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Final Report

Wide Area Protection and Emergency Control

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Introduction

System-wide disturbances in power systems are a challenging problem for the utility industry because of the large scale and the complexity of the power system. When a major power system disturbance occurs, protection and control actions are required to stop the power system degradation, restore the system to a normal state, and minimize the impact of the disturbance. The present control actions are not designed for a fast-developing disturbance and may be too slow. Further, dynamic simulation software is applicable only for off-line analysis. The operator must therefore deal with a very complex situation and rely on heuristic solutions and policies. Today, local automatic actions protect the system from the propagation of the fast-developing emergencies. However, local protection systems are not able to consider the overall system, which may be affected by the disturbance.

Most of the time, a modern interconnected electrical power system provides quality electric energy to the customers. Unfortunately, intermittently, the power system is exposed to serious disturbances that lead to the interruption of the power supply to the customers. The planners of the power system try to design reliable systems that are able to cope with probable contingencies. But even for the best planned system, unpredictable events can stress the system beyond the planned limits. Some of the reasons why completely reliable operation cannot be achieved are:

1. Practically an infinite number of possible operating contingencies in modern, interconnected power systems.

2. Unpredictable changes, due to the evolving nature of power systems, generate dynamical changes. Inevitably, the operation of the power system is considerably different from the expectation of the system designers, particularly during an emergency.

3. A combination of unusual and undesired events (for example, human error combined with heavy weather and scheduled or unscheduled maintenance outages of the important system element).

4. Reliability design philosophy that is pushing the system close to the limits brought about by economic and environmental pressures.

While reliability is the concern of system designers, operators deal with system security. Security is an on-line, operational characteristic which describes the ability of the power system to withstand different contingencies without service interruptions. Security is closely related to reliability: an unreliable system cannot be secure. The security level of the power system (desired to be high enough to enable robust operation) changes dynamically as the power system operation changes and depends on the factors outside the control of power system operators (eg. weather).

The trend in power system planning utilizes tight operating margins, with less redundancy, because of new constraints placed by economical and environmental factors. At the same time, addition of non-utility generators and independent power producers, an interchange increase, an increasingly competitive environment, and introduction of FACTS devices make the power system more complex to operate and to control, and, thus, more vulnerable to a disturbance. On the other hand, the advanced measurement and communication technology in wide area monitoring and control, FACTS devices (better tools to control the disturbance), and new paradigms (fuzzy logic and neural networks) may provide better ways to detect and control an emergency.

Better detection and control strategies through the concept of wide area disturbance protection offer a better management of the disturbances and significant opportunity for higher power transfers and operating economies. Wide area disturbance protection is a concept of using system-wide information and sending selected local information to a remote location to counteract propagation of the major disturbances in the power system. With the increased availability of sophisticated computer, communication and measurement technologies, more "intelligent" equipment can be used at the local level to improve the overall emergency response.

The modern energy management system (EMS) is supported by supervisory control and data acquisition (SCADA) software; by numerous power system analysis tools such as state estimation, power flow, optimal power flow, security analysis, transient stability analysis, mid-term to long-term stability analysis; and by such optimization techniques as linear and nonlinear programming. The available time for running these application programs is the limiting factor in applying these tools in a real-time during an emergency, and a trade-off with accuracy is required. The real time optimization software and security assessment and enhancement software do not include dynamics. Further, propagation of a major disturbance is difficult to incorporate into a suitable numerical algorithm, and heuristic procedures may be required. For example, unexpected hidden failures in relaying equipment may cause unexpected multiple contingencies. The experienced and well trained operator can recognize the situation and react properly given sufficient time, but often not reliably or quickly enough. In modern interconnected networks, fast-developing emergency may comprise a wide area. Since operator response may be too slow and non-consistent, local, fast automatic actions are implemented to minimize the impact of the disturbance. Currently, the local automatic actions are conservative, act independently from central control, and prevailing state of the whole affected area is not considered. Furthermore, future power systems will encounter new components (energy storage, load control, and solar power), new systems

(FACTS elements and HV DC integration), as well as regulatory changes (wheeling of power, NUG). An intelligent and adaptive control and protection system for wide area disturbance is needed to make possible full utilization of the power network, which will be less vulnerable to a major disturbance.

Historically, only centralized control was able to apply sophisticated analysis because only at this higher level could computers and communication support be technically and economically justified. However, with the increased availability of sophisticated computer, communication and measurement technologies, more intelligence can now be used at local level. The possibility to close the gap between central and local decisions and actions will depend on the degree of intelligence put in the local subsystems. Decentralized subsystems, that can make local decisions based on local measurements and remote information (system-wide data and emergency control policies) and/or send pre-processed information to higher hierarchical levels are an economical solution to the problem. A major component of the system-wide disturbance protection is the ability to receive system-wide information and commands via the data communication system and to send selected local information to the SCADA center. This information should reflect the prevailing state of the power system.

An Example: WSCC Disturbance - 10 August, 1996

The conditions leading to this incident built up over a period of 1 1/2 hours before the disturbance started. During this preliminary period three 500 kV lines in Washington and Oregon tripped out. Since these lines were not heavily loaded at the time, it was not recognized that the transmission system strength was being dangerously undermined with respect to its ability to withstand another contingency. At the time, there was a large amount of power (4700 MW) being transmitted from Canada and the Pacific Northwest to the California area. The heavy power flow was a result of low energy prices due to the availability of surplus hydroelectric power in Canada and the Pacific Northwest.

The disturbance started when a fourth 500 kV line tripped out due to a fault, with coincident loss of a fifth line due to unusual station configuration at one of the terminals resulting from station equipment being out of service. Loss of these two last lines forced heavy load flow through 230 kV and 115 kV transmission lines underlying the 500 kV system. About 5 minutes later, a 115 kV line tripped due to a faulty relay, and heavy load caused a 230 kV line to sag and flash over to a tree. Generators at McNary hydroelectric power station on the Oregon Washington border to go to full excitation in an attempt to maintain system voltages. Internal problems with the exciters at that station caused the units there to trip out within a minute of each other. Immediately after the generators tripped negatively damped voltage and power oscillations started on the California Oregon Intertie. This tie tripped 27 seconds after the loss of the McNary generators. After the California Oregon intertie tripped, out of step conditions caused a separation of Northern California from Southern California, and other Southern states in the WSCC. The rapid frequency changes and out of step conditions resulted in the loss of a large amount of generation. Although only 4800 MW of transmitted power from North to South was interrupted, an additional 21500 MW of generation in the South was lost resulting in a total loss of load of 27400 MW affecting more than 7 million customers.

When the Pacific Northwest and Canada separated from the rest of the WSCC, the system frequency rose quickly. Overloading of a single 500 kV tie caused the Canadian province of Alberta to separate from the Pacific Northwest island. After separation, the frequency in Alberta declined, resulting in a loss of 1000 MA of load.

In total, 30500 MW of load and 27300 MW of generation was lost, affecting 7.5 million customers over an area reaching 2500 km North to South and 2000 km East to West.

A wide area monitoring scheme could have helped recognize the development of a weak and heavily loaded transmission system which could have been subject to the type of breakup that resulted from negatively damped oscillations between wide areas.

Disturbances: Causes and Remedial Measures

Phenomena that create wide area power system disturbances are divided, among others, into the following categories: angular stability, voltage stability, overloads, power system cascading, etc. They are fought against using a variety of protective relaying and emergency control measures.

Out-of-step protection as it is applied to generators and systems, has the objective to eliminate the possibility of damage to generators as a result of an out-of-step condition. In case the power system separation is imminent, it should take place along boundaries, which will form islands with matching load and generation. Distance relays are often used to provide an out-of-step protection function, whereby they are called upon to provide blocking or tripping signals upon detecting an out-of-step condition.

