

**FINAL REPORT ON COMPUTER BASED
PROTECTION AND DIGITAL TECHNIQUES IN
SUBSTATIONS**

Working Group 01 OF Study Committee 34 (Protection)

Convener : A.G. PHADKE

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Working Group 02 of Study Committee 34

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1. ABSTRACT

While computer based Supervisory Control and Data Acquisition (SCADA) systems are quite common in the power industry, the use of digital computers for protection of high voltage power apparatus and systems has been investigated quite exhaustively during recent years. Although a substantial amount of the work reported in the technical literature has been of an analytical nature, several experimental systems have been developed leading to field trials of computer based relays. It appears likely that an integrated system of digital computers dedicated to all the tasks in a substation such as protection, control, monitoring, alarm, sequence of event recording and analysis, and oscillography will

emerge as one capable of realizing the fullest potential of a computer based system for high voltage substations and power generating stations. The Working Group has attempted to highlight the technical aspects of such a hierarchical substation computer system, the potential benefits that are likely to flow from this technology, and some of the problems that need attention during the early stages of its development. It is hoped that this paper will be viewed as a status report on this emerging technology, and an indication of the interest in, and expectation for it on the part of the protection engineering community.

2. DIGITAL TECHNIQUES IN SUBSTATIONS

2.1. GENERAL INTRODUCTION

Digital computer technology has been applied in electric power substations for many years. Data acquisition, alarms, status monitoring and supervisory control systems have all been converted to digital computer systems to some extent, and in many cases these systems are entirely digital in nature.

Protection of power apparatus and systems is a function that has been considered for conversion to digital computer technology during recent years. Several experimental projects in this field have been undertaken by various research groups, and are being actively pursued at present. With the prospect of using computers for protection clearly in the offing, a consensus appears to have formed that full realization of the potential that digital technology offers can come only through a hierarchical system of computers dedicated to protection, control and monitoring functions for the entire substation and for groups of substations. Certainly the independence of the protection function must be maintained for reasons of reliability. However, communication capability between various computers belonging to the integrated system is far more beneficial than a collection of isolated digital computer based systems.

2.2. EXPECTED BENEFITS OF DIGITAL TECHNIQUES

The benefits of the integrated concept have been enumerated in the literature. It is good to repeat them here :

- a. Higher reliability in all functions due to the self diagnostic and communication capability.
- b. Better performance due to improved monitoring of plant and equipment in the station.
- c. Shared data permitting improvements in individual subsystem performance, and a reduction in duplicate signal and control channels.
- d. Possibility of data validation and error correcting based upon multiple data sources.

- e. More complete information and records, sophisticated computing power leading to informed and more intelligent decision making at all levels. Possibility of adaptive protection and control.
- f. More economical digital computer hardware, because of its wider user base and a corresponding larger volume of production.
- g. A digital computer based system in the substation leading to newer (and more desirable) transducer and other interface equipment. Possibility of better EMI immunity by adapting fiber-optic communication links into the substation yard.
- h. Example of the application of a modern technology in the electric power field acts as a strong attraction to many bright students of electrical engineering and young electrical engineers to this field. No doubt this will help both the electric power industry and electric power programmes at leading universities throughout the world.

Along with these expected benefits of the digital technology, are certain unanswered questions. Among these, the important areas are :

- a. Limited experience with digital computer performance in the harsh substation environment.
- b. The high cost of software. Problems of maintainability and transportability of software.
- c. Impact of the new technology on personnel familiar with the old technology and organizations based upon the characteristics of the older technology.
- d. The relatively short life span of digital equipment due to rapid advances in technology, and the resulting difficulty an assured supply of spare parts.

2.3. INTEGRATED SYSTEMS AND STAND-ALONE FUNCTIONS

In conventional protection systems as they exist now, each system is capable of working independently of all other protection functions in the substation. This of course is not always achieved entirely, as some subsystems such as the battery or

the transducer secondary windings may be shared among several protection systems. However, to the greatest extent possible, this independence of protection system is maintained. This aspect is often described by the phrase "stand-alone".

In an integrated computer system in the substation, the concept of stand-alone systems needs some consideration. On the one hand, one could take a strict view of the situation and require that, to the greatest extent possible, each protection function be contained in separate, distinctly identifiable hardware which may not be shared by or linked to another system within the substation. Such a protection system is a computerized replacement of conventional relays, and may not permit full realization of the benefits of a computer based system.

A somewhat different view would be expressed by interpreting the phrase stand-alone as a functional concept - the function of a given protection must remain intact (to the greatest extent possible) independently of any other functions in the hierarchy of computers. Such a view would also look to sharing data and hence some equipment (perhaps in the back-up protection functions only in the early stages of development), thus allowing the realization of the benefits of a hierarchical computer system. It is to be expected that as more experience is gained with computer based relays, this second (functional) interpretation of the phrase "stand-alone" may become accepted in the protection engineering community.

3. CONSIDERATIONS FOR HIERARCHICAL COMPUTER SYSTEMS IN SUBSTATIONS

3.1. INTRODUCTION

A questionnaire (Appendix I) was sent out to all working group members, and through Study Committee 34 to utilities in different countries, to gather information on the current and future developments in implementing computer systems with hierarchical configurations in transmission substations.

The objective was to establish the trends in the application of microprocessor technology to the protection, control and instrumentation of plant in substations. It was hoped to identify a pattern of development which would indicate a consensus of opinion on how the design of systems using computing capability at different levels was evolving.

Hardware development has proceeded at such a pace that it is difficult to identify any particular implementation as being representative. Each approach has merits and restrictions. However, it has become clear that the effort put into the conceptual system design is of crucial importance. As diverse as the individual applications appear, it is quite clear that the availability of low price microcomputers has made a multi-level hierarchical structure a common factor.

Almost all countries reported activity in developing schemes which will ultimately result in some form of hierarchical structure, although only five replies (United States - 2, United Kingdom, France and Canada) dealt in any detail with overall conceptual design in terms of currently evolving technology. Some reported schemes have operated successfully in the field but cannot now be considered state-of-the-art. There is every reason to believe that significant developments have taken place in some countries but have not been reported.

Unfortunately, not all replies complied with the requested format of answers and some requested information is not available.

3.2. ANALYSIS AND SUMMARY OF QUESTIONNAIRE RESPONSES

3.2.1. FUNCTIONS

Table A lists the functions that have been

implemented or proposed for both hierarchical and other computer systems reported. The functions listed can be separated into the following categories :

- a. protection
- b. alarm monitoring
- c. data logging
- d. control

Almost all replies listed several protection functions. These functions are based, in most cases, on microprocessor technology and perform on conventional principles. Several replies considered the integration of solid state relays into the hierarchical system as a first step. It is apparent from Table A that there is a wide range of functions which can be implemented with digital technology. The significant factor, it would appear, to most designers is the correctness of the basic system concept rather than the difficulty of implementing a specific function.

The time frame of most developments is first control and monitoring, followed by a host of functions which are non critical in nature, followed by protection. Protection is perceived logically as being a part of the complete scheme, but the availability of fast, reliable, solid state protection appears to have reduced the urgency of incorporating digital versions.

Two approaches to control relating to opposite ends of the control spectrum are mentioned in the Belgian and Japanese replies. The former is an example of using sophisticated computer aids to assist operations personnel exercise manual control. The latter cites an example of out-of-step stabilizer control with system-wide implications.

3.2.2. CONFIGURATIONS

It is evident from the survey replies that the design concepts used in configuring the computer elements within the system are different in a number of respects. However, the perceived fundamental requirements are :

- a. that the system design be technically and economically viable, i.e competitive with present methods.
- b. that the system design be flexible enough to allow easy expansion, modification and maintenance

TABLE A

Function	Country														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Line Fault Location			x	x			x	x	x	x	x		x	x	x
Line Loading		x	x	x					x	x	x			x	x
Out of Step			x	x			x			x	x				x
Transformer Loading		x	x	x						x	x				
Overtoltage/Undervoltage			x										x	x	x
Distance		x	x	x	x	x	x		x	x	x	x	x		x
Busbar Differential			x	x	x	x	x		x	x	x		x	x	x
Breaker Fail			x	x	x	x	x		x	x	x		x	x	x
Protection Carrier			x	x	x								x	x	x
Instantaneous or															
Timed Overcurrent			x	x	x				x	x			x	x	x
Transformer Differ-			x	x	x				x	x	x		x		
ential									x	x					
Reactor & Capacitor			x	x					x	x			x		
Pilot & Transfer Trip Moni-															
toring				x					x		x				x
Load Shedding (Underfrequency)				x			x			x	x		x	x	
Diagnostic Self-check	x		x	x	x		x		x					x	x
Trend Recording					x										
State Estimation				x	x										
Transmission to/from Central															
Remote	x		x		x		x		x	x					x
High Speed Reclosing	x		x	x	x		x		x	x	x			x	x
Low Speed Reclosing	x	x	x	x	x	x	x		x	x	x			x	x
Automatic Sequential Switching	x	x	x	x	x	x	x	x	x	x	x			x	x
Oscillograph	x		x	x	x		x	x	x	x	x			x	x
Synchronism Check	x	x	x	x	x	x	x		x	x	x			x	x
Voltage Control	x	x	x	x	x	x	x	x	x	x	x			x	x
Zero Voltage Tripping	x														
Arc Suppression Coil Switching		x													
Interlocking		x							x	x					x
Status Monitoring		x	x	x	x		x		x	x	x			x	x
Data Validation/Security															
Assessment			x	x	x					x	x			x	
Transformer Tap Position	x	x	x	x							x			x	
Alarms & Data Logging	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Metering	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Sequence of Events Recording		x	x	x	x	x	x	x	x	x	x	x	x	x	x
Alarm Analysis										x				x	
Local Manual Switching										x				x	
Tripping			x							x	x	x		x	x

Notes: 1 - Sweden
2 - Austria
3 - Japan
4 - United States (EPRI/Westinghouse)
5 - United States (AEP)
6 - Belgium
7 - France
8 - Czechoslovakia
9 - West Germany
10 - United Kingdom
11 - Switzerland
12 - Brazil
13 - Canada
14 - United States (EPRI/GE)
15 - United States (EPRI/GE)

c. that the critical functions can be designed to have the necessary reliability

It is difficult to categorize the configurations reported into well defined groups because some of the systems are stages in an overall development, while others are limited to dedicated applications. It can, however, be inferred that the configurations described will evolve into the use of microcomputers dedicated to functions at circuit (plant) level with a central substation computer communicating with the circuit functions. In almost all cases, the links between the two levels are not required to deal with real time data gathered at high sampling rates.

Two representative configurations are shown on Figures 3.1 and 3.2. The first scheme accesses data via a remote data acquisition module and serial link, passing control actions via the same channel. The number of signal paths between plant and compu-

ter is minimized, thus saving in wiring. In the second scheme, all analog and digital signals are hard wired directly into dedicated processors to give security of essential data paths. In both examples, there is provision for redundant data sources and, where appropriate, redundant function modules to improve reliability. In both schemes, links between the circuit and central computers provide information at the central location for alarm and monitoring purposes.

Almost all schemes provided communication to a remote centre for the transmission and receipt of data and commands. Several replies mentioned concentration of data at the central substation level for onward transmission to save on communications requirements.

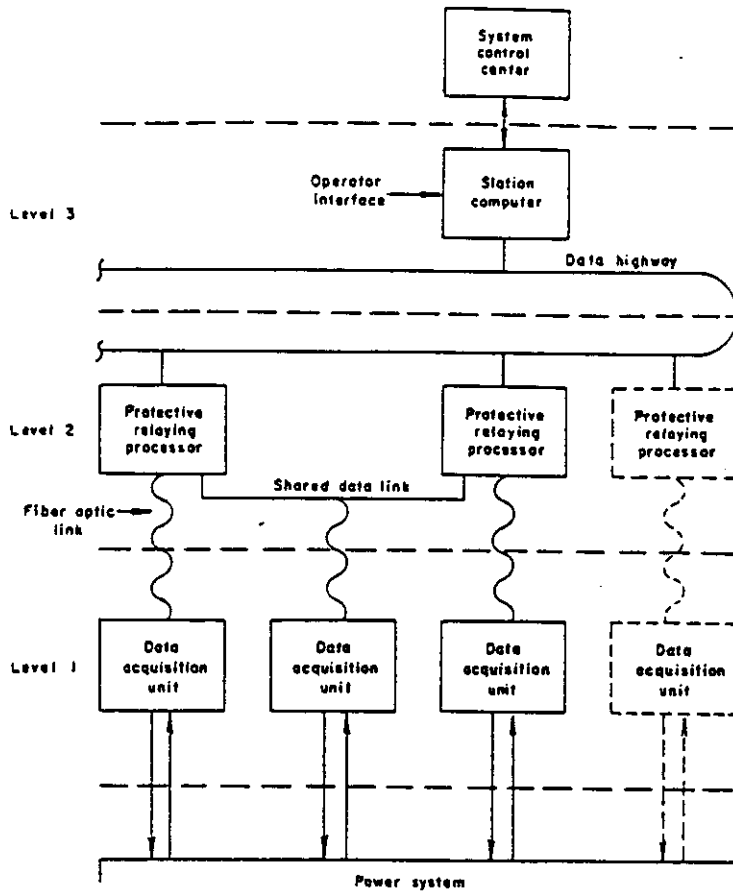


Figure 3.1 Architecture of Substation Computer Protection System Hardware

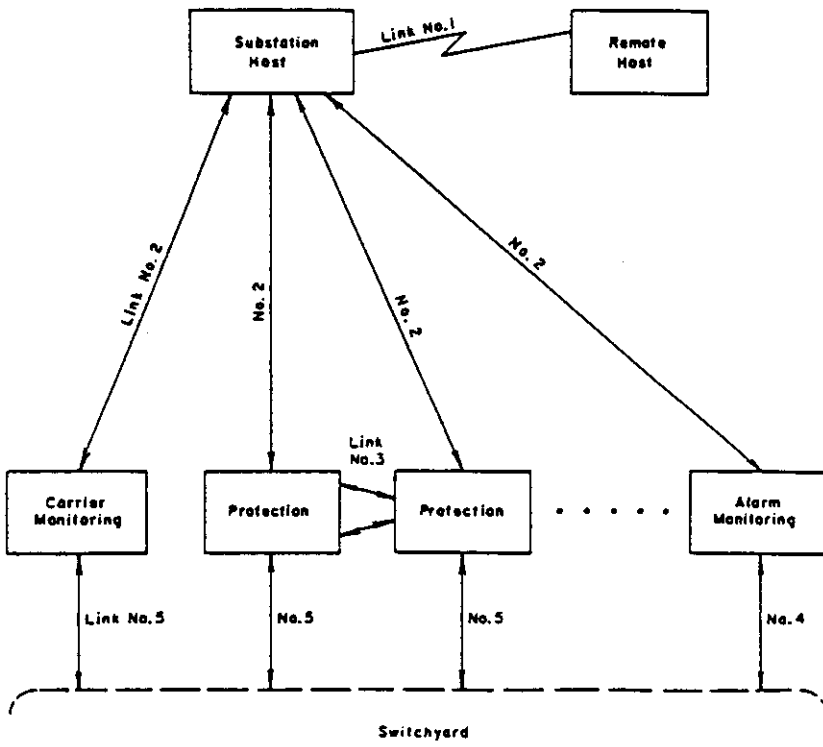


Figure 3.2 AEP Hierarchical Substation Computer System

3.2.3. SAMPLING AND SYNCHRONIZATION

The information on this subject contained in the replies was rather limited. Some general conclusions can be drawn from those schemes which had been developed to an advanced stage. The sampling rate most popular for use in high speed functions lies in the 1 kHz region, although sampling rates ranging from 240 to 1200 Hz were reported. Only a few replies mentioned a standardized sampling frequency for all functions. Since some of the replies referred to older designs, it may be inferred that the sampling rates were restricted to accommodate the capability of the equipment.

Few replies specified a common synchronized sampling rate for the substation. This feature could become important for new designs by introducing flexibility and a reduction in cost. It allows raw data samples to be transferred between devices if required. The sampling described in the replies is that within the substation. The need to transmit information to a remote central computer results in a sampling rate appropriate to the class of data being sent (or received). This data is transferred via a buffer in all cases. The sampling rate is thus independent of other requirements within the substation. A few replies mentioned a facility to freeze data in the substation on receipt of a broadcast synchronizing signal. The "freeze" capability is provided to ensure that data gathered from different substations for state estimation computations at a control centre is consistent in time.

As might be expected, the highest rates of sampling are carried out at the circuit level,

although two schemes required high speed sampling at the central level to perform distance protection. The provision for making redundant sampled data available for critical functions differ between schemes. Generally, the two most common methods are the use of point-to-point links between processors, or the duplication of signals into the processors via hard wired links. A few schemes, however, consider that the best method is to duplicate the function completely. Since the use of two sets of main protection for important circuits is a common feature, this approach is considered a logical and straightforward way of providing redundancy.

Several schemes mentioned the use of sampled data (obtained for protection) for oscillography purposes. Some replies emphasized the need for good resolution in oscillography output and the need to supply this information from data sampled at higher sampling rates.

3.2.4. COMMUNICATION LINKS AND PROTOCOLS

The link transfer capabilities reported depend upon the use to which the link is put. For substations to remote centres, the serial link capability is typically 1200 bits/s. For point-to-point serial transfer of data between devices using high speed sampled data, the upper capability reported is 1.2 Mbits/s. For communications using parallel links (e.g. 16 bit highway), the speed is a function of the computer hardware and is typically 800 to 1000K words/s. Many replies mentioned the use, or intention to use, fibre optic technology for serial links within substations to eliminate the problems associated with electromagnetic interference.

* 4. FUNCTIONAL CRITERIA FOR EVALUATING DIGITAL PROTECTION AND CONTROL SYSTEMS

4.1. PROTECTION SYSTEMS

4.1.1. INTRODUCTION

The protection areas to be considered are transmission line protection, power transformer protection, and bus protection. All share certain features that must be considered in the conversion to digital computer technology. General criteria common to all digital protection schemes include the following :

- a. Speed
- b. Selectivity
- c. Reliability (Dependability/Security)
- d. Hardware Requirements
- e. Adaptability
- f. Diagnostics
- g. Man-Machine Interface

These general criteria will be discussed before proceeding to the specific protection areas.

4.1.1.1. RELAY SYSTEM COMPONENTS

The functional blocks shown in Figure 4.1. are assumed to represent the digital relay system.

The current and/or voltage signals from the power system are processed by analog circuits

(such as transducers, surge suppression circuits, filters, etc.) before being sampled and converted to digital form by the Analog/Digital Converter.

The relaying algorithm processes the sampled data to produce the relay output, which in most cases is a digital output. It is anticipated that most digital relaying systems can be described by the functional blocks of Figure 4.1. For systems that do not conform to this block diagram, a different technique for describing the relay operating times may be necessary.

4.1.1.2. SPEED

Speed can be defined rather simply as the speed of a computer-based digital relay; however, it is recognized that a relay system has different speeds of operation under different operating conditions. Thus, it is necessary to identify those conditions which may influence the operating time of a relay and help obtain a proper understanding of the operating speed of a digital relaying system.

* Certain sections of this chapter were written as parts of an IEEE Working Group Report. Several members of CIGRE WG 34.02 are also members of the IEEE Working Group and have contributed to the IEEE Working Group Report.

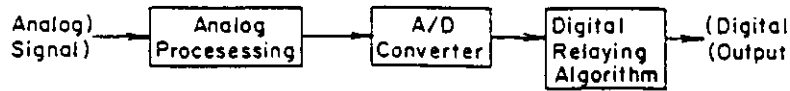
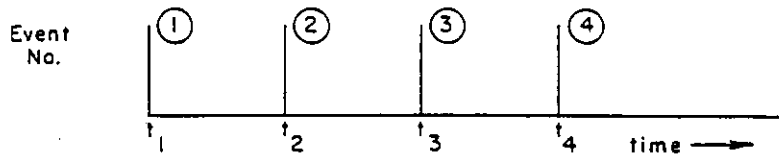


Figure 4.1 Functional Block Diagram of Digital Relay System



Event No. 1 Occurrence of a fault on the system.

Event No. 2 Appearance of the fault signals at the input of the A/D converter.

Event No. 3 Conversion of the last data sample used by the relaying algorithm in its decision-making process.

Event No. 4 Completion of the relaying program execution, signified by the production of an appropriate digital output.

Figure 4.2 Relay Operating Times

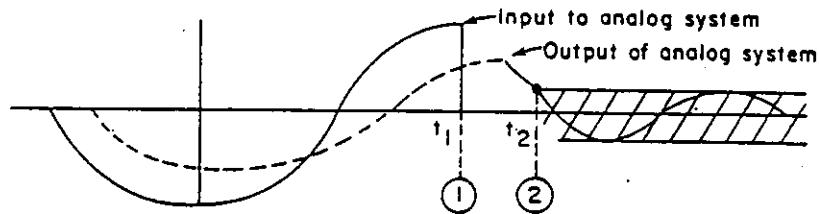


Figure 4.3 Definition of Event 2

4.1.1.2.1. Relay Operating Time : Figure 4.2 identifies certain significant events which will help identify relay operating times.

Note that the definition of Event No 2 requires some explanation. A suggested definition of Event No 2 is illustrated in Figure 4.3. Assume that at t_1 , a full sine wave at the input of the analog system goes to zero from its peak value. Thus t_2 can then be identified as that time at which the output enters the $\pm 10\%$ band around the steady-state value of the output.

4.1.1.2.2. Algorithm Time : A useful measure of the performance of a digital relay is its algorithm execution time. This can be measured experimentally or can be estimated from special tests. Assume that all the data samples needed for the execution of the algorithm become available at t_2 and that t_2 and t_3 are coincident. (See Figure 4.2.). The relay operating time t_4 under this condition is a measure of the algorithm execution time.

Relay Operating Time

	Time	Accuracy
Minimum Operating Time (Specify Conditions)		
Maximum Operating Time (Specify Conditions)		
Analog System Response Time (Time to A/D Converter)		
Algorithm Time		
Relay Function (Depends on Relay Type)		
Special Needs Additional Computation for Phase Selection Directionality		

4.1.1.2.3. Special Needs : There may be special requirements for a given algorithm. For example, the algorithm may depend upon a specific sampling rate or additional computation may be required to determine directionality or faulted phase identification. Such special requirements should be clearly identified.

The above discussion leads to a possible form for the specification of the relay operating time.

4.1.1.3. SELECTIVITY

Selectivity (of a protective system). A general term describing the inter-related performance of relays and breakers, and other protective devices; complete selectivity being obtained when a minimum amount of equipment is removed from service for isolation of a fault or other abnormality.*

Selectivity is discussed in detail in the following sections for transmission line, power transformer, and bus protection.

4.1.1.4. RELIABILITY (DEPENDABILITY/SECURITY)

The consideration of reliability for digital relays requires an examination of several items. First, a review of general reliability concepts as applied to protective relaying will be presented. Some special considerations for digital relays will also be covered.

Reliability, in general, refers to the ability of an item to perform a required function under stated conditions for a stated period of time. Often this definition is expanded to include the probability that a device will function without failure over a specified time period. These conditions can be summarized as the performing of a function correctly or the probability of functioning without a failure. A simple example could be the ability of an alarm clock to awaken a person every morning for a year. This could also be stated as the probability that the alarm will go off every morning for a year. For protective relaying additional concepts are introduced.

Reliability (of a relay or relay system). A measure of the degree of certainty that the relay, or relay system, will perform correctly. NOTE : Reliability denotes certainty of correct operation together with assurance against incorrect operation from all extraneous causes. See also "Dependability" and "Security"†

It is not enough for the alarm clock to go off in the morning ; but there must be certainty that it will not go off in the middle of the night as well. This two-sided version of reliability introduces two new terms for reliability as applied to relay systems :

Dependability (of a relay or relay system). The facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly.*

Security (of a relay or relay system). That facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly.*

These additional considerations arise from the nature of the operation of protective systems where a false trip or an incorrect operation can be as disturbing as a failure to trip. The reliability of a digital relay system must include these considerations of dependability and security.

Definitions for reliability are important and necessary, but actual information on relay system performance is desirable. This, unfortunately, is not an easy task and reflects a different problem associated with relay systems. In a five-year summary of protective relay performance on a U.S. utility, 1969 through 1973, there were 5,260 relay operations. Of these 4,555 or 87 per cent, were correct operations while 705 or 13 per cent were incorrect operations. ** Of the 705 incorrect operations, three were failure to trip, while 702 were undesirable or false tripping. However, these figures could be misleading as applied to reliability considerations. During that same period, there were undoubtedly many other relays which were not called upon to operate. Of these, some probably were in a failed state or inoperable. This latter condition would have been detected during routine periodic relay maintenance. Other data could be accumulated relating operation, failure to operate, or inoperable but not called upon to operate, to the total relay population. This could offer insight into the probabilities associated with these conditions. Work has been done in these areas and is continuing, but published work available to the power industry is scant. Many millions of correct nonoperations were incurred during this time.

There is some data available on relay operation, but reliability goals are not widely accepted. The general tone of such goals is the nebulous statement : "Make it as good as existing equipment or better." The question is "Just how good is that ?" What mean time between failure (MTBF) or mean time to repair (MTTR) is desirable and acceptable ? The answer may lie in existing maintenance procedures. It is here that a digital system may offer an advantage. If a maintenance schedule involves a two-year cycle, it is desirable that a system does not fail during that period. It is also hopeful that any incipient failure could be detected and repaired during routine maintenance. The self-testing capability of a digital system would be useful here. Therefore, a mean time between failure of two years appears to be a minimum goal while five years may be more desirable.

