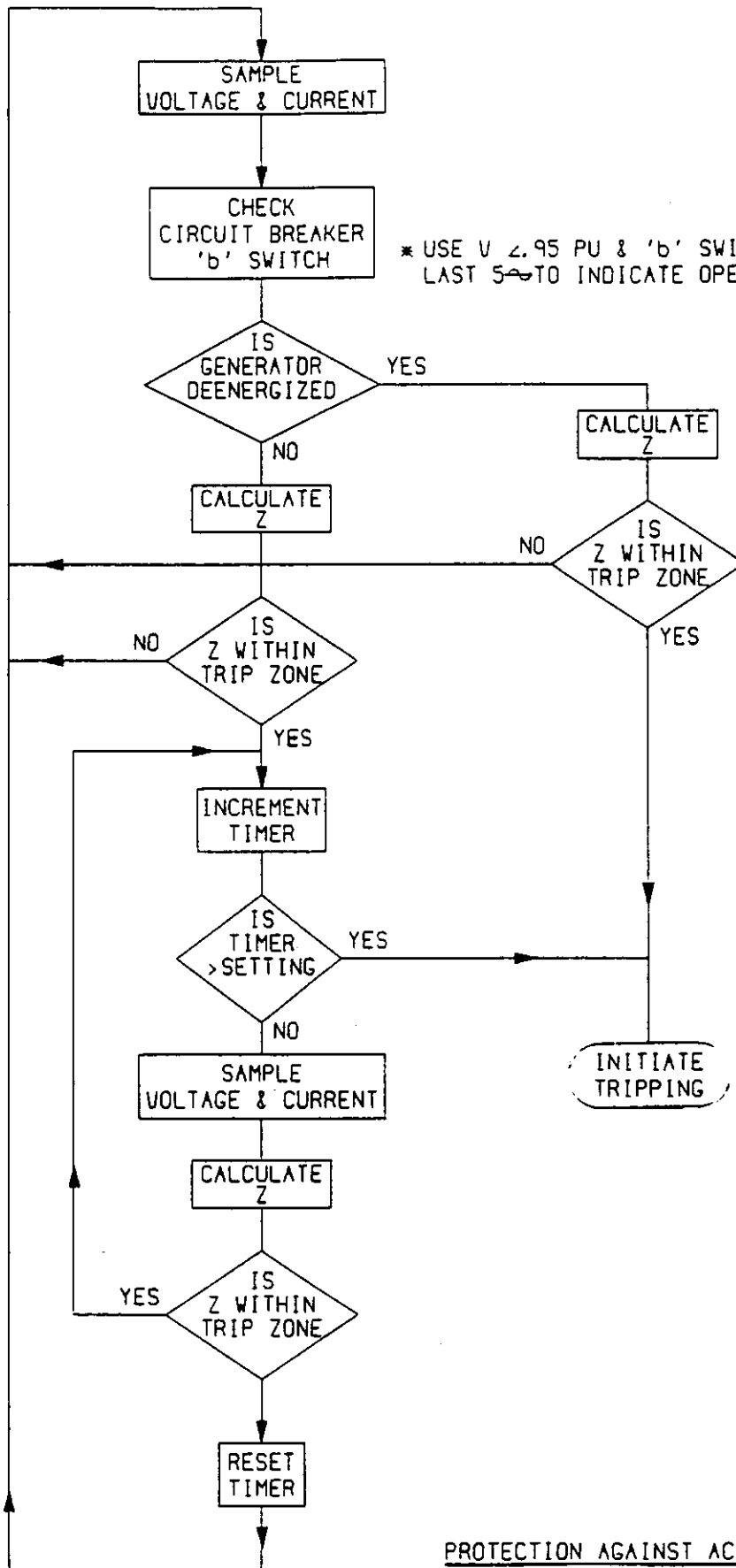
The scheme provides time delayed backup for faults in the generator or transformer during normal service as well as instantaneous tripping while at standstill or on turning gear. Both undervoltage and the breaker 'b' switch are used to determine that the machine is out of service; this prevents a stuck 'b' switch from switching the protection to high speed tripping. A 5 ~ window of high speed tripping is provided after the 'b' switch opens.

The tripping region should be similar to that shown on the attached sketch as OM-1 and OM-2. The OM-1 is set for a reach of one per unit impedance. This setting will cover the transformer impedance plus the generator subtransient reactance. The OM-2 should be sufficient to include the synchronous reactance of the machine.



21-CEH99





\* USE  $V \geq 0.95$  PU & 'b' SWITCH CLOSED WITHIN LAST 5s TO INDICATE OPEN BREAKER.

PROTECTION AGAINST ACCIDENTAL ENERGIZATION OF A GENERATOR ON TURNING GEAR

Description of the flow chart concerning bus changing

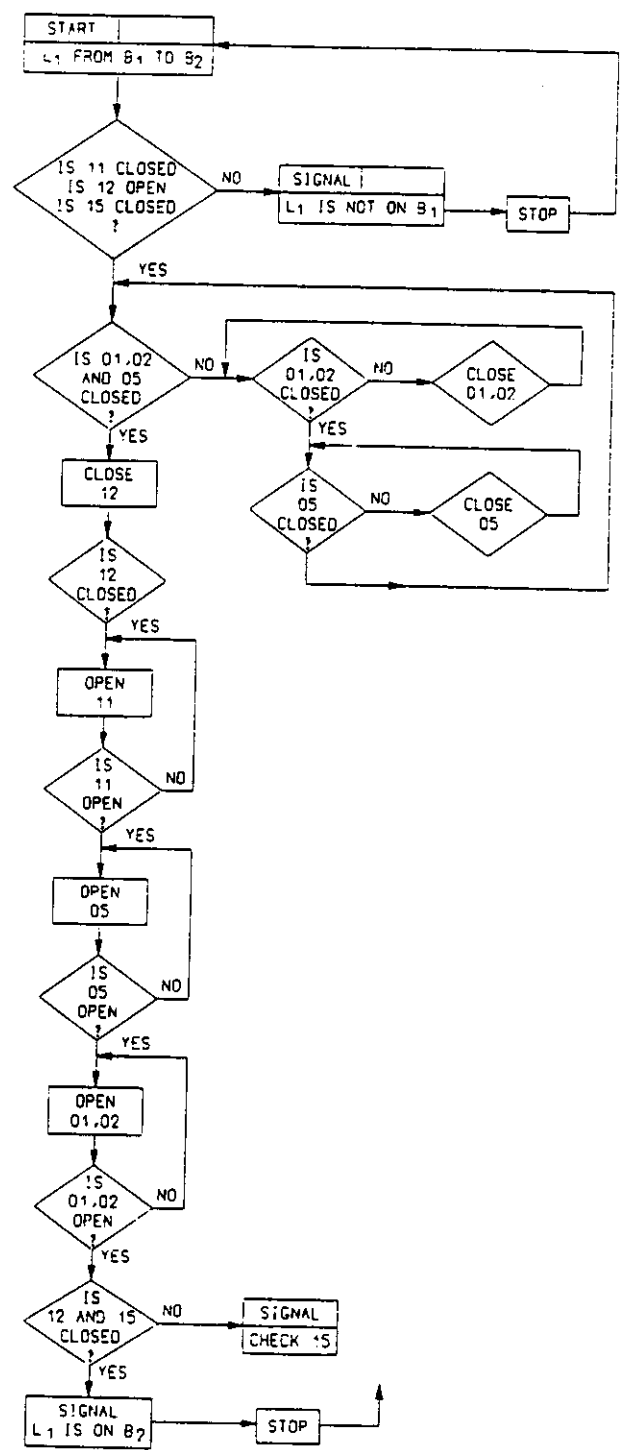
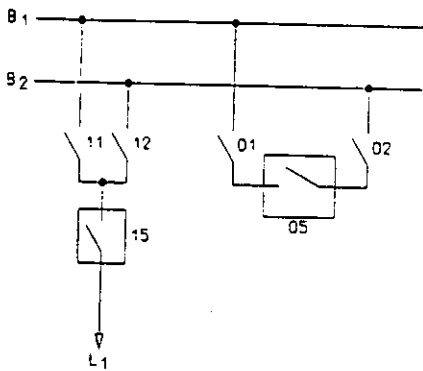
The action shall change the connection of line  $L_1$  to bus  $B_2$ .