The most common predictive scheme to combat loss of synchronism is the Equal-Area Criterion and its variations. This method assumes that the power system behaves like a two-machine model where one area oscillates against the rest of the system. Whenever the underlying assumption holds true, the method has potential for fast detection.

Voltage stability is defined by the System Dynamic Performance Subcommittee of the IEEE Power System Engineering Committee [1] as the ability of a system to maintain voltage such that when load admittance is increased, load power will increase, and so that both power and voltage are controllable. Also, voltage collapse is defined as being the process by which voltage instability leads to a very low voltage profile in a significant part of the system.

It is accepted that this instability is caused by the load characteristics, as opposed to the angular instability, which is caused by the rotor dynamics of generators.

The risk of voltage instability increases as the transmission system becomes more heavily loaded. The typical scenario of these instabilities starts with a high system loading, followed by a relay action due to either a fault, a line overload or hitting an excitation limit.

Voltage instability can be alleviated by a combination of the following remedial measures means: adding reactive compensation near load centers, strengthening the transmission lines, varying the operating conditions such as voltage profile and generation dispatch, coordinating relays and controls, and load shedding. Most utilities rely on planning and operation studies to guard against voltage instability. Many utilities utilize localized voltage measurements in order to achieve load shedding as a measure against incipient voltage instability [2].

Outage of one or more power system elements due to the overload may result in overload of other elements in the system. If the overload is not alleviated in time, the process of power system cascading may start, leading to power system separation. When a power system separates, islands with an imbalance between generation and load are formed with a consequence of frequency deviation from the nominal value. If the imbalance cannot be handled by the generators, load or generation shedding is necessary. The separation can also be started by a special protection system or out-of-step relaying.

A quick, simple, and reliable way to re-establish active power balance is to shed load by underfrequency relays. There are a large variety of practices in designing load shedding schemes based on the characteristics of a particular system and the utility practices [3], [4].

While the system frequency is a final result of the power deficiency, the rate of change of frequency is an instantaneous indicator of power deficiency and can enable incipient recognition of the power imbalance. However, change of the machine speed is oscillatory by nature, due to the interaction among generators. These oscillations depend on location of the sensors in the island and the response of the generators. The problems regarding the rate-of-change of frequency function are [5]:

- A smaller system inertia causes a larger peak-to-peak value for oscillations. For the larger peak-to-peak values, enough time must be allowed for the relay to calculate the actual rate-of-change of frequency reliably. Measurements at load buses close to the electrical center of the system are less susceptible to oscillations (smaller peak-to-peak values) and can be used in practical applications. A smaller system inertia causes a higher frequency of oscillations, which enables faster calculation of the actual rate-of-change of frequency. However, it causes faster rate-of-change of frequency, and, consequently, a larger frequency drop.

- Even if rate-of-change of frequency relays measure the average value throughout the network, it is difficult to set them properly, unless typical system boundaries and imbalance can be predicted. If this is the case (eg. industrial and urban systems), the rate of change of frequency relays may improve a load shedding scheme (scheme can be more selective and/or faster).

- Adaptive settings of frequency and frequency derivative relays may enable implementation of a frequency derivative function more effectively and reliably.

Relay Hidden Failures

Protection or relaying systems plays a very important role in events leading to power system blackouts or major disturbances encompassing wide areas. Failures or misoperations in various protection systems are very significant factor in the overall process of reported wide area disturbances. Of all the protection system failures, the ones that remain dormant or hidden until some unusual system events occur are the most important. A reason for that is since failures that lead to an immediate misoperation during normal power system states can be corrected right away and should not be a contributing factor in wide area disturbances.

The abnormal power system states are usually due to faults, heavy load, shortages in reactive power, etc. They can trigger the hidden failures to cause relay misoperations which can worsen the situation since the power systems may already be operated in an emergency state when those abnormal states occur, eventually leading to the wide area disturbances. A better understanding of the hidden failures is required to prevent or at least reduce the likelihood of the occurrence of the wide area disturbances due to the hidden failures.

Commonly used transmission relaying systems have been studied to identify possible hidden failures and their consequences on the power systems. A concept of region of vulnerability associated with each mode of hidden failure has been proposed. It is the region in which the hidden failure can cause a relay to incorrectly trip its associated circuit breaker. The relative importance of each region of vulnerability, called vulnerability index, is computed using steady-state and transient stability criteria. A larger value of the vulnerability index indicates that the relay, in which if that hidden failure mode exists, is relatively more important and can cause more serious wide area disturbances or has a higher possibility to cause the disturbances than the one with a smaller index. Therefore, more attention should be paid to those key relays to prevent the hidden failure and its consequences. A scheme of digital monitoring and control system is proposed for that task.

The analysis of North American Electric Reliability Council Disturbance Reports showed that around 70% of the reported wide area disturbances involved relaying systems or special protection systems. The involvement of the protection systems does not necessarily mean that they initiated the disturbances. Most of the disturbances were, however, initiated by some abnormal power system states due to severe weather, device failures, human errors, faults, heavy load, reactive power shortages, etc. The subsequent misoperations of the protection systems then further degraded the power system states and eventually caused the wide area disturbances. In other words, the hidden failures in the protection systems that had not been seen or detected prior to the disturbances were triggered by the abnormal events and caused the protection systems to misoperate.

A failure that results in an immediate trip without any prior events is not considered a hidden failure. The power system must be planned and operated to withstand the loss of any single element without exceeding the NERC criteria for reporting a disturbance. A hardware failure that results in a relay failing to operate its breaker and trip out a faulted line or device is also not considered a hidden failure since its backup protection must normally be provided for such contingency. A defect or malfunction that occurs at the instant of a fault or switching event, e.g., a hole in the blocking signal or an insulation failure caused by a surge, is similarly not considered a hidden failure since such a failure is not permanent and cannot be monitored or detected before hand.

After the regions of vulnerability have been identified, the next step is to calculate the relative importance of each region, called vulnerability index. One of the measurements that can be used to determine this index is the stability or instability of the system following some power system contingencies: one caused by normal operations of healthy primary relays to clear a fault, and the other by the misoperation of a relay with a hidden failure.

One indication that the steady-stability limit is violated is the lack of a load flow solution. This can be determined by performing load flow calculations until no solution can be found. This process is time-consuming and it does not indicate how stable or unstable the system is.

It has been observed that of all the reported cases of major system blackouts (wide area disturbances) in North America, about 70% of the cases have relay system contributing to the initiation or evolution of the disturbance. On closer examination, it became clear that one of the major components of relay system misoperations is the presence of relays which have failed during service, and their failure is not known. Consequently, there is no alarm, and no repairs or replacements are possible. These *hidden failures* are different from straight relay misoperations, or failures which lead to an immediate trip. The hidden failures remain undetected (and substantially undetectable), until the power system becomes stressed, leading to an operating condition which exposes the hidden relay failures. For example, a common hidden failure mode may be an incorrect trip function supervised by a fault detector. If the system loading is not high enough to cause a pick up of the fault detector, the hidden failure of such a relay would not be exposed. On the other hand, during a stressed state, the fault detector could pick up, and now the hidden failure of the trip function would cause a false trip. The elements of the underlying theory of the hidden failures are presented in Appendix B.

Technology Issues in Wide Area Protection

Monitoring and Protection for Wide Area Disturbances

The disturbance in the power system usually develops gradually; however some phenomena, such as transient instability, can develop in a fraction of second. Regardless of the phenomena and available measures, any protection/control procedure during an emergency should consist of the following elements:

- Identification and prediction - A fast identification of the specific phenomena, from the power system parameters and from the predisposing factors, is required to start the procedure to return the power system to a healthy state. An emergency may be identified from the primary consequences which are either directly or not-directly observable from local measurements [38]. Further, secondary consequences need to be predicted to avoid adverse impact of protection/control measures.