For a digital relay system with processing capability, there is the possibility for self-test and diagnostics. With such an addition, a digital relay system could detect a failure and alarm the operator. This could enable repair before an actual fault occurs. Thus, an unsuccessful operation could be avoided. This whole concept of self-testing presents another facet to the reliability considerations for digital relay systems.

To summarize reliability considerations for digital relay systems, there are the following points : first, a digital relay must satisfy the traditional concepts of dependability and security; Second, although supporting information is scant, present relay systems exhibit satisfactory reliability which a digital relay system must duplicate. Mean time between failures should be of the order of five years to fit into maintenance programs.

* "IEEE Standard Definition for Power Switchgear" ANSI/IEEE C37.100-1981.

**Cogburn, C.W., "Experience with Protective Relays on a Bulk Power System", 1974 American Power Conference

Finally, the capability for selftest associated with digital systems should be utilized by digital relay systems to enhance their reliability.

4.1.1.5. HARDWARE REQUIREMENTS

These requirements identify those special capabilities which will be needed by a digital computer hardware system; general guidelines are given below.

4.1.1.5.1. Processors and Memory : the number and type of processors required for the implementation of a protective relaying device, as well as the amount and type of memory required, are important considerations. For example, a specific implementation may call for multiple processors, parallel processors, RAM, EPROM, non-volatile RAM, etc. However, there should be no special requirements that are outside the bounds of available technologies.

4.1.1.5.2. Substation Environment : Digital processing hardware must be able to withstand the temperature and humidity variations which occur in a substation environment with a minimal amount of environmental control equipment. Contamination from dirt and dust must also be tolerated.

The following performance criteria may be used as a guide in selecting a substation computer relaying system.

- a. Permissible humidity limits (to be determined)
- b. Permissible temperature limits (to be determined)
- c. Permissible pollutant levels (to be determined)
- d. Surge Withstand Capability (SWC) compliance

4.1.1.5.3. Power Supply: an uninterruptible and well-shielded power supply is of prime importance to the reliability of a digital relaying system. Although the digital relaying system must be designed to recover from a power failure without misoperation, such failures will temporarily bring down the protection function. Power supplies, including sources, should be evaluated upon their ability to meet the following performance criteria :

- a. Reliability of power supply (i.e. probability that power supply will not fail) including the influence of the source on the power supply and the effect of clearing shorts at other locations that result in "voltage dips" in the power supply.
- b. Response to and protection from induced voltage surges.
- c. SWC compliance
- d. Design basis, component selection, and quality control during manufacturing process.

4.1.1.5.4. Data Interference Access : when evaluating the relaying system it is important that a substation operator or a relay engineer have the ability with appropriate safeguards and without bringing down the whole protective system, to perform the following functions :

- a. Modify existing relay settings, either temporarily or permanently
- b. Modify relay tripping characteristics in existing programs
- c. Modify interlocks in existing programs to provide for system changes

Another important function to be considered in the relaying system evaluation is its ability to

provide information currently supplied by other equipment or to provide information not currently available. The availability of the following information may be used in the evaluation.

Does the relay provide information about :

- a. Fault location, type, magnitude, and duration ?
- b. Circuit loadings - MW, Mvar, A and V ?
- c. Alarms and targets ?
- d. Software events during a fault ?

Since some or all of these functions may be interfaced with SCADA (supervisory control and data acquisition system) equipment, output modes for the data also need consideration. The relaying system may be evaluated upon its ability to provide information :

- a. In a graphic or tabular display
- b. At frequent intervals as determined by system operators

4.1.1.6. ADAPTABILITY

A relay must be adaptable to a wide variety of conditions, system configurations, substation designs and configurations, substation environmental conditions, and secondary protection schemes and protection schemes for various elements in the substations. The protection algorithm must work in harmony with the other protection algorithms which initiate control action from the physical location.

4.1.1.7. DIAGNOSTICS

One distinct advantage of having a computer in a substation is the ability through software to provide self-checking to verify that the system is in working condition. Self-testing can be performed at regular intervals to determine various system conditions. At present, relays are idle 99.999985 percent of the time (assume relay operates 300 cycles/year) and are in effect tested when called upon to operate by an abnormal condition in the system. This operating test usually provides information about the condition of the relay, however, the consequences of a failure are undesirable and sometimes very difficult to diagnose. The digital system can provide information not only to specify that there is a malfunction but can be programmed to partially diagnose the problem. The results of each diagnostic test can be available to the substation operator, and if a malfunction exists, the system dispatcher can be notified to dispatch maintenance personnel.

Each specific component of the digital protection system can be periodically checked. The elements necessary to check are : sensors, processing and A/D equipment, CPU system, and software routines. The self-checking capabilities can be evaluated as follows :

- a. Do self-checking and verification capabilities exist within the system ?
- b. What portions of the system are checked and verified ?

- CPU
- Input signal validity (i.e., A/D converter accuracy)
- Output signal integrity
- Interference noise level
- Communications noise/failure
- Algorithms execution/logic performance
- Power supply noise/failure

4.1.1.8. MAN-MACHINE INTERFACE

A reliable, economical, and simple man-machine interface should be provided. The man-machine interface in the substation should be simple enough for an untrained substation operator to operate and determine needed information. Yet it should be able to aid maintenance personnel in problem diagnosis and repair and should be able to provide information for engineering evaluations in both normal and abnormal conditions.

4.1.2. LINE PROTECTION

4.1.2.1. FUNCTIONAL BEHAVIOUR

Much of the recent literature on digital protection of transmission lines is devoted to the relative performance virtues of various algorithms and equations. When executed as computer programs, these algorithms process raw samples of AC voltage and current signals from the line into numerical quantities useful for locating faults or making related relaying decisions.

The purpose of this section is to highlight the salient features and trade-offs of the algorithms. It points out particular functional behaviour characteristics required for specific sensing tasks within a complex line protection system.

4.1.2.2. SAMPLE-PROCESSING ALGORITHMS

Sample-processing algorithms are mathematical procedures which transform the instantaneous samples of power-system waveforms into derived quantities useful for relaying decisions. In general, high-speed methods yielding fast relaying decisions suffer large errors when working from badly distorted fault waveforms, while procedures producing slow responses are able to filter out the non-power frequency components to achieve higher accuracy.

The choice of speed versus accuracy depends on the particular job the algorithm is doing within the overall line protection function. In some cases it is possible and desirable to design an algorithm to adjust its operating speed according to the quality of the AC data, yielding the best of both performance extremes.

4.1.2.3. COMPENSATION FOR POWER-SYSTEM EFFECTS

Algorithm errors caused by waveform distortion are only part of the error problem. Power-system effects will cause reach variations regardless of the filtering ability of the algorithm. Salient power system effects include :

- Zero-sequence mutual coupling of parallel lines
- Arc or tower-footing resistance
- The interaction of fault resistance and out-of-phase sources at the two line terminals to produce misleading apparent fault reactance
- Source-impedance variations, which have a drastic effect on overcurrent only functions

Digital processors have a largely unexplored capability to deal with these phenomena in conventional or novel ways. The user should be aware of such potential since the designer can utilize it to advantage in improving the accuracy and/or speed of non-pilot functions.

4.1.2.4. FAULT-TYPE COVERAGE

Relaying capabilities must be provided to handle all ten combinations of phase and ground faults.

This is done in one or three ways :

- A fault-type processing selector chooses the most likely fault type and invokes a ground- or phase-distance relaying program, as appropriate, using the selected AC quantities. These schemes are computationally the simplest but must be carefully designed to minimize the possibility of a wrong choice and consequent delay of tripping. For two-phase-to-ground faults, phase distance processing should be selected for the best reach accuracy.
- A group of distance or related programs covering all fault types is executed simultaneously. This is unconditionally reliable but requires a great deal of processing capability.
- One or two polyphase algorithms respond to all fault types. This is more efficient than the last method but still computationally more burdensome than the first.

4.1.2.5. SINGLE-PHASE TRIPPING

If single-phase tripping is required, the programs must have the ability to select the faulted phase or phases in order to support this tripping logic. The phase-selector and all-fault calculation approaches inherently meet this requirements. Poly-phase methods should be checked to confirm that such an output is easily obtained through some ancillary computation.

4.1.2.6. IMMUNITY TO POWER-SYSTEM EFFECTS

Digital protection algorithms are subject to errors from many power system phenomena. Ground distance relays, in particular, are sensitive to the effects of pre-fault load-flow, arc and tower footing resistance, residual current flow, and zero-sequence mutual coupling. As with conventional relays, the user must determine the errors which might be caused by such effects and must incorporate specific compensating calculations to meet error objectives.

4.1.2.7. DISTANCE PROTECTION FUNCTIONAL REQUIREMENTS

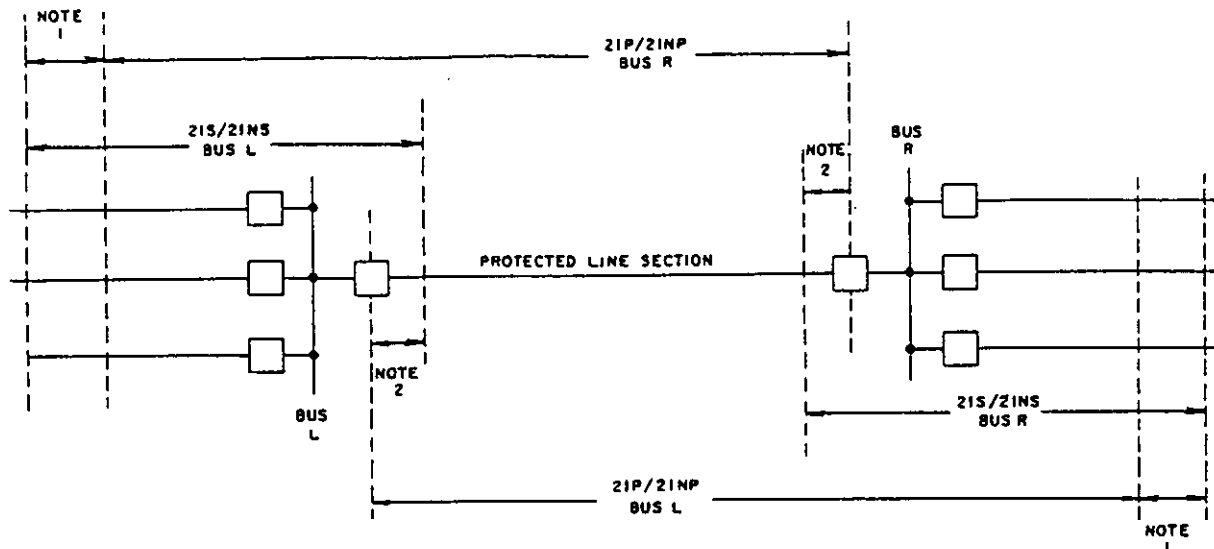
4.1.2.7.1. Pilot Relaying* : Conventional pilot relaying schemes can be effectively implemented on digital computers using algorithms which calculate apparent impedance or some other measure of physical distance from the relaying point to the fault. The algorithm-based fault decisions are combined with results from the remote line terminal, communicated over a pilot channel, to yield a local trip decision.

Figure 4.4 shows examples of the zones of measurement associated with a conventional pilot blocking system. The following are the key algorithm requirements :

4.1.2.7.1.1. Speed Versus Accuracy : the forward-reaching tripping relay function operating zone (21P/21NP) is set to overreach the remote terminal by a considerable margin, so that it operates for all internal, and many forward external, faults. It trips the local breaker only when permitted to do so by the remote reverse-looking (21S/21NS) relays, which signal over the pilot channel.

The pilot protection is intended to be the fastest relaying for line faults. Accuracy of reach is less important. The forward-reaching tripping function

* Distance schemes which are supplemented by signalling among terminals, e.g. pilot-wire, carrier-current, microwave, etc.



- NOTES: 1. REVERSE CARRIER-START FUNCTION 21S/21NS MUST OVERREACH REMOTE TRIP FUNCTION 21P/21NP FOR ALL EXTERNAL FAULTS.
2. IN CONVENTIONAL PILOT LOGIC, 21S/21NS MAY OPTIONALLY REACH INTO FORWARD ZONE; LOCAL 21P/21NP PROVIDES DIRECTIONALITY AND TRIPPING.

Figure 4.4 Zones of Protection for Carrier Blocking Pilot Protection

is set for considerable overreach of the far line terminal and yet need only operate for faults along the line itself. The reverse-looking function need only respond to all faults which might trigger the forward looking relay at the remote line terminal; response to more distant faults is not detrimental.

In light of these requirements, short-window, high speed algorithms tend to be well-suited for all pilot protection distance sensing. The specific operating time which can be achieved depends on the level and types of waveform contamination expected in the worst case.

4.1.2.7.1.2. Directionality : We must, of course, be concerned not only with fast and accurate classification of faults near the far zone boundary, but also with the proper directional resolution of faults near the origin where the collapse or distortion of the polarizing voltage waveform may make it difficult for the program to determine which way the fault current is flowing. Relaying programs can determine fault direction, in such cases, by using voltage signals from sound phases; this may be done by a specific test-and-select program or by an inherently polyphase measurement program. For near three-phase faults, which collapse all voltage signals, the program must sense direction using an extension of pre-fault voltage phase, derived from pre-fault voltage sample memory. Ground or negative sequence polarization, familiar in conventional relays, is also usable. Some computational approaches may inherently consider pre-fault conditions in directional determination.

Forward reaching pilot tripping relay functions must have secure directional sensing. However, in some logic schemes, such as conventional blocking logic, it is acceptable for the reverse looking relays, to respond to close-in faults in the forward direction. In this case, reverse direction is determined by lack of response from the forward looking relay.

4.1.2.7.1.3. Series Capacitor Tolerance : series capacitors in adjacent lines sometimes produce reversals of bus voltage phase which lead to erroneous directional sensing, and thus misoperation. If such capacitors are in service near the intended line relay installation, the relaying programs must be capable of detecting the reversal and invoking pre-fault memory polarization.

For reliable distance protection of EHV lines having series compensation in the protection zone, one must employ specialized processing of AC signals using measurements, specially designed for this application. For example, protection elements could detect reversal of the bus voltage (voltage detection with memory) and influence the measuring characteristic accordingly. An alternative is a phase comparison protection program, which is insensitive to voltage or impedance anomalies.

Some series capacitor installations place another stringent requirement on protection algorithms - the ability to function reasonably in the presence of resonance currents. The worst expected magnitudes and ranges of frequency for these currents must be estimated and the error-inducing effects figured in light of the known-off-normal frequency rejection of the algorithms in use.

4.1.2.7.2. Non-Pilot Relaying : Non-pilot distance relaying capabilities are likely to be programmed in a pilot line terminal for multiple-zone backup protection. For non-critical transmission or subtransmission circuit protection, non-pilot distance or inverse time-distance relaying functions are used for primary fault protection. The requirements are different from those of pilot schemes in certain critical regards.

4.1.2.7.2.1. Measurements Needed : Pilot systems for important lines frequently include local backup dis-

tances relaying. The local backup is normally a non-pilot underreaching function which covers most of the line when pilot protection fails or is out of service. Ground- and phase-distance measurements are employed, with steady-state reach characteristics of the types used in pilot functions. Independent reach settings are required. Such a function can also operate as stand-alone for a less critical line.

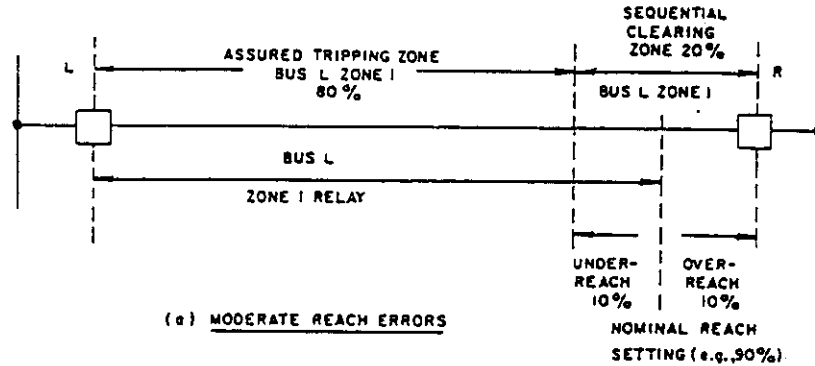
Additional zones of distance protection may be programmed for direct non-pilot trips after time delays to provide remote backup for bus transformer, or line relays and breakers which fail to clear faults outside the primary line zone. The same zones or reach settings used in pilot relaying are frequently provided with the extra time delayed trip output but one or more extended reach zones may be added for only this purpose. In computer based schemes where calculated distance numbers are compared with reach limits, the extra zone entails just one more such comparison.

Subtransmission circuits can be protected with inverse-time distance relays. The trip speed is proportional to fault distance from the relaying location. Each relay is inherently backed up by another relay or an adjacent line section which will trip after a longer time when the primary relay or breaker fails.

Finally, supplemental non-directional overcurrent measurements may be included for quick tripping of nearby faults, or of faults which appear when the line is energized.

4.1.2.7.2.2. Speed Versus Accuracy - Zone 1 Relays : The local backup non-pilot function should offer better reach accuracy than the pilot relay it backs up. Since the local backup relay receives no supervising signal from the remote end, it must never overreach the remote terminal for the worst combination of algorithm errors and power-system induced overreach. Figure 4.5(a) shows that the normal reach must be shorter than the protected line length to allow for the overreach condition. Since the errors can cause either overreach or underreach, the assured zone 1 coverage of the line is substantially less than 100 per cent. Figure 4.5(b) shows that worse errors require a still shorter setting, and the assured line coverage is reduced by up to twice the setting reduction.

For faults on some line beyond the assured coverage zone, tripping of the remote breaker by the remote Zone 1 or pilot relay will cause reach of the local relay to extend to the end of the line ; therefore, sequential high-speed clearing is assured for all line faults. The user must confirm that anticipated reach errors and consequent underreaching settings



NOTE: SIMILAR COVERAGE PROVIDED BY BUS R ZONE 1. BOTH ENDS TRIP AT HIGH SPEED ONLY FOR FAULTS NEAR THE CENTER OF THE LINE.

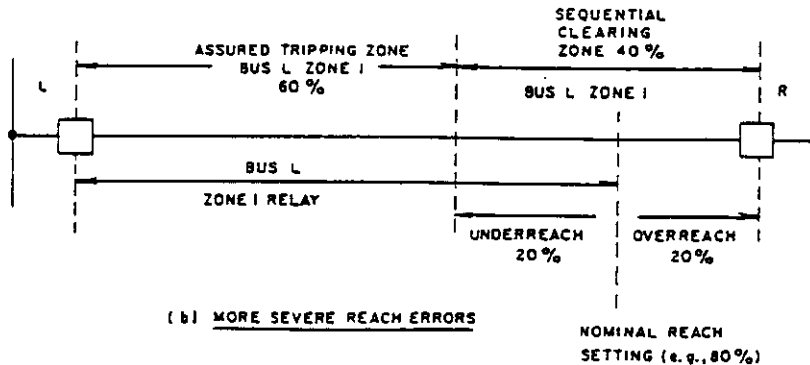


Figure 4.5 Zone 1 Relay Assured Tripping Zone

are not so severe that sequential clearing may not occur if he depends on this mode of protection.

The above discussion should lead the user to realize that accuracy is more critical here than for pilot functions. Since, this is a backup function, a little speed can usually be sacrificed. Long-window algorithms, or integrating or filtering procedures used with short-window algorithms, are best suited to the job.

4.1.2.7.2.3. Remote Backup and Time-Distance Tripping: Neither speed nor high accuracy is needed for the time-delayed remote-backup protection. Therefore, time delays appended to existing pilot or non-pilot measurement functions usually suffice.

Reasonably accurate trip times for a given distance measurement, perhaps to within 5 per cent, are needed for overlapping zone, inverse time distance protection to minimize coordinating delays. However, trip times are so long that accuracy is easy to achieve with long-window low-computation-rate algorithms.

4.1.2.7.2.4. High-Set Overcurrent Tripping : Applications with source impedances comparable to or lower than line impedance permit the use of a non-directional high speed overcurrent tripping function. These underreaching non-pilot protection algorithms, which calculate peak current magnitude require a speed-accuracy tradeoff just as for distance methods. The completeness of coverage is strongly coupled to the accuracy of the algorithm, as was true for the Zone 1 function. However, high-set functions serve more to speed up tripping for near high-current faults which threaten stability than to back up pilot tripping. Therefore, it makes sense to emphasize speed and to use a high current setting to prevent false trips due to algorithm errors. Fast short-window algorithms with limited coverage are attractive.

4.1.2.7.2.5. Line-Energization Tripping : This function uses high-set non-directional overcurrent sensing that is disabled after a time delay following breaker closing. Requirements are similar to those for high-set tripping, but settings may be lowered to sense faults over the entire line length. Some overreach is acceptable since the remote terminal is open for line energization.

4.1.2.8. SPEED

In addition to the general specifications of the speed of a digital relay presented in 4.1.1.2, there are specific issues involved in the discussion of an impedance relaying system.

4.1.2.8.1. Relaying Functions : An impedance relaying system performs many functions, and in general the operating time associated with each function is different. Consequently, every speed specification should identify the corresponding relaying function. Following are suggested categories of functions :

- a. Zone 1, direct trip function
- b. Carrier start and stop function
- c. Breaker-failure protection function
- d. Overcurrent
- e. Transfer trip function
- f. Other functions

4.1.2.8.2. Accuracy : The speed of an impedance relay is inextricably linked with the accuracy of the relay. In fact, the dependence of relay speed upon function discussed in the previous sections is primarily due to different accuracy requirements for each of those functions. Thus, when specifying the relay operating time for a specific function, it is essential to pro-

vide the assumed relaying accuracy for that function.

4.1.2.8.3. Relay Operating Time Range : It is recognized that the relay operating time would depend upon the nature of a fault. It is suggested that the following fault categories be considered while determining the minimum and maximum (range) operating times for the relay.

- a. Fault type : ground, phase, etc.
- b. Fault incidence angle
- c. Need for memory voltage (e.g. fault voltage less than 5 percent of its normal value)
- d. Evolving faults
- e. Low-fault currents (e.g. less than 1.5 times pick-up)

4.1.2.8.4. Fault Location : It is recommended that operating time data be provided for faults at 90 percent of the appropriate zone boundary. Data for other fault location should also be provided if significantly different from those at 90 percent of its reach setting.

4.1.2.9. SELECTIVITY

Selectivity should be considered from two aspects. First, it should be considered by fault location (evaluated at several specific locations).

- a. Reach
- b. Directionality (inherent or added)
- c. Zone boundaries

Second, it should be considered by fault type.

- a. Faulted-phase identification (inherent or added)
- b. Evolving faults (ability to determine possible fault-type changes)
- c. Simultaneous faults on different phases of double circuit lines

Selectivity by location refers to the relay's ability to discriminate between a fault that is internal or external to the intended zone of protection.

One important aspect in determining whether the fault is in the tripping zone is directionality. Does the algorithm inherently provide directionality or must the directionality determination be added? In some cases, the directionality determination can be as time consuming as the fault determination calculation. Another consideration is the possible loss of directionality for close-in faults. Reach of the relay can be thought of as selectivity in the forward direction.

The following criteria should be evaluated for the selectivity determination.

Selectivity

	YES	NO
Is the distance calculation directional?		
Is there a directionality provision for close-in faults?		
Does the distance calculation identify the faulted phase?		
Do fault type changes affect selectivity?		
Do fault type changes affect relay operate time?		
Does the relay discriminate faults from other abnormal conditions?		

	ACCURACY
Zone 1 location	
Zone 2 location	
Zone 3 location	
High-Set location	
Blocking-Zone location	

Selectivity by fault location for a line impedance relay is gauged by its ability to correctly calculate the actual distance of the fault from the relay terminal especially when the fault is close to or at the end of the intended zone of protection. Thus, the impedance relay's fault location selectivity is a gauge of its measuring accuracy and the evaluation criteria established for the accuracy criterion would identically apply to fault location selectivity.

Selectivity by fault type would include evaluation parameters on the relay's ability to discriminate line faults from other abnormal conditions such as out-of-step or heavy line loading, which exhibit similar voltage and current signals at the relay terminal ; or the relay's ability to distinguish among various types of line faults (i.e. identification of faulted phase) where single-phase tripping is desired. These parameters would be found among the functional requirements criterion in an impedance relay specifications.

4.1.2.10. FAULT WAVEFORM SPECIFICATIONS

A set of basic tests is desired so that the comparison of various impedance relaying schemes based on digital techniques is easily made. Although not part of the purpose, such a set of test conditions may also find application in the evaluation and comparison of non-digital relays. The basic tests may be deemed bench marks.

The waveforms typifying the test conditions should be realistic, yet straight forward to generate, both in software and in hardware. Furthermore, the waveforms must represent inputs to a relaying system, as opposed to representing sampled waveform data for direct input to an algorithm. That is, prefiltering of the waveform data is assumed to occur in the relay system under test.