Start: 11 + 15 is closed, 12 open

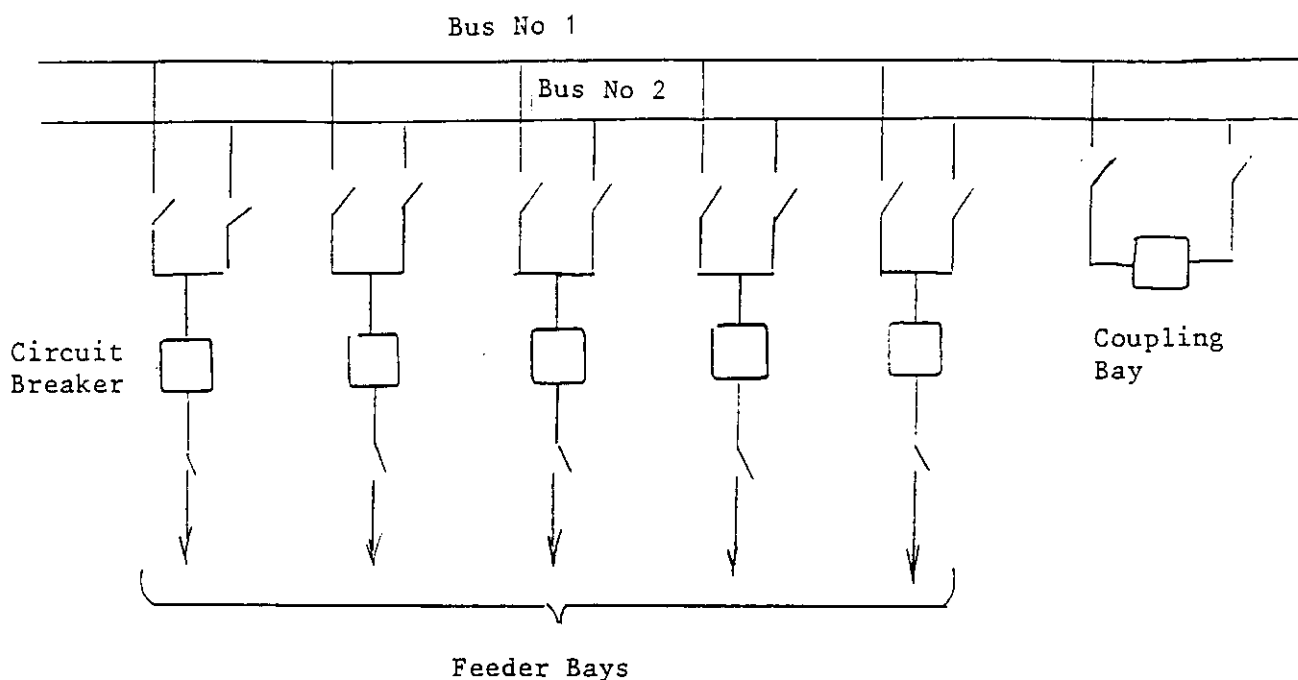
End: 12 + 15 is closed, 11 open

Between Start and End: 01, 02 and 05 has to be closed, to enable the isolators 11 and 12 to switch over without current.

After closing 01 and 02 and afterwards 05 the two buses are connected via 05 and therefore 12 can be closed, paralleling now 11. Then 11 is to open and consequently the bypass 05 will be opened following by the opening of 01 and 02.



## Switching Sequences: Operating Notes



### 2-Bus Station

Switching Sequences are aimed to modify the circuit configuration within the substation, securely and as quickly as possible.

A whole sequence is composed of successive orders to the breakers or to the disconnecting switches. The orders are automatically chained, the one after the other. Sometimes, each order has to be acknowledged by the operating people before being executed.

For determining the individual orders, two principal methods are used:

- (1) Orders may be preregistered in the nonvolatile memory of the computer (preregistered switching sequences).
- (2) Orders are determined by program before execution (functional switching sequences).

Four Switching Sequences are described hereafter:

- 1) Feeder in on a given bus bar  
A disconnected feeder has to be connected to a given bus.
- 2) Feeder out  
A connected feeder has to be completely disconnected (the disconnecting switches have to be opened at the end of the operation).
- 3) Bus exchange for a single feeder  
A feeder connected to bus #1 has to be switched to bus # 2 without interruption and vice versa.
- 4) Bus exchange for all feeders  
All feeders connected to bus # 1 have to be switched to bus # 2 without interruption and vice versa.

#### REMARKS

Feeder in:	The disconnecting switches are first operated. The circuit breaker is closed last.
Feeder out:	The circuit breaker is operated first.
Bus exchange:	The circuit breaker is not operated, not the line disconnecting switches.  First, the switch to busbar 2 is closed and then, the switch to busbar 1 is opened.  The coupling breaker has to be closed in before exchanging feeder from busbar.

#### General Features

The following flow charts of switching sequences are applicable to 2 or 3 busbar sub-stations, with only one circuit breaker per feeder.

Between two successive commands, a delay is always provided.

If anything goes wrong during the operation, the sequence is stopped and the substation remains in the latest configuration.

Four flow charts are given as examples.

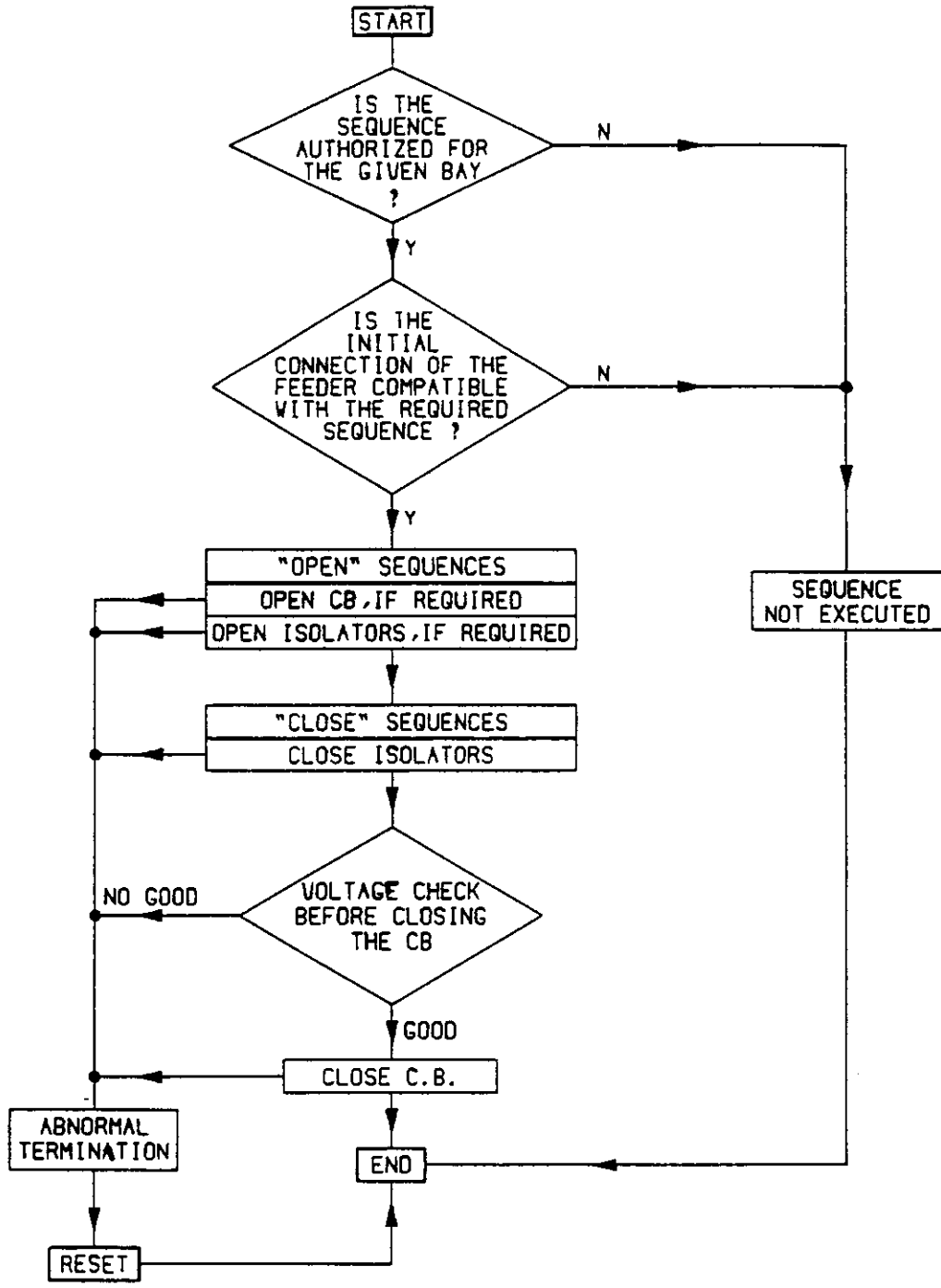
1. Feeder switched in to a given busbar.
2. Feeder switched out.
3. Bus exchange for one feeder.
4. Bus exchange for all feeders.