- Classification - Disturbance classification is based on the constraints that are violated, severity and combination of violations, time scale of the phenomena, and utility control policy. Classification should include identification of the place of a disturbance (eg. the procedure may be different if a disturbance is caused by an internal or an external event).

- Decisions and actions - The choice of the measures is strongly related to the level of priority during emergency. These levels are:

    - stop the degradation of the system,
    - return the system to a secure state, and

  - consider the economical and social impacts.

- Often, to ensure satisfaction of priorities, suboptimal actions are performed. For example, a load shedding scheme is chosen for the worst case contingencies and not for the prevailing system state. Further, consequences of the protection/control measures need to be determined to avoid other disturbances (eg. overfrequency due to overshedding of underfrequency relays).

- Coordination - Different measures may be used to solve different problems. An uncoordinated action may not be economical or secure (eg. trip of the plant on underfrequency protection before operation of the last step of the system underfrequency protection). An intelligent coordination of the protection and control actions is a major challenge and a major requirement for any successful emergency procedure.

- Corrections - After control measures have been applied, the system can be in an improved but unsatisfactory state. This is acceptable, since it may be advantageous to implement initial measures to stop further degradation of the system and then to continue with more optimal actions when time allows. For example, initial load can be shed merely to stop rapid frequency decline; and additional load, required to return frequency to normal, can be calculated more accurately.

- Time scale - For any of the previous elements, available time is a vital factor in selecting appropriate actions. A trade-off between optimal methods and time is very often required. The decision time includes selection of the remedial measure and implementation of remedial measure.

Inputs to protection/control systems and actions which may be available to minimize the impact of the disturbance will be shown next.

Inputs to Control and Protection Systems

The state of the power system is represented by several network parameters. Thresholds, trends, patterns, and sudden changes of these parameters provide key information to detect an emergency. Some of the key system parameters which constitute the possible inputs to improved protection and control systems are:

- Active power flows in the network - If the limits on active power are violated, the system is in a viability crisis. For the overloaded transformer, a loss-of-life occurs. Thus guidance for loading is established to assure a long life. The limit for the transmission line loading is set by transient and steady-state stability conditions (usually long lines), voltage collapse conditions (usually medium lines), and thermal conditions (usually short lines).

- Voltage magnitude and reactive power flows - The voltages in the power system as well as sudden voltage changes need to be contained within a small range. The voltage and reactive power and their rate-of-change can provide valuable information on voltage instability.

- Angles between buses - Stability limits for every line will be satisfied, if the difference in angles across the line do not exceed a certain limit. Detection of the out-of-step condition can prevent instability, and, consequently, cascading.

- Impedance - Unstable swing, stable swing, and fault condition may be detected and distinguished by observing behavior of the impedance loci at the local bus. A typical out-of-step blocking or tripping scheme is accomplished by "blinders" or circles in R-X diagram and timers.

- Resistance and rate-of-change of resistance - These parameters may be used to speed-up the out-of-step detection.

- Frequency - Frequency deviation from the nominal value is a result of power imbalance. In modern interconnected systems, frequency deviation usually occurs in the islanded area (a definite indicator of "in extremis" crisis).

- Rate of change of frequency - Unlike frequency, rate of change of frequency is an instantaneous indicator of power deficiency in the islanded area. The oscillatory nature of the rate of change of frequency needs to be considered in utilizing this feature.

- Spinning reserve - The spinning reserve quantity, distribution, and the speed of its' dynamical response are factors that influence the effectiveness of the spinning reserve during an emergency. The speed of the dynamic response for the hydro units the first few seconds after a demand is made is relatively slow compared to thermal units. Consequently, the spinning reserve needs to be distributed throughout the system on both hydro and thermal units. The spinning reserve needs to be considered in load shedding schemes to optimize shed load.

- Cold reserve - The quantity, allocation, and required time for on-line start of available generation should be considered in an emergency.

- Inertia constant H - The value of the average system inertia is inversely proportional to the rate-of-change of frequency. The precalculated value of the average network inertia may help in adaptive setting of frequency relays.

- Load - Load is a non-linear function of voltage and frequency. These changes in load impact power system imbalance and frequency behavior. Further, load changes with the season and the time of the day. In addition, underfrequency load shedding programs specify percent of the total load that should be shed at each step. As load changes, actual load for shedding does not correspond to planned load.

- Weather/season - The weather/seasonal changes directly influence both system operation and security level, and, consequently, response to a disturbance. An approach of a severe storm, can transfer the system from a normal to an alert state; more faults occur in summer and winter than in spring and autumn.

- Relays and breaker status - Operation of the protective relays (desired or undesired) and network configuration have an essential impact to disturbance propagation. If undesired operation may be avoided by detecting hidden failures or by adapting relay settings to prevailing system conditions, unwanted transition of the system to a less desirable emergency state may be prevented. Further, equipment unavailability because of maintenance and testing needs to be recognized and considered.

Modelling of the power network is required to simulate disturbances and to choose features that will be extracted. The disturbance in the power network usually develops gradually; however some phenomena, such as a rise of transient instability, can develop in a fraction of second. Selection of appropriate power network analysis tools is important (load flow, transient stability, mid and long term dynamic models, EMTP, etc.).

Available Actions

The corrective and emergency actions are limited to a finite number of measures. A detailed description of these measures will be provided as implementation issues for different types of disturbances are analyzed. A set of available measures includes:

- Out-of-step relaying
- Load shedding
- Controlled power system separation
- Generation dropping
- Fault clearing
- Fast valving
- Dynamic braking
- Generator voltage control
- Capacitor/reactor switching and static VAR compensation

- Load control
- Supervision and control of key protection systems
- Voltage reduction
- Phase shifting
- Tie line rescheduling
- Reserve increasing
- Generation shifting
- HVDC power modulation

As an emergency progresses and the state of the system degrades, less desirable measures may become necessary. All the above measures are suitable during "in extremis" crisis. However, "last resort" measures are acceptable only in an unavoidable transition to "in extremis" crisis. Alternatively, preventive measures, are usually only measures suitable in an alert state.

The above measures are implemented in the emergency procedures for the power system. Every system has its own emergency control practices and operating procedures dependent on the different operating conditions, characteristics of the system, and engineering judgement. In other words, the operating procedure for every system is unique and heuristic procedures are extensively used, although the set of measures is the same.

State of the system parameters and sensitivity of the system to certain measure are the factors that influence the choice of the measure. Any one of the measures mentioned above is usually helpful for different problems, having direct or indirect influence. From the problem perspective, different measures can help to overcome different problems with some degree of sensitivity. Another important aspect in implementing control actions is optimization with respect to security and costs. For example, such coarse measure as load shedding need not be executed if generation shifting is satisfactory (regarding speed and amount) in relieving overloaded lines. Further, even when load shedding is necessary to help alleviate overloads, less load is required to be shed if it can be determined that there is a generation shifting capability. Thus, appropriate coordination can optimize actions.

A major component of adaptive protection systems is their ability to adapt to changing system conditions. Thus, relays which are going to participate in wide area disturbance protection and control must of necessity be adaptive. At the very minimum, this implies a relay system design which allows for communication links with the outside world. The communication links must be secure, and the possibility of their failure must be allowed for in the design of the adaptive relays. The failure of communication systems will be considered in greater detail in the section 2.5.