Before discussing the fault waveform specifications, it may be desirable to recall the several components of fault waveforms. Different algorithms use different components of the fault waveforms. The component used by one technique for fault determination may pose serious problems for other techniques. The fault waveform consists of a steady-state power frequency component, exponentially decaying DC offset transient and other frequency components. One source of low frequency components is the coupling capacitor voltage transformer (CCVT). The high frequency components are produced by a number of phenomena. One is caused primarily by what is connected at the line terminals which produces frequencies in the range of 150-600 Hz. Other high-frequency components are caused by the propagation and successive reflection of the fault initiated surge. This phenomenon will produce components of considerably higher frequency. The high-frequency voltage and current waveforms are not related by the line impedance ($R + j\omega L$). Most digital impedance algorithms can successfully filter the higher frequency components due to the fault surge ; however, the lower frequencies may create problems with the algorithm. These frequency components are more difficult to

filter. Therefore, the specified test waveform should include these frequency components. Any filtering that is required by the algorithm causes time delay and phase shift. It is important that required filtering be included in any evaluation.

4.1.2.10.1. Fault Waveform Models :

4.1.2.10.1.1. Wave Propagation Model : Computer models may be sufficient for the generation of the waveforms, yet it is probably not necessary since the relay schemes under consideration for testing have been limited to include only impedance based techniques. The EMTP (electromagnetic transients program) program developed by Bonneville Power Administration is one such model. It is reasonable to consider the generation of waveform data derived from that package for an agreed-upon set of fault conditions and system configurations. The output data could be made available on digital magnetic tape. Advantages of this approach include : the suitability of such data for use with travelling wave relays as well as with conventional types ; use is made of what is probably the best model, and the growing acceptance of this model. Disadvantages include : inconvenience and expense in obtaining the data ; format compatibility problems between computer systems ; the need for a person or organization to agree to generate and provide such data ; and difficulty in generating analog data from the digital data.

4.1.2.10.1.2. Steady-State Model : This simplest model neglects all transients generated by the occurrence of fault. Waveforms from such a model are easily generated in hardware and in software. A steady-state model may find usefulness in a preliminary evaluation of relaying schemes. Furthermore, it is easily specified by pre/post-fault impedances, fault-type, angle of fault inception, and fault location.

4.1.2.10.1.3. Lumped-Parameter Model : If the model consists of series R-L representations of the source, line and load, then the system response contains a steady-state component and a transient component. The transient component is determined by a single negative real eigenvalue and the time of fault inception. It represents the so-called DC offset, or e^{-at} term. Such a model is the simplest departure from the steady-state model. Again, it is easily implemented and defined.

If the line is modelled as one or more "lumps" consisting of series R-L and shunt C parameters, then a multiple-eigenvalue system response is created which includes the high-frequency components particularly noticeable in the voltage waveforms.

A generalized equation for the multiple-eigenvalue model is easily written ; however, determining appropriate values for the eigenvalue and the relative magnitude and phasing is important and difficult.

4.1.2.10.2. System Considerations : Three important considerations in specifying conditions for bench mark development are listed below :

- Bench mark waveforms should be derived from models of realistic systems.
- The parameters of lower voltage systems differ substantially from those of higher voltage systems.
- The termination at the line ends (e.g. sources, loads, capacitors, reactors) must be considered.

4.1.3. TRANSFORMER PROTECTION

4.1.3.1. FUNCTIONAL BEHAVIOUR

Much of the recent literature on digital protection of power transformers has been devoted to different algorithms for differentiating between transformer faults and magnetizing inrush. Most approaches use a current differential technique with a restraint that is indicative of the inrush phenomenon. The current differential is adjusted to make the differential relay insensitive to ct and relay inaccuracies, as well as off-nominal tap positions of the transformer. A variety of techniques have been suggested for differentiating between inrush currents and transformer fault currents. These techniques all depend on the inrush current being distorted, i.e. is not a pure sinusoid. Major sources of such distortion in the transformer current are :

- a. Magnetizing inrush
- b. Overexcitation of the transformer due to overvoltage condition.
- c. Saturation of current transformers

The restraint must be designed so that the current differential is restrained during magnetizing inrush and overexcitation but is not restrained by a saturating current transformer during an internal fault.

4.1.3.2. FUNCTIONAL REQUIREMENTS

Digital systems for power transformer protection must be capable of protecting three-phase multi-winding transformers in a variety of situations. The algorithm should be applicable to two or three winding transformers with primary, secondary and tertiary connected in wye or delta. In addition, the algorithm should be appropriate for three-phase, core and shell type transformers and three-phase banks of single-phase transformers.

The relay must operate successfully in a variety of situations. Following are possible phenomena to be considered in evaluating relay performance.

- a. All types of internal faults (phase to ground, phase to phase)
- b. All types of external faults (phase to ground, phase to phase)
- c. Energization into an internal fault
- d. Energization into an external fault
- e. Part-winding faults
- f. Inrush on energization
- g. Inrush on energization of a parallel bank
- h. Inrush on removal of a fault
- i. Overexcitation
- j. Current transformer saturation for internal faults
- k. Current transformer saturation for external faults

4.1.3.3. SPEED

In addition to the general specifications of the speed of any digital relay discussed in the introduction, there are several specific issues involved in the consideration of transformer relay systems.

4.1.3.3.1. Fault Types : The speed of the transformer relay could depend on the type of distortion present in the fault currents. Speed specifications should identify the type of fault. Following are suggested categories :

- a. Internal full-winding fault with no ct saturation
- b. Internal part-winding faults with no ct saturation
- c. Internal faults with ct saturation
- d. Energization into an internal fault
- e. Energization into an internal fault with ct saturation

4.1.3.4. SELECTIVITY

Selectivity of transformer relays can be viewed as the relay's ability to discriminate between internal faults and a variety of other phenomena. The possible phenomena listed under functional requirements can be divided into internal faults and other phenomena. The selectivity of the transformer relay can be thought of as the ability to differentiate internal faults from other phenomena in the presence of severe inrush or ct saturation.

A second type of selectivity for transformer relays is sensitivity to part-winding faults. The slope of the present differential characteristic determines how small a part winding fault can be detected by the relay. The need to allow for off-nominal turns ratios with the percent differential characteristic limits the sensitivity of the relay to part-winding faults.

4.1.3.5. WAVEFORM SPECIFICATION

As in the case of impedance algorithms, it is important in evaluating transformer algorithms that a method for specifying a set of fault test waveforms be developed. A broad set of standard tests of relay performance during inrush, overexcitation and ct saturation is desired so that a comparison of various relaying schemes is easily made. Oversimplified descriptions of waveforms by harmonic content does not seem adequate considering the complex non-linear phenomena involved. Three possible sources of standard test waveforms are :

- a. Small Scale Physical Models. Inrush and overexcitation have been generated by small scale physical models to test transformer algorithms. Inrush currents decay somewhat rapidly due to the higher losses associated with small scale models ; however, the inrush currents are realistic during the period of interest for relaying applications. On the other hand, the ct saturation is quite difficult to simulate in a small scale physical model. One possible solution to the ct saturation problem is to combine analog or digital computer simulations of the ct with a small scale physical model of the transformer.
- b. Electronic/Analog Computer Models. Modern analog computer systems are capable of modelling both the transformer itself and the saturation ct in real time. Nonlinear function generators can be used to simulate both the nominal B-H curve and hysteresis in the transformers and ct's. There would be considerable expense involved in simulating a multi-winding three-phase transformer with a large number of ct models.
- c. Digital Simulation Models. A special-purpose program can be written to generate voltage and current samples using a simple modelling of power transformer or ct core behaviour. The EMTP program package developed by Bonneville Power Administration can also be used to generate standard inrush, overexcitation, ct saturation, and fault waveforms. The disadvantages mentioned under the digital simulation section of line relaying waveform discussion of expense and inconvenience should be repeated here.

Whichever model is used, a representative set of waveforms for agreed upon levels of overvoltage, remanent flux, and some quantitative measure of ct saturation must be produced.

4.1.3.6. SPECIAL FEATURES AND HARDWARE NEEDS

Given that the transformer relay is part of an integrated digital protection scheme several interesting issues and features can be considered :

- a. Can the line relay and transformer relay share samples of any currents ? This has an impact on the analog filters used for each.
- b. Can voltage signals be used to improve the transformer relay performance ?
- c. Can the transformer relay use digital inputs of tap position or deduce tap position from measured voltage and current to change its characteristics so that it is more selective to part-winding faults ? Can the relay, in essence, match ct ratios exactly (in software) and thereby reduce the percent differential slope ?
- d. Can transformer load monitoring be performed with the relay ?
- e. Operation at abnormal frequency
- f. Unit transformers (V/Hz)
- g. Hot spot versus load-plus-ambient-temperature
- h. Improved fault detection sensitivity during transient conditions

4.1.4. BUS PROTECTION

4.1.4.1. INTRODUCTION

There has been relatively little literature on protection of power buses as a stand-alone task for a digital computer. This reflects the fact that existing conventional bus differential relays have provided reliable and secure protection using simple hardware and operating characteristics. Even though the cost of hardware components for digital relays is falling dramatically, there is still little incentive to replace conventional relay designs if those relays are considered only by themselves.

However, interest in the possibilities for digital bus protection arises in conjunction with the design and development of integrated systems for relaying, monitoring and control of substations. The economics are quite different in this environment. The dedicated current transformers and special wiring schemes which support conventional relays may be incompatible with the multiplexed, shared-transducer approach of the integrated system. Prospective users of the digital control system are focusing on the economics and performance of the entire system and will accept digital bus protection in light of its compatibility with and support of overall system operation.

Once the use of digital bus protection has been justified, the relay designer can utilize the unique strength of computers to overcome deficiencies in conventional bus differential relays. Two examples are refinement of operating characteristics and dynamic software selection of ct input signal samples to relay main-and-transfer bus arrangements in light of changing protection zone boundaries. Totally novel schemes of waveform analysis are also possible and are being proposed by some investigators.

4.1.4.2. FUNCTIONAL BEHAVIOUR

Bus protection schemes now in use employ several methods including current differential measurements, and directional or phase comparison.

However, most installations employ the differential current summation of ct signals for each phase; The main difficulty in this scheme is not so much in detecting internal faults as in avoiding misoperation for faults just outside the zone. False differential currents arise from saturation of the iron ct core and consequent ratio error. All the bus feeders supply a nearby external fault through a single ct whose likelihood of saturation is high.

Conventional bus differential schemes use one of the following methods to overcome the problem of saturation and ratio error.

4.1.4.2.1. High-Impedance Burden : The ct secondaries are wired in parallel across a non-linear (varistor) burden. A voltage-sensing relay element responds to power-frequency overvoltage on the varistor to trip the bus. For external faults with ct saturation, moderate voltage, developed across the varistor, drives false differential current through the low secondary existing impedance of the saturated ct. A high voltage cannot be developed, and the relay does not trip.

High-impedance bus protection is in common use now but is not well suited to digital adaptation. The ct secondaries must be physically parallel, with careful wiring practices, across the nonlinear burden. The resulting voltage signal is not readily usable for other substation measurement purposes. The only task for the computer is the checking of a power frequency voltage threshold - this underutilizes even simple digital hardware.

4.1.4.2.2. Linear-Coupler (lc) : Iron-core cts are replaced with air-core mutual inductors which never saturate and which yield a secondary voltage proportional to primary current. In conventional practice, these secondaries are connected in series to operate a differential voltage measuring element.

For digital protection system application, the lc secondaries may be individually wired to analog interface points and digitized. Differential protection is achieved by summing instantaneous sample values of algorithm-derived phasors. The individual signal sample sets do reflect current waveforms in each feeder and can support other non-relaying measurement functions.

4.1.4.2.3. Percentage-Differential Current : Secondary signals from iron-core cts are summed instantaneously to yield a differential operating signal. Tripping is restrained by a second signal proportional to the sum of the current magnitudes in the feeders. The differential and restraint signals are compared such that the differential current must exceed some percentage of the restraint current for tripping to be performed. The percentage may be fixed or may increase with increasing restraint magnitude.

Percentage-differential schemes are well-suited to computer relaying when only iron-core ct's are available. The current signals from each ct may be connected to a separate input channel, and the digitized samples may be used for other substation purpose. Differential and restraint values can be derived by software summation and application of appropriate algorithms. The comparison employs either conventional or novel nonlinear percentage-differential characteristics.

4.1.2.4.2. Directional Comparison : The directions of current flow in circuits connected to the bus are compared to that of the sum of currents to overcome saturation problems of low performance ct's in large

stations. This method requires adaptation to changing bus configurations. Information on the states of breakers and switches is readily obtained in an integrated system and control system.

4.1.4.3. FUNCTIONAL REQUIREMENTS :

Since all the bus protection schemes employ the same underlying differential concept, the user should focus attention on the suitability of the particular implementation for his contemplated use. The following points should be checked.

4.1.4.3.1. Types of Faults : The relaying must provide coverage for all internal fault types. This would not normally present a problem. Some users, however, may require an unrestrained time-delayed ground backup differential measurement in addition to individual high-speed phase measurements. Also, consider the response of the scheme to evolving faults.

4.1.4.3.2. Number of Current Transformer Inputs : If the ct's or other transducers connect to individual inputs of the analog interface, the largest number of cts the user may eventually employ must not exceed the design limits of the digital system.

4.1.4.3.3. Matching Current Transformer Ratios : If the cts on various feeders do not have matching ratios, either the analog interface hardware or the protection programs must be able to convert the signals to a common base.

4.1.4.3.4. Transducer Input : The burden presented by the analog interface must be appropriate for accurate transducer performance. For cts, this means a low impedance such that ct secondary voltage capability is not exceeded during faults. Linear coupler secondaries, on the other hand, are voltage sources requiring a high input impedance. Also, note that lc's act like differentiators, shifting the power frequency component by 90° and changing other components in an analogous way. The input hardware or software must accommodate this difference.

4.1.4.3.5. Protection Zone : If the protection zone boundary moves in normal substation operation (e.g. main-and-transfer bus arrangement), the protection programs must include special provisions for dynamic selection of relevant inputs. Typically, this calls for access to status inputs from breakers and isolation switches. Also, current summation schemes may require an overall checking zone which operates as a backup to the variable zones during switching operations.

4.1.4.3.6. Range and Characteristics : Setting ranges and characteristics must be suitable to the applications, considering the calculated severity of the worst ct saturation. The ground differential backup, if used, must coordinate with primary protection.

4.1.4.4. SPEED

Operating times for bus differential protection are more predictable and stable than for line or transformer protection since internal faults are generally robust and easy to detect. However, some protection methods using filtering algorithms may trip a little more slowly for an internal fault with severe ct saturation, if the magnitude of power-frequency differential current is substantially reduced.

The following design issues impact on the speed of protection.

4.1.4.4.1. Linear-Coupler (lc) : Linear-coupler relaying can act on instantaneous differential values to yield very fast trips - a few milliseconds or less.

4.1.4.4.2. Current Transformer (ct) : For iron-core cts, the protection must overcome the tendency to trip falsely for external fault saturation either by using filtering of signals and suitable characteristics or by somehow identifying and avoiding the saturation time interval. Different approaches may yield very different trip times. The user should check the assumptions about ct response which are built into a particular method, to be sure they hold for his installation.

4.1.4.4.3. Surge Arrester Currents : If a conventional surge arrester (not of the new metal-oxide gapless type) is included in the bus protection zone, follow current can flow for up to one-half power cycle after arrester firing. This current looks like a fault. Be sure that instantaneous protection is set to avoid operation on this low current.

4.1.4.5. SELECTIVITY

The key issues of discrimination between internal and external faults have been addressed in the preceding sections. To summarize :

4.1.4.5.1. Fault Current Magnitude : Internal faults tend to be robust ; fault current is limited mainly by source impedance of feeders and not by the impedance of the buswork or the fault itself. Adequate sensitivity is rarely a problem.

4.1.4.5.2. Current Transformer Saturation : The main causes of misoperations are near by external faults which cause ct saturation. The user must consider the relaying method in light of the worst possible false differential current which can arise.

4.1.4.6. WAVEFORM SPECIFICATION

Protection methods can be tested by simulation in an off-line computer system, using simulated data samples. These may be obtained in several ways listed below. In all cases, the most critical parameters for the user to specify are ct characteristics curve, worst remnant flux, worst offset, and worst fault current. This leads to an acceptably accurate simulation of the ct saturation.

a. Current Transformer Modeling : Simple ct performance modeling can be performed by a data-generation program that combines a sinusoidal fault current with an exponentially-decaying offset transient. The result is processed through a ct model which includes the non-linear B-H curve and hysteresis effects. Remnant flux is specified to enhance the saturation effect. The difference between the ct input and output signals, compared on a common base, is a fine simulation of false differential current for an external fault.

b. Digital Simulation Model : A detailed digital power-system simulation, such as the EMTP modeling package developed by the Bonneville Power Administration, can be used to generate a variety of fault signals. This may include ct saturation effects with much greater realism than simple ct modeling. Off-normal frequency transients and distortion from adjacent apparatus zones are included in the

test samples. The digital simulation study is far more expensive and time consuming than the simple ct modeling effort.

- c. Analog Simulation : Analog power-system simulation using analog computer/transient network analyzer (TNA) facilities offer the most realistic test signals. An associated digital recording system can take samples of fault conditions, or a special data acquisition system can be attached. The TNA study also has the disadvantages of expense and inconvenience.

If the actual hardware and software implementation of the relaying is to be tested, signal-generating sets of the types used with conventional relays are a convenient, if only approximate evaluation tool. With some effort, a designer or user could develop a system which plays an analog or digital recording of a simulated fault condition to the analog interface of the digital relay at a point in the circuit where only low energy is required.

With any of these simulation-testing methods, be sure that the important antialiasing filter function is not lost. In particular, if a computer simulation program generates sample values for processing by protection programs, the antialiasing filter effect must be built into the model - by the time the sample values are generated, aliasing will already have occurred if high-frequency components are present in the sampled signal.

4.2. CONTROL SYSTEMS

4.2.1. INTRODUCTION

Most of the measurements and status information used by digital protection system are also used by digital control systems.* It is therefore natural to attempt to pass on the input subset used by the protection systems to the units of the control systems (Figure 4.6). In those instances where

* Digital Techniques for Control and Protection of Transmission Class Substations, EPRI Report WS79-184, August 1980

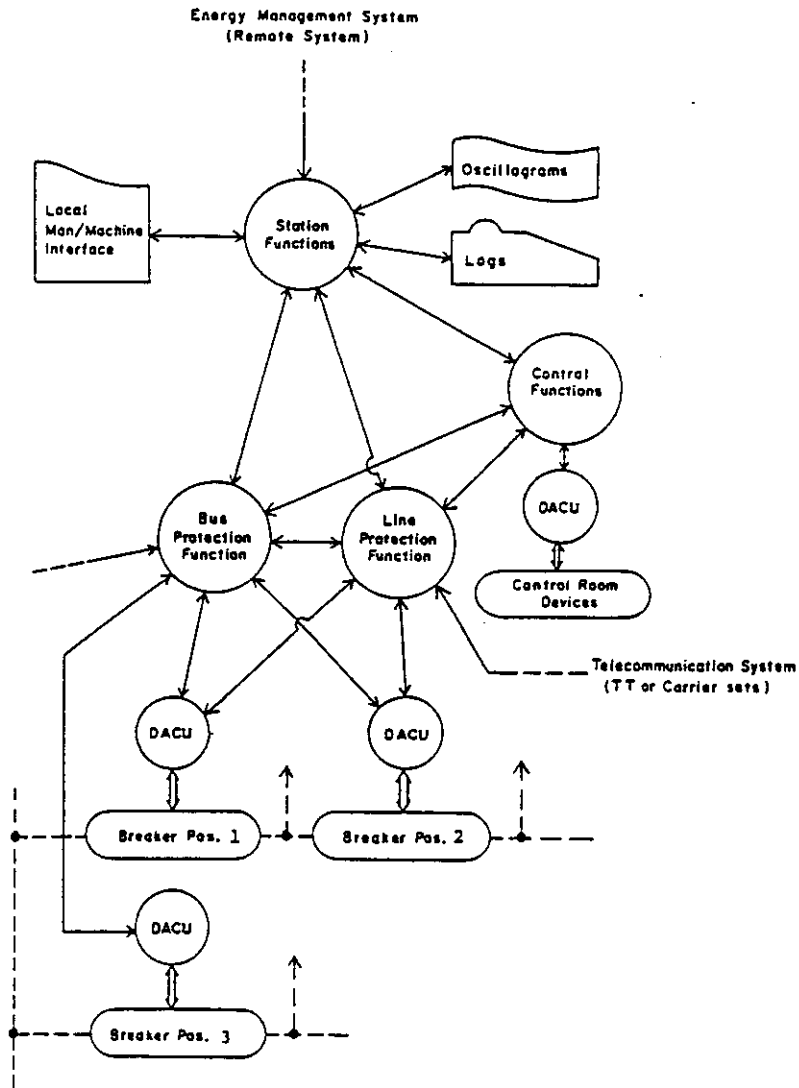


Figure 4.6 Signal Flow Diagram for an Integrated Protection and Control System

the data acquisition and control units (DACU) are placed in the switchyard, there may be a significant economic gain from expanding the DACUs to handle all of the input-output for the protection systems as well as the control systems (Figure 4.7). This can be accomplished in a way that is transparent to the protective relaying functions and without any loss of protection system reliability. Where breaker-and-a-half schemes and bus differential schemes are used, incentives, economic or otherwise, do not seem to exist for placing the protective relaying processors close to the circuit-breakers. If this were done, the communication system would be more complicated, and the cable routing would not follow normal patterns.

The following sections discuss the functional criteria that must be met when digital control systems are combined with digital protection systems to produce integrated substation protection and control. **

** System Requirements Document, substation Control and Protection Project, EPRI Report, EL-1813, April 1981.

4.2.2. ANALYSIS

An analysis of typical control and supporting data acquisition functions is as follows :

4.2.2.1. PROTECTION SYSTEM REQUIREMENTS

The commonly proposed functions are listed in Table A; Section 3. The service which these functions demand from the protective relaying system can be characterized in many ways. Functionally, the following generic requirements must be considered :

- a. Speed of response
- b. Computational burden
- c. Data volume
- d. Special considerations (accuracy, reliability, fail-safe aspects, etc.)

4.2.2.2. CONTROL SYSTEM CATEGORIES

The control functions can be divided into different categories :

- a. Automatic control (closed loop control)
Examples : automatic reclosing
load shedding

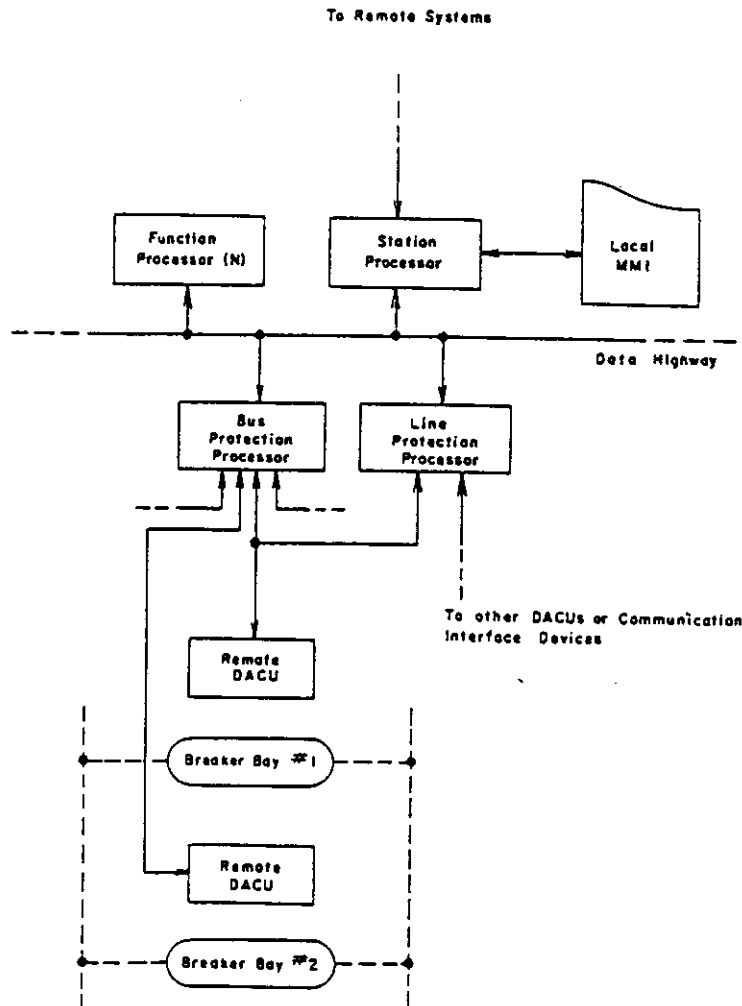


Figure 4.7 One Possible Architecture of an Integrated Protection and Control System (Non-redundant System)

breaker failure back-up protection
voltage and var control
on-line self-checking
automatic switching sequences

oscillography (fault recording)
alarming
metering
system monitoring

- b. Manual control (open loop control)
Examples : local switch and breaker controls
load tap changer control
setpoint changes for the automatic
control functions
control system operating mode control

In addition to a. and b., the operators need information about the system health in order to make intelligent operating decisions. These support functions are :

- c. Automatic data acquisition
Examples : sequence of event recording

The most important performance characteristics are shown in Tables 1, through 3.