### Remarks

In the following flow—charts, the expression "if required", applied to the operation of the high voltage gear indicates that the operation is not executed if the gear is already in the required position.

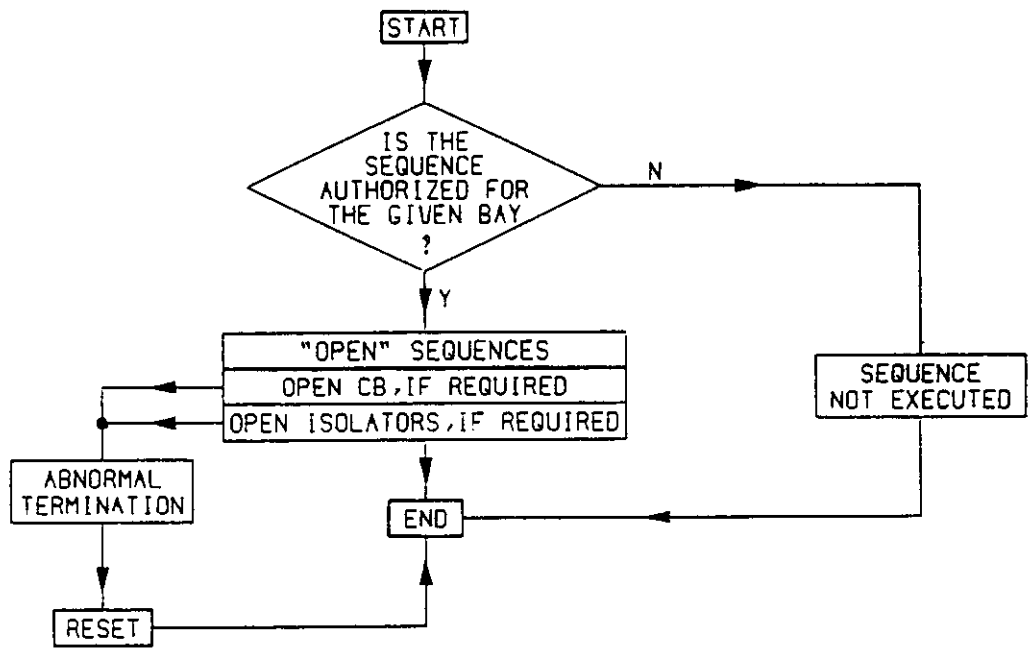
### Remarks

- (1) The sequence is not executed if several conditions are not satisfied.
  - The bay is temporarily out service.
  - The bay may not be operated from local or remote control.
  - A high voltage gear in the bay is out of service.
- (2) The sequence is not executed if the initial connection of the feeder is incompatible with the required sequence.
  - The feeder is already connected to the destination busbar.
  - The feeder is connected to another busbar.
- (3) Abnormal terminations are:
  - No back signalization after a command.
  - Double signaling contact are not complementary.
  - Time out elapsed after command.
  - Interlocking not verified.
  - Voltage conditions not good for closing a circuit—breaker.
- (4) Closing a coupling between 2 busbars is a special case of a "Feeder In". There are isolators operations and a breaker operation, the latest one being preceded by a voltage check.