The information brought to adaptive relays from external sources should reflect the prevailing state of the power system. The specific information required by a relay will of course depend upon the function of the relay. But in general, it can be concluded that the system measurements brought to the relays must be related to the parameters which help observe the disturbance propagation. Such measurements must be responsive to changing system conditions so that they will be useful in the management of the disturbance, and the measurements must be brought to the relays quickly enough to be of use in the execution of appropriate control measures. It is reasonable to assume that the angular instability phenomena have natural frequencies about 1~2 Hz. The phenomena during viability crisis are at the low end of the frequency scale, say about 0.001~0.05 Hz. Phenomenon of system frequency change is in the range of 0.1~10 Hz. The frequency decline and angular stability phenomena impose the most stringent time response requirements. To track phenomena at 1 Hz, the system measurements must be obtained and communicated to the adaptive relay in about 50~100 ms. Depending upon the nature of the system data being communicated, it would be essential to have this measurement transmission maintained on a continuous basis. Thus, dedicated communication links to the relays, with speeds of 4800 baud or better would be essential. However, some information may need to be refreshed only periodically with a longer time span than a second. We may form a rough estimate of measurement response time, and communication channel requirements as indicated below. This could be a subject for investigation during the course of this research.

Performance Requirements for Wide Area Measuring System Sensors

It is very important to understand the functionality, limitations, and various relevant performance requirements of wide area measuring systems (WAMS). This information is helpful in:

- understanding the application benefits and limitations of WAMS for protection and emergency control of power systems.
- detailed specification of WAMS.

Following is a sample list of parameters that are important in the application and use of WAMS. For certain applications of WAMS, some parameters will be more or less important than for other applications of WAMS. Similarly, some parameters may have stricter specifications for some applications than for other applications. We suggest the following types of applications could be considered as general broad categories:

- System operation (Real time applications, for system protection, or for manual or automatic control)
- System maintenance (applications such as disturbance analysis)
- System planning (applications such as model validation)

Sample parameters are:

- Voltage and current phasor magnitude and angle, steady state accuracy (with respect to power system primary quantities).
- Wide area simultaneity of phasor measurements (time difference relative to measurements at various locations in the power system).
- For magnitude accuracy, range over which accuracy is required (e.g., Currents, 0.1 p.u. to max. short circuit levels).
- Dynamic range for currents and voltages (if this is different from above specified range over which accuracy is required).
- Transient response of voltage and current phasor measurement. How quickly must steady state accuracies reached? Is it necessary to measure full voltage depression during short circuit (transient) conditions? If so, how accurately? Related to this question, what is the maximum frequency dynamic system changes to be considered? A figure is attached to illustrate the questions regarding transient response.
- Frequency measurement accuracy. Steady state range, and maximum rate of change of frequency which must be measured, and maximum accuracy during transient conditions.
- Minimum sample rate.
- Minimum sample word size.
- Requirement for harmonics measurements?
- Requirement for unbalance measurements? Associated with this question is the question as to whether three phase measurements are always required to establish positive sequence quantities.
- Special requirements (e.g. any need for WAMS equipment to meet ANSI C37.90, C37.90.1 etc.)?
- Required locations of WAMS sensors within an interconnected power system.
- Historical WAMS applications. How (if at all) have WAMS measurements been made in the past?
- Measurement latency. What is maximum tolerable delay before measurement is available to application?
- Measurement storage and/or trigger requirements.
- Any other requirements not listed above.

Figure comparing the result of a power system simulation with a possible response of a phasor measuring unit to the disturbance being simulated. The simulated system response and the measuring unit response are both arbitrary estimates and are not derived from actual studies or actual phasor measurement units. The power system simulation plot is intended to represent the output of a conventional dynamic power system simulation, which is the plot of a series of steady state solutions to the system power flow equations, with a simulated short circuit at a nearby location for a three cycle duration (0.05 seconds to 0.1 seconds).

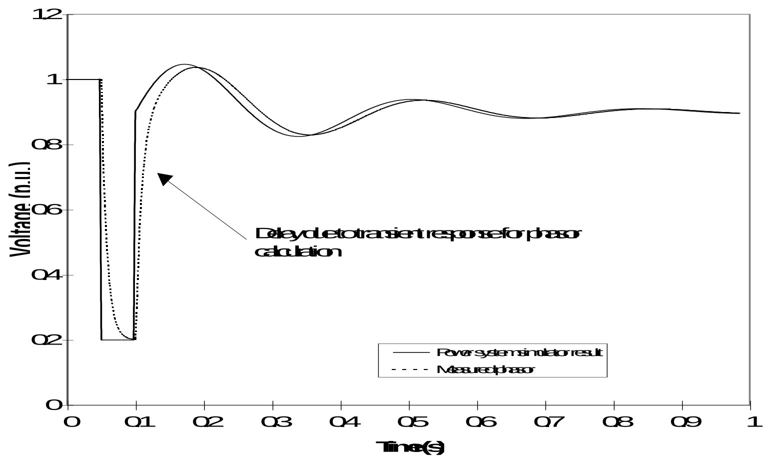


Figure. Relationship between signal and its phasor reconstruction.

The above figure shows both the possible delay in accurately measuring the voltage depression during the short circuit, and the possible phase delay in measuring the system swings after the short circuit is cleared. If the delays in measurements are significant with respect to the frequency of the phenomena being measured, there could be some problems in using the measurements to validate power system simulator models.

Technology Infrastructure

Phasor Measurement Technology

The technology of synchronized phasor measurements is well established. It provides an ideal measurement system with which to monitor and control a power system, in particular during conditions of stress. A number of publications are available on the subject. The essential feature of the technique is that it measures positive sequence (and negative and zero sequence quantities, if needed) voltages and currents of a power system in real time with precise time synchronization. This allows accurate comparison of measurements over widely separated locations as well as potential real-time measurement based control actions. Very fast recursive Discrete Fourier Transform (DFT) calculations are normally used in phasor calculations.

The synchronization is achieved through a Global Positioning Satellite (GPS) system. GPS is a US Government sponsored program that provides world wide position and time broadcasts free of charge. It can provide continuous precise timing at better than the 1 microsecond level. It is possible to use other synchronization signals, if these become available in the future, provided that a sufficient accuracy of synchronization could be maintained. Local, proprietary systems can be used such as a sync signal broadcast over microwave or fiber optics. Two other precise positioning systems, GLONASS, a Russian system, and Galileo, a proposed European system, are also capable of providing precise time.

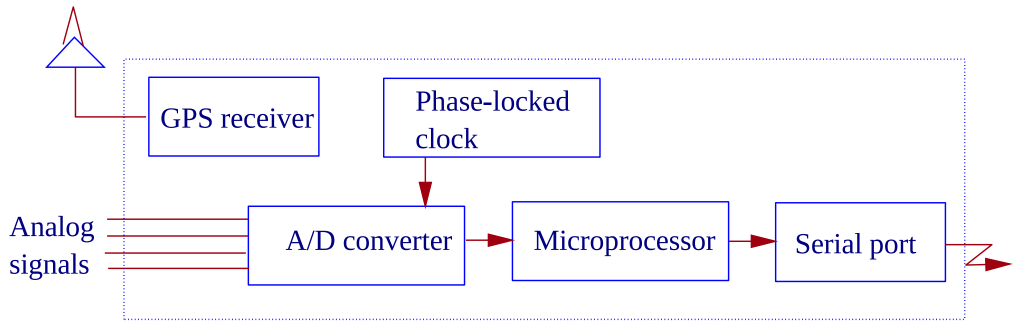


Figure: Block diagram of the Synchronized Phasor Measurement System (PMU).

Figure shows a typical synchronized phasor measurement system configuration. The GPS transmission is received by the receiver section, which delivers a phase-locked sampling clock pulse to the Analog-to-Digital converter system. The sampled data are converted to a complex number which represents the phasor of the sampled waveform. Phasors of the three phases are combined to produce the positive sequence measurement.

Any computer-based relay which uses sampled data is capable of developing the positive sequence measurement. By using an externally derived synchronizing pulse, such as from a GPS receiver, the measurement could be placed on a common time reference. Thus, potentially all computer based relays could furnish the synchronized phasor measurement. When currents are measured in this fashion, it is important to have a high enough resolution in the Analog-to-Digital converter to achieve sufficient accuracy of representation at light loads. A 16-bit converter (either a true 16-bit, or a dynamic ranging converter with equivalent 16-bit resolution) generally provides adequate resolution to read light load currents, as well as fault currents.