4.2.2.3. AUTOMATIC CONTROL FUNCTIONS

Most of the automatic switching functions are high priority, high-speed functions. The functions, when called for, are normally needed after a fault has been detected and the primary protections have initiated the fault isolation. Hence, free processing power should be available in the protection processors for execution of these functions. The dependability and security requirements are about the same as for regular back-up protection func-

Table 1. Automatic, Closed-Loop Control Functions

<u>Function</u>	<u>Output</u>	<u>Speed of Response</u>	<u>Accuracy or Range</u>	<u>Computational Load</u>
High Speed Reclosing	Breaker close	0.1 to 1 s	$\Delta t = 0.05 \text{ s}$	Low/Infrequent execution
Low Speed Reclosing	Breaker close	10 to 200 s	$\Delta \phi \leq 2^\circ$ $\Delta U \leq 1\%$ $\Delta f < 0.3 \text{ Hz}$	Synchcheck needed, which requires phasor computation/Infrequent execution
Breaker Failure Backup Trip	Trip of <u>all</u> backup breakers	<20 cycles	$\Delta t: 1 \text{ to } 2 \text{ ms}$ $I: 0.02 \text{ to } 3 \text{ p.u.}$	Medium/Infrequent execution
Out of Step Protection	Trip breakers or interlock breaker trip	$\geq 2 \text{ cycle}$	$\Delta f: 0.1 \text{ to } 5 \text{ Hz}$ $t \text{ (response)} \geq 0.15 \text{ s}$	High/Periodic execution
Load Shedding	Trip breakers	$\geq 0.1 \text{ s}$	$\Delta f: 0.5 \text{ to } 3 \text{ Hz}$ step 0.05 Hz	Medium/Periodic execution
Voltage and VAR Control	1) Load-tap changer control 2) Shunt capacitors 3) Shunt reactors	$\geq 1 \text{ s}$	$\Delta V: \text{ better than } 1\%$ $\frac{\Delta Q}{S} = 0.02$	Low/Periodic execution
Automatic Switching Sequence	Control of Breakers & Switches	$> 5 \text{ s}$	$\Delta t \leq 1 \text{ s}$	Low/Infrequent execution
On-line Self-checking	1) Blocking of checked function units 2) Alarm 3) Mode switching	<fastest function	ms to s	High/Periodic execution
Supervisory Control-Remote unit function	1) Data transmission to control system 2) Control commands to local systems	0.05 to 2 s	Data typically 0.25 to 1% accuracy, setpoints typically 8 bits	Medium/Periodic execution
Protective Trip (Ex: Transfer Trip Trans. Fault Detector trip, etc.)	Transmit TT Trip breaker(s)	<4 ms	-	High but short/Burst mode/execution

Table 2. Manual, Open-Loop Control Functions

<u>Function</u>	<u>Output</u>	<u>Speed of Response</u>	<u>Accuracy or Range</u>	<u>Computational Load</u>
Local Control of Breakers, Switches, etc.	On - close Off - trip, open	0.25 to 3 sec (for beginning of operation) Completion depends on device characteristics	2 or 3 device states, 1% or better readouts	<u>Control sequences:</u> Low/Infrequent execution. Data Display: Medium/Periodic execution.
Control of Setpoints	On/off or close/trip of switches; raise/lower or continuous quantity (analog or high resolution digital) outputs	1 s or more	1 in 127 or 1 in 255 resolution and range normally adequate	Low/Infrequent execution
Control of System Operating Modes	On/off enable/disable service/test set/reset, etc.	0.25 to 3 s	2 or more state feedback	Low/Infrequent execution

Table 3. Automatic Data Acquisition

<u>Function</u>	<u>Output</u>	<u>Speed of Response</u>	<u>Accuracy or Range</u>	<u>Computational Load</u>
Sequence of Event Recording	Sorted lists of events	Output list formatted within 1 to 10 s	Time resolution 1 to 8 ms	High (event detection) Medium to low for output record/Burst execution
Oscillography	Data file of instantaneous samples of continuous input quantities (voltages, current, etc.)	Output records within 1-2 min.	Bandwidth: 300 to 2500 Hz Capacity: 1/4 to 2 s per record (data file)	High/Burst mode Note: Large data memory demands
Alarm Function	Alarm status lists	Output within 1 to 10 s	Time resolution: 1 s or better	Medium/Periodic execution (Note: the input to this function is typically the event list from the SEM function)
Trend Recording	Trend display/file	Minutes	Time step: >10 s	Low/Periodic execution when in use
Metering	Energy measurement	15 minutes or more	Accuracy: for revenue metering purposes 0.1 to 0.2%. For non-revenue purposes - 0.5 to 2%	High/Periodic execution
System Monitoring (Ex. Pilot Channel Monitoring, Memory Checksum Program, etc.)	Function blocking alarms	<1 s	Noncritical	Low/Periodic Execution

tions. It is, of course, more critical to clear a fault than it is to restore the system to operation again after the fault is cleared. Successful reclosing can, however, mean the difference between a minor and a major disturbance so the functions are by no means unimportant.

Phasor quantities for some of the functions need to be measured or computed with a fairly high sampling frequency. It would be desirable to have a function like load shedding needs to operate in time to prevent out-of-step conditions. The synch-check function needs angle information

as well as voltage across the breaker. These phasor quantities can be computed from voltage samples used by the protection functions. Efficient algorithms need to be used to avoid excessive computer loads.

The most demanding execution speeds are imposed on the system by the triactions associated with operation of Buchholtz relays, transformer fault, pressure relays or transfer trip transmitter/receivers. Really input detectors, communications links, program execution and output controllers all have to be operating without any undue delays, yet with very high dependability and security.

The automatic control functions need to be carefully coordinated with operator controls. If a work-clearance has been issued for work in the station, the automatic control functions must not make any outputs that jeopardize the safety of people. This is a key requirement that may be embedded in the software of any integrated control and protection system not incorporating conventional lock-out relays. This will not be a problem in a properly constructed system; however, people must be convinced that the safety features are implemented in a fail-safe and reliable manner.

4.2.2.4. MANUAL CONTROL FUNCTIONS

Manual control functions are those presently performed by the substation operators; i.e. operation of breakers, switches, transformer load tap changers, supervision of automatic control systems, and those manual functions normally associated with voltage or var control. In a digital control and protection system, there is sometimes a need for operator intervention. Typically, this will be associated with abnormal operating modes such as a test modes or isolation of faulted subsystems or components.

Manual control requires proper feedback, such as "device state" feedback to give the position of switches and breakers, as well as measured voltage and current quantities. Often derived quantities such as active or reactive power are also needed.

Transducers of the type used in SCADA systems can be used for voltage and current quantities. However, this increases the amount of wiring and duplicates input points, which is unattractive from the cost point of view. Also, currents and voltages have to be brought to a common point for conversion to a power quantity. The same currents and voltages are used in the protection devices. Hence, in a digital system, the instantaneous current and voltage sample sets can be passed to the man-machine interface subsystem. An equivalent RMS quantity is needed, however, for the operator display. Fortunately, the accuracy requirements are reasonable and simple conversion algorithms can be used that do not require processing time.

The device-state feedback must handle "don't know" conditions, as well as full-state information. This is important for correct decisions and for the safety of personnel. Full-state feedback is also necessary for control systems incorporating an interlock function. Fail-safe decision must be made in all cases, where an abnormal state can exist. Manual override capability is required to by-pass a device state that the computer control system is not programmed to handle.

The speed of response required from the manual control functions should be determined from human engineering design requirements. Faster response times will apply to a normally manned location with the slower response times usually acceptable for a normally unmanned location. As a rule, even for a very slow process, the display should indicate without excessive delay that the command has been accepted and that the execution of the input order is in process. Completion of the process should also be indicated. Any abnormality must promptly result in alarms directed to the operator;

The operator interface must be reliable because this is the only available point from which the power system can be controlled during a failure of the SCADA system or the communication system. Also, operator inputs must be secure to avoid false or undesirable operations. Echoing, checkback before operate procedures are therefore necessary or desirable.

4.2.2.5. AUTOMATIC DATA ACQUISITION FUNCTIONS

Automatic data acquisition functions are used in substations to support operators, planners and maintenance crews. An integrated digital control and protection system must, of course, support these needs.

Long term data collection (data logging) used by planners is normally a part of an energy management system. Thus, it can be assumed that these needs are handled as part of the SCADA function.

The most demanding functions are those taking snapshots of fault situations. These are the sequence of events and oscillography functions. High sample rates are needed to get the desired time resolution and bandwidth. At least, in the U.S., most event recorders operate with a 1 ms time resolution. This is needed for timing of breaker operations. Analog quantities exceeding check limits are often included in the event list. Also, the operator actions are included in the event list to provide a complete picture of an outage.

The oscillography function will be needed for the foreseeable future. However, the bandwidth provided from the protection relaying system is limited. It is determined by the sample rate required by the protective relaying algorithm; typically 12 to 16 samples per cycle. This probably provides sufficient bandwidth for relay system analysis. If higher bandwidths are needed for monitoring of breaker performance or for ultra high speed relaying system, separate sampling systems and data transmission channels will be required. There are some arguments for eliminating the oscillography function altogether but it is not easy to replace human analytical power with machines. Routine fault reports can be produced by the computers, but unusual faults must still be analyzed by people. Hence, the function should be included.

The alarm and trend recording functions are used for management of critical operating conditions. Hence, they are supporting the manual operating functions. The alarm function is a subset of the sequence of events function. Whereas, the events are a history of state changes, the alarm function is a list of critical states. Trend recording is a temporary short-term data logging function used to monitor evolving emergencies. Both of these functions are only in use when operators are present. At other times, the SCADA system link will handle the functional needs.

The system monitoring function as defined here (Table 3) is used to monitor the control and protection system itself. This function generates alarms and sometimes changes the operating mode of the control and protection system (such as automatic failover), are generated by this function.

The revenue metering function is included in this list because where needed, it is very demanding of the data acquisition system. Most other inputs do not have to be more than 0.5 to 1 percent

accurate. The revenue metering function cannot tolerate microseconds time skew between voltage and current samples and needs at least 12 bit resolution for full-scale inputs equal to 2 p.u.* This is almost an order of magnitude increase in the requirements as compared to the requirements for the protective relaying functions. If, however, the time skew requirements can be met by the sample synchronization system, the other requirements can be handled by using special, high accuracy input circuits. In this way, the system cost impact from the revenue metering function will be minimal.

5. RECENT DEVELOPMENTS IN PROTECTION AND CONTROL WITH COMPUTERS

5.1. GENERAL INTRODUCTION

5.1.1. OBJECTIVES

To provide a convenient ongoing summary of specific projects and their related publications. The specific projects are those :

- a. Of significant scope, e.g., integrated substation systems or subsystems which are planned to become part of future integrated substation systems.
- b. Which include field experience or laboratory demonstrations planned for field installation in the near future.

5.1.2. LISTING OF PROJECTS

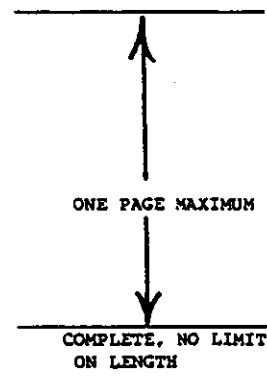
The listing of projects which the Working Group is familiar with is included as Appendix II of this report.

5.1.3. CONTINUING ACTIVITY

The Working Group recommends that periodic updating of this list be an ongoing activity. The updated listing of projects (Appendix II) should be published periodically as further activities and developments justify. To help assure that future updatings of this listing are complete, those responsible for projects meeting the criteria of Section 5.1.1. are encouraged to submit description of their project to the Chairman of CIGRE Study Committee 34 in the format described in Section 5.1.4.

5.1.4. STANDARD FORMAT

1. PROJECT NAME
2. PARTICIPATING COMPANY (IES)
3. WHERE INSTALLED
4. TYPE INSTALLATION
 - A. Regular operating installation
 - B. Temporary operating installation
 - C. Temporary Demonstration
 - D. Field Experiment
 - E. Laboratory demonstration prior to field demonstration
5. ACTUAL/PLANNED DURATION OF FIELD EXPERIENCE
6. SYNOPSIS OF PROJECT
7. PUBLISHED PAPERS/ARTICLES/REPORTS THAT GIVE ADDED INFORMATION



6. OPPORTUNITIES FOR ADAPTIVE PROTECTION CONTROL AND MONITORING

6.1. GENERAL INTRODUCTION

6.1.1. OBJECTIVES

This section is prepared with the following objectives in mind :

- a. To describe how digital protective control and monitoring equipment can be adaptive to varying power system conditions, requirements and environments. This contrasts with electromechanical and solid state analog equipment which are very limited in their adaptive capability.
- b. To catalog adaptive possibilities

- c. To express working group opinion on how the use of these adaptive techniques will increase as digital systems are implemented over the next several years.

6.1.2. EVOLUTIONARY ACCEPTANCE

Since there is only modest experience with digital systems for protection, control and monitoring, and even less with adaptive features of these

* Digital Revenue Metering Algorithm, EPRI Report EL-1601, November 1980.

systems, there is an inherent tendency to "walk before you run". Hence, the majority of functions in early digital systems are not adaptive, or have quite limited adaptive characteristics, as compared to feasible possibilities. Most historic experience is to have adaptive changes made by human intervention, either operating personnel, technicians, or engineers, through periodic update and changing of settings and characteristics.

Selection of initial adaptive applications to be functions without a critical time requirement permits check features to be included to insure that the requested change is a credible one. In this way, confidence can be achieved in the use of adaptive techniques, and should lead, over time, to acceptance of adaptive procedures for higher speed functions. As experience and confidence is gained with adaptive digital characteristics it is expected that the utilization of adaptive functions will grow significantly.

Acceptance is forecast to be evolutionary, with a significant step between first generation and second generation digital systems.

6.1.3. ADAPTABILITY NOW EXISTS TO LIMITED EXTENT

There is limited adaptive capability included in some electromechanical and solid state analog systems. But the amount of adaptive capability incorporated is small due to the extremely limited logic and memory capability of electromechanical and solid state analog technology. In essence, this capability is limited to the ability to retain pre-fault voltage by capacitor storage and the limited logic of hard wired, and preselected and/or decisions. Hence, general practice is to depend upon operating and engineering personnel to identify the need for a change from that normally performed by the equipment, and to manually input that change. Usually, the protective and control equipment is now set up to respond properly for normal operating conditions and/or for the worse perceived conditions that may exist. This often results in the system performance being less than optimum for the many conditions between normal and worst case, yet it is under these conditions that the power system is operating the majority of the time.

Nonetheless there is a small amount of adaptive capability included in non-digital systems. For example, fault selectors and fault current magnitude are sometimes utilized to change from one type of protection to another, or to select the type or speed of automatic reclosing. Phase angle and synchronism checks, as incorporated in reclosing schemes, are in essence adaptive functions.

It may be convenient to think that adaptive in the future, means that the system performance can be optimum regardless of whether the power system state is normal, alert, emergency or restorative.

6.1.4. DIGITAL TECHNOLOGY MAKES ADAPTIVE FUNCTIONS FEASIBLE

Digital technology is inherently programmable and has "essentially" unlimited logic and memory capability. Digital systems also have greatly enhanced capability for data transfer, analysis, communications between different modules (both local and remote) data reduction, and exception reporting.

The most powerful of these capabilities are the increased memory, logic processing and program capability. These expanded capabilities make adap-

tive functions much more feasible with digital systems. The protection, control and monitoring functions can automatically adjust their performance to match the needs of changing power system conditions such as normal, alert, emergency, restorative. The adaptive characteristics can handle changing system configuration such as a line, generator, transformer or bus out of service, with automatic adjustment of operating limits of the digital equipment to reflect the new system configuration, new system state or new ambient/environmental conditions. The adaptive approach may utilize comparison of present conditions with previous history, for example :

- a. Compare with prefault or previous peak load conditions.
- b. Compare with some acceptable rate of change, for example, present trend of temperature increasing at 3 degrees per hour, or frequency dropping at a rate of .01 Hz per second.
- c. Compare present conditions versus capability, for example transformer load versus thermal capability, taking into account the previous 6 hours of history and measured rather than assumed ambient conditions.

It is easier to visualize and implement adaptive changes if all of the required information is available within a given location. (For example, one circuit-breaker, one line, or within one substation.) Then, the adaptive changes have little or no effect on other locations.

There will, however, be adaptive applications where coupling occurs between locations via the power system. Experience with adaptive performance will increasingly permit these interactions to be anticipated, understood, and reflected into future adaptive specifications and performance.

6.1.5. WHAT FOLLOWS IS A CATALOG OF FUTURE POSSIBILITIES

Section 6.2 of this report is a catalog listing of adaptive possibilities which are feasible with digital systems. Some of these adaptive characteristics are incorporated in systems today, others are contemplated and forecast for the future. They are presented so that system designers and operators can select those features which best meet their needs and requirements, both today and in the future. In this section, there is no attempt made to separate between those which are in use today vs. those which are feasible and visualized for the future. Information on present practice is included elsewhere in this working group report, particularly sections 3 and 5.

6.2. CATALOG OF ADAPTIVE POSSIBILITIES

6.2.1. DIAGNOSTICS AND ALARM

6.2.1.1. SELF TEST

There are various techniques whereby continuously active digital systems can periodically check their own performance. For example, automatic and periodic check of actual vs. intended relay pick up characteristics. When abnormal or out of limit performance is found there are several alternatives. For example :

- a. Alarm only, but continue to function in an abnormal or degraded mode
- b. Alarm and disable

- c. Self-diagnose the abnormality further, and depending upon the seriousness :
1. Alarm, providing further information about the abnormality
 2. Disable and isolate defective portion, switching to redundant path, alarm that redundancy no longer available
 3. Alarm and disable
 4. Respond to interrogation with further information so that trouble shooting and diagnostics can be carried out from a remote location prior to sending someone to this site

6.2.1.2. PERIODIC AND AUTOMATIC SELF DIAGNOSTICS

If particular function (of protective, control or monitoring system) is no longer functioning normally, disable and isolate defective portion, alert operator and maintenance personnel, reset adjacent protection for new conditions, e.g. modify trip settings of adjacent relays, modify tripping sequence.

If pilot communication channel is not functioning properly, switch to back up channel, alarm that redundancy is no longer available. Alternatively monitor 2 channels and in case of disagreement use information from best perceived or deduced channel. If communications continue to prevent normal protection or control, then automatically remove sick unit from service, alarm operator and maintenance personnel and reset adjacent protection for new conditions, e.g. modify trip settings of adjacent relays, modify tripping sequence.

6.2.1.3. INPUT DATA ERROR DETECTION

There are several techniques whereby continuously active digital systems can screen input data for errors, sensor failure, or sensor drifts. Some examples of data and sensor checking are :

- a. Trend measurements and implement corrective action if sample-to-sample variation is unreasonable, e.g. temperature of transformer top oil increases faster than thermal time constant will allow.
- b. Utilize one set of input signals while comparing with a second set of signals, automatic change-over to alternate source (for instance second winding on instrument transformers or second analog to digital converter) when discrepancy occurs.
- c. In measuring the phase currents in a 3-phase circuit, also measure the neutral or residual current. If the sum of the 3 individual phase currents does not add to the residual current, within acceptable tolerances, then reject all 4 measurements and take corrective action, such as :
 1. Alarm
 2. Hold all 4 samples while attempting to determine correct values by some other means, such as (a) comparison with other local measurements, of same or related quantities (b) comparison with remote measurements of same quantities e.g. measurements at remote end of line (c) sum of all other currents into or out of a bus, transformer, etc. and subtract to check suspect measurements. (d) compare related quantities for each phase, e.g. suppose phase A current increases 10 times previous sample, but phase to neutral voltage A-N, B-N, C-N are all within 1 percent of values on previous sample, or the corresponding sample 1 cycle earlier. (e) wait for subsequent digital samples and see if the 3-phase currents then add to the residual current. If so determine which of the previous samples was in error and interpolate to

obtain correct previous digital value. (f) Feed known test signals into the input and determine which signals are not coming through correctly.

6.2.2. MAN-MACHINE INTERFACE

6.2.2.1. SELECTABLE OPERATION MODE

The system may have selectable modes (or adaptive changes in mode) for different operating conditions. For example :

- a. Manual Mode

Protective functions are executed automatically without operator involvement. Monitoring continues to gather data and update internal records but no data output. Control functions not executed, except by specific operator action.
- b. Open loop Operating Mode
 1. Manually selectable by operator, function by function or by groups of functions. The digital equipment performs in usual way except that output commands are not executed. Instead they are displayed so that the operator can manually implement them if he so desires, ignore them or he can execute some other command. Used for trouble shooting, for maintenance and diagnostics, for operator training, and to demonstrate/gain confidence in digital equipment.
 2. Semi-automatic step-by-step, protective actions executed without operator intervention. Control actions that normally would involve more than one step of execution, are now executed one step at a time, then operator had to acknowledge that step before then next step is executed, etc.
- c. Automatic Closed Loop Operating Mode :
 1. Fully Automatic - Normal operation of equipment in which protective, control and monitoring actions are executed by the digital equipment without operator intervention.

6.2.2.2. Manual Initiation of Step-by-Step Automatic Control Sequence

Local operator, or remote dispatcher, selects and initiates switching to be accomplished, with automatic step-by-step implementation carried out locally, with appropriate sequential checks. For example, operator initiates taking one of two transformers out-of-service. Local control equipment automatically carries out the following steps :

1. Match LTC (Load Tap Changer) positions and hold
2. Close LV (Low Voltage) tie breaker
3. Trip LV (Low Voltage) Breaker(s)
4. Trip HV (High Voltage) Breaker(s)
5. Open isolating switches
6. Close grounding switches
7. Return other transformer LTC controls to automatic

6.2.2.3. Monitored Operator Mode

Control equipment checks proposed operator actions before implementation. For routine condi-

tions the operator's actions are implemented without delay. For usual conditions, the actions would be implemented only after the operator acknowledges resulting message. For example :

- a. "closing breaker C23 will connect 2 busses that now have 63 degrees phase displacement"
- b. "closing breaker C25 will energize transformer bank 31 from 115 kV side plus 100 miles of 230kV line. Resulting voltage on 230 kV side will be 248 kV."

6.2.2.4. OPERATOR TRAINING SIMULATOR

At Substations and Dispatch Centers make available a mode of operation, on lower priority basis, that permits training/retraining of operators by simulating rather than actually performing switching operations.

6.2.2.5. VOICE INPUT/OUTPUT

Utilize voice commands for data and command input, in addition to conventional keyboard.

Utilize voice outputs for alarm purposes, in addition, or in lieu of bell/siren annunciator, flashing data or messages on video screen.

6.2.3. LINE PROTECTION AND CONTROL

6.2.3.1. TRANSMISSION LINE PROTECTION

- 1. Features of traditional distance protection in directional comparison schemes, plus new features. For example :
 - a. Positive, negative and zero phase sequence currents calculated and available for use in protective, monitoring and control schemes.
 - b. Output (locally or remote) of fault type (L-G, L-L, 3-phase, etc.) fault current magnitude, distances from terminal to fault, relay time, breaker clearing time, prefault load currents and voltages
 - c. Variable Speed/Security using magnitude of fault current and type of fault, e.g : 3 phase vs. single phase, to intentionally bias line protection :
 - 1. Less Severe Faults - bias towards slower more secure operation
 - 2. More Severe Faults - bias towards faster operation, even though possibly less secure

An example of how this intentional bias could be accomplished digitally would be to vary the number of successive digital samples and associated impedance calculations required to fall within the trip zone for trip output to occur, e.g.

NOTE : This approach may present a coordination problem with conventional existing or conventional back up relaying.

- d. Compensation for line charging current, adaptively adjusted to reflect actual operating voltage level.
 - e. Compensation for prefault load flow
 - f. Protection (or monitor and alarm) for excessive zero sequence circulating current or common modal circulating current
- 2. Adaptively adjust protective settings for system conditions. Some examples :
 - a. When breakers, lines, busses or transformers are switched in or out, adaptively (and locally) re-adjust zone settings on adjacent distances relays to preselected settings for the new system conditions.
 - b. Remotely adjust distance back-up zone settings. (similar to G1 but accomplished by remote operator actions)
 - c. Three Terminal Line - Protection normally set for this operating condition, however, adaptively re-adjust when one-terminal is open and operation is actually as a two terminal line, re-adjust back when third terminal is restored to service.
 - d. Local Generation intermittently, such as hydro, customer co-generation, or peaking units. Normally protection is set for intermittent generation to be in service, adaptively re-adjust for new operating conditions when local generation is out of service, or vice-a-versa.
 - 3. A natural concern, when settings are changed adaptively, is to understand what the actual operating characteristics (settings) were when a specific operation or event took place. Accordingly it is feasible to have logged out at the appropriate place(s) :
 - a. The characteristic or setting just prior to operation of the specific function.
 - b. The new characteristics every time an adaptive change takes place.
 - c. The operating characteristic of all protection and control associated with a specific breaker just prior to opening (or closing) of that breaker
 - 1. for any reason, including manual
 - 2. by a protective or automatic control function

		INCREASINGLY SEVERE TYPE FAULTS		
		→		
		L-G	L-L & L-L-G	3 PHASE
FAULT	LOW	6	5	4
CURRENT	MED	5	4	3
MAGNITUDE	HIGH	4	3	2

NOTE: This approach may present a coordination problem with conventional existing or conventional back up relaying.