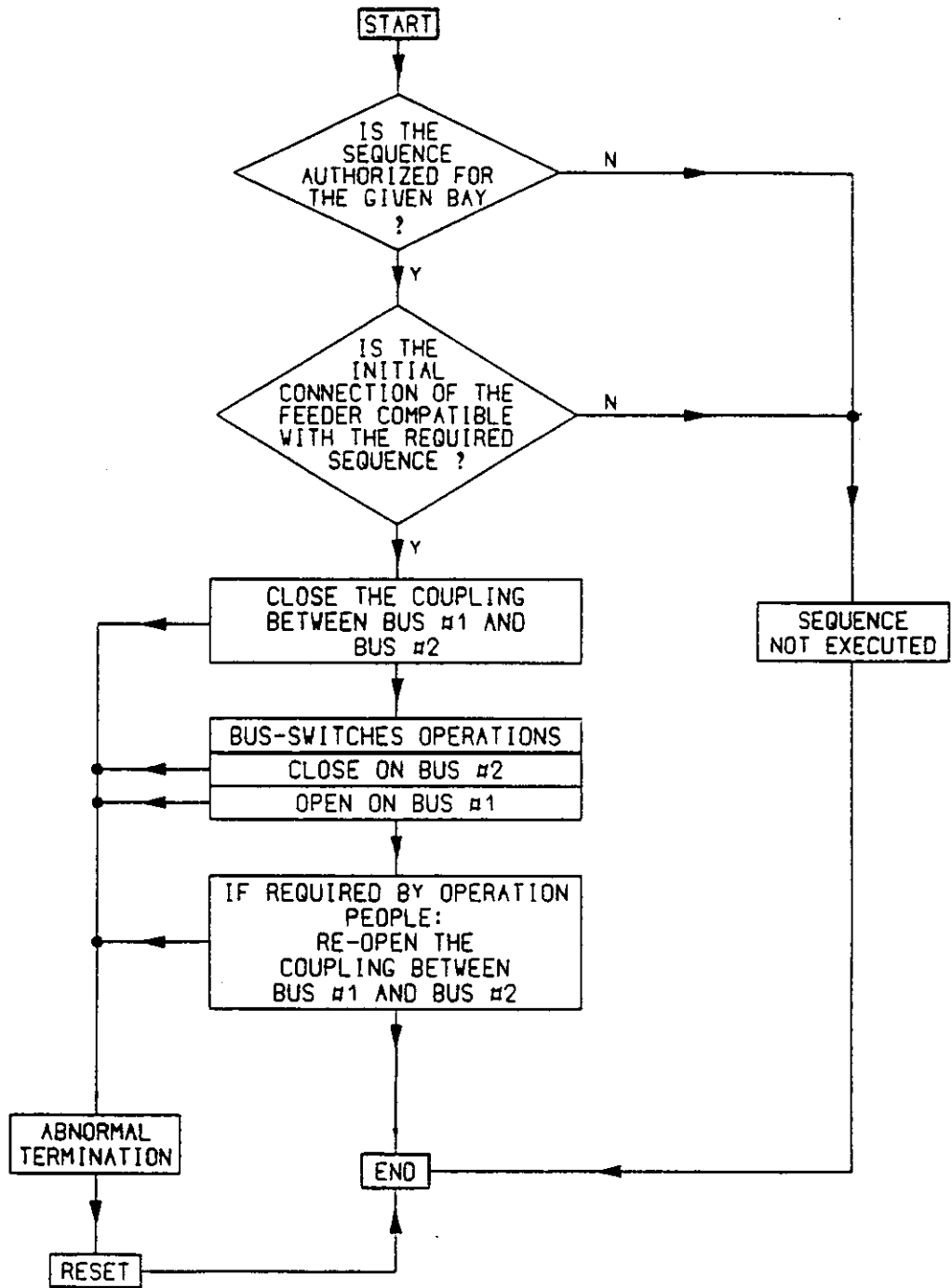


FEEDER SWITCHED IN ON BUSBAR No. X

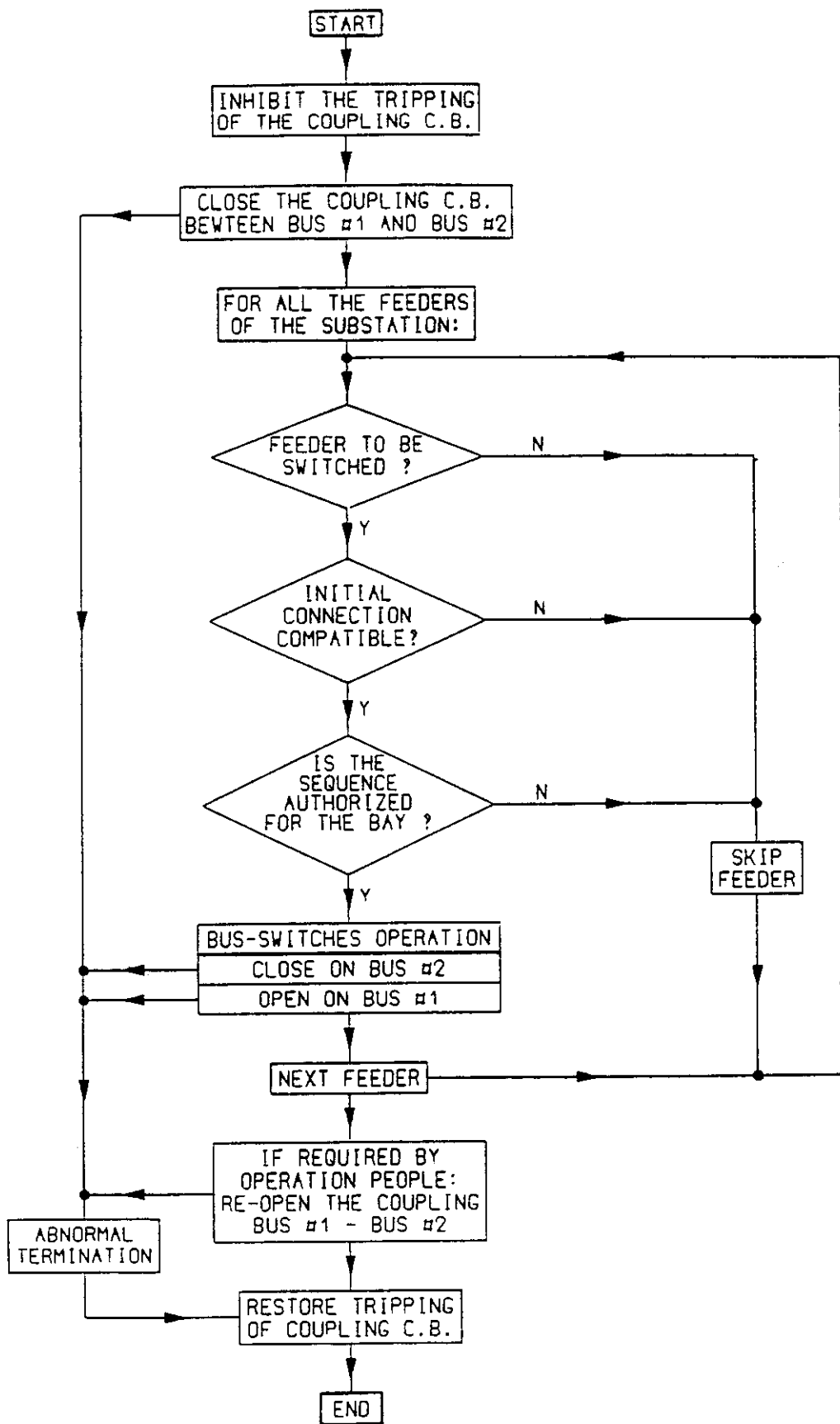
AP1



FEEDER SWITCHED OUT



CHANGE OVER FROM  
BUS No. 1 TO BUS No. 2  
(ONE FEEDER)

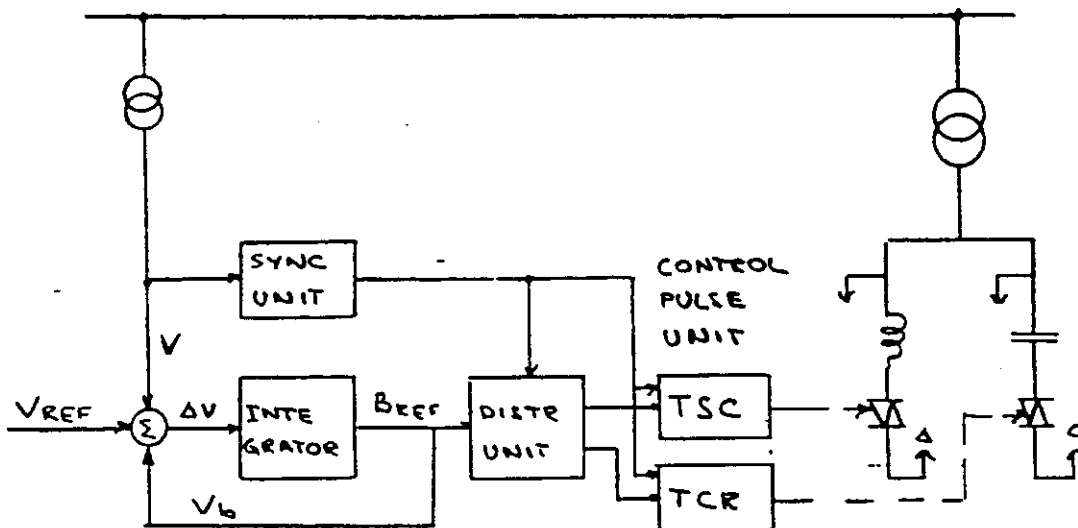


CHANGE OVER FROM  
BUS No. 1 TO BUS No. 2  
(ALL FEEDERS)

## Voltage Control for a Static VAR Compensator (SVC) System

The main input to the automatic voltage regulator is the voltage on the main voltage bus. The voltage response ( $V$ ) is fed to the summing junction of the regulator together with the voltage reference ( $V_{ref}$ ).

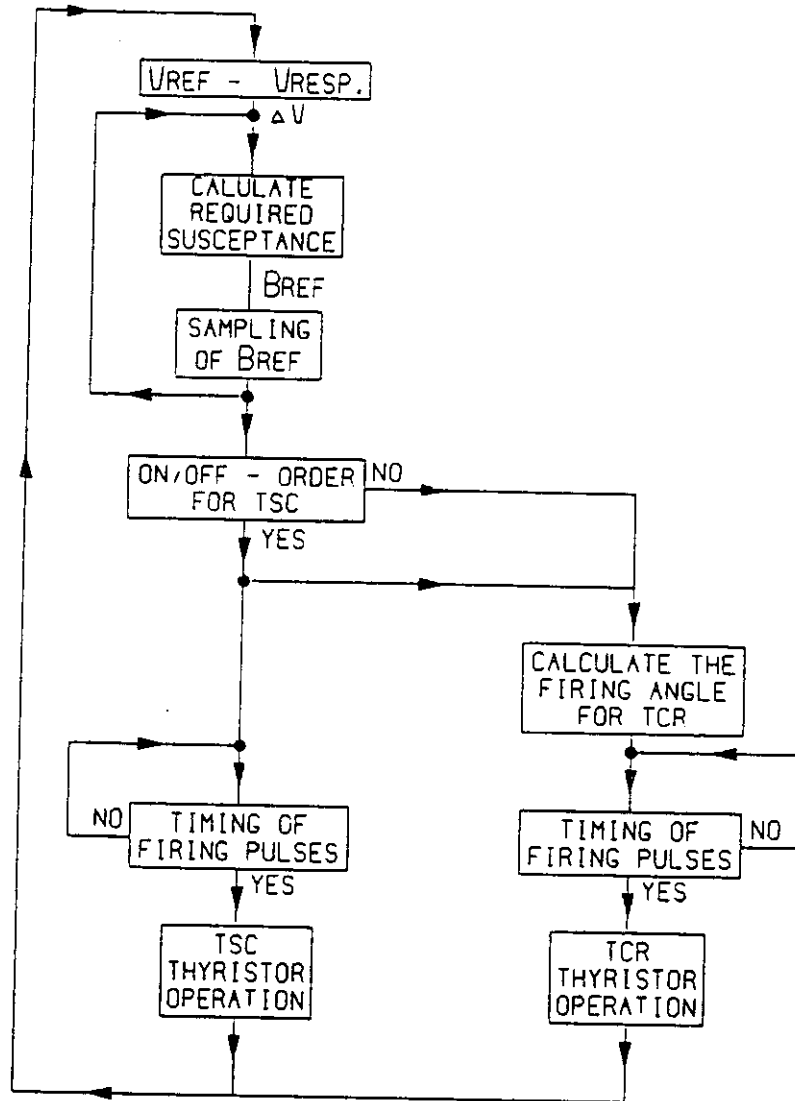
If the voltage response deviates from the reference, an error signal ( $\Delta V$ ) will appear. This signal is fed to an integration amplifier, with an output that will increase or decrease, depending on the sign of  $\Delta V$ , until  $\Delta V$  is zero and  $V = V_{ref}$ . The output from the integrator is the susceptance reference  $B_{ref}$ , for the SVC.  $B_{ref}$  is decomposed in the distribution unit in a digital signal ("On/Off-order for TSC) and an analog signal (control signal for TCR) in such a way that the effective susceptance of the SVC will correspond to the susceptance reference.



SVC Control System. Block Diagram.

A droop compensation is achieved by reedback of the regulator output ( $B_{ref}$ ). A signal  $V_b$  proportional to  $B_{ref}$  is formed and added to the summing junction of the regulator.