For the most effective use of phasor measurements, some kind of a data concentrator is required. The simplest is a system that will retrieve files recorded at the measurement site and then correlate files from different sites by the recording time stamps. This allows doing system and event analysis utilizing the preciseness of phasor measurement. For real time applications, from soft real time for SCADA to hard real time for response based controls, continuous data acquisition is required. Several data concentrators have been implemented, including the PDC (phasor data concentrator) at the Bonneville Power Administration. This unit inputs phasor measurement data broadcast from up to 32 PMUs at up to 60 measurements/sec, and performs data checks, records disturbances, and re-broadcasts the combined data stream to other monitor and control applications. This type of unit fulfills the need for both hard and soft real time applications as well as saving data for system analysis. Tests performed using this PMU-PDC technology on the BPA and SCE (Southern California Edison) systems have shown the time intervals from measurement to data availability at a central controller can be as fast as 60 milliseconds for a direct link and 200 milliseconds for secondary links. These times meet the requirements for many types of wide area controls.

A broader effort is the WAMS or Wide Area Measurement System concept explored by the US Department of Energy and several utility participants. WAMS includes all types of measurements that can be useful for system analysis over the wide area of an interconnected system. Real-time performance is not required for this type of application, but is no disadvantage. The main elements are timetags with enough precision to unambiguously correlate data from multiple sources and the ability to all data to a common format. Accuracy and timely access to data is important as well. Certainly with its system-wide scope and precise timetags, phasor measurements are a prime candidate for WAMS.

Communication Technology [12], [13]

Communications systems are a vital component of a wide area relay system. These systems distribute and manage the information needed for operation of the wide area relay and control system. However, because of potential loss of communication, the relay system must be designed to detect and tolerate failures in the communication system. It is important also that the relay and communication systems be independent and subject as little as possible to the same failure modes. This has been a serious source of problems in the past.

To meet these difficult requirements, the communications network will need to be designed for fast, robust and reliable operation. Among the most important factors to consider in achieving these objectives are type and topology of the communications network, communications protocols, and media used. These factors will in turn effect communication system bandwidth, usually expressed in bits per second (BPS), latency in data transmission, reliability, and communication error handling.

Presently, electrical utilities use a combination of analog and digital communications systems for their operations consisting of power line carrier, radio, microwave, leased phone lines, satellite systems, and fiber optics. Each of these systems has applications where it is the best solution. The advantages and disadvantages of each are briefly summarized in the following paragraph.

Power line carrier is generally rather inexpensive, but has limited distance of coverage and low bandwidth. It is best suited to station-to-station protection and communications to small stations that are hard to access otherwise. Company owned microwave is cost effective and reliable but requires substantial maintenance. It is good for general communications for all types of applications. Radio tends to be narrower band but is good for mobile applications or locations hard to access otherwise. Satellite systems likewise are effective for reaching hard to access locations, but are not good where the long delay is a problem. They also tend to be expensive. Leased phone lines are very effective where a one solid link is needed at a site served by a standard carrier. They tend to be expensive in the long term, so are usually not the best solution where many channels area required. Fiber optic systems are the newest option. They are expensive to install and provision, but are expected to be very cost effective. They have the advantage of using existing right-of-way and delivering communications directly between points of use. In addition they have the very high bandwidth needed for modern data communications.

Several types of communication protocols are used with optical systems. Two of the most common are Synchronous Optical Networks (Sonet/SDH) and Asynchronous Transfer Mode (ATM). Wide band Ethernet is also gaining popularity, but is not often used for backbone systems. Sonet systems are channel oriented, where each channel has a time slot whether it is needed or not. If there is no data for a particular channel at a particular time, the system just stuffs in a null packet. ATM by contrast puts data on the system as it arrives in private packets. Channels are re-constructed from packets as they come through. It is more efficient as there are no null packets sent, but has the overhead of prioritizing packets and sorting them. Each system has different system management options for coping with problems.

Synchronous optical networks are well established in electrical utilities throughout the world and are available under two similar standards: 1) Sonet (Synchronous Optical Networks) is the American System under ANSI T1.105 and Bellcore GR Standards; 2) SDH (Synchronous Digital Hierarchy) under the International Telecommunications Union (ITU) Standards.

The transmission rates of Sonet systems are defined as OCx (Optical Carrier x, x = 1…192); with OC1 = 51.84 Mbps and OC192 = 39.8 Gbps. Available in the market and specially designed to meet the electrical utility environment are Sonet systems with bit rates of OC1 = 51.8 Mbps and OC3 = 155 Mbps.

Sonet and SDH networks are based on a ring topology. This topology is a bi-directional ring with each node capable of sending data either direction; data can travel either direction around the ring to connect any two nodes. If the ring is broken at any point, the nodes detect where the break is relative to the other nodes and automatically reverse transmission direction if necessary. A typical network, however, may consist of a mix of tree, ring, and mesh topologies rather than strictly rings with only the main backbone being rings.

Self healing (or survivability) capability is a distinctive feature of Sonet/SDH networks made possible because it is ring topology. This means that if communication between two nodes is lost, the traffic among them switches over to the protected path of the ring. This switching to the protected path is made as fast as 4 ms, perfectly acceptable to any wide area protection and control.

Communication protocols are an intrinsic part of modern digital communications. Most popular protocols found in the electrical utility environment and suitable for wide area relaying and control are DNP, Modbus, IEC870-5, and UCA/MMS. TCP/IP probably the most extensively used protocol and will undoubtedly find applications in wide area relaying.

UCA/MMS protocol is the result of an effort between utilities and vendors (coordinated by EPRI). It addresses all communication needs of an electric utility. Of particular interest is its “peer to peer” communications capabilities that allows any node to exchange real time control signals with any other node in a wide area network. DNP and Modbus are also real-time type protocols suitable for relay applications. TCP on Ethernet lacks a real-time type requirement, but over a system with low traffic performs as well as the other protocols. Other slower speed protocols like ICCP (Inter Control Center Protocol - America) or TASEII (Europe) handle higher level but slower applications like SCADA. Many other porotocols are availiable but are not commonly used in the utility industry.

Analytical Issues and Approaches

Angular Stability Techniques

Angular instability has been a concern to utilities since the early days of the electric power industry. The research on this subject is extensive and many approaches have been thoroughly investigated in order to predict it.

The objective of out-of-step relaying as it is applied to generators and systems is to eliminate the possibility of damage to generators as a result of an out-of-step condition; and, in the case of the power system, to supervise the operation of various relays such that when a system separation is imminent, it should take place along boundaries which will form islands with matching load and generation.

The protection against transient instability and consequent out-of-step condition is a major concern for the utility industry. Transient instability develops as a result of excessive power imbalance between generation and load following a major disturbance. The loss of synchronism can take place either on the first-swing, or after multi-swings. The first-swing out-of-step is a faster phenomenon than the multi-swing one, and thus requires faster detection and correction measures. The first-swing type of angular instability may develop in a fraction of a second, while the multi-swing instability requires more than half a second to develop.

Out-of-step can take several forms:

1. A single generator losing synchronism.
2. A single power plant losing synchronism.
3. A whole area of the power system (several plants) losing synchronism.
4. Many areas of the power system losing synchronism.

The location and type of a disturbance as well as the transmission configuration and operating conditions in a power system dictate the type of the resulting instability. Angular instability might involve a large geographical area and thus is classified as a wide-area disturbance.

A careful analysis of the various types of out-of-step conditions shows that they can be lumped into two main categories: a two-area instability and a multi-area instability. The state of the art in out-of-step relaying has focused only on the two-area instability since it is a well understood phenomena and is easier to analyze.