6.2.3.2. LINE RECLOSING

1. Select appropriate reclosing practice depending upon fault that caused line trip.
 - a. Reclose first from terminal :
 1. most remote from turbine generators
 2. that contributes minimum fault current
 3. with highest positive phase sequence phase voltage during fault
 - b. When line is re-energized for "X" seconds, close second end
 1. if in synchronism and phase displacement less than "Y" degrees,
 2. or when V_L (Line) exists without V_B (Bus) (unless bus is locked out)
2. Variable reclosing time delay determined from severity of prior fault.
Examples :

if fault must be interrupted again.

8. If $I_F > M$, trip normally closed bus tie breaker(s) before line reclosing. (Minimizes I_F on unsuccessful reclosing, thus reduces system disturbance, also reduces duty on both transformers and switchgear). Close tie breaker(s) when line stays closed "X" seconds or when line retrips and locks open.
9. Select modified reclosing practice when live line maintenance or construction is being carried out on specific line.
Examples :
 - a. Disable all reclosing
 - b. Only one reclosing delayed "X" seconds
 - c. Make ground tripping more sensitive and or faster

6.2.3.3. FLASHOVER ACROSS OPEN BREAKER CONTACTS

Flashover may occur due to low pressure (air,

		INCREASINGLY SEVERE TYPE FAULTS		
		L-G	L-L & L-L-G-L	3 PHASE
FAULT	LOW	3 PHASE RECL DELAY = X	3 PHASE RECL DELAY = Y	3 PHASE RECL DELAY = Z
CURRENT	MED	3 PHASE RECL DELAY = Y	3 PHASE RECL DELAY = 2Y	1 PHASE RECL DELAY = 2Z
MAGNITUDE	HIGH	1 PHASE RECL DELAY = Z	1 PHASE RECL DELAY = 2Z	NO AUTOMATIC RECLOSE, OPER- ATOR MANUALLY SELECTS SINGLE OR 3 PHASE AND TIME DELAY

WHERE $X < Y < Z$

3. Select reclosing time based on measured system phase angle between two locations in system.
Examples :
 - a. two ends of tie line
 - b. load area and generating station
 - c. generating station vs. standard system Hz reference.
 And actuate reclosing to improve stability of systems and/or minimize torque on turbine generators.
4. Selectively block high speed reclosing and extend time delay of delayed reclosing when severe lightning storm is in the area (to minimize number of operations on equipment, particularly for less critical lines and loads).
5. Initially close single pole at one end. When line remains re-energized for "X" seconds close 2nd and 3rd phase. If trips after single pole closing, then block further reclosing. (To avoid closing into three phase fault if safety grounds are not removed. Also on double circuit lines to minimize phase to phase or 3 phase fault on one line from spreading to the second circuit).
6. If an island has occurred disable synchronism check closing of follow terminals to avoid random attempts to re-establish ties. Instead select optimum tie for first closing (e.g. strongest tie) and activate it, when it holds, then close other ties in planned sequence.
7. If I_F (fault current magnitude) $> M$, increase reclosing time delay to appropriate value so that derated breaker capability will not be exceeded

SF_6 , etc.), high transient voltage or combinations. Subsequent current may be quite low depending upon other system conditions, e.g. only energizing transformer, section of bus, line, etc. Detect by very sensitive overcurrent function that is operational, only while breaker contacts are open. Corrective actions adaptively selected by system conditions or pre-selected by operator.

Examples :

- a. Close one pole of breaker, or close all three poles of breaker, then
 - re open breaker or
 - if current is low enough, open disconnect switches to isolate
- b. Trip adjacent breakers through stuck breaker trip logic, open motor operated isolating switches of failed breaker, restore bus by closing all other breakers to previous conditions.

6.2.3.4. MATCHING PLANT OUTPUT TO TRANSMISSION CAPACITY

Connection of a large generating station to high voltage network requires minimum number of transmission lines in service to assure transient stability when all generating units are operating at full load. Alternatively, transmission investment savings can sometimes be achieved if loss of a unit for loss of a circuit is acceptable to the operating utility. Adaptive control/tripping can ensure that the appropriate unit is tripped, only when necessary, according to actual operating conditions.

6.2.3.5. SEQUENTIAL TRIPPING TO LIMIT SWITCH-GEAR DUTY

When system growth causes overstressing of switchgear and circuit-breaker, a selective tripping scheme may be utilized, with appropriate sequential logic automatically implemented depending upon actual measured magnitude of fault current. Implementation of such a scheme may avoid replacing the switchgear or permanently splitting busbars to contain the fault level.

6.2.3.6. COLD LOAD PICK-UP

1. When re-energized after extended outage and overload trip occurs, compare load with pre-selected value. If $I_L > M$ then raise pick-up value 1.5 times and re-energize. Re-check and in 10 minutes (or X minutes) if $I_L < L$, then lower pick-up to original value.
2. Increase degree of inverseness of overcurrent relays temporarily for variable time duration after closing breaker. Increase degree of inverse characteristic and duration of effective time as a function of :
 - a. load current being carried before last trip
 - b. How long breaker was open
 - c. deviation of bus voltage from nominal

6.2.4. TRANSFORMER PROTECTION AND CONTROL

6.2.4.1. TRANSFORMER FAULT PROTECTION

1. Current differential with variable sensitivity or slope, phase by phase depending upon :
 - a. turns ratio (LTC Tap position)
 - b. excitation level, or rate of change of excitation level (Desensitize when being energized and when voltage recovering after a system fault)
 - c. phase current unbalance
2. Different approach is feasible for digital implementation, e.g.
 - a. combination of different measuring principles (current differential + high impedance) to realize a more effective protection
 - b. use of extra analog signals, like voltages, to calculate core remanence and the necessary inrush stabilization.
 - c. establish more definite criteria in the form of harmonic proportions and their comparison, to distinguish between internal short-circuits and energizing of transformers
3. Monitor periodic analysis of gas dissolved in oil, trend results and compare with specific events such as top oil temperature de-energized "X" minutes/hours and re-energized, "Y"Z overexcitation for "Z" minutes.

6.2.4.2. TRANSFORMER AUXILIARY MOTOR PROTECTION

Vary protection and sensitivity depending upon actual operating conditions :

- running	- Stalled
- Cold Start	- Unbalanced supply voltages
- Restart	- Current unbalance

6.2.4.3. TRANSFORMER LTC CONTROL

1. Conventional control of one or more LTC transformers including : voltage level setting, time delay to minimize unnecessary operations, line drop compensation and circulating current control, hold schedule of voltage that varies throughout the day, or is a function of load.

2. Absorb vars at light load via intentional mismatch of LTC positions. With banked transformers, (2,3, or 4 in parallel) lagging Mvar reactive supply is possible by intentionally mis-matching taps to circulate current between the transformers. Adaptive control can adjust the tap settings to give the desired Mvar, yet comply with constraints imposed by transformer loading and the need to ensure that system voltage does not become excessive if a transformer should trip.

3. Derive LTC mechanism position through calculation of V, I, Z, etc and compare with indicated position. In case of disagreement disable automatic control and alarm for problem with mechanism.

6.2.2.4. MINIMIZE TRANSFORMER LOSSES

Vary number of transformers in service depending upon load. Incorporate constraints, depending upon load, to ensure that security criteria are preserved.

6.2.4.5. TRANSFORMER LOAD MONITOR

Calculate expected top oil and winding hot spot temperature from measured ambient plus measured transformer load :

- a. If temperature are increasing, calculate how long it will take to reach limiting values and alarm in advance
- b. Compare calculated vs. measured values. If differ by more than "X" degrees, alarm operator and maintenance people to inspect transformer for :
 - (a) cooling equipment not functioning properly
 - (b) physical obstructions such as wet leaves in coolers, etc.

6.2.5. BUS PROTECTION

6.2.5.1. BUS DIFFERENTIAL PROTECTION

1. Verify periodically that CT mismatch error is less than X% of load current
2. Use magnitude of fault current and type of fault, e.g. 3 phase vs. 1 phase to intentionally bias bus protection :
 - a. less Severe Faults - bias towards slower, more secure operation
 - b. more Severe Faults - bias towards faster, less secure operation
3. Automatically disable protection during interval that switching is being performed to transfer breakers and CT's from one bus section to another. Verify that protection is restored after switching sequence is completed.
4. Log after operation, both locally and remote
 - a. pre-fault load currents by circuit
 - b. fault currents by circuit
 - c. sequence and time of each relay operation, breaker operations, current interrupted
5. Selectively reclose depending upon fault characteristics
 - a. if single phase to ground fault
 - b. $I_p < M$
 - c. Fault resistance $> M$

6.2.6. SYSTEM WIDE PROTECTION AND CONTROL

Some of the following functions may require the involvement of a central system, or may reside at a

central system computer instead of residing at the substation computer.

6.2.6.1. OUT-OF-STEP PROTECTION

Improve out-of-step blocking/tripping by measuring rate of change of frequency at specific location plus phase angle at this location vs. phase angle at some other location in system. Examples :

- a. other end of this line
- b. some reference generating station
- c. standard system frequency reference

6.2.6.2. CAPACITOR BANK PROTECTION

1. Some protective schemes detect voltage unbalance or current unbalance within the banks as an indication of number of failed capacitors with blown fuses. Measure actual power system voltage unbalance and make appropriate corrections to the measured capacitor bank voltages and currents. This will permit more sensitive protective settings to be used because they do not have to include an allowance for variable effect of power system voltage unbalance.
2. Some protective schemes are also affected by number of banks in service, so settings are selected for worst operating condition such as only one bank in service or all banks in service. These fixed settings result in less than optimum protection for all but the worse planned operating condition. Instead settings can be adaptively adjusted automatically for the actual operating conditions.

6.2.6.3. ISLANDING

1. When system split occurs, continue tripping to establish specific islands :
 - a. pre-selected
 - b. depending up measured conditions
2. When system underfrequency occurs and reaches a selected value in spite of load shedding, split to establish specific islands :
 - a. pre-selected
 - b. depending upon measured conditions
3. On interconnections to adjacent utilities, monitor both system frequency and power out-flow, adaptively trip on lower out flow depending upon :
 - a. extent of frequency decline, or
 - b. faster rate of frequency decline

6.2.6.4. LOADING VS. VOLTAGE REDUCTION

Measure Loading of Line(s) and/or Measure Loading of Transformer(s)

1. When appropriate, reduce and maintain schedule of voltage via Transformer Load Tap changing, Voltage Regulators, Control for Switched capacitors, Reactors, Static var Control Equipment, for example by -3%, -5%, -8% or -X%.

After voltage is reduced, switch capacitors to minimize kVA loading for this new condition. (Lowering voltage increases var's required by motor driven loads but if capacitor switching control is by voltage they may all come on and increase total kVA loading. Or if time clock controlled capacitors may all be off, than lowering the voltage may increase total kVA loading.)

2. If loading still excessive, initiate load management at user level, or selective load shedding.

6.2.6.5. LOAD SHEDDING AND RESTORATION

Measure system frequency, rate of change of frequency, voltage plus phase angle.

Examples :

- a. Between 2 ends of a line
- b. Between 2 parts of a system
- c. At important generator terminals or at generating station bus
- d. Absolute vs. a fixed reference frequency

1. Drop and reconnect selected loads to minimise system frequency oscillations - can improve transient stability
2. Detect different oscillations in one part of a system vs. another part - connect and disconnect selected loads in each area to improve transient stability. If unsuccessful, split into preselected islands.
3. Use magnitude of frequency to initiate load shedding, rate of decay to determine how much (minimize time delay), adaptively keep dropping load until frequency stabilizes.
4. After load shedding has stabilized frequency, selectively restore blocks depending upon rate of frequency recovery, projecting from previous load increment(s) and frequency effect.

6.2.6.6. SYSTEM LOADING MONITOR

Measure phase angle between two parts of systems or between two ends of a line :

1. If $0 < M$, switch in capacitors - series, shunt or both
2. If $0 > H$, reduce load or generation (e.g. reduce output or trip one unit in a multi unit generating station)

6.2.6.7. SELECTIVE SWITCHING FOR STABILITY ENHANCEMENT

Measure system phase angle between two locations in system.

Examples :

1. two ends of tie line
 2. load area and generating station
 3. generating station rate of change vs. network frequency standard
- a. Switch selected interruptable load or dynamic breaking resistor to slow down part of the system that is swinging ahead (advancing). Switch off again after selected interval or when affected portion of system is falling behind remainder of system. Approach may also be used to determine when to reclose line after fault trip.

6.2.6.8. SELECTIVE BUS THROWOVER

6.2.6.8. SELECTIVE BUS THROWOVER

In bus transfer schemes, such as generating station auxiliary busses, monitor system conditions and vary the closing sequence.

Examples :

- a. Routine transfer :
 1. If in synchronism, parallel before opening via automatic sequence, controlled to minimize the overlap time
- b. Emergency transfer :
 1. If in synchronism and residual voltage magnitude $> M$ and voltage decay rate $< H$, close tie breaker with appropriate time delay to achieve synchronous closing.

2. If residual voltage $> M$ and decay rate $> H$, delay closing tie breaker until residual voltage $< L$
3. If residual voltage $< M$, delay closing tie breaker until residual voltage $< L$

6.2.6.9. SYSTEM VAR CONTROL

Optimize var supply for various system conditions.

Examples :

a. Normal :

1. As load increases switch on distribution capacitors first, and until specific power factor achieved, followed by substation and transmission banks
2. As load decreases switch off combination of distribution and substation capacitors to approach unity power factor throughout system. This may require overriding local voltage control which would otherwise keep too many capacitors in service.

b. Load shedding :

1. Shed appropriate capacitors, as well as load, to avoid overvoltage

c. System restoration :

1. Either switch in shunt reactors or be sure adequate blocks of load are re-energized as part of transmission system to avoid overvoltages and minimum excitation level on generation.

6.2.6.10. ACOUSTIC MEASUREMENTS

Utilize acoustic measurements (signature analysis) to monitor normal vs. abnormal conditions of equipment such as motors, generators transformers, circuit breakers, disconnect and interrupter switches, transformer load tap changes, etc. correlate acoustic measurements with electrical measurements. Log, alarm or trip depending upon adverse change.

6.2.6.11. UNIVERSAL MODULES

Digital systems by their nature can be flexible to varying degrees. The element that makes them unique is their program, which is alterable. With the basic potentials and currents, a digital protection module could assume a multitude of personalities, from distance, overcurrent to differential protection, for example. One of the challenges of the future is how to take advantage of this flexibility in an appropriate manner, for example will universal modules have the same reliability as dedicated modules, excessive cost, degraded performance ?

6.2.7. MONITORING

6.2.7.1. LOAD MONITORING AND RECORDING

By circuits, transformer bank, bus and substation, calculate watts, vars, power factor, kWh, RMS values of voltage and currents.

- a. On current basis (integrated over "X" milliseconds).
- b. Integrated values for 15 minute, 30 minute or 60 minute interval.
- c. Load factor and loss factors daily, weekly, monthly and annually.

- d. Keep peak values (with time tag) and cumulative maximum values daily, weekly, monthly and annually
- e. Keep cumulative records of upper and lower RMS voltages and time when specified bands exceeded, with time tags and duration.
- f. Data available for call out and log or display, locally and/or remote
- g. Periodic summary logs printed out at designated locations to comply with planning needs, regulatory requirements, company practices

6.2.7.2. SERVICE MONITORING AND RECORDING

By circuit transformer bank, bus and substation, keep record of outages, with times tags, causes and durations plus interrupted kVA peak, and kWh :

- a. Provision for additional information on causes to be input by operator, remotely or locally
- b. Data available for call out and display, locally and remote
- c. Periodic summary logs printed out at designated location(s) to comply with regulatory requirements, company practices, and need to know.

6.2.7.3. THERMAL MONITORING OF CIRCUITS

1. Overhead Conductor Sag (Annealing) Monitoring Alarm, shed load and/or trip depending upon conductor temperature
Determine conductor temperature by :
 - a. Direct measurement
 - b. Calculated from :
 - Integrated I vs. Time
 - Measured Ambient Temp.
 - Measured Wind Velocity and
 - Measured Solar Radiation
 - c. Correlation with measured sag in specific span
2. Cable Thermal Monitoring Alarm, shed load and/or trip depending upon cable temperature
Determine cable temperature by :
 - a. Direct measurement in duct
 - b. Calculated from :
 - Measurements in duct, sheath or trench
 - Integrated I vs. Time

6.2.7.4. EQUIPMENT CUMULATIVE SERVICE MONITORING

As Real Time Indication of Maintenance Need, continually up date records of :

- a. Circuit breakers
 1. Opening and closing speed vs. temperature, control, voltage, air pressure, etc.
 2. Compressor running time
 3. Difference in phase closing, phase opening
 4. Trend in interrupting time or arcing time
 5. Cumulative Number of Operations - since last maintenance and during total equipment life
 - Integrated I^2 arcing
 - Number of times I_F Interrupted $> H$
 - Number of times I_F Interrupted $> M$, etc.
 6. Time of closing/opening resistor insertion
- b. Power Transformers
 1. Integrated loading and cumulative loss of life (vs. Industry Standard)
 2. Through faults :
 - Integrated I^2T by phase
 - Number of cycles $I_F > H$

- Number of cycles $I_f > M$
- Number of cycles $I_f > L$

- c. Transformer LTC and Voltage Regulator Mechanisms
1. Operating speed vs. temperature, control voltage, etc.
 2. Differences between phases - opening, closing, transfer
 3. Cumulative number of operations since last maintenance since last change of arcing contacts and total since installed.
 - Integrated I²T Arcing
 - Number of Times I Interrupted > H
 - Number of Times I Interrupted > M, etc

6.2.7.5. EQUIPMENT STATUS

1. Capacitors and Shunt Reactors
- For routine, or specially initiated command, monitor before and after Kvar, kVA, kV, A, etc, and correlate with normal response based on rating of equipment. If no change or abnormal change occurs, log and alarm for maintenance. (For example normal control calls for switching on 10,000 kVA capacitor bank at substation 34. The comparison of before and after conditions may be :

	Before switching command	After switching command
kW Load	50000	50000
kvar Load	20000	10000
kV	113kV	115kV

These readings confirm that the 10,000 kVA bank did come on as intended, and there is no need for operator to become involved.

2. Gas Insulated Substations

Monitor operating conditions, log, trend and compare vs. allowable limits. Include pressure of each section, moisture content, corone level, etc. Alarm when out of limits or consistent unfavourable trend, take corrective action, e.g. trip circuit breakers to de-energize and isolate affected section.

3. Communication Channels

1. Monitor performance, and log degraded performance to aid in scheduling repair maintenance, and upgrading.
2. Periodically test, monitor and log to confirm performance, log and alarm degraded performance

6.2.7.6. REMOTE LOG OF PROTECTIVE SETTING

Log at selected location, upon request, when changes have been implemented, or periodically (such as at six month intervals):

- a. Present protective settings for each function
- b. Last change in settings for each function
- c. Worst case load current, voltage limits and fault currents for most recent time period (T_1 to T_2)
- d. Last periodic test, last periodic maintenance
- e. Diagnostic summary of present operational performance

6.2.7.7. REMOTE LOG OF PROTECTIVE OPERATIONS

Log at selected location, after each operation, upon request and/or automatically :

- a. Sequence of Events
- b. Summary of I, V, Z, X etc. for this event
- c. Comparison of this event with
 1. Last 2 or 3 events
 2. Reference case - e.g. this I_{A-G} of 10000 A was 67% of $I_{Max} = 15000$ A, or this I_{A-G} of 10,000 A was 85% of capability of breaker No. 2601.

6.2.7.8. REMOTE LOG OF SYSTEM CONDITIONS VS. PROTECTIVE SETTINGS

Log at selected location, upon request, periodically or when within X% of settings :

- a. Present system conditions vs. protective settings e.g. I, V, kW, kVA, vs. I_{pu}, Z_{pu}, etc.
- b. Max values over time period T_1 to T_2
- c. When within X% of settings
- d. Percent increase over last maximum value

6.2.7.9. SYNCHRONISM CHECK RELAY MONITORING

When a synchronism check function prevents breaker closing ; e.g. during manual remote control, or during automatic reclosing :

- a. Alarm remote operator and display the setting of the synchronism check function and the actual phase displacement across the open breaker
- b. Permit operator override after the operator acknowledges and verifies that the displayed phase displacement is in excess of setting.

6.2.7.10. MONITOR VOLTAGE UNBALANCE

Compare new value with previous value. If increase is :

- a. Large
 1. Compare with recent switching operations for correlation, e.g. single pole trip of a line fault
 2. Measure current balance at various locations to seek source of unbalance voltage, e.g. one open pole of breaker or disconnect switch.
 3. High level alarm, display and trend to remote operator
- b. Moderate
 1. Compare with recent switching operations for correlation, e.g. opening of long untransposed line, re-energising transformer or reactor bank with taps different between phases, re-energising capacitor bank.
 2. Compare other voltages and currents to seek sensor error, e.g.
 - CVT with shorted capacitor packs
 - CVT with tuning different between phases
 3. Low level alarm, display and trend to remote operator

6.2.7.11. ALARM SUPPRESSION

Upon notice from higher hierarchical level operating centers, forward only highest level alarms. Hold and later forward middle and lower level alarms. This will help relieve higher level operators during times that power systems is in alert, emergency or restorative states.

6.2.7.12. MONITOR SUBSTATION OPERATING STATE

Determine from local data the operating state of this substation, e.g.

- Normal, alert, emergency, restorative

a. When in other than Normal state :

1. alarm higher level hierarchical control centers
2. continue to give highest priority to protective functions
3. reassess priorities of monitoring and control functions. Give higher priority to those directly related to this abnormal condition, lower priority to those less related. For example, if a transformer bank becomes overloaded, give higher priority to functions like transformer load monitoring, voltage var control and lower priority to functions like minimizing transformer losses, monitoring cumulative circuit breaker duty, and remote log of protective relay settings.
4. reassess alarm priorities.

6.2.7.13. LOG OF FAULTS, SEQUENCE OF EVENTS, OSCILLOGRAPHY

Log locally, display, and/or printout remotely, for "X" minutes after each fault either automatically or on request. May incorporate adaptive selection data displayed to include significant changes only, of number of samples, sampling rate and/or data compression for remote data transmission and display.

a. Line Faults

1. Type fault, (L-G, L-L, 3 phase etc.) fault current magnitude, distance from terminal to fault relay time, breaker clearing time, prefault load currents and voltages.
2. Log of relay targets
3. Reclosing operations, sequences, timing, if unsuccessful why. If successful post fault load currents and voltages.
4. Repeat from stored samples, prefault and during fault V & I wave forms, calculated quantities such as impedance, kW, kVA, etc.

b. Bus Faults

1. Type fault, (L-G, L-L, 3 phase, etc.) fault current magnitude, relay time, breaker clearing time; prefault load currents and voltages.
2. Log of relay targets
3. Post fault voltages where sensors are still energized, e.g. incoming lines
4. Repeat from stored samples, prefault and during fault V & I waveforms, calculated quantities such as impedance, kW, kVA, etc.

c. Transformer Faults

1. Type fault, (L-G, L-L, 3 phase etc.) fault current magnitude, relay time, breaker clearing time, prefault load currents and voltages.
2. Log of relay targets
3. Post-fault load currents and voltages, loading on remaining transformers
4. Repeat from stored samples, prefault and during fault V & I waveforms, calculated quantities such as impedance, kW, kVA, etc.

6.2.7.14. HARMONIC CONTENT

Monitor and log, alarm for excessive harmonic content of currents, and/or voltages. For possible use near generators, capacitor banks, HVDC installations, large rectifier loads, sensitive and critical loads.

6.2.8. BREAKER AND TRANSFORMER CONTROL

6.2.8.1. SYNCHRONOUS TRIPPING

Local control would determine appropriate

point on voltage/current wave, and open each breaker pole to minimize breaker arcing. This would take into account breaker contact parting time as determined from previous operations - modified as necessary for related conditions such as control voltage, air pressure, ambient temperature, etc. Delay tripping in case phase current does not cross zero value. (3-phase, or phase-by-phase).

6.2.8.2. SOFT BREAKER CLOSING (SYNCHRONOUS CLOSING)

1. Circuits and Busses

Time closing of each pole of breaker to occur at appropriate point on voltage-current wave to minimize transient overvoltage. Adaptive control can take into account actual closing time interval of breaker based on most recent closing operations - modified as necessary for related conditions such as control voltage, ambient temperature, air pressure, etc.

2. Transformers

Time closing of each pole of breaker to occur at appropriate point on voltage-current wave to minimize inrush current

6.2.9. INTERLOCKING

6.2.9.1. ISOLATING SWITCHES

Assure that appropriate breakers are open before electrically operated isolating switches are opened or closed. If not display message to initiating operator, e.g. "Isolating switches for breaker 2301 should not be opened while breaker is closed."

1. Breaker isolating switches
2. Transformer isolating or transformer magnetizing current interrupter switches.

6.2.9.2. GROUNDING SWITCHES

Assure that appropriate breakers and/or isolating switches are open before electrically operated grounding switches are closed or opened. If not, display message to initiating operator, e.g. "grounding switch 2301N should not be closed while breaker 2301 is closed and isolating switch 2301B is closed."