The control system contains also a synchronizing unit, which ensures the exact timing of the control pulses to the thyristors as well as the sampling of regulator signals.



VOLTAGE CONTROL FOR A STATIC VAR COMPENSATOR (SVC) SYSTEM

## Appendix IV

### Example of Standard Data File Format

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## APPENDIX IV

This appendix includes copies of two sample files, one containing the header and the other containing the data recorded at a utility substation. The files are recorded in ASCII. The header file, named HEADER01, is alphanumeric in nature and the data file, named DATA01, contains numerical information.

### HEADER01

#### SOURCE ORGANIZATION:

Saskatchewan Power Corporation  
2025 Victoria Avenue  
Regina Sask.  
Canada S4P 0S1

#### CASE IDENTIFICATION:

Currents and voltages, and digital outputs in this file were sampled from the Condie terminal of the 230 kV transmission line, No. 907, from Condie to Popular River. The Condie switching station, P2C, is located near Regina in the Province of Saskatchewan, Canada. The 230 kV transmission line branches into a Tee at the Condie end. On either side of the branch is a circuit breaker. The currents in the two branches are sampled and the sum of the currents in the two branches (i.e. current in the line) is also sampled.

This case concerns a disturbance on the transmission system of the Saskatchewan Power Corporation. The type of fault and its location are not known. The parameters of the system element on which the fault was experienced and the source impedances are, therefore, not known.

- The operating conditions that existed immediately prior to the occurrence of the disturbance were not recorded. However, six cycles of pre-disturbance data is recorded in this file and the operating conditions can be calculated from that data.

The disturbance occurred on 1983-04-13 at 13:53:23 hours.

#### NATURE OF DATA:

Six cycles of pre transient data and eight cycles of post transient data are on the file. In total there are fourteen cycles of data recorded on the file.

#### SAMPLING INFORMATION:

Data has been sampled at 480 Hz.

#### ANTI\_ALIASING FILTERS:

Anti-aliasing filters used for recording this data were second order Butterworth filters that have a cutoff frequency of 180 Hz.

#### MIMIC CIRCUITS USED:

No mimics were used in this case.

#### DATA FORMAT:

All data is recorded as offset binary integers with 0 corresponding to -10 volts and 4096 corresponding to +9.995 volts. Data is recorded in the format I6. Data is separated within each record by a comma.

#### DATA IDENTIFICATION:

The information in columns three through six are the sampled values of the measured sum of the currents in the two branches. The information in columns seven through ten are the sampled values of the measured currents in one of the branches of the Tee. The information in columns eleven through fourteen are the sampled values of the measured currents in the other branch of the Tee. In each case three phase currents and the sum of the three phase currents (representing the  $3I_0$  current) are sampled. Columns fifteen to seventeen contain sampled values of the measured phase-voltages. The sampled values of the measured power are recorded in column eighteen. This totals sixteen channels of analog data. The status of sixteen event channels is also recorded. The event channels monitor the flags on relays associated with the line. The time skew of recording within each data set is not known. The nature of data in each column and the scaling factor for each operating parameter are as follows.

Column #1: Serial number of data set

Column #2: Time in milliseconds from the beginning of the record

Column #3: 907 RC1 Red Phase Current (1V = 320A)

Column #4: 907 RC1 Yellow Phase Current (1V = 320A)

Column #5: 907 RC1 Blue Phase Current (1V = 320A)

Column #6: 907 RC1 Neutral Current (1V = 320A)

Column #7: 907 AC4 Red Phase Current (1V = 320A)

Column #8: 907 AC4 Yellow Phase Current (1V = 320A)

Column #9: 907 AC4 Blue Phase Current (1V = 320A)

Column #10: 907 AC4 Neutral Current (1V = 320A)

Column #11: 907 BC4 Red Phase Current (1V = 320A)  
 Column #12: 907 BC4 Yellow Phase Current (1V = 320A)  
 Column #13: 907 BC4 Blue Phase Current (1V = 320A)  
 Column #14: 907 BC4 Neutral Current (1V = 320A)  
 Column #15: 907P Red Phase Voltage (1V = 23000V)  
 Column #16: 907P Yellow Phase Voltage (1V = 23000V)  
 Column #17: 907P Blue Phase Voltage (1V = 23000V)  
 Column #18: Power Transducer (No conversion factor given)  
 Column #19: Event channel #1 RY, YB, BR 21-1 907L  
 Column #20: Event Channel #2 R 21N-1 907L  
 Column #21: Event Channel #3 Y 21N-1 907L  
 Column #22: Event Channel #4 B 21N-1 907L  
 Column #23: Event Channel #5 Z1 Inst 21;21N-1 907L  
 Column #24: Event Channel #6 Z2 Start 21;21N-1 907L  
 Column #25: Event Channel #7 Z3 Start 21;21N-1 907L  
 Column #26: Event Channel #8 Z2 Timed 21;21N-1 907L  
 Column #27: Event Channel #9 Z3 Timed 21;21N-1 907L  
 Column #28: Event Channel #10 PST 21-1 907L  
 - Column #29: Event Channel #11 94-1R 907L  
 Column #30: Event Channel #12 94-1Y 907L  
 Column #31: Event Channel #13 94-1B 907L  
 Column #32: Event Channel #14 85-2 907L  
 Column #33: Event Channel #15 79X-1 907L  
 Column #34: Event Channel #16 77A-1 907L

The identification codes used in the above list refer to the following devices.

21 refers to a distance relay.

77A-1 refers to a carrier transmitting relay.

79X-1 refers to a reclosing relay.

85-2 refers to a carrier receiving relay.

94-1 refers to a tripping relay.

DATA01

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0										
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1957,	1866,	2038,	489,	2424,	3180,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
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1926,	2304,	2042,	2816,	2847,	394,	1122,	0,	0,	0,	0,
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0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
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0										
15,	31,	1813,	1974,	2268,	2044,	2042,	2057,	2026,	2040,	1887,
1926,	2304,	2043,	2815,	2850,	394,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
16,	33,	1914,	1838,	2236,	2042,	2030,	2059,	2040,	2040,	2086,
1792,	2238,	2042,	1611,	3590,	803,	1121,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
17,	35,	2092,	1826,	2092,	2044,	2022,	2050,	2052,	2041,	2260,
1808,	2058,	2041,	661,	3420,	2060,	1054,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
18,	37,	2244,	1937,	1918,	2044,	2026,	2038,	2063,	2042,	2303,
1956,	1866,	2038,	488,	2424,	3182,	1120,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
19,	39,	2274,	2113,	1818,	2043,	2039,	2026,	2057,	2042,	2195,
2160,	1783,	2038,	1268,	1236,	3640,	1088,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
20,	41,	2171,	2250,	1846,	2043,	2052,	2024,	2045,	2041,	1996,
2291,	1847,	2039,	2474,	491,	3127,	1126,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
21,	43,	1993,	2259,	1994,	2042,	2058,	2032,	2034,	2042,	1822,
2278,	2030,	2043,	3423,	416,	1982,	1103,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
22,	45,	1842,	2150,	2166,	2042,	2055,	2044,	2023,	2040,	1781,
2128,	2218,	2042,	3592,	1662,	836,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
23,	47,	1812,	1975,	2266,	2042,	2044,	2056,	2025,	2039,	1886,
1924,	2302,	2042,	2816,	2846,	397,	1121,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
24,	50,	1913,	1839,	2236,	2042,	2030,	2059,	2038,	2039,	2086,
1792,	2238,	2042,	1610,	3591,	810,	1120,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
25,	52,	2092,	1827,	2092,	2044,	2024,	2052,	2051,	2042,	2262,
1807,	2058,	2042,	662,	3423,	2058,	1052,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