The traditional "equal area criterion" is a graphical method of explaining one form of the out-of-step condition, that is when only one group of the generators accelerates against the rest of the power system. The equal area criterion also provides the mechanism to accurately predict, under some modeling assumptions, the critical clearing time of a disturbance. When the system instability exhibits itself as three or more groups of machines losing synchronism, the equal area criterion is inadequate for predicting the critical clearing time. Some attempts to extend the equal area criterion for multi-area instability exist in the literature under the title of "extended equal area criterion". The fundamental difference between two-area out-of-step and a multi-area out-of-step is that the machine angle motion is restricted along one direction in the two-area case, while it is allowed to move in any direction in a high-dimensional space in the multi-area case. Thus searching along one direction to predict instability is relatively easy for the two-area instability and is very difficult for the multi-area case.

If the out-of-step condition is manifested as only two groups of machines losing synchronism, then as the angle separation between the two areas increases, the apparent resistance measured by a relay at the mid point between them decreases and the voltage at the mid point sags. It is therefore beneficial for the power system to bring about an orderly breakup of the system as early as possible in the disturbance. However, the detection or prediction of out-of-step and subsequent system breakup should not be hastily done in order not to jeopardize dependability. Many approaches have been invented to quickly predict or monitor the angular instability.

State of the Art

Several out-of-step detection methods have been employed in relays or discussed in the literature. A brief exposition to some methods of predicting and identifying out-of-step conditions is given in the remainder of this section.

(a) Distance Relays

Distance relays are often used to provide an out-of-step protection function, whereby they are called upon to provide blocking or tripping signals upon detecting an out-of-step condition. When used on a transmission network, they are instrumental in creating viable islands in a power system, when there is an impending system break-up. Out-of-step relays are designed to block the tripping of distance relays at some locations. When applied at generator terminals, the task of the out-of-step relays is to determine an impending loss of synchronism following a system disturbance and to trip the unit along with its station load.

The detection of out-of-step is generally based upon the rate of movement of the apparent impedance, as estimated by blinders or zones, and the time of transition between different zones. Additional information regarding the settings and application of out of step relays is provided in Section "Remedial Actions Against Wide Area Disturbances" of this report, and in [9], [10], [11].

<u>Pros :</u>

- Proven technology with a long history and de facto acceptance from the utility industry.

<u>Cons:</u>

- Performance is being questioned by some large utilities, since distance relays have to be set based on the worst disturbance scenario and this may initiate tripping on recoverable disturbances in some cases.
- The relay monitors only the apparent impedance which may not be sufficient to correctly predict all forms of out-of-step.

(b) R-Rdot Out-Of-Step Relay

This out-of-step relaying concept was developed by Bonneville Power Administration (BPA). A relay was installed at Malin Substation on the Pacific 500 KV AC intertie in February 1983. The intended benefit of this relay over conventional distance relays is the ability to initiate early tripping for non-recoverable swings, while avoiding tripping on recoverable swings.

The conventional apparent resistance measurement is augmented with the rate-of-change of apparent resistance computation. A trip signal is initiated from this relay when the out-of-step swing trajectory crosses a switching line on the R-R^{dot} phase-plane.

If the instability develops quickly, then the rate of change of the measured resistance will be large, which will provide an indication of the incipient instability. Therefore, this relay will trip at a high level of apparent resistance if the rate of change of this resistance is high. This provides an early indication of impending angular instability and allows the relay to initiate tripping at a higher voltage levels.

BPA claims that this relay concept has the following advantages over conventional impedance-based relays :

- More information is available to avoid tripping on recoverable swings while initiating early tripping for non-recoverable swings.

- Worst case considerations do not dictate the relay settings and thus the transmission line performance.

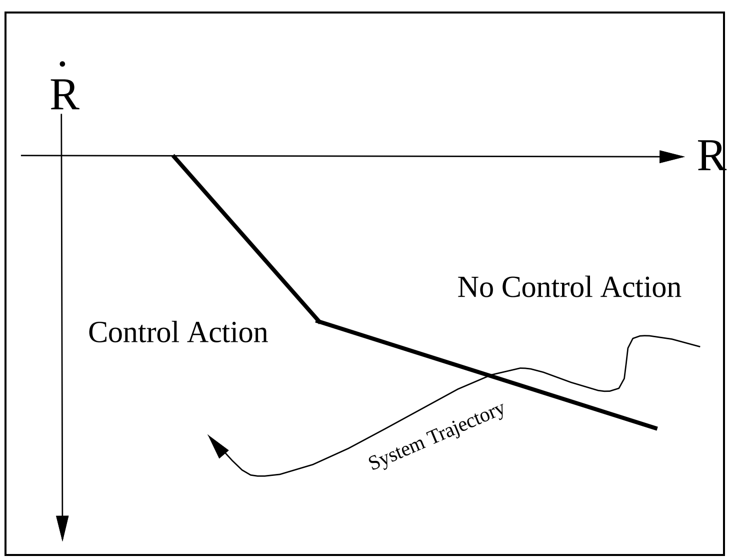


Figure R-R^{dot} Out-of-Step Relay

Pros:

- One practical experience by a well-respected utility as well as an attempt by another.

- Ability to predict out-of-step condition before it actually happens.

- Two inputs are utilized which provide more degrees of freedom in the setting of the relay than the traditional impedance relay.

Cons:

- The design of this relay is based on a single area losing synchronism with the rest of the power system, and as such its performance for a more complex type of instability is unknown.

(c) Power-Angle Estimation Method

Tokyo Electric Power Co., Inc. (TEPCO) applied this relaying scheme to its pumped storage generators. A large nuclear generator was chosen as a reference generator and its instantaneous power and voltage were communicated to each pumped-storage plant via a microwave link. At each pumped-storage plant, the received data and the plant's own instantaneous voltage and active power (12 samples per cycle) are input to the plant processor. Based on this data, the plant processor predicts step-out and estimates the optimum shedding capacity. It then orders selective tripping of some local pumped-storage generators.

In the power-angle estimation method, the deviation in the phase angle is estimated from the difference in power between the pumped-storage generators and the reference generator before and after inception of a fault. Using the estimated phase angle along with the phase angle before the fault, the relative phase angle is predicted for the following 0.2-0.3 seconds. If this value exceeds a pre-determined (based on off-line simulations) threshold phase angle, a step-out is predicted. The minimum number of pumped-storage generators that must be shed to prevent step-out is subsequently determined.

An explanation of the mathematical formulation of this out-of-step prediction method follows.

Algorithm:

1. The electrical power output of the machines involved in the out-of-step is measured and sampled 12 times per cycle. At any point in time, the average of previous 12 samples is taken as the electric power output at that time.

2. The speed of separation between the 2 areas is estimated using the swing equation

$$\Delta\omega_k = \Delta p \,.\, \Delta t / M = (P_k - P_n) \,.\, \Delta t / M$$

where:

P_n : the mechanical power
P_k : the electrical power output
k : time index
M : Equivalent inertia
Δt : Time interval from previous computation point
$\Delta\omega_k$: change in speed from previous computation point

Then the speed and angle of separation are given by :

$$\omega_k = \omega_{k-1} + \Delta\omega_k$$
$$\delta_k = \delta_{k-1} + 0.5(\omega_k + \omega_{k-1})\,\Delta t$$

3. The speed and angle of separation at some time in the future (0.2-0.3 seconds) are predicted for both the accelerating and decelerating machines using

$$\omega(t) = \omega(t_2) + a_1(t-t_2) + a_2(t-t_1)(t-t_2)$$
$$\delta(t) = \delta(t_0) + \omega(t_2)(t-t_0) + a_1[\,(t^2 - t_0^2)/2 - t^2(t-t_0)\,] + a_2\,[\,(t^3 - t_0^3)/3 - (t_1+t_2)(t^2-t_0^2)/2 + t_1t_2(t-t_0)\,]$$

where :

$$a_1 = [\,\omega(t_2) - \omega(t_1)\,] / (\,t_2-t_1)$$

$$a_0 = [\,\omega(t_1) - \omega(t_0)\,] / (\,t_1-t_0)$$

$$a_2 = [\,a_1 - a_0\,] / (\,t_2-t_0)$$

4. If the angle of separation exceeds a threshold then out of step is detected.

Pros:

- A practical experience by a large utility.