1. Breaker grounding switches
2. Transformer grounding switches
3. Bus grounding switches
4. Line grounding switches

6.2.9.3. PREFERRED SWITCHING SEQUENCES

Assure that preferred switching sequences are carried out, or that operator acknowledges that a deviation from the preferred sequence is being intentionally executed. If other than preferred sequence is called for display message to initiating operator. Example : " Preferred switching sequence per pg. 29 of manual AAA is to trip transformer breaker 2301 or 2309 before closing bus tie breaker 2305. Confirm that you want to deviate from this preferred sequence by - (taking specific action) and breaker 2305 will be closed."

6.2.10. SYSTEM RESTORATION

6.2.10.1. SERVICE RESTORATION SEQUENCE

a. Substations

Upon complete loss of voltage for time duration "X", trip selected breakers. Upon restoration of voltage restore sequentially in pre-selected sequence with time delays determined by local monitoring of incoming line voltages, system frequency, transformer loads, transformer tempera-

tures, and outgoing line loading.

b. Islands

If an island has occurred disable automatic line reclosing and synchronism check closing of follow terminals to avoid random attempts to re-establish ties. Instead select optimum tie for first closing (e.g. stronger tie) and activate it, when it holds close to other ties in preferred sequence.

6.3. WORKING GROUP COMMENTS AND OPINIONS

The working group is of the opinion that acceptance and increased use of adaptive approaches will be evolutionary. First applications are now tending to be in the less critical applications of monitoring and control. With familiarity and confidence the applications will expand into the protection area.

This evolutionary, rather than revolutionary, acceptance of adaptive approaches reflects three major factors.

- a. The majority of experience to date is with non-adaptive approaches. Hence, there is natural skepticism of abandoning tried and proven approaches in favour of something new and different, which adaptive represents. In addition to skepticism and "prove that digital can do the

traditional approaches first, then I'll see how far I'm ready to go in adaptive" there is a natural concern about knowing what the protective and control system characteristics were when specific actions took place automatically. Confidence in this will also grow as experience is gained in displaying the characteristics in effect at the time that a function was carried out as well as the results of the function itself e.g. closing a breaker, changing a relay setting to a higher or lower value. And confidence must be gained in being able to display what the operating characteristics are for various adaptive conditions.

- b. The degree of successful performance achieved by early installations.
- c. Some adaptive approaches will be so beneficial that they will be accepted earlier than others are more of the refinement or nice-to-have category.

While the working group predicts that acceptance and implementation will be evolutionary, we do predict that the acceptance will increase at an exponential rate, rather than straight line, as further experience is gained.

Future working groups can assess whether these predictions have been borne out.

7. FUTURE RESEARCH AND DEVELOPMENT NEEDS

7.1. INTRODUCTION

The availability of a new technology challenges researchers to find suitable applications. The digital computer technology has for a long time been expected to play a major role in fulfilling the protective relaying needs. However, it is not sufficient to have a technology which is challenging. It must also be economically viable as well as being acceptable to the user community. Both of these conditions now appear to be met. This probably accounts for the significant investments being made for the development of digital protective relaying devices and systems.

In earlier sections of this report, the Working Group has attempted to identify many developments for which digital techniques might be employed. It is to be expected that as more experience is gained with digital computer based protection systems, need for additional research in some areas will become apparent. The Working Group has attempted to identify some possible subjects for research in this chapter.

7.2. METHODS FOR CONTROL AND PROTECTION

Results of virtually all of the R&D effort have been in the area of line protection and to a lesser extent in transformer protection. This has been pursued from the point of view of replacing presently used devices on a one-for-one basis with digital devices. However, this replacement strategy is not necessarily the best for economical viability of digital relays. In fact, as is readily seen in Table A, section 3 of this report, most of the ongoing research is now directed towards digital protective relaying systems, which also will incorporate the

control functions. The first few systems to be used are now likely going to serve primarily the most basic functional needs. Thus significant efforts can be expected to go into the development of new functions as well as refinement of the existing ones. Specifically the following areas need future R&D.

7.2.1. RELAYING ALGORITHMS

Bus protection algorithms are virtually non-existent in the digital relaying literature. Transformer protection algorithms too need to be further developed because there is less experience from field trials of transformer protections than from line protections. Shunt reactor and shunt capacitor protective relaying algorithms are also needed. Digital UHSR algorithms have been published but the practicality of many of the proposed algorithms remains to be proven. More sophisticated algorithms for multiterminal, parallel and series compensated line applications are needed, too.

Some of the subjects needing additional work are;

- a. Tapping of lines more prevalent because of the increasing difficulties in obtaining new transmission line right-of-way.
- b. Increasing use of parallel or multi-circuit lines to utilize existing right-of-ways.
- c. Heavy line loads because of difficulties in building new lines
- d. Reduction of breaker usage in order to save on capital

- e. Increased reliability requirements on the protection system as a result of the stretched transmission system.
- f. Reduced clearing time requirements for stability reasons
- g. Improved equipment monitoring with the goal of detecting incipient faults, thus minimizing repair costs.
- h. Recognition of new protection needs, such as the detection and clearing of subsynchronous resonances.
- i. Generator protection

7.2.2. IMPROVED EQUIPMENT MONITORING

Significant developments of incipient fault detectors and equipment monitoring devices are being pursued in many countries. Detection of partial discharges in dielectric systems of transformers, cables and generators under normal operating conditions has been made possible. On-line analyses of dissolved gases in transformers should become economical in the near future. Improved monitoring of SF₆ equipment, including the quality and density of the gas, is made possible through recent developments. Fault location indicators and incipient fault detectors for GIS equipment have been or are being developed. Torsional monitors for generator shafts have been developed. So have transformer hottest spot detectors. However, many of these developments have yet to show operational benefits, which is needed for utility acceptance. Many other needs such as transformer load tap changer monitoring breaker health evaluation, generator and transformer winding vibrations monitoring and many other monitoring needs have yet to be addressed by the researchers.

7.2.3. TEST METHODS

Uniform methods for evaluating relaying algorithms need to be established. It is not easy to determine accuracy, speed of response, security and dependability of a digital relaying algorithm and even more difficult to get a fair comparison in these regards between the conventional and digital relaying devices. The difficulties lie partly in the fact that the performance of the relaying system depends to some degree on the power system itself. However, in spite of these difficulties, criteria and methods for algorithm evaluation are needed to reduce the time to get a new algorithm qualified for use in a digital relay. Standard sets of synthesized or actually recorded fault cases might be one way to solve this problem. It is also necessary to develop standard formats for data exchange among researchers.

7.3. RELIABILITY ANALYSIS

The overall reliability of a system depends on the failure rate of the individual components. Digital components are fairly reliable by themselves. However, a digital relaying device uses quite a number of chips, which leads to a reliability penalty in comparison to conventional solid state relays. This is by itself not a severe problem, because a relay needs high security and dependability, which can be more easily achieved in a digital system by incorporation of self-checking features and

appropriate system redundancy. This does increase the number of components and therefore the number of component failures, which in turn, increases the maintenance costs. Research is needed on the impact of self-checking of relays on reliability dependability and security. Can self-checking be biased towards maximum dependability or maximum security? What are the economic limitations? Is there a balance between reliability needs and maintenance costs?

7.4. HARDWARE DEVELOPMENTS

Although one cannot exclude the development of special LSI-type components for future digital relaying devices, the hardware R&D emphasis is most likely going to be on the application of components for relaying processors. In fact, most of the hardware developments today do not even address processor developments but the development of interface devices to relatively standard processors. There are, however, some specific hardware related topics that should be considered from the R&D point of view.

7.4.1. COMMUNICATION INTERFACES

Cost goals for the digital control and protective relaying systems can only be met if the individual function processors are tied together in a local network. This means that communication links of various types are needed. The optimum use of communication links, their characteristics and mode of operation will be the subject of more R&D. Optical versus metallic communication media, modulation method, control scheme (full or half duplex system), response modes, etc. will not be fully researched in a few demonstration systems. Future work is clearly needed.

The architecture and economics of an integrated system are influenced by the data capacity of communication links which interconnect the hardware modules or the levels of the hierarchy. Major improvements could result if more data could be sent over the available links. Research may uncover characteristics of the substation application which permit compression or compacting of the data at the sending end, thus increasing the effective data rates for a given level of hardware capability.

System-wide data collection, analysis, and resulting control would be vastly simplified and improved if the sampling of data were accurately synchronized over the entire breadth of the power system. Researchers should focus on evaluation of hardware technology which can be applied for this purpose with appropriate reliability and economy.

7.4.2. PROCESS INTERFACES

More than half of the system cost is likely to be found in the input-output systems of the digital relaying equipment. Hence, there should be a lot of benefits from future developments leading to lower cost interfaces. This should include the development of lower cost, high accuracy and high performance sampling systems for conversion of the continuous current and voltage input signals to sampled data for the processors. Optimization of signal conditions hardware is also a desirable R&D objective.

7.4.3. TRANSDUCERS

Presently used current and voltage transformers (including coupling capacitor voltage transformers) are fairly difficult to replace at any but the highest voltage levels with electronic transducers. However, there ought to be opportunities for improved relaying system performance with more ideal, noise free transducers. Although a lot of work has been going into this area during the last 20 years, until today there has been no suitable protective relaying device with which to interface a low energy transducer. Hence, commercialization of the electronic transducers has not been successful. However, the digital protective relaying device will change that and renewed attempts to build advanced, low energy current and voltage transducers can be expected.

7.5. SOFTWARE AND HIGH LEVEL LANGUAGES

Developers of experimental or prototype substation computer systems are generally using standard software development tools provided by the computer manufacturer. The cost and effort of the additional custom programming required for such a specialized application is massive. Looking towards the opportunity for future widespread commercial use, most investigators realize that this custom programming with standard tools is too expensive, and may be impossible for some users to deal with when the substation is expanded or changed.

To manage this situation, the industry is likely to develop application specific high level program assembly tools which both suppliers and users can deal with. Research in this area can yield at least three useful bodies of information :

- (1) Standard formats and storage methods for the input data base which describes the substation and which is used to generate the software package—whether it be done automatically or manually.
- (2) Standard interfaces and protocols among systems elements, if some sort of common architecture or hierarchy arrangements can be identified. Where the interface cannot be standardized in all respects among different suppliers, perhaps some level of hardware or software standardization for interfacing purposes can be developed.
- (3) Investigation into levels of commonality in format or content of operating information among various users of substation computer equipment. Thus, one could visualize the development of an engineering dialog language which would be the only standard interface between the substation computer system and the protection engineers responsible for setting and commissioning the equipment.

7.6. ENVIRONMENTAL RESEARCH

In the past 20 to 25 years, semiconductor devices have become accepted and relatively well understood components of the power system. Conventional environmental concerns such as temperature, humidity, mechanical shocks etc. should not really be of significant concern to the industry except where electronic equipment leaves the relative safety of the control house and moves out into the switchyard. Even so, the thermal and mechanical environment is sufficiently well defined as a result of a lot of military equipment developments. However, one area

remains of significant concern and that is the electromagnetic interference (EMI) levels to be expected in the control room but primarily in the switchyard environments. The transient fields arising from switching operations can be characterized relatively well but the fields associated with faults will be much more difficult to determine. This is an area in need of much more research.

Once the field intensities and temporal characteristics have been established, the question of testing to ensure survival in the environment comes up. The emphasis must be on proper test methods, which are practical, relevant and not resulting in substantially oversized equipment. This is very difficult task in need of significant research.

7.7. IMPACT ON POWER SYSTEM CONTROL TECHNIQUES

The presence of substantial computing power in substations and access to real-time data from the transmission network at the substation level may open up the avenues of research for newer power system control strategies. For example real time synchronized measurements of power system voltages (as phasors) as well as of local frequency may affect the estimation and control techniques now used in centrally located computers for power dispatch. Other possibilities are the construction of new performance indices for the power system based upon local real-time measurements of key system parameters. One could visualize a multi level computational technique for power system state estimation. Dynamic modelling and modal parameter estimation may also become feasible in the future. Much work remains to be done and many theoretically challenging questions need to be answered.

Given widespread application of substation computers, every piece of data in any substation is available at any other location if the access facilities to the distributed data bases are made available.

One will know the exact cause of an alarm instead of having to guess at how critical a critical alarm indication is, etc. One can only begin to speculate about the possibilities. There are more questions than answers, which should be fertile ground for much future, challenging research.

7.8. CONCLUSION

There are a lot of ongoing research activities all over the world, which should make digital protective relaying systems a reality in the near future. However, the future requirements on power system control and protection will most likely lead to demand for higher performance systems. Also, the new technologies have opportunities in them for cost reduction of the control and protection systems that will generate additional developments. The future R&D will most likely encompass all of the system design disciplines and the component design areas as well. Hence, there should be many interesting and challenging developments left for future researchers.

APPENDIX I - QUESTIONNAIRE ON HIERARCHICAL SYSTEMS
SURVEY ON HIERARCHICAL DISTRIBUTED COMPUTER SYSTEMS
FOR PROTECTION

This survey is designed to provide a unified system of reporting on computer systems that exist or are presently being designed. This survey has been laid out in the form of criteria which an ideal system should comply with. In practice, only some of these criteria will be met. The degree to which a scheme does so is a measure of its suitability compared to what is desirable. The criteria are as specific as possible to avoid ambiguity in replies to the survey.

You are asked to provide the following information about the hierarchical structure of computer-based protection and control systems for substations. The systems may actually exist, or they may be in the process of planning, design, or implementation.

1. The list of functions to be performed. Begin with broad categories such as Protection Control, Alarm, Datalogging. Within each category, please give detailed listing of functions. For example, the Protection category may have three levels of detail :

Protection : Lines	- three-zone distance
	- carrier interface
	- ground faults
	- high-speed reclosing
Transformers	- etc.

please give a breakdown of functions to as many levels of detail as possible.

2. A block diagram of the hierarchical computer system. This may well be a collection of several block diagrams.

There should be a functional block diagram where the functions listed above are assigned to individual logical blocks associated with hardware modules. Another block diagram should identify the various hardware entities and their communication links.

3. A description of the nature of each communication link. For example, the medium of communication, the data rate, limits, serial or parallel, whether a computer data bus, whether private or commercially available communication protocols are used, the nature of the data (what it represents), modes of initiating data transfer (whether master/slave, party line, etc.).

The Working Group expects to assess each of the proposed hierarchical systems based on a list of criteria given below. If you can aid in this assessment by discussing the features of the proposed schemes in terms of these criteria, it would be of great help to the Working Group.

The criteria are listed below :

- a. Data flow should (i) minimize transfer of information between parts of the system to reduce processing overhead, (ii) provide redundancy in data paths serving critical functions, (iii) give access to data for specific functions at appropriate data rates, (iv) process input data to eliminate errors, (v) generate a secure data base.
- b. The system should be designed to be modular in

concept to allow (i) the expansion of a system from a nucleus to cover all desired functions without requiring modification to existing modules, (ii) the addition of modules without taking the existing system out of service, (iii) a mix of functions without jeopardizing the reliability of critical applications, (iv) the same basic module to be used for all functions.

- c. The hardware/software should be organized to give redundancy and added security of operation where necessary. It should be possible to remove a module performing a critical function without depriving the system of the availability of that function.
- d. A man/machine interface will be necessary to (i) communicate with the machine for setting in new data or for extracting information, (ii) give an output in hard copy for analysis or record purposes, (iii) allow interrogation of the system for fault finding.

Access to specified activities should be safeguarded by providing a facility to limit access to authorized personnel.

- e. Provision must be made to (i) communicate between the substation system and a remote location, (ii) incorporate local check features to give secure operation from remote commands, (iii) synchronize data acquisition for subsequent onward transmission to a dispatch center, (iv) validate and concentrate data before onward transmission.

- f. Automatic control and switching functions should be designed on a failsafe basis to accommodate computer system failures.

- g. Self-checking capability should be included in the system to cover all modules. Any failure detected should produce diagnostic output to assist in identifying the cause of failure. Where appropriate, a back-up capability for the failed function should be included.

It should be possible to carry out in-service testing without affecting the operational status of the function.

- h. Post-fault analysis for appropriate functions should be provided in a form which is readily available to operating personnel.

APPENDIX 2 - RECENT DEVELOPMENTS CATALOG AND
BIBLIOGRAPHY (COMPILED JUNE 29, 1983)

APPENDIX II A - DESCRIPTION OF PROJECTS

PROJECT 1

- 1.1 Project Name - DDPS (Digital Distance Projection System)
- 1.2 Participating Company - The Electricity Commission of New South Wales
- 1.3 Where Installed - Sydney West 330/132 kV Substation, Australia
- 1.4 Type Installation - Field Experiment
- 1.5 Actual Duration of Field Experience - November, 1978 to present time

1.6 Synopsis of Project

Following several years of research by the University of New South Wales into the development of various algorithms for the on-line monitoring and protection of a simple transmission line, it was decided to install a commercially-available computer in a high-voltage substation to test the algorithm and to obtain field experience with a computer in an actual substation environment.

The digital equipment monitors a single-circuit, 238 km long, 330 kV line. Every half milli-second, it samples the currents and voltages derived from conventional CT's and VT's. Digital techniques are utilized to detect faults, to determine the type of fault, and the algorithm calculates R and L to the fault from the integral form of differential equation $V=L (DI/DT) + RI$. In addition, two cycles of pre-fault and 20 cycles of post-fault information are recorded on a disc.

Since its commissioning, there were no false trips and the DDPS correctly identified numerous external power system faults as being outside the protected zones and responded satisfactorily to an internal solid fault. The response to an internal high-resistance earth fault was just as erratic as

would be expected of a conventional distance relay. A valuable by-product of the project was the experience obtained regarding the flexibility and usefulness of digitally stored fault data.

PROJECT 2

2.1 Project Name - SACS (Substation Automated Control System)

2.2 Participating Company - South East Queensland Elect. Board (SEQEB)

2.3 Where Installed

Makerston Street, Surfers Paradise and Albany Creek 132 kV Substations. (Six more units on order, for delivery December 1982.)

2.4 Type Installation - Permanent control facilities within the substations

2.5 Actual Duration of Field Experience

January 1981 to present, preceded by prototype installation since 1978.

INDEX

<u>PROJECT NO.</u>	<u>COUNTRY</u>	<u>PROJECT NAME</u>	<u>SYSTEM VOLTAGE-kV</u>	<u>FIELD EXPERIENCE DATES</u>
1	AU-AUSTRALIA	DDPS	330	11/1978-TO DATE
2	AU-AUSTRALIA	SACS	132	1978-TO DATE
3	BE-BELGIUM	ALPES	150-70	5/1981-TO DATE
4	CA-CANADA	SCARBOROUGH DAS	27	1982-TO DATE
5	CH-SWITZERLAND	DISTANCE RELAY LZK7	220	9/1981-TO DATE
6	DE-GERMANY (F.R. of)	PPC	110-20	4/1977-TO DATE
7	DE-GERMANY (F.R. of)	HV-LINE PROTECTION	?	7/1981-TO DATE
8	DE-GERMANY (F.R. of)	INTEGRATED CONTROL & PROTECTION	110-20	8/1982-TO DATE
9	DE-GERMANY (F.R. of)	DIGITAL PROTECTION & FAULT RECORDING	LAB/380	1983-
10	FR-FRANCE	PAN	400	6/1981 - 11/1981
11	FR-FRANCE	PANDOR	245/LAB	6/1982 - 9/1982
12	GB-UNITED KINGDOM	PERM	400-11	1974-TO DATE
13	GB-UNITED KINGDOM	MICROMHO DISTANCE RELAY	500-220	1981-TO DATE
14	GB-UNITED KINGDOM	MULTIPROCESSOR DISTANCE RELAY	LAB	7/1983
15	GB-UNITED KINGDOM	MICROCOMPUTER OVERCURRENT RELAY	DISTRB 'TN	1983-
16	GB-UNITED KINGDOM	WAVE DIFFERENTIAL PROTECTION	?	1983-
17	JP-JAPAN	CDCR	500 & 275	7/1977-TO DATE
18	JP-JAPAN	SDCS-I	77-6.6	12/1977 - 3/1980
19	JP-JAPAN	SDCS-II	77-6.6	5/1981 - 3/1983
20	JP-JAPAN	GRCZ	66	1/1979-TO DATE
21	JP-JAPAN	BACKUP RELAYING	500	6/1979 - 3/1980
22	JP-JAPAN	DIRECTIONAL COMP. LINE RELAYING	154	6/1980 - 8/1981
23	JP-JAPAN	DFL	275	11/1980 - 9/1982
24	JP-JAPAN	LINE RELAYING	154 & 66	5/1981 - 3/1983
25	JP-JAPAN	77kV BACKUP RELAYING	77	6/1981-TO DATE
26	SE-SWEDEN	INTEGRATED CONTROL EQUIPMENT	220-70	7/1983
27	US-UNITED STATES	CRS FOR TRANSMISSION LINES	230	2/1972-1979
28	US-UNITED STATES	PROBE	138/12	10/1976 - 6/1980
29	US-UNITED STATES	DIPS	500	6/1977 - 6/1978
30	US-UNITED STATES	SCDR	138 & 765	4/1979 & 7/1980-TO DATE
31	US-UNITED STATES	DTLPCS	500	1/1984 - 1985
32	US-UNITED STATES	ICPDS	138-12	3/1984 - 1985
33	US-UNITED STATES	SUB. DIGITAL C. & P. SYSTEM	500-230	1984 - 1985

2.6 Synopsis of Project

The impact of changing technology, combined with a heavy substation expansion program, prompted SEQEB to undertake development of an integrated, multiple microprocessor-based system for substation monitoring and control functions. With such totally new concepts, the system purposely excludes primary protection functions.

The system developed comprises a three-segment processor system based on the INTEL multibus structure. The input/output subsystem hardware, and all of the software was developed in-house to satisfy special diagnostic requirements and to simplify the installation/test/operation effort.

Functions currently performed by SACS include : (A) analogue, status and alarm acquisition for display on a VDU in the substation, (B) centralized control of all substation CB's from the operator's VDU keyboard, (C) auto-reclosing of CB's, (D) tap changer control and parallel operation of transformers, (E) load shedding and restoration, (F) auto-changeover routines, (G) interlocking of special functions, (H) CB failure protection, (I) remote control of the substation via a communications link to the control center.

The system is less than half the cost of conventional hardware and reduces substation circuitry design time to one-third of that taken for conventional hardware. Most of the equipment problems were eliminated in workshop testing and the first three months of field operation; no known bugs exist at this stage.

PROJECT 3

3.1 Project Name - ALPES (An Integrated Control System for EHV Substation)

3.2 Participating Companies

ACEC (Belgian manufacturer)
LABORELEC (Central Laboratory of the Belgian Utilities)
UNERG, EBES, INTERCOM (Belgian Utilities)
TRACTIONEL, ELECTROBEL (Belgian Consultants)

3.3 Where Installed

TERGNEE 150/70 kV Substation of UNERG (Near Charleroi, Belgium).

3.4 Type Installation - Operational

3.5 Actual Duration of Field Experience

May 1981 to date, preceded by laboratory checking of hardware and software in 1980 and early 1981.

3.6 Synopsis of Project

The ALPES project was begun in Belgium in 1974. The general aim was the progressive and coordinated application of digital techniques applied to EHV substations. The decision was made to develop a system in two steps (1) a substation integrated control system and (2) a complete control + protection system. The first step is now a reality.

After a market analysis, it was recognized that a new digital system had to be designed to cope with a wide range of substations size and applications, without excluding the old substations whose equipment is to be renewed. Accordingly the

system had to respect the following requirements :

- a. to be modular from hardware and software point of view.
- b. to be compatible with conventional relaying.

The guidelines were the following :

- c. at substation level : a centralized control system (SICS) with capability for local control, centralized automatic control and remote control from an area control center.
- d. at circuit level : protection and emergency control are decentralized. They have to be connected to classical relaying and to conventional CT's and PT's.

The SICS was specified during 1977. It was built by ACEC and programmed by Laborelec. After lab checks, it was commissioned in May 1981 and has worked since, including successfully passing the functional and EMI tests.

It is a cluster of 5 processors (Intel 8080) assuming the following tasks :

- Processor 1 : acquisition, emission of the orders.
Processor 2 : event recording and dispatching of the events to the other tasks of the system.
Processor 3 : local control and man-machine interfacing.
Processor 4 : remote control to/from the area control center of Charleroi.
Processor 5 : automatic control

All the SICS are contained within 2 cubicles. It has 750 logical inputs, 60 measurements, 40 metering inputs and 160 orders.

PROJECT 4

4.1 Project Name : Scarborough DAS (Distribution Automation System)

4.2 Participating Companies

Ontario Hydro
The Public Utilities Commission of the Borough of Scarborough
Motorola Dacscan Limited

4.3 Where Installed

In the Borough of Scarborough, in Metropolitan Toronto, on two, 27.6/16 kV grounded neutral distribution feeders supplied from Agincourt Transformer Station.

4.4 Type Installation - Field Experiment

4.5 Planned Duration of Field Experience - Late 1982, two years.

4.6 Synopsis of Project

The Scarborough DAS is a computer-based multi-functional control/monitoring system having the following functions :

- a. Load Management - controlling and monitoring individual customer loads to increase load factors.
- b. Fault Isolation and Service Restoration - isolating faulted feeder sections and restoring service to non-faulted sections.
- c. Loss Minimization - dynamically changing feeder configurations by opening and closing switches, in order to minimize the I²R losses in the feeder conductors.
- d. VAR Control - switching feeder capacitor banks on/off as required to dynamically meet

- feeder VAR requirements.
- e. Street Light Control - simulating an alternative method of street light control. This method has a lower energy requirement.
- f. Distribution System Monitoring - monitoring currents, voltages, etc., and analyzing the data collected.