26,	54,	2244,	1937,	1918,	2044,	2027,	2038,	2059,	2042,	2302,
1955,	1867,	2040,	490,	2422,	3184,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
27,	56,	2272,	2112,	1818,	2043,	2038,	2026,	2058,	2043,	2194,
2160,	1782,	2040,	1270,	1234,	3641,	1090,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
28,	58,	2172,	2248,	1846,	2043,	2052,	2024,	2047,	2044,	1996,
2290,	1847,	2041,	2471,	491,	3127,	1126,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
29,	60,	1994,	2259,	1994,	2043,	2058,	2031,	2034,	2042,	1822,
2276,	2030,	2042,	3423,	418,	1984,	1102,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
30,	62,	1844,	2149,	2166,	2042,	2055,	2046,	2024,	2042,	1782,
2128,	2219,	2042,	3593,	1663,	838,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
31,	64,	1814,	1973,	2266,	2044,	2042,	2056,	2024,	2040,	1887,
1924,	2302,	2042,	2812,	2850,	396,	1120,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
32,	66,	1916,	1839,	2236,	2042,	2030,	2059,	2038,	2039,	2087,
1792,	2239,	2043,	1611,	3590,	806,	1120,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
33,	68,	2092,	1827,	2092,	2043,	2026,	2053,	2052,	2042,	2260,
1807,	2058,	2042,	662,	3422,	2060,	1052,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
34,	70,	2244,	1938,	1916,	2044,	2027,	2038,	2059,	2042,	2303,
1955,	1867,	2040,	490,	2421,	3184,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
35,	72,	2274,	2113,	1818,	2044,	2038,	2026,	2057,	2044,	2194,
2160,	1782,	2038,	1268,	1236,	3641,	1088,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
36,	75,	2172,	2249,	1848,	2043,	2052,	2024,	2046,	2045,	1995,
2292,	1847,	2039,	2476,	489,	3124,	1124,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
37,	77,	1991,	2260,	1994,	2043,	2059,	2032,	2034,	2042,	1823,
2278,	2030,	2041,	3423,	415,	1984,	1103,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
38,	79,	1844,	2150,	2168,	2042,	2054,	2046,	2024,	2040,	1779,
2128,	2219,	2043,	3594,	1662,	838,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

39,	81,	1812,	1971,	2265,	2044,	2041,	2056,	2025,	2040,	1887,
1924,	2304,	2044,	2812,	2850,	390,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
40,	83,	1913,	1838,	2236,	2044,	2028,	2058,	2038,	2040,	2086,
1792,	2238,	2040,	1610,	3589,	802,	1119,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
41,	85,	2091,	1826,	2092,	2044,	2023,	2052,	2052,	2040,	2261,
1808,	2057,	2041,	660,	3420,	2060,	1052,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
42,	87,	2242,	1936,	1916,	2044,	2026,	2038,	2060,	2043,	2304,
1956,	1866,	2041,	490,	2419,	3184,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
43,	89,	2273,	2114,	1816,	2042,	2040,	2024,	2057,	2042,	2194,
2159,	1783,	2038,	1269,	1232,	3640,	1086,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
44,	91,	2172,	2249,	1848,	2043,	2052,	2023,	2047,	2042,	1996,
2292,	1847,	2039,	2474,	492,	3126,	1124,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
45,	93,	1994,	2261,	1992,	2042,	2058,	2032,	2033,	2042,	1822,
2276,	2030,	2041,	3426,	420,	1979,	1106,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
46,	95,	1843,	2149,	2168,	2043,	2053,	2046,	2023,	2042,	1782,
2127,	2219,	2042,	3593,	1666,	835,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
47,	97,	1813,	1977,	2262,	2042,	2045,	2060,	2024,	2037,	1890,
1926,	2300,	2042,	2806,	2849,	401,	1122,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
48,	100,	1924,	1867,	2222,	2046,	2000,	2074,	2030,	2056,	2058,
1810,	2232,	2050,	1656,	3566,	822,	1121,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
49,	102,	2013,	1899,	2150,	2047,	1908,	2089,	2088,	2068,	2162,
1844,	2098,	2052,	726,	3394,	1988,	1072,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
50,	104,	2006,	2014,	2154,	2042,	1841,	2074,	2200,	2041,	2158,
1982,	1987,	2040,	526,	2466,	3100,	1118,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
51,	106,	1960,	1959,	2142,	2042,	1950,	1930,	2245,	2042,	2128,
2065,	1934,	2038,	1099,	1393,	3629,	1070,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

52,	108,	2057,	1927,	2080,	2043,	2109,	1835,	2171,	2044,	2051,
2134,	1946,	2040,	2335,	538,	3235,	1104,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
53,	110,	2135,	1987,	1990,	2043,	2226,	1878,	2022,	2042,	1963,
2154,	2010,	2042,	3344,	335,	2143,	1020,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
54,	112,	2152,	2066,	1934,	2043,	2238,	2010,	1885,	2042,	1930,
2102,	2093,	2041,	3620,	1523,	1010,	1083,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
55,	114,	2116,	2139,	1944,	2042,	2126,	2158,	1842,	2040,	1954,
2022,	2147,	2042,	2962,	2698,	454,	1072,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
56,	116,	2025,	2154,	2010,	2042,	1974,	2244,	1918,	2039,	2033,
1950,	2139,	2042,	1766,	3539,	666,	1062,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
57,	118,	1949,	2105,	2099,	2043,	1853,	2206,	2065,	2041,	2114,
1935,	2075,	2041,	728,	3497,	1944,	1005,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
58,	120,	1928,	2019,	2154,	2044,	1843,	2074,	2202,	2043,	2151,
1982,	1993,	2042,	458,	2581,	3060,	1046,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
59,	122,	1968,	1945,	2146,	2044,	1953,	1921,	2246,	2043,	2126,
2061,	1942,	2040,	1126,	1387,	3626,	973,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
60,	125,	2057,	1928,	2079,	2042,	2105,	1838,	2168,	2046,	2051,
2132,	1948,	2042,	2308,	552,	3248,	1042,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
61,	127,	2134,	1978,	1987,	2042,	2228,	1874,	2021,	2042,	1972,
2146,	2008,	2041,	3321,	346,	2158,	967,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
62,	129,	2161,	2065,	1927,	2042,	2241,	2007,	1884,	2039,	1934,
2101,	2089,	2041,	3633,	1493,	1026,	1053,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
63,	131,	2119,	2143,	1934,	2042,	2129,	2161,	1837,	2040,	1957,
2024,	2141,	2041,	2972,	2689,	451,	1063,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
64,	133,	2031,	2159,	2000,	2042,	1976,	2245,	1914,	2039,	2032,
1954,	2133,	2041,	1779,	3533,	652,	1074,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

65,	135,	1952,	2113,	2092,	2042,	1853,	2211,	2061,	2042,	2110,
1941,	2076,	2041,	746,	3511,	1909,	1066,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
66,	137,	1924,	2023,	2154,	2044,	1841,	2077,	2202,	2042,	2147,
1982,	1996,	2040,	455,	2600,	3042,	1107,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
67,	139,	1962,	1946,	2149,	2044,	1950,	1926,	2245,	2043,	2125,
2060,	1945,	2039,	1101,	1406,	3621,	1094,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
68,	141,	2054,	1926,	2084,	2042,	2105,	1837,	2171,	2044,	2052,
2129,	1949,	2040,	2291,	559,	3256,	1148,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
69,	143,	2136,	1974,	1990,	2042,	2227,	1874,	2023,	2042,	1976,
2143,	2009,	2040,	3312,	343,	2173,	1112,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
70,	145,	2166,	2064,	1926,	2044,	2241,	2005,	1882,	2041,	1936,
2102,	2087,	2042,	3627,	1479,	1040,	1200,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
71,	147,	2125,	2143,	1932,	2044,	2132,	2158,	1836,	2039,	1960,
2024,	2139,	2042,	2978,	2674,	460,	1228,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
72,	150,	2032,	2161,	1996,	2041,	1977,	2246,	1911,	2040,	2031,
1955,	2133,	2041,	1796,	3520,	652,	1255,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
73,	152,	1952,	2115,	2090,	2044,	1853,	2211,	2060,	2042,	2109,
1941,	2076,	2041,	750,	3509,	1907,	1283,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
74,	154,	1922,	2026,	2151,	2042,	1841,	2079,	2197,	2042,	2146,
1981,	1996,	2040,	455,	2610,	3034,	1315,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
75,	156,	1959,	1947,	2150,	2044,	1950,	1926,	2247,	2046,	2122,
2059,	1945,	2039,	1091,	1413,	3623,	1342,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
76,	158,	2052,	1926,	2084,	2044,	2104,	1838,	2171,	2044,	2053,
2128,	1951,	2040,	2276,	565,	3268,	1375,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
77,	160,	2136,	1975,	1990,	2042,	2228,	1872,	2024,	2042,	1975,
2143,	2011,	2039,	3303,	342,	2184,	1407,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