- On-line prediction of the separation angle between areas using well-accepted formulas.

Cons:

- Might conflict with some patent rights.
- A knowledge is assumed of the inertia of the area which lost synchronism.
- The mode of instability is assumed to be known, i.e., the accelerating and decelerating machines are known a priori.
- The mode of instability is assumed to be a one area losing synchronism with the rest of the power system.
- Can only predict the first-swing type of angular instability.

(d) Voltage-Angle Estimation Method

Tokyo Electric Power Co., Inc. (TEPCO) applied this out-of-step relaying scheme in February 1989. The relaying system was built by Toshiba Corporation. Most loads in TEPCO's system are concentrated in Tokyo and the surrounding area, particularly to the west. Large capacity power plants are distributed to the east, north, and southeast. Slow unstable oscillations (~ 0.5 Hz) can develop under some contingency conditions between the western part of TEPCO's system and the other regions. This relaying scheme measures the voltage waveforms at four locations on the bulk 500 KV transmission system, and communicates these measurements using microwave communication system. The phase differences between the western region and each of the other regions of the TEPCO's system is estimated from the voltage waveforms. Then the phase angle differences for the following 10 cycles are predicted using extrapolation. If predicted phase differences exceed a pre-determined threshold phase angle, a step-out is predicted, and system separation and load shedding are initiated. The following algorithm shows the steps and formulas used in this out-of-step method.

Algorithm :

1. The voltage at substation busbars in the vicinity of the generators is collected on-line and sampled at 12 samples per cycle.

2. The phase difference between two areas at the present time (n) is calculated from the voltage waveforms at both locations using the following Equation :

$$\delta = \tan^{-1} [\; (V^1_n V^2_{n-3} \; - \; V^1_{n-3} V^2_n) \; / \; (\; V^1_n \; V^2_n \; + \; V^1_{n-3} V^2_{n-3}) \;]$$

where:

V^1_n : Voltage at location # 1 at present time n.
V^1_{n-3}: Voltage at location # 1 , three samples prior to present time.
V^2_n : Voltage at location # 2 at present time n.
V^2_{n-3}: Voltage at location # 2 , three samples prior to present time.

The above Equation is derived by assuming pure sinusoidal voltage waveforms at both areas, i.e.,

$$V^1_n = V_1 \sin(\omega t_n) \quad ; \qquad V^2_n = V_2 \sin(\omega t_n + \delta)$$

Then

$$V^1_n \; V^2_n \; + \; V^1_{n-3} V^2_{n-3} = \; V_1 \sin(\omega t_n) \; V_2 \sin(\omega t_n + \delta) \; + \\ V_1 \sin(\omega t_n -90) \; V_2 \sin(\omega t_n + \delta - 90) \; = \; V_1 \; V_2 \; \cos (\delta)$$

and

$$V^1_n \; V^2_{n-3} \; - \; V^1_{n-3} V^2_n = \; V_1 \sin(\omega t_n) \; V_2 \sin(\omega t_n + \delta - 90) \; - \\ V_1 \sin(\omega t_n -90) \; V_2 \sin(\omega t_n + \delta) \; = \; V_1 \; V_2 \; \sin (\delta)$$

3. The phase difference between the two areas after some time in the future is predicted using the following equation:

$$\delta^* = \delta_n + \lambda \, d_n + \mu \; d_{n-1}$$

where:

$$d_n = \delta_n - \delta_{n-1} \qquad d_m = \delta_m - \delta_{m-1}$$
$$d_{n-1} = \delta_{n-1} - \delta_{n-2} \qquad d_{m-1} = \delta_{m-1} - \delta_{m-2}$$
$$d_{n-2} = \delta_{n-2} - \delta_{n-3} \qquad d_{m-2} = \delta_{m-2} - \delta_{m-3}$$

$$\lambda = (d_n \, d_{m-2} - d_m \, d_{n-2}) / (d_{n-1} \, d_{m-2} - d_{m-1} \, d_{n-2})$$

$$\mu = (d_{n-1} \, d_m - d_{m-1} \, d_n) / (d_{n-1} \, d_{m-2} - d_{m-1} \, d_{n-2})$$

4. If δ^* exceeds a threshold (determined by simulations), then out-of-step is detected.

Pros:

- A practical experience by a large utility.
- On-line prediction of the separation angle between areas using well-accepted formulas.
- Ability to deal with the oscillatory type of out-of-step.

Cons:

- Might conflict with some patent rights.
- Prediction accuracy is unknown for general applications.

(e) Energy Function Method

Tokyo Electric Power Company Inc. installed this out-of-step prediction relaying system in June 1983. This relaying system utilizes energy functions to predict an impending out-of-step and to determine the amount of generator shedding required to stabilize the system. The computational algorithm used is based on a two-machine power system assumption. The system energy right after fault clearing is calculated and compared to a threshold value. If the system energy exceeds the energy threshold, then instability is predicted. The level of generator shedding that will stabilize the system is computed by comparing system energy right after fault clearing with an energy threshold that correspond to shedding one generator. This procedure is repeated with more generator shedding, if necessary, until system energy is below the threshold of stability.

A relay system has a decentralized configuration (see Figure 3.1.10) whereby a fault detection equipment is installed at a large machine which is representative of all the machines that pickup speed following a fault application. This equipment transmits the electric power of this large machine to all the generators that are candidates for generator shedding. At those candidate power plants, both a fault detection equipment and a CPU is installed. Each generator predicts its own stability and the level of generator shedding needed.

Pros:

- Ability to predict out-of-step immediately following fault clearing and thus capability for fast response.

Cons:

- Many approximations are used in the derivation of the algorithm, and thus the accuracy for general applications is unknown.

- The algorithm is suited for a two-machine type instability.

Voltage stability

Power systems throughout the world have been experiencing voltage stability problems. That type of system-wide disturbance is manifested by several distinguishing features: low system voltage profiles, heavy reactive line flows, inadequate reactive support, heavily loaded power systems. The voltage collapse typically occurs abruptly, after a symptomatic period that may last in the time frames of a few seconds to several minutes, sometimes hours. The onset of voltage collapse is often precipitated by low-probability single or multiple contingencies. The consequences of collapse often require long system restoration, while large groups of customers are left without supply for extended periods of time. Schemes which mitigate against collapse need to use the symptoms to diagnose the approach of the collapse in time to initiate corrective action.

Analysis of voltage collapse models can be divided into two main categories, static or dynamic:

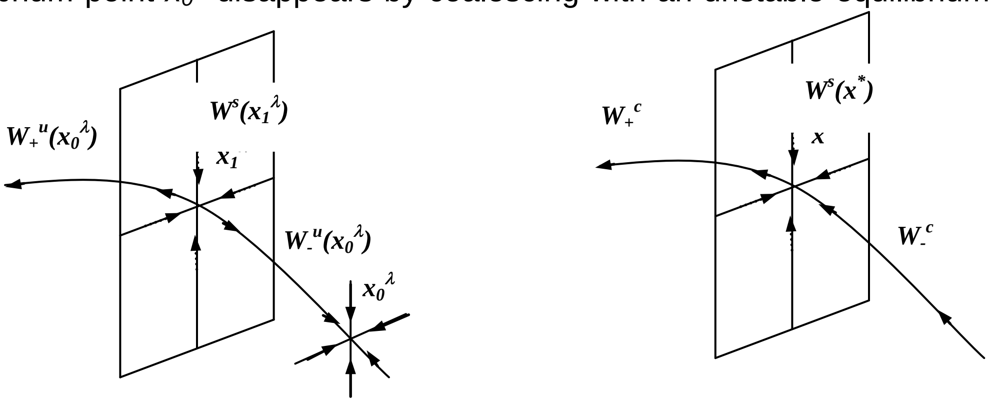
- Fast: disturbances of the system structure, which may involve equipment outages, or faults followed by equipment outages. These disturbances may be similar to those which are consistent with transient stability symptoms, and sometimes the distinction is hard to make, but the mitigation tools for both types are essentially similar, making it less important to distinguish between them.