The objectives of the project are :

- a. to do a cost/benefit analysis on a multi-functional system, as opposed to a system involving load management only, and
- b. to evaluate the worth of distribution automation in general, and each function individually.

The control computer, a PDP-11/34, communicates across telephone circuits with numerous remote terminal units (RTU's) located on customers' premises and at various points along the two distribution feeders.

There are a total of 30 RTU's installed on the feeders. These control a total of 21 feeder switches, the two feeder breakers located at the TS, and 8 capacitor banks. The total numbers of points on these 30 RTU's are 219 analog points, 107 status points, 6 counter points and 84 control points. It is hoped that the system will be operational by the summer of 1983.

PROJECT 5

5.1 Project Name - LZK7 (Microprocessor Based Distance Relays)

5.2 Participating Companies

Brown Boveri & Cie. AG, Baden, Switzerland
Bernische Kraftwerke AG, Bern, Switzerland

5.3 Where Installed

Bernische Kraftwerke AG
Bickigen 220 kV Substation (20 km from Bern)

5.4 Type Installation - Field experiment

5.5 Actual Duration of Field Experience - September 1981 - present time

5.6 Synopsis of Project

The main object is to demonstrate the feasibility of digital distance protection for HV-transmission lines. Special attention is paid to the performance of the implemented algorithm.

5.6.1 Hardware

Distance Relay LZK7

- CPU - with INTEL 8086 microprocessor (SBC 86)
 - A/D - with 8 channels, low pass filters, 15 bits resolution, 24 samples per cycle (50 Hz)
 - Man-Machine-Interface, I/O-Interfaces, DC-Supply, reclosing unit.
- BBC Fault Recorder Type INDUCTIC 65
- CPU - with INTEL 8085 microprocessor
 - I/O - ≤ 12 analog channels, sampling frequency 500 Hz, resolution, 12 bit
 - ≤ 16 digital channels, sampling frequency 500 Hz
 - Record length - ≥ 8 sec (all channels)
 - ≥ 33 sec (all channels) with cassette drive.

5.6.2 Software

Distance Relay LZK7

- 5 zone distance scheme
- Phase-selection based on current-step
- Non faulted reference or memory voltage
- Saturation-stabilised
- Event-printout with results before and after fault inception

5.6.3 Results

- No false operations
- 6 missed operations (Hardware down time)
- 10 correct operations

PROJECT 6

6.1 Project Name - PPC (Protection with a Process Computer)

6.2 Participating Companies

Ueberlandwerk Unterfranken, Wuerzburg, West Germany
Siemens AG, Erlangen, West Germany

6.3 Where Installed

110/20 kV Substation Bad Kissingen of Ueberlandwerk Unterfranken.

6.4 Type Installation - Regular operating installation

6.5 Actual Duration of Field Experience

April 1977 and still in service - preceded by laboratory testing during end of 1976 and beginning of 1977.

6.6 Synopsis of Project

As a first step towards the realization of an integrated digital control and protection system, it was necessary to demonstrate the technical feasibility of protection functions in a relatively harsh electrical environment. A 110/20 kv substation consisting of 11-20 kv feeders and 2-110 kv step down transformers was chosen for this purpose. Digital techniques were used to realize the following protection functions :

- a. 110 kV/20 kV transformer differential with second harmonic restraint
- b. 3-zone distance protection of 11 feeders
- c. Single shot 3-pole autoreclosure for 11 feeders
- d. Distance to fault location
- e. 20 kV busbar protection
- f. Earth fault detection and
- g. Short circuit datalogging and transmission to the remote central control center

Currents and voltages obtained from conventional instrument transformers were scanned and sampled at the rate of 20 times per cycle.

During the field tests extending over a period of almost 6 years, there were two hardware failures and two software errors. More than 250 short circuits have been cleared successfully. Experience regarding speed, accuracy and availability were comparable to the present day conventional systems.

A commercial Siemens process computer of the type 300-330 (16 bit machine) was used to realize the above mentioned functions. The machine has 40 kilowords of core memory supplemented with process peripheral units for processing analog and digital inputs. Standard peripheral unit consists of an input-output typewriter for datalogging and relay setting.

The protection function will be supplemented by control, monitoring and data acquisition functions as a planned future activity and to develop reliable, cost effective digital equipment for distributed hierarchical configurations.

PROJECT 7

7.1 Project Name - HV-Line Differential Protection With Optical Fibre.

7.2 Participating Companies

Badenwerk AG Karlsruhe / Fed. Rep. of Germany
AEG - Telefunken Frankfurt / Fed. Rep. of Germany

7.3 Where Installed

Badenwerk AG
- Substation Kuppenheim
- Substation Rastatt

7.4 Type Installation

Temporary, but operating installation,
Voltage = ?

7.5 Actual / Planned Duration of Field Experience - Since July 1981

7.6 Synopsis of Project

To demonstrate the technical feasibility of transmitting digital data for HV-Line differential protection and permissive intertripping scheme of distance protection.

PROJECT 8

8.1 Project Name - ICPS (Integrated Control and Protection System)

8.2 Participating Companies

Ueberlandwerk Unterfranken, Wuerzburg, West Germany
Siemens AG, Erlangen, West Germany

8.3 Where Installed

110/20 kV Substation Fuchsstadt of Ueberlandwerk Unterfranken

8.4 Type Installation - Regular operating installations

8.5 Actual / Planned Duration of Field Experience

In operation since August 1982. Field experience data are not available.

8.6 Synopsis of Project

All the protection and control functions were realized for a 110 kV/20 kV substation consisting of 16 20 kV exits including 2 110 kV/20 kV stepdown transformers and 6 110 kV exits and one bus coupler. The busbar arrangement is a sectionalized double bus system with bypass bus.

Digital techniques were used to realize the following protection functions :

- a. 110 kV dedicated line protection
- b. 110 kV bus protection
- c. 110 kV/20 kV transformer differential with second harmonic restraint
- d. 3-zone distance protection for 11-20 kV feeders
- e. Single shot 3-pole autoreclosure for 20 kV feeders and 1-3 pole autoreclosure for 110 kV lines.

- f. Distance to fault location for 110 kV and 20 kV feeders
- g. 20 kV busbar protection
- h. Earth fault detection and
- i. Short circuit datalogging and transmission to the remote central control center.

Control functions realized include switch-gear interlocking, local control, remote control, load data acquisition, real time event data acquisition and transmission to remote end. Currents and voltages obtained from conventional instrument transformers were scanned and sampled at the rate of 20 times per cycle.

The computer configuration consists of a mixture of process computer of Siemens type 300-R30 with 128 K semiconductor memory and 16 bit microprocessor of INTEL type in a multi-processing mode an 8 bit up. Analog and digital data bases are independently established with microprocessors without loading the processor of the process computer.

Standard peripheral units consist of input-output typewriter for datalogging and relay settings and floppy disk for system restoration.

The same utility has given 3 more orders to the above-mentioned manufacturer with an identical technical concept as detailed above. These units would be commissioned between middle/end 1983.

PROJECT 9

9.1 Project Name - DPFS (Digital Protection and Fault-recording System)

9.2 Participating Companies

Nordwestdeutsche Kraftwerke, Oldenburg, West Germany
Siemens AG, Erlangen, West Germany

9.3 Where Installed

Laboratory prior to 380 kV Substation Conne Forde of NWK

9.4 Type Installation

Laboratory demonstration prior to field demonstration

9.5 Actual / Planned Duration of Field Experience

At present being tested in the laboratory and is scheduled to be commissioned end of 1983.

9.6 Synopsis of Project

On an experimental basis, a computer configuration is planned in a 380 kV substation to perform the following functions using digital techniques.

- a. Oscilloperturbography for the 12 exits
- b. Busbar protection for the 3 bus, 2 coupler, 1 bypass configuration
- c. Distance to fault location
- d. Real time data acquisition
- e. Logging of short circuit data

The computer configuration is a mixture of process computer and microprocessors. Process peripherie includes a Winchester hard-disk and Cal-comp drum digital plotter of type 1039.

Planned future activity includes functionally dedicated software implemented with independent

processors to replace the process computer.

PROJECT 10

10.1 Project Name - PAN (French Acronym for Digital Protection and Control in Substations. Was Extended to Pandor Project-11)

10.2 Participating Company - Electricité de France

10.3 Where Installed

Albertville (400 kV Substation)
Tricastin, Saint-Vulbas, Baixas (400 kV Substations)

10.4 Type Installation - Temporary Demonstration

10.5 Actual Duration of Field Experience

June 1, 1981 to November 30, 1981 (Preceded by Lab. Simulator Testing) and November 1, 1982 to Present Time.

10.6 Synopsis of Project

To demonstrate the technical feasibility (algorithm and hardware) for digital relaying of a 400 kV line. The protection uses a digital impedance scheme (3 zones) based on a mean-square-error estimation; the voltage and current samples (12 bits, 24 times a cycle) are derived from conventional transformers; the algorithm computes resistances R and inductances L at each sample (sample window is 18 samples) for the three loops.

The architecture is a multiprocessor approach, including four 16-bit microprocessor boards (1 for each phase plus 1 for data acquisition control and tripping logic), and three dedicated multipliers (TRW) to enhance computation speed. The microprocessor boards are standard ones (Intel SBC 86/12).

The average operating time is about 11 MS for first zone and 17 MS for second zone (french cycle is 20 MS).

In Albertville substation, the digital protection was connected to a digital fault recorder (8 12-bit channels and 16 digital inputs, 5000 Hz sampling rate, 2000 Hz bandwidth, 136 MS pre-fault and 750 MS post-fault recording; designed with 8086 Intel SBC 86/12 microcomputer). 24 faults were recorded, showing correct tripping; faults included phase-to-earth, 3-phases, resistive and evolutive ones.

Other digital fault recorders were installed in Baixas, Tricastin, and Saint-Vulbas 400 kV substations (4 ends of a double-circuit line).

10.6.1 Conclusions

- Algorithm performed well during field test
- Fault location was achieved with 3% accuracy; may be improved by using data from fault inception to clearing.

10.6.2 Future Plans

Actual operation in 400 kV substations with a manufacturer-designed digital impedance relay.

PROJECT 11

11.1 Project Name - PANDOR (French Acronym for Digital Protection and Control

and Fast Circuit-Breaker in Substation).

11.2 Participating Companies

Electricité de France
Merlin-Gerin, Enertec-Schlumberger, Alstom Atlantique.

11.3 Where Installed - High Power Laboratory at "Les Renardières" Substation.

11.4 Type Installation - Field Experiment

11.5 Actual Duration of Field Experience - Second and Third Quarters 1982.

10.6 Synopsis of Project

Pandor project aims at using modern technology (optical fibers, communication link inside substation, digital technology) for protection and control systems in EHV substations. The 1982 demonstration in "Les Renardières" was a field test of several parts of the whole system, in order to prepare future technological choices, assess and test each component's behaviour, and solve interface problems.

The demonstration included :

- A fast circuit-breaker (Merlin-Gerin) : SF6, 245 kV, 40 kA; for breaking operation, less than 20 MS from tripping signal to "ready to break" contact position. The device is equipped with optical sensors (positions, jack displacement, oil, and SF6 pressure thresholds), and digital control system (control, test, digital communication with line bay through optical fiber-HDLC frame).
- Two digital distance protections :
One EDF protection (see "PAN Project")
One Enertec protection based on six measurement loops with fast fault detection, direction, and phase selection, tripping logic (main microprocessor), distance and resistance measurements (auxiliary microprocessors). Current and voltage transformers are conventional, but values are sent to protection through optical fibers (frequency modulation). Operating time is from 4 to 15 MS according to faults.
- One EDF digital fault recorder (see "PAN Project").
- One electronic measuring unit (Alstom Atlantique); electronic measure, conversion, multiplexing at line voltage; measures transmitted to ground level, then to bay building through optical fibers. Measure in 19 bits for currents and 12 bits for voltage. Sampling time from 19 microseconds to 1 millisecond.
- One line-bay control system connected to the two protections; tripping order transmitted to circuit-breaker through optical fibers. Performs automatic control (reclosing, voltage,...) by using Petri Networks.

11.6.1 Future Plans

Include communications inside the substation (local area network, CSMA/CD Ethernet and Token Systems, optical fibers, optical star coupler) digital differential protections, communications between substations through optical fibers in earth wire, system architecture.

PROJECT 12

12.1 Project Name - PERM (Programmable Equipment for Relaying and Measurement)

12.2 Participating Companies - GEC Measurements, Stafford, U.K.

12.3 Where Installed

Several Transmission and Distribution Substations worldwide operating at voltages between 400 and 11 kV.

12.4 Type Installation - Regular Operating Installations.

12.5 Actual Duration of Field Experience

First installation 1974, 300 equipment years cumulative.

12.6 Synopsis of Project

The project was started in 1974 to meet a need of utilities for better, cheaper, more flexible and cheaper form of control and data collection equipment. The microprocessor based equipment (PERM) has so far been utilized for the following functions; utilizing user friendly application based software :

- a. High speed digital event recording
- b. Automatic switching
- c. Automatic voltage control (control of transformer tap change equipment)
- d. Telecontrol (intelligent outstation)
- e. Fault level monitoring
- f. Interlocking
- g. Automatic sequence control of hydro and diesel generators.

The main features incorporated into the equipment when used for the different functions are given below :

- TELECONTROL
 - Monitoring of plant states
 - Monitoring of analog data
 - Transmission of selected data to central control
 - Local print out facilities
 - Ability to match any transmission protocol
- AUTOMATIC SWITCHING
 - Control of circuit breakers and isolators
 - Local/remote supervisory switching and alarms
 - Built in security circuits
- EVENT RECORDING
 - Invalidation of alarm and plant inputs
 - Priority alarm indication
 - Selection of local and remote indications
 - Monitoring up to 2000 points
 - Date/time resolution down to 1 ms
 - Routine print out of alarm states
- VOLTAGE CONTROL
 - Voltage control of up to eight transformers
 - Line drop compensation
 - Provision of automatic transformer switching

PROJECT 13

13.1 Project Name - Micromho Distance Relay Scheme

13.2 Participating Companies - GEC Measurements U.K., and several operating utilities

13.3 Where Installed - Several transmission substation worldwide at voltages between 220 and 500 kV.

13.4 Type Installation - Regular operating installation.

13.5 Actual Duration of Field Experience - First installation 1981, 80 equipment years cumulative.

13.6 Synopsis of Project

This new type of relay was developed to provide an integrated high speed distance protection scheme for the protection of high voltage feeders.

The impedance measurement is carried out by comparators based on Uncommitted Logic Arrays (ULA's) which are customized to meet the required functional requirements. Novel polarising and memory circuits are included in the relay using shift registers driven by a clock locked to system frequency thus overcoming the problem of energy storage circuits and phase angle shift due to variation of system frequency.

A microcomputer is included in the relay to provide the necessary logic circuits and time relays required in a total distance scheme working in conjunction with a signaling channel. The various schemes are called up on thumbwheel switches.

Inbuilt automatic supervision of essential elements is provided in the relay and the microcomputer is used to enable internal relay signals to be monitored and to simplify and speed up commissioning and routine testing using conventional test equipment.

PROJECT 14

14.1 Project Name - Multiprocessor Distance Relay System.

14.2 Participating Companies - GEC Measurements U.K. University of Manchester Institute of Science and Technology.

14.3 Where Installed - GEC Measurements Lab.

14.4 Type Installation - Laboratory Demonstration Prior to Field Demonstration

14.5 Actual Duration of Field Experience - Computer based simulator testing has been completed. Field trials due to start mid 1983.

14.6 Synopsis of Project

To demonstrate the feasibility of a multi-microprocessor based relay for the protection of transmission lines.

14.6.1 Hardware

The multiprocessor relay system has four Intel ISBC 86/12A single board 16 bit computers as its main processors. The main processors perform concurrently system and application tasks except input/output tasks which are handled by a specific input/output processor, all the processors are connected together by a common bus through which the processors access the memories.

14.6.2 Software

Although the basic design of hardware is such that the system can be used for a number of different high speed protection functions a distance protection algorithm has been used in this particular system. A polynomial curve fitting algorithm is used to measure the system impedance for distance protection application solving for R and L in the equation

$$e = Ri + L \frac{di}{dt}$$

The sample rate is 24 per cycle. Time between samples is 833 microseconds. Filters are provided on both current and voltage inputs to remove any DC offsets. Comprehensive tests have been carried out on a computer based power system simulator on which the effect of travelling waves etc., on the relay performance can be measured. The operating time achieved was approximately 10 ms over a wide range of system conditions.

14.6.3 General

Although the hardware and software design have been shown to satisfy the technical requirements of high speed distance protection the present cost of the hardware results in the cost/performance ratio being higher than non computer based equipment.

14.6.4 Planned Future Work

To put the equipment on site to gain experience and also investigate other possible applications of microcomputers for protection functions. A microprocessor based overcurrent relay is already commercially available and a design of a universal two input relay suitable for many applications such as directional control, power measurement, etc., looks very promising.

PROJECT 15

15.1 Project Name - Microcomputer Based Overcurrent Relay

15.2 Participating Companies - GEC Measurements, Stafford, U.K., plus several utilities.

15.3 Where Installed - Several distribution substations worldwide

15.4 Type Installation - Regular Operating Installations

15.5 Actual Duration of Field Experience - First installation 1983, 20 equipment years cumulative.

15.6 Synopsis of Project

Static relays using analogue techniques to derive the various current/time characteristics have been used for overcurrent protection for a number of years. The use of digital relays for this application has been limited due to relatively high cost and complexity of the analogue to digital conversion.

The availability of low cost microprocessors with analogue-digital convertors on chip has enabled a cost effective design to be produced having a number of significant advantages over previous designs.

Seven different time/current curves are available on the one relay selectable by D.I.L. switches on the relay nameplate. The programme which is in a masked PROM is broadly divided into three sections. The derivation of the current/time characteristic, the high set characteristic and the reading of the relay setting controls which are all achieved by D.I.L. switches.

PROJECT 16

16.1 Project Name - Wave Differential Based Protection System

16.2 Participating Companies - GEC Measurements, Stafford, U.K., plus University of Bath, U.K..

16.3 Where Installed - GEC Measurements Laboratory

16.4 Type Installation - Laboratory demonstration prior to field demonstration.

16.5 Planned Duration of Field Experience

Extended testing on computer based simulator has been completed. Field trials due to start mid 1983 at ? kV.

16.6 Synopsis of Project

To demonstrate the feasibility of the Directional Wave Detection Technique for the protection of two and multi-ended transmission lines.

Every component, both transient and steady state, within the system voltages and currents is utilized to determine the status of the circuit so that directional measurement is still true even if a particular system fault does not generate a significant travelling wave.

The principal innovation is a specially adapted decision logic process that is able to distinguish noise from genuine signal changes generated by system faults.

The relay utilizes a Motorola MC68000 16 bit microprocessor. The sampling rate is 4kHz.

Comprehensive tests have been carried out on a computer based power system simulator prior to site trials planned to start on the CEGB system mid 1983.

PROJECT 17

17.1 Project Name - CDCR (Current Differential Carrier Relaying) System for EHV lines

17.2 Participating Companies
Tokyo Electric Company
Toshiba Corporation
Hitachi Ltd

17.3 Where Installed - 4 Transmission Lines of Tokyo Electric Power Company

17.4 Type Installation
2 Field Tests and 2 Operating Installations

17.5 Actual Duration of Field Experience

2 field tests at 275 kV (July 1977 - April 1978, October 1982 - October 1983)
2 operating installations - at 275 kV April 1980 to date - at 500 kV January 1981 to date.

17.6 Synopsis of Project

In TEPCO, multi-terminal transmission lines and long-distance heavy-load transmission lines have been constructed to keep the satisfactory interconnection between generating areas and dense load areas.

Conventional relaying systems, such as directional, or phase comparison carrier relaying systems, cannot protect the above mentioned transmission lines sufficiently. To solve this problem, the CDCR has been developed.

In this relaying system, a high speed microcomputer calculates to detect the fault by the method of current differential principle with digitized current data which are sampled simultaneously at a fixed time interval and transmitted by using pulse code modulation via microwave

channels to each other terminal. Furthermore, automatic checking and monitoring methods are fully adopted.

During field tests, correct operations were achieved for one internal fault and three external faults with no failure in system equipment.

As the CDCR has been confirmed to have high performance, and reliability through the field test, and the CDCR can protect multi-terminal transmission lines reducing the construction cost of power system, it has been applied as the standard primary protection in TEPCO's 500 kV and 275 kV network.

PROJECT 18

18.1 Project Name - SDCS-I (Substation Digital Control System - I)

18.2 Participating Companies

The Kansai Electric Power Company, Inc
Mitsubishi Electric Corporation

18.3 Where Installed - Nasuzukuri Substation of Kansai Electric Power Company (Hirakata-C, Osaka)

18.4 Type Installation - Field Experiment

18.5 Actual Duration of Field Experience - December 1977 to March 1980.

18.6 Synopsis of Project

SDCS-I was produced for field experience to make sure of operational reliability, space factor, and maintainability when accomplishing total integrated automation functions of distribution substation, with hierarchical multi-micro-processor system.

18.6.1 System Functions

Protection

- 6.6 kV bus-bar
- 6.6 kV distribution line
- 77 kV bus-bar
- 77 kV/6.6 kV transformer

Control

- CB,LS, transformers tap individual operation
- pattern operation
- automatic restoration from transformer fault
- voltage regulation with transformer tap-changing
- 77 kV line switching for automatic restoration to live line
- automatic reclosing of distribution line

Measuring

- A, V, Vo and WH
- demand
- fault location

Monitoring

- CB,LS status
- Vo
- bus-bar voltage
- input data checking
- digital relay operation
- system self-monitoring

Data Transmission

- Sending

- supervision and telemeter data for telecontrol
- telemeter data for management use
- supervision and telemeter data for fault analysis

- Receiving

- automatic control setting data
- remote control signal

During field test period, protective functions operated correctly for every interval fault (8 ground faults, 2 phase faults). In addition monitoring, measuring, control and data transmission functions operated correctly.

PROJECT 19

19.1 Project Name - SDCS-II (Substation Digital Control System - II)

19.2 Participating Companies

The Kansai Electric Power Company, Inc
Mitsubishi Electric Corporation

19.3 Where Installed - Hiraike Substation of Kansai Electric Power Company

19.4 Type Installation - Temporary operating installation

19.5 Actual Duration of Field Experience - May 1981 to March 1983.

19.6 Synopsis of Project

SDCS-II was produced for practical use based on experience of SDCS-I with improvement of H/W structure and functions from viewpoint of cost-performances.

19.6.1 Maximum System Specification for Application

77 kV power : receiving line, 2 ccts; sending line, 2 ccts; main transformer 77 kV/6.6 kV, 3 banks. 6.6 kV distribution line, 8 feeders x 3 banks = 24 feeders.

19.6.2 Functions

Protection

- 77 kV auto. Thrower
- 77 kV bus-bar
- Main transformer
- 6.6 kV distribution lines

Control

- Automatic voltage regulation (LDC/program control)
- 6.6 kV line automatic reclosing
- Autoselective CB operation for short circuit of distribution line
- Autoselective CB operation for continuous ground on distribution line
- CB,LS transformer tap individual operation (remote/direct)

Measuring

- A, V, Vo, WH
- Demand
- Fault location
- Current logging of distribution line

Monitoring

- Annunciation of system operation - fault annunciation

Data transmission

- For remote monitoring
- For remote control

SDCS-II has faithfully accomplished its functions. Protection functions operated correctly for four internal power system faults (2-77 kV line phase faults, 1-6.6 kV feeder phase fault and 1-6.6 kV feeder ground fault). The system cost is equal with the conventional one, even at the present time, and will become more favorable in the future. The performance of maintenance operation and reliability have been recognized to be excellent together with the easier work for increasing functions, expansion and modification.

We are investigating how to reach to practical application of this system, considering the introduction of high level monitoring and control system into substation functions which will become necessary in the future.

PROJECT 20

20.1 Project Name - GRCZ (Ground Relaying With Countermeasure Zero-Phase-Sequence Circulating Current)

20.2 Participating Companies

Tokyo Electric Power Company - Japan
Meidensha Electric Manufacturing Company - Japan

2.3 Where Installed

66 kV Hakone lines at Nishi-Sagami Sub (field experiment)
66 kV Higashi - Izu lines at Tagata Sub (Operating)

20.4 Type Installation - Field experiment
- Operating installation

20.5 Actual Duration of Field Experience

Field experiment January 1979 to January 1980
Operating installation - June 1982 to date

20.6 Synopsis of Project

In Japan, the layout of multiple transmission lines on a common tower has been introduced due to difficulty in obtaining the right-of-way of towers.

In these transmission lines, the load currents may induce a considerable amount of the zero-phase-sequence circulating current. In Japan, 66 kV power systems are neutral grounded through high resistance.

Therefore, 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.

This new type relaying system has been developed so that it will be applied commonly to the various types of 66 kV multiple transmission lines on a common tower. It is more applicable than a conventional type relaying system.

The detection of the single phase to ground fault has been executed with microprocessors. Automatic checking and monitoring methods are also included in this system. During field test, correct operations were achieved for 3 internal faults and 13 external faults. One component failure in PROM occurred. This component failure was detected by built-in diagnostic system with no incorrect operation.