78,	162,	2166,	2062,	1926,	2043,	2241,	2005,	1881,	2039,	1936,
2103,	2086,	2042,	3625,	1470,	1053,	1439,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
79,	164,	2125,	2140,	1930,	2044,	2132,	2157,	1835,	2039,	1959,
2025,	2139,	2042,	2989,	2659,	464,	1472,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
80,	166,	2032,	2161,	1996,	2041,	1979,	2245,	1910,	2039,	2030,
1957,	2132,	2040,	1809,	3514,	649,	1501,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
81,	168,	1952,	2115,	2088,	2044,	1856,	2211,	2057,	2042,	2108,
1941,	2074,	2042,	758,	3514,	1892,	1533,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
82,	170,	1922,	2028,	2151,	2043,	1841,	2079,	2197,	2043,	2145,
1982,	1997,	2039,	459,	2614,	3029,	1543,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
83,	172,	1959,	1949,	2150,	2042,	1950,	1927,	2246,	2044,	2123,
2059,	1946,	2041,	1084,	1425,	3618,	1591,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
84,	175,	2049,	1927,	2086,	2043,	2103,	1840,	2172,	2041,	2054,
2127,	1951,	2042,	2269,	572,	3269,	1621,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
85,	177,	2135,	1973,	1991,	2043,	2229,	1873,	2025,	2042,	1978,
2143,	2009,	2040,	3295,	337,	2198,	1651,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
86,	179,	2166,	2062,	1926,	2043,	2241,	2005,	1886,	2041,	1937,
2103,	2086,	2042,	3627,	1461,	1062,	1680,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
87,	181,	2125,	2141,	1930,	2044,	2132,	2156,	1837,	2038,	1960,
2024,	2138,	2041,	2998,	2655,	466,	1709,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
88,	183,	2033,	2161,	1996,	2042,	1980,	2245,	1910,	2039,	2029,
1957,	2134,	2041,	1819,	3509,	639,	1735,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
89,	185,	1952,	2115,	2088,	2042,	1856,	2212,	2057,	2042,	2108,
1941,	2073,	2041,	763,	3516,	1886,	1761,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
90,	187,	1921,	2028,	2154,	2044,	1842,	2080,	2197,	2041,	2146,
1983,	1998,	2041,	457,	2628,	3014,	1717,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

91,	189,	1959,	1948,	2150,	2043,	1949,	1929,	2245,	2043,	2124,
2057,	1948,	2039,	1070,	1438,	3613,	1812,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
92,	191,	2049,	1926,	2086,	2043,	2101,	1840,	2174,	2045,	2053,
2128,	1952,	2042,	2258,	577,	3275,	1797,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
93,	193,	2134,	1972,	1992,	2043,	2228,	1871,	2026,	2042,	1976,
2142,	2009,	2044,	3288,	338,	2207,	1859,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
94,	195,	2164,	2060,	1927,	2042,	2241,	2003,	1885,	2042,	1938,
2104,	2087,	2042,	3630,	1445,	1073,	1882,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
95,	197,	2128,	2140,	1931,	2044,	2134,	2155,	1836,	2039,	1959,
2026,	2137,	2042,	3001,	2645,	466,	1906,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
96,	200,	2035,	2161,	1994,	2042,	1982,	2243,	1908,	2039,	2030,
1960,	2133,	2042,	1831,	3503,	633,	1926,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
97,	202,	1952,	2117,	2086,	2042,	1857,	2211,	2053,	2042,	2107,
1942,	2076,	2040,	771,	3520,	1873,	1945,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
98,	204,	1923,	2029,	2150,	2044,	1842,	2083,	2196,	2044,	2145,
1982,	1999,	2041,	455,	2638,	3006,	1903,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
99,	206,	1957,	1948,	2150,	2042,	1948,	1929,	2246,	2044,	2123,
2057,	1948,	2042,	1051,	1450,	3612,	1982,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
100,	208,	2047,	1925,	2086,	2042,	2100,	1840,	2174,	2044,	2054,
2126,	1952,	2041,	2247,	582,	3283,	1931,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
101,	210,	2134,	1972,	1994,	2042,	2226,	1871,	2027,	2042,	1978,
2142,	2007,	2042,	3277,	335,	2219,	2013,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
102,	212,	2166,	2059,	1928,	2042,	2240,	2002,	1888,	2039,	1938,
2103,	2085,	2042,	3629,	1438,	1081,	2026,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
103,	214,	2129,	2139,	1930,	2043,	2135,	2153,	1838,	2039,	1958,
2028,	2135,	2042,	3013,	2631,	469,	2034,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

104,	216,	2037,	2159,	1994,	2042,	1983,	2242,	1908,	2038,	2029,
1959,	2134,	2042,	1843,	3500,	624,	2039,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
105,	218,	1954,	2115,	2085,	2044,	1857,	2214,	2054,	2041,	2106,
1942,	2077,	2041,	773,	3526,	1860,	2043,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
106,	220,	1922,	2030,	2149,	2042,	1842,	2083,	2194,	2043,	2143,
1981,	2000,	2041,	454,	2652,	2995,	2014,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
107,	222,	1957,	1951,	2150,	2042,	1946,	1932,	2245,	2044,	2121,
2055,	1949,	2041,	1031,	1463,	3609,	2046,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
108,	225,	2049,	1926,	2087,	2042,	2097,	1842,	2173,	2043,	2055,
2125,	1952,	2041,	2233,	587,	3292,	1974,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
109,	227,	2133,	1971,	1994,	2043,	2224,	1872,	2029,	2042,	1980,
2141,	2007,	2042,	3270,	332,	2234,	2043,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
110,	229,	2164,	2058,	1928,	2042,	2241,	2002,	1889,	2040,	1939,
2102,	2081,	2042,	3631,	1420,	1090,	2041,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
111,	231,	2128,	2137,	1931,	2041,	2136,	2152,	1837,	2039,	1959,
2028,	2134,	2042,	3015,	2628,	468,	2040,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										
112,	233,	2036,	2160,	1994,	2041,	1985,	2241,	1910,	2038,	2026,
1960,	2133,	2041,	1853,	3493,	614,	2041,	0,	0,	0,	0,
0,	0,	0,	0,	0,	0,	0,	0,	0,	0,	0,
0										

## Appendix V

### Engineering Dialog for Setting Digital Relays

Appendix V  
Engineering Dialog for Setting Digital Relays  
List of Settings of Various Digital Relays  
CIGRE 34.01 Working Group

The following lists of settings (shown on the following pages) from the various implementations of digital line protection are each limited to the functions below:

- A. PHASE AND GROUND DISTANCE PROTECTION (Zone 1, Zone 2, Zone 3, etc.)
- B. PHASE AND GROUND PILOT PROTECTION (Directional Comparison Blocking)
- C. LINE PICK-UP PROTECTION
- D. HIGH-SET PHASE OVERCURRENT DIRECT TRIP
- E. HIGH-SET GROUND OVERCURRENT DIRECT TRIP
- F. FAULT LOCATION

## AEP DIGITAL RELAY

1. Positive Sequence Impedance of transmission line (magnitude in primary ohms)
2. Zero Sequence impedance of transmission line (magnitude in primary ohms)
3. Positive Sequence Impedance line angle
4. Zero Sequence Impedance line angle
5. Zone 1 phase reach in secondary ohms
6. Zone 1 ground reach in secondary ohms
7. Zone 1 resistance allowance in secondary ohms
8. Zone 2 phase reach in secondary ohms
9. Zone 2 ground reach in secondary ohms
10. Zone 2 time to trip
11. Zone 3 phase reach in secondary ohms
12. Zone 3 ground reach in secondary ohms
13. Zone 2 & 3 resistance allowance in secondary ohms
14. Zone 3 time to trip
15. Carrier trip coordination time
16. Phase carrier start reverse reach in secondary ohms
17. Phase carrier start resistance allowance in secondary ohms
18. Ground carrier start reverse reach in secondary ohms
19. Ground carrier start resistance allowance in secondary ohms
20. Carrier start turn off delay time
21. Instantaneous phase and ground high set
22. Instantaneous phase and ground low set
23. Low set enable time
24. Time delay ground backup overcurrent setting
25. Single phase tripping enable – yes or no
26. Signal conditioning unit current ratio
27. Line length
28. PT ratio
29. CT ratio

EPRI—GENERAL ELECTRIC DIGITAL RELAY (at PSE&G Branchburg)

- 2.1 X1 phase
- 2.2 X2 phase
- 2.3 XB phase
- 2.4 R2 phase
- 2.5 R3 phase
- 2.6 RB phase
- 2.7 RB' phase
- 2.8 Line theta
- 2.9 X1 ground
- 2.10 X2 ground
- 2.11 XB ground
- 2.12 R2 ground
- 2.13 R3 ground
- 2.14 RB ground
- 2.15 RB' ground
- 2.16 X1' ground
- 2.17 A Timer pickup
- 2.18 B Timer pickup
- 2.19 D Timer dropout
- 2.20 D Timer pickup
- 2.21 T Timer pickup
- 2.22 T Timer dropout
- 2.23 Phase overcurrent supervision
- 2.24 Ground overcurrent supervision
- 2.25 Phase Overcurrent Direct Trip Enable
- 2.26 Ground Overcurrent Direct Trip Enable
- 2.27 Phase Overcurrent Direct Trip Level
- 2.28 Ground Overcurrent Direct Trip Level
- 2.29 Zone 1 Trip Enable
- 2.30 Zone 2 Trip Enable
- 2.31 K Prime Num. (zero Sequence Compensation)
- 2.32 Minimum Fault I (Zero Sequence Directional Element)
  