- Slow: load disturbances, such as fluctuations of the system load. Slow load fluctuations may be treated as inherently static. They cause the stable equilibrium of the system to move slowly, which makes it possible to approximate voltage profile changes by a discrete sequence of steady states rather than a dynamic model.

Suppose that the power system is described with a set of differential equations and a slow varying parameter vector λ (load injections). We assume that the system model has a stable operating point (equilibrium x_0) for a certain load level (a fixed value of the load parameter vector λ_0). As the parameter λ varies slowly, the stable equilibrium point x_0 also varies in the state space, and can disappear or become unstable. There are two typical ways in which the system may lose stability: either through abrupt appearance of self-sustained oscillations in the system, or by disappearance of the equilibrium point.

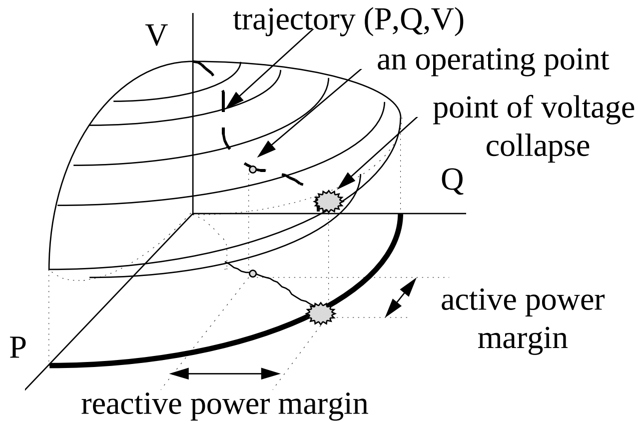
In the first case, the equilibrium point persists but becomes unstable following the parameter variation. This type of oscillatory instability is consistent with Hopf bifurcation. Oscillation instabilities are not important in voltage collapse because voltage collapse is not observed to be oscillatory.

In the second case, at some critical value of the load level, $\lambda=\lambda^*$, a stable equilibrium point x_0^λ disappears by coalescing with an unstable equilibrium point



x_1^λ on the system stability boundary.

The Jacobian matrix f_x of the system model evaluated at the operating point consistent with the critical load level x^* has one zero eigenvalue and the real parts of other *n-1* eigenvalues remain negative (stable). Therefore, the system state x^* has a one *dimensional center manifold* $W^c(x^*)$, through which the system state may escape the stable operating region, and *n-1* dimensional stable manifold $W^s(x^*)$. If load parameter λ increases beyond the critical (bifurcation value λ^*), then the stable operating point (eqwuilibrium x^*) disappears and there are no other equilibrium points nearby to which the system state may transition.



Symbolic depiction of the process of coalescing of the stable and unstable power system equlibria (saddle node bifurcation) through slow load variations, which leads to a voltage collapse (a precipitous departure of the system state along the center manifold at the moment of coalescing). VPQ curve representing the trajectory of the load voltage V of a 2-bus system model when active (P) and reactive (Q) power of the load can change arbitrarily.

The Figure represents a trajectory of the load voltage V when active (P) and reactive (Q) power change independently. Figure also shows the active and reactive power margins as projections of the distances. The voltage stability boundary is represented by a projection onto the PQ plane (a bold curve). It can be observed that: (a) there may be many possible trajectories to (and points of) voltage collapse; (b) active and reactive power margins depend on the initial operating point and the trajectory to collapse.

There have been numerous attempts to use the observations and find accurate voltage collapse proximity indicators. They are usually based on measurement of the state of a given system under stress and derivation of certain parameters which indicate the stability or proximity to instability of that system.

Parameters based on measurement of system condition are useful for planning and operating purposes to avoid the situation where a collapse might occur. However, it is difficult to calculate the system condition and derive the parameters in real time. Rapid derivation and analysis of these parameters is important to initiate automatic corrective actions fast enough to avoid collapse under emergency conditions which arise due to topological changes or very fast load changes.

It is preferable if a few critical parameters that can be directly measured could be used in real time to quickly indicate proximity to collapse. An example of such indicator is the sensitivity of the generated reactive powers with respect to the load parameters (active and reactive powers of the loads). When the system is close to a collapse, small increases in load result in relatively large increases in reactive power absorption in the system. These increases in reactive power absorption must be supplied by dynamic sources of reactive power in the region. At the point of collapse, the rate of change of generated reactive power at key sources with respect to load increases at key busses tends to infinity.

The sensitivity matrix of the generated reactive powers with respect to loading parameters is relatively easy to calculate in off-line studies, but could be a problem in real-time applications, because of the need for system-wide measurement information. Large sensitivity factors reveal both critical generators (those required to supply most of the newly needed reactive power), and critical loads (those whose location in the system topology imposes the largest increase in reactive transmission losses, even for the modest changes of their own load parameters). The norm of such a sensitivity matrix represents a useful proximity indicator, but one that is still relatively difficult to interpret. It is not the generated reactive power, but its derivatives with respect to loading parameters which become infinite at the point of imminent collapse.

Proximity Indicators to the Point of Instability

Given current operating state of the system x_0 and corresponding loading level parameter value λ_0, an obvious question is: "How far is the system from the stability boundary?" In the literature, we find different approaches to this problem. The idea of computing a closest instability point in a real power injection space was first introduced by Galiana and Jaris [17], [18], who minimize a non-Euclidean distance to the instability point in a load power and voltage magnitude parameter space using the Fletcher-Powel method.

There are three different methods for computing a closest saddle node bifurcation. These are:

- direct methods [19], [21]
- iterative methods [21], [26], [27]
- continuation methods [24], [25]

All three methods are applicable to any power system model of form (1.8), (1.9) or any static power system model equivalent to some underlying different equivalent model of the form (1.1) and for any parameter space.

Direct Method: One possible way to obtain a measure of the system stability at current operating point would be to estimate the minimum distance in the load parameter space to the point of collapse λ^*, given as a norm $||\lambda^* - \lambda_0||$. The direction of the margin is not unique (margin could be chosen in different directions, a seen in the Figure preceding this text), but the smallest margin is obtained as the worst case parameter variation. The convergence of the direct methods is excellent provided a sufficiently close initial guess.

Iterative method: The computation of the stability margin and the normal vector may be iterated. The idea is to iteratively change the load parameters by solving a standard bifurcation problem using until the algorithm converges to the desired solution. Given the current value of the parameter vector λ_0 and the initial guess for the direction n_0 we can compute the closest saddle node bifurcation *(point of collapse)* along the given linear direction (ray) of load parameter increase, using direct [19], [21] or continuation methods [24], [25]. The direction of load increase is chosen such that increase of load (parameter λ) leads to disappearance of the operating point. The procedure is repeated until convergence within a desired tolerance is reached. An important advantage of the iterative method is that its convergence ensures that a solution is the locally closest bifurcation. The method requires the initial guess, but it is more robust to choice of initial conditions than the direct method.

The main drawback of both direct and iterative methods is that when they converge the convergence is to a bifurcation λ^* that is locally closest to λ_0, which is not necessary the closest bifurcation. Multiple locally close bifurcations may exist and hence multiple minimum of the stability margins exist. Alvarado [27] proposed to compute the minimum margin using Monte Carlo optimization. Initial directions for