This system will be widely applied in the near future for improving the protection reliability of the multiple transmission lines.

PROJECT 21

21.1 Project Name - Back-up Digital Relaying for UHV Systems

21.2 Participating Companies

Chubu Electric Power Company
Hitachi, Mitsubishi, and Toshiba Electrical Manufacturers - Japan

21.3 Where Installed

Chubu Electric Power Company, Inc
- Tobu 500 kV Substation (20 miles east of Nagoya)
- Hokubu 500 kV Substation (25 miles north of Nagoya)
- Seibu 500 kV Substation (20 miles west of Nagoya)

21.4 Type Installation - Temporary demonstration

21.5 Actual Duration of Field Experience - June 28, 1979 to March 4, 1980.

21.6 Synopsis of Project

Microprocessor-based digital relays are useful for improvement of calculation performance, manpower-saving in maintenance, space-saving and cost-saving by standardization of hardware. Then we are expecting much of them as the future protection relays.

For the following reasons, we manufactured the digital back-up protective relaying equipments for 500 kV power systems as the first object of study and made a field demonstration.

- The digital relays could make kinds of characteristic (resistance, reactance, etc.) from same data (voltage and current)
- The conventional back-up protective relaying equipment require much trouble to maintain and so digitalization of them had much effect on manpower-saving in maintenance
- The number of relay panels could be reduced to 1/4
- The distance relaying (=back-up relaying) was a basis of protective relaying and easily developed into others.

During the field experience there were 48 power system faults and the equipment operated correctly for all of them. This showed they were worth using in practice. There were 6 equipment problems during these 250 days. The problems were detected and alarmed by self-diagnostic functions via microcomputers. The equipment was out of service for investigation a total of 12 days.

By means of this field experience we demonstrated sufficiently the protective performance of the digital relays. Judging from recent rapid progress of techniques, we think it feasible to expand the application of digital relays in about 1985 from the view-point of technology and economy. Until that time, we will proceed with the standardization of digital relays and establish the maintenance philosophy for digital relays.

To accelerate this work, we will apply the digital relays in 3 stations for practical use in 1983. (1 x 77 kV main protection, 2 x 154 kV back-up protection).

PROJECT 22

22.1 Project Name - Directional Comparison Line Relaying.

22.2 Participating Companies

Kansai Electric Power Company, Inc., Osaka, Japan
Mitsubishi Electric Corporation, Kobe, Japan

22.3 Where Installed

Kansai Electric Company Inc.
- Kitakata Switching Station (in western suburbs of Gifu City)

- Osaka Switching Station (15 miles south of Takayama city)

22.4 Type Installation - Temporary operating installation

22.5 Actual Duration of Field Experience - June 1980 - August 1981

22.6 Synopsis of Project

A microprocessor based system for a two terminal directional comparison relaying was developed and installed at terminals of 154 kV 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.

We are planning, for the next step, the practical use at the minor transmission line system after 1984 to enrich the technical experience about maintenance, operation, treatment to the system failure, software management, etc.

PROJECT 23

23.1 Project Name - DFL (Digital Fault Locator)

23.2 Participating Companies

Tokyo Electric Power Company - Japan
Toshiba Corporation, Tokyo - Japan

23.3 Where Installed - 275 kV Naka-Tokyo line at Shinanogawa Power Station.

23.4 Type Installation - Field experiment

23.5 Actual Duration of Field Experience - November 1980 - September 1982

23.6 Synopsis of Project

In a trunk transmission line, it is very important to detect a fault point accurately in spite of high arc resistance, which prevents accurate location by a conventional fault locator.

This system, that calculates a reactance of faulty line from the one-terminal voltage and

current data, has been developed using a micro-processor. In this system, errors caused by various factors such as fault resistance, load flow, unbalanced self and mutual impedances are automatically corrected by an efficient use of software.

The equipment was tested at 275 kV Naka-Tokyo line which is 71.2 km long and consists of two parallel transmission lines. The long term field test of the DFL, using these newly developed methods, showed outstandingly accurate locating results against 10 system faults.

As the DFS can be easily realized by only preparing CT and VT signals of one-terminal, gaining system cost reduction and high accuracy, it will be surely used in the trunk transmission lines widely in the very near future.

PROJECT 24

24.1 Project Name - 154 / 66 kV Line Relaying

24.2 Participating Companies

Tokyo Electric Company, Tokyo, Japan
Fuji, Hitachi, Meidensha, Mitsubishi, and Toshiba Electrical Manufacturers of Japan.

24.3 Where Installed - Substations of Tokyo Electric Company

24.4 Type Installation

- 4 field tests (3 at 66 kV, 1 at 154 kV)
- 4 operating installations at 66 kV

24.5 Actual Duration of Field Experience - May 1981 to March 1983

24.6 Synopsis of Project

This relaying system has been developed to meet the expected future needs, for example, reduction of maintenance, shortage of installation space, and improved functional characteristics.

As primary protection, a balance relaying method for parallel transmission lines has been applied. The back-up protection is also included. In this relaying system the detection of faults are all calculated by microprocessor with digitized data which is sampled 12 times per cycle. Furthermore, automatic checking and monitoring methods are fully adopted.

During field tests, correct operations were achieved for 16 internal faults and 88 external faults, though one component failure in RAM and one in ROM occurred. These two component failures were detected by built-in diagnosis system, causing no incorrect operation.

This system will be widely applied on future heavily loaded 66 kV transmission lines which are very difficult to protect, and which will be more economical because of saving of relaying space and reduction of maintenance vs conventional relaying systems.

PROJECT 25

25.1 Project Name - 77 kV Local Back-up Relaying

25.2 Participating Companies -

The Kansai Electric Power company Inc.
Mitsubishi Electric Corporation, Toshiba Corpora-

tion, Hitachi Ltd.
Nissin Electric Co.

25.3 Where Installed - 5 substations such as Konan Substation of the Kansai Electric Power Company Inc.

25.4 Type Installation - Operating installation

25.5 Actual Duration of Field Experience - from June 1981 up to this day

25.6 Synopsis of Project

25.6.1 Functions

- a. Detection of continuance of line fault - After detecting the continuance of line fault due to CB failure or relay equipment failure, this system gives the alarm and indication of a faulty line.
- b. Record and analysis of system fault - At the fault occurrence, this system prints out bus voltage, fault current, the response of the system and calculates the fault location.
- c. Back-up protection - This system can be used for the temporary time protection, in place of the existing relay equipment under locking operation.

25.6.2 System Specification

- This system has three parts, main relaying, fail-safe relaying, and recording, each of which has an independent microprocessor.
- The main relaying detects system faults with the function of phase distance relay and ground directional relay.
- The main relaying has the ability of dealing with 4 line circuits, and the fail-safe part has the ability of dealing with 8 circuits with each one CPU, which output is based on plural (3 times) calculation checks.
- This system at every substation executes alarm, indication and recording functions under simultaneous multi-faults of 20 circuits.
- This system is composed of 3 panels for the power system of 4-section bus and 20 circuits of 77 kV line.
- The fault records, from occurrence to elimination, are printed out successively for every circuit, including simultaneous multi-faults.

25.6.3 Operating Results

For the 5 systems, 139 correct operations have resulted totally with no incorrect operation.

Fault analysis accuracy and operation efficiency has been proved to be excellent for the complicated fault such as multi-fault and evolving fault, which is difficult to be analyzed by means of a traditional oscillograph

PROJECT 26

26.1 Project Name - Integrated Control equipment

26.2 Participating Companies -

Swedish State Power Board
ASEA
South Swedish Power Company

26.3 Where Installed - SSSB 220/70 kV substation (commissioned July 1983)

26.4 Type Installation - Operating pilot installation

26.5 Actual Duration of Field Experience - Planned for mid 1983

26.6 Synopsis of Project

The aim of the project has been to develop an integrated control system for transmission substations.

The project started to determine and analyze the requirements which must be set on a computerized control system. The following are the most important requirements :

- each substation must be autonomous;
- must be able to withstand the electrical and physical environment;
- must be economically competitive with the conventional equipment (installed);
- application programming must be easy for personnel without programming experience;
- the system must have high availability

The system will perform the following main functions :

- Control
- Alarm
- Datalogging
- Communication with remote control center

The protection function is not integrated into the microcomputer system. The reasons include (a) Protective relays set high requirements on processing times and reliability, (b) Integration of all protective functions represents too great a step. It has therefore been decided to omit protection at this stage. Computerized protective relays are studied in a separate project, with the same participating companies and the target is set on field installation in mid 1985.

The control equipment is hierarchically arranged in two levels. The control and supervision of the substation is coordinated at the higher level(substation level). From the lower level, (unit level), individual lines, transformers, etc. are controlled and supervised. Unit control is performed by a number of dedicated control modules. This subdivision greatly simplifies future expansion such as installation of an additional line. It also improves the availability since a fault only affects a part of the control equipment.

PROJECT 27

27.1 Project Name - Prodar 70 Computer Relaying System for Transmission Lines

27.2 Participating Companies

Westinghouse Electric Corporation, Newark, NJ (now at Coral Springs, FL)
Pacific Gas & Electric Company, San Francisco, CA

27.3 Where Installed - Tesla 500/230 kV Substation of PG&E Co., Tracy, CA

27.4 Type Installation - Temporary Demonstration

27.5 Actual Duration of Field Experience - Approx. seven years, from February 1972 to early 1979.

27.6 Synopsis of Project

This development was undertaken when the technology of digital protection was undeveloped and there was no field experience with computer-based relays. The objectives were to devise technical approaches and to assess the benefits and limitations of computer relaying through an experimental installation. The project did not focus on economics or the design of a commercial prototype.

Prodar 70 Provided non-pilot 3-zone ground- and phase-distance protection for a single 38-mile, 230 kV transmission line. Programs included memory-based directional sensing for collapsed-voltage-phase faults associated with nearby 500 kV series capacitors. Ancillary software provided breaker failure detection, reclosing, hardware self-checking and extensive logging of program performance and fault data.

The system was configured around a Westinghouse P-2000 16 bit industrial minicomputer with 16 K words of magnetic core memory. Peripheral hardware included a programmer's console interface, specially-designed high-speed A/D conversion subsystem with analog signal conditioning package, high-speed thyristor control outputs, and UPS for station-battery operation.

The Prodar 70 System received extensive factory casting, including model power system tests. The field demonstration included staged faults, to which the protection responded well. In seven years of field service, Prodar 70 has correctly responded to hundreds of disturbances and has yielded trip outputs for 12 natural internal faults. Prodar 70

Prodar 70 has never false-tripped in the field, and hardware reliability has been excellent.

PROJECT 28

28.1 Project Name - PROBE

28.2 Participating Companies

General Electric Company, Malvern PA
Commonwealth Edison Company, Chicago, IL
Niagara Mohawk Power Corporation, Syracuse, NY
Public Service Electric and Gas Company, Newark, NJ

28.3 Where Installed - La Grange Park 138-12 kV Substation of Commonwealth Edison Company

28.4 Type Installation - Temporary Demonstration

28.5 Actual Duration of Field Experience - October 1976 - June 1980

28.6 Synopsis of Project

28.6.1 Objectives

- Determining and defining the automation functional specifications
- Developing and verifying a common integrated digital data base

28.6.2 Functions

Thirteen functions were demonstrated, including protection, control, and monitoring, both within the substation and out on the 12 kV feeders.

28.6.3 Digital Equipment

The digital equipment varied from the commercially available minicomputers (Varian V72 and Varian V77) to specially designed microprogrammed preprocessing units, microprocessor-based feeder remote units, and a microprocessor-based feeder simulator. The equipment was selected to readily demonstrate the digital implementation of functions, but not to demonstrate hardware reliability, modularity, or maintainability.

PROBE was connected to 32 analog inputs and 112 status inputs from La Grange Park Substation and provided 24 control outputs to the substation for closing and tripping of breakers and switches and controlling transformers LTC. Analog inputs

derived from wave form sampling, field testing from 4 to 32 samples per cycle were evaluated, most were at 16 samples per cycle. Both distribution line carrier and radio were used for two-way distribution communication between PROBE and experimental microprocessor-based feeder remote units at feeder sectionalizing and capacitor bank switches on two 12 kV feeders.

28.6.4 Results

The PROBE demonstrations verified the technical feasibility of an integrated digital systems approach to distribution substation and feeder automation.

- a. The original system architecture was viable and has been improved
- b. The digital equipment and data base was shown to be immune to substation surges and transients and maintainable in real-time.

Results from this project are being utilized and improved in EPRI RP-1472-1, see project 32 in this Appendix.

PROJECT 29

29.1 Project Name - DIPS (Digital Integrated Protection System)

29.2 Participating Companies

General Electric Co - Power Systems Mgmt. Dept.
Malvern, PA
Philadelphia Electric Company, Philadelphia, PA

29.3 Where Installed

Philadelphia Electric Company
Whitpain Substation (in northern suburbs of Philadelphia, PA)
Peach Bottom Generating Station (65 miles SE of Philadelphia, PA)

29.4 Type Installation - Temporary demonstration

29.5 Actual Duration of Field Experience - 6/22/77 to 6/30/78.

29.6 Synopsis of Project

To demonstrate the technical feasibility, and the algorithm (but not the hardware) for digital relaying of a 550 kV line, 116 km in length. This digital protection system used a directional comparison blocking scheme for its tripping logic, with conventional power line carrier communication between the two line terminals. The digital equipment sampled voltages and currents 16 times per cycle, samples were derived from conventional current and voltage transformers. Digital techniques were utilized to determine the type of fault, and distance to the fault, the algorithm calculates R and L to the fault as a function of the current, and the rate of change of current.

During the field test there were no false trips and external power system faults resulted in 15 correct blocking operations. The equipment performed correctly for 3 staged faults on the protected line on April 6, 1978. The project successfully demonstrated the feasibility and performance of digital techniques for transmission line protection. The system as installed in the field operated with speed and security comparable to that of present advanced relaying systems.

At the onset of the project, it was decided to use commercially available digital equipment, even though it was recognized that such equipment

may not be suitable for operation in a power substation environment. The commercially available mini-computer equipment utilized were Varian type V72 16K core, 660 Nano-sec cycle time and Varian type V73, 16K core, 330 Nano-sec cycle time. During the 374 days of the field investigation, the Whip-pain terminal was on-line 314 days and the Peach Bottom terminal was on-line 302 days.

29.6.1 Future Plans

Planned future activity is to extend digital techniques to other protective relaying applications, to control and monitoring functions, and to develop reliable, cost effective digital equipment for distributed hierarchical configurations in transmission substations. Results from this project are being utilized and improved in EPRI RP-1359-5, see project 31 in this Appendix.

PROJECT 30

30.1 Project Name - Substation Computer Project and SCDR (Symmetrical Component Distance Relay)

30.2 Participating Company - American Electric Power Service Corp. - New York City.

30.3 Where Installed

Kammer Sub - Ohio Electric Power Company
Matt Funk Sub - Appalachian Pwr Co.

30.4 Type Installation - Operating demonstration at Matt Funk Sub; field test at Kammer Sub.

30.5 Actual Duration of Field Experience

7/80-Present time at Matt Funk 345-138 kV sub of Appalachian Pwr Co., Roanoke, VA. Two weeks in April 1979 at Kammer 765 kV substation of Ohio Power Company, near Wheeling, West Virginia. Preceded by laboratory testing and 1975 field testing of previous algorithm and IBM system 7 minicomputer hardware.

30.6 Synopsis of Project

To demonstrate feasibility of digital relaying a 765 kV 151 mile line and a 138 kV 40 mile line.

This digital protection system uses a direction comparison, 3 zone step distance blocking scheme for its tripping logic, with conventional power line carrier communication between the two line terminals. Digital techniques are utilized to determine the type of fault, and distance to the fault, using an algorithm based on symmetrical components. The digital equipment samples voltages and currents 12 times per cycle from conventional current and voltage transformers. Equipment utilized : for SCDR : Plessey MIPROC-16 processor; for substation host computer : PDP 11/03. To evaluate other equipment at the Kammer substation plus this digital distance relaying equipment, 31 staged 765 kV faults were imposed at the remote end of the 151 mile line.

30.6.1 Conclusions from Field Tests at Kammer Substation

- Symmetrical component distance relay performed well. The average operating speed for Zone-1 faults was observed to be about 1/2 cycle.
- Accurate fault location calculations are achieved, as they use fault waveform data obtained up to the time of fault clearing.

30.6.2 Conclusions from Analysis Subsequent to the Kammer Tests

- An ultra-high-speed mode of operation of this relay has been demonstrated using an off-line program operating on real time data. Average response time for the UHS mode is shown to be one-quarter of one cycle.
- When the load currents are comparable to fault currents, it has been experimentally verified that the factor K1 in the operating equation of the SCDR correctly accounts for the pre-fault load effects.

30.6.3 Future Plans

To be defined after further field experience is obtained at Matt Funk Sub.

PROJECT 31

31.1 Project Name - DTLPCS (Digital Transm. Line Prot. and Cont. System)

31.2 Participating Companies

Electric Power Research Institute - Palo Alto, CA (RP - 1359 - 5)
General Electric Co., Malvern, PA
Public Service Electric and Gas Co., Newark, NJ

31.3 Where Installed - Deans Substation and Branchburg Substation of P.S.E. & G.

31.4 Type Installation - Temporary demonstration

31.5 Actual Duration of Field Experience

Laboratory and simulator testing completed in 1983
Field Operation January 1984-1985

31.6 Synopsis of Project

Demonstration of hierarchical digital system consisting of specifically designed microprocessor based modules to protect a 20 mile 500 kV line. This program is a continuation of the effort started under the DIPS project 29.

31.6.1 Initial Equipment

- Digital protection modules
- Data acquisition and control systems (2 located in control houses, one remote at 500 kV breaker and interconnected via fiber-optics to associated protection module)

31.6.2 Initial Control Functions

- Automatic reclosing
- Synchronism check

Future Systems

- Automatic transformer LTC control

31.6.3 Initial Projective Functions

- Transmission line protection (in directional comparison blocking scheme)
- out of step blocking
- Breaker failure

Future Systems

- Transformer protection
- Bus protection

31.6.4 Initial Monitoring Functions

- Voltage, current
- Self test and diagnostics
- Pilot channel (carrier current)
- Fault reports

Future Systems

- Transformer loading,
- transformer loss of line
- transformer auxiliaries
- Power system trends
- Breaker health

- 31.6.5 Initial Interface to
- Power line carrier
 - Existing local and remote control
- Future Systems
- SCADA
 - Remote EMS

PROJECT 32

32.1 Project Name

ICPDS (Integrated Control and Protection of Distribution Substation and System)

32.2 Participating Companies

Electric Power Research Institute - Palo Alto, CA (RP - 1472 - 1)
 General Electric Company, Malvern, PA
 Texas Electric Service Company - Ft. Worth, TX

32.3 Where Installed - Handley Substation of TESCO - Ft. Worth, TX

32.4 Type Installation - Temporary demonstration

32.5 Planned Duration of Field Experience

Laboratory and stimulator testing to be completed 9/1984.
 Partial field operation 3/1984-9/1984, full field operation 9/1984-1985.

32.6 Synopsis of Project

Demonstration of digital protection, control and automation system consisting of following specifically designed hierarchical system of micro-processor based modules to be installed, tested and operated in a 138-12.5 kV distribution substation. This program is a continuation of the effort started under the PROBE project 5.28.

32.6.1 Equipment

- substation integration module
- 11 data acquisition & control systems
- 4 protection modules
- 15 feeder remote units

32.6.2 Control Functions

- feeder fault deployment switching and service restoration
- integrated volt/var control
- automatic bus sectionalizing

32.6.3 Protective Functions

- time overcurrent
- instantaneous overcurrent
- synchronism check
- underfrequency
- breaker failure
- automatic breaker reclosing

32.6.4 Data Acquisition and Processing Functions

- data acquisition
- data monitoring and logging
- data validity checking
- alarm
- sequence of events
- status

32.6.5 Interface To

- remote SCADA/DDC interface (through existing GE/TAC system)
- local substation user via color CRT/keyboard
- distribution communication system (telephone lines to remote FRU's, future distribution line carrier)

- conventional relays and overlapping protection
- future load management and automatic meter reading

PROJECT 33

33.1 Project Name - Substation Digital Control and Protection System

33.2 Participating Companies

Electric Power Research Institute (EPRI), Palo Alto, CA (RP - 1359 - 1 and - 7)
 Westinghouse Electric Corporation, Pittsburg, PA
 Public Service Electric and Gas (PSE&G) Company, Newark, NJ

33.3 Where Installed - Deans & Branchburg 500 kV Substations of PSE&G Company

33.4 Type Installation - Operating demonstration

33.5 Actual Duration of Field Experience - Extended period following 1984 installations

33.6 Synopsis of Project

A major cooperative effort of EPRI, several Westinghouse divisions, and six advisory utilities including host PSE&G Company is producing a commercial prototype integrated digital system which performs all of the relaying and control functions for a transmission-level substation.

System hardware is configured in a three-level hierarchy. A number of Data Acquisition Units (DAU's) are located in the switchyard, where they connect to analog and status signals as well as control circuits of power apparatus. An optical-fiber serial digital data link connects each DAU to one or more clusters of high-speed protection and control processors. These protection clusters (PC's) are located in the control house, with one PC associated with each zone of protection. The PC's in turn are all connected via a serial multidrop coaxial-cable data highway to a station computer (SC) cluster, also in the control, plus local-operator and remote interfaces.

Switchyard data is sampled every millisecond by the DAU's and sent via the optical links to the PC's, which execute high speed relaying and control programs. Control commands are also returned to the apparatus via the optical links.

The PC's send processed analog, status, and event information over the data highway to the SC to support data-base, display, and overall-station control functions. Operator or remote control commands pass through the SC to the PC's, where they are processed and transmitted to the appropriate DAU's.

The laboratory phase of the project, completed in 1982, led to demonstration of an integrated hardware/software system. The following list of functions is to be provided for the 1984 field installation :

- Pilot protection of transmission line
- Transformer protection
- Bus protection
- Breaker failure protection
- Breaker and ct-module ground protection
- Monitoring and control of circuit breakers and switches
- Transfer-tripping
- Channels monitoring of pilot and T-T
- Automatic reclosing
- Synchronism checking

- Automatic switching sequences
- Transformer overload monitoring
- Oscillography
- Local-operator interface
- Event recording and alarming
- Line-fault location
- Remote SCADA interface

APPENDIX II B - BIBLIOGRAPHY

PROJECT 1

1.1. Project Name - DDPS (Digital Distance Protection System)

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2.1. Project Name - SACS (Substation Automated Control System)

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3. "Problems of Electromagnetic Capability Between Auxiliary Circuits and the High Tension of EHV Substations".
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8. P. Van Miegroet, "Substation Computers - Actual Practice and Trends in Belgium", CIGRE Study Committee No 34 Colloquium, Tokyo, Japan, November 1983.

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4.7. Published Papers/Articles/Reports That Give Added Information

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- 8.7. Published Papers/Articles/Reports That Give Added Information
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PROJECT 9

- 9.1. Project Name - DPFS (Digital Protection and Fault-Recording System)
- 9.7. Published Papers/Articles/Reports That Give Added Information
- 1.

PROJECT 10

- 10.1. Project Name
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PROJECT 11

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- 11.7. Published Papers/Articles/Reports That Give Added Information
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 2. "Application of Microcomputer Based Equipment for Data Collection and Control of Power System Equipment". IEE (India) Conference on Power System Protection, 1980.

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- 13.7. Published Papers/Articles/Reports That Give Added Information
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 2. M.A. Redfern, M.M. Elkateb and E.P. Walker, "An Investigation into the Effects of Travelling Wave Phenomena on the Performance of a Distance Relay". IEE Conference Publication Number 185.
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- 14.1. Project Name - Multiprocessor Distance Relay System
- 14.7. Published Papers/Articles/Reports That Give Added Information
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- 15.1. Project Name - Microcomputer Based Overcurrent Relay
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- 16.1. Project Name - Wave Differential Based Protection System
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 2. Johns and Aggarwal, "New Ultra High Speed Directional Blocking Scheme", IEE Conference Publication Number 185, 1980.
 3. Johns and Baker, "Wave Differential Protection for Sequential Faults Clearance", UPEC Proceedings 1981.

PROJECT 1717.1 Project Name

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2. Y. Akimoto, M. Yamaura, T. Matsushima, "Digital Current Differential Carrier Relaying System for EHV Transmission Line". 1981 IFAC Paper CS-2.3.1.
3. T. Takagi, Y. Yamakosi, M. Yamaura, R. Kondow, T. Matsushima, M. Masui "Digital Differential Relaying System for Transmission Line Primary Protection Using Travelling Wave Theory - Its Theory and Field Experience". 1979 IEEE A79096-9.

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15. A.G. Phadke, S.H. Horowitz, J.S. Thorp, "Integrated Computer System for Protection and Control of High Voltage Substations". CIGRE Study Committee No 34 Colloquium, Tokyo, Japan, November 1983.
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PROJECT 31

31.1 Project Name

DTLPCS (Digital Transmission Line Protection and Control System)

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2. "Substation Control and Protection Project, System Requirement Specification", EPRI Report EL-1813, April 1981.

PROJECT 32

32.1. Project Name

ICPDS (Integrated Control and Protection of Distribution Substation and Systems)

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