- 3.15 Line Pickup Enable
- 3.16 Line Pickup Voltage
- 3.17 Line Pickup Current
  
- 4.17 Conversion Factor Num. (Fault Location)
- 4.18 Conversion Factor Denom. (Fault Location)
  
- 4.10 PDifference Current
- 4.11 GDifference Current
- 4.12 Difference Voltage
- 4.13 Close Test Value
- 4.14 RScale Factor
- 4.15 Refining Value
- 4.16 Refining Value
- 4.21 Rec Timer External

## EPRI-WESTINGHOUSE DIGITAL LINE RELAY (AT PSE&G Branchburg)

### Data Computation and Checking

- 1.54 Dead Line Voltage Limit
- 1.55 Live Bus Voltage Limit
- 1.126 Data Checking Inhibit
- 26.1 Data Check IR Tolerance
- 26.2 Data Check Current Balance Tolerance
- 26.3 Data Check Voltage Balance Tolerance
- 26.4 Data Check Zero Voltage Tolerance
- 26.5 Data Check Minimum Voltage—On Magnitude
- 26.6 Data Check Maximum Voltage—On Magnitude

### Fault Detection Settings

- 1.12 Fault Detection Minimum Sensitivity Base
- 1.13 Fault Detection Loss—Of—Potential Reset Voltage
- 1.14 Fault Detection Voltage Change Limit
- 1.60 Loss—Of—Potential Reset Voltage
- 1.112 Fault Detection Residual Current Limit
- 1.125 Fault Detection Inhibit

### Fault Type Analysis

- 1.22 VFTA Prefault Unbalance Limit
- 1.23 VFTA Fault Collapse Limit
- 1.24 VFTA Collapse Limit — Polarizing
- 1.25 VFTA Prefault Voltage Limit
- 1.29 FTA Processing Time

### All—Phases Check

- 1.45 All Phases Maximum Passes
- 1.113 All Phases Multiplier

### Distance Checking Settings

- 1.25 VFTA Prefault Volt Limit
- 1.31 Zone Pri Algorithm Max Passes
- 1.32 Zone B—U Algorithm Start Delay
- 1.41 Zone Trip OC Suprv Current Lim
- 1.84 Line Angle
- 1.85 Reverse R Reach Zone 1,2,3
- 1.86 Reverse R Reach Zone 4
- 1.87 Zero/Positive Sequence L Ratio
- 1.88 Zero/Positive Sequence R Ratio
- 1.89 Zero/Positive Sequence Z Ratio
- 1.116 Pri Algorithm ON = 0 Off = 1

- 1.117 B-U Algorithm ON = 0 Off = 1
- 1.119 Zone Trip OC Suprv Enable

Zone Checking and Pilot Logic Settings, Action Tables

- 1.7 No Zone Found Pass Limit
- 1.8 Zone Found Pass Limit
- 1.9 Pilot Mode PRI = 1, BU = 0, BOTH = 1
- 1.10 B-U Carrier Start Delay
- 1.11 Pri Carrier Start Delay
- 1.34 Z4 Carrier Hold Delay
- 1.35 Zone Pri Delta Z Sensitivity
- 1.36 Zone B-U Delta Z Sensitivity
- 1.42 Zone 2 Remote B-U Timer
- 1.43 Zone 3 Remote B-U Timer
- 1.44 Zone 4 Remote B-U Timer
- 1.57 Fault Locator Scaling
- 1.61 Open Line Current Limit
- 1.66 Zone 1 X Reach - Primary Alg
- 1.67 Zone 2 X Reach - Primary Alg
- 1.68 Zone 3 X Reach - Primary Alg
- 1.69 Zone 4 X Reach - Primary Alg
- 1.70 Zone 1 X Reach - Backup Alg
- 1.71 Zone 2 X Reach - Backup Alg
- 1.72 Zone 3 X Reach - Backup Alg
- 1.73 Zone 4 X Reach - Backup Alg
- 1.74 Zone 1 R Reach - GND
- 1.75 Zone 2 R Reach - GND
- 1.76 Zone 3 R Reach - GND
- 1.77 Zone 4 R Reach - GND
- 1.78 Zone 1 R Reach - PHASE
- 1.79 Zone 2 R Reach - PHASE
- 1.80 Zone 3 R Reach - PHASE
- 1.81 Zone 4 R Reach - PHASE
- 1.82 Magnitude of Line Impedance
- 1.83 Z1 Compensation Constant
- 1.84 Line Angle
- 1.85 Reverse R Reach Zone 1,2,3
- 1.86 Reverse R Reach Zone 4
- 1.87 Zero/Positive Sequence L Ratio
- 1.88 Zero/Positive Sequence R Ratio
- 1.89 Zero/Positive Sequence Z Ratio
- 1.110 B-U Boundary Angle
- 1.111 Pri Boundary Angle
- 1.113 All Phases Multiplier
- 1.116 PRI Algorithm ON = 1 OFF = 1
- 1.117 B-U Algorithm ON = 1 OFF = 1
- 1.120 Z1 Compensation PERM
- 1.121 Zone 2 BU Time Delay PERM
- 1.122 Zone 3 BU Time Delay PERM
- 1.123 Zone 4 BU Time Delay PERM
  
- 1.49 Zone 1 Trip Action Table Num

- 1.50 Pilot Trip Action Table Num
- 1.51 Zone 2 Rem BU Trip Action Table Num
- 1.52 Zone 3 Rem BU Trip Action Table Num
- 1.53 Zone 4 REM BU Trip Action Table Num

#### High-Set and Close-in Protection

- 1.2 Hi Set-Overcurrent Pickup
- 1.3 Close In-Overcurrent Pickup
- 1.4 Hi Set Bias
- 1.5 Close In Bias
- 1.54 Dead Line Voltage Limit
- 1.58 Dead Line Time Setting
- 1.59 Close-In Time Setting
  
- 1.47 Hi-Set Trip Action Table Number
- 1.48 Close-In Trip Action Table Number

#### Fault Locator Settings

- 1.46 Fault Locator Distance Passes

the thermal limits of the winding.

- The tertiary winding may be connected to a reactive compensation bank, and/or to a station service transformer. Inverse time—overcurrent measurements may be applied to the phase—current connections from the tertiary winding to protect it from external faults.
- Time—overcurrent checks may be included for the main winding phase currents to protect the windings from the effects of any uncleared through fault.
- Any of the main windings may be connected to the power system through a disconnecting or loadbreak switch. If the switch is opened, the stub section of the bus between the transformer bushing and the switch may be left unprotected. A fault on the stub will be fed through the transformer, but will not be seen by adjacent—zone relays because of the open switch. Among the possible solutions is to connect a sensitive overcurrent relay to the bushing CT signal, and to trip breakers on the other transformer winding if the relay operates when the switch is open.

#### 4.5.6 Overexcitation Protection

The problem of false differential operation in response to overexcitation or overfluxing has already been addressed. However, if the overexcitation is sustained, the transformer core will heat up and may suffer thermal damage. Therefore, some applications call for an overexcitation function which will alarm and/or trip transformer breakers for this condition.

The simplest solution, applicable to most substation transformers, is to apply one or two overvoltage measurement elements, each with its own time delay. The first, set just above the maximum normal voltage, or just above the minimum value which can overheat the core, has a short time delay and sounds an alarm. The second, set with a longer delay and/or a higher voltage threshold, trips the breakers. A more sophisticated solution is an inverse time—overvoltage function whose alarming and tripping characteristics are coordinated with the thermal capability of the transformer. It is a straightforward matter to program a microprocessor relay to evaluate voltage inputs according to such a function, and to put out both alarms and trip commands in sequence. Thermal recovery of the core can be modeled in the reset characteristic of the voltage measuring function.

In the general case, excitation is proportional to volts per Hertz. For most of the network, we can assume that the Hertz value is constant and consider only volts. For generator step—up (GSU) transformers, however, the applied frequency may be well below the nominal value (for example, during startup of the unit). With depressed frequency, even normal voltage magnitudes may overflux the core and cause damage. The thermal modeling must be done in terms of the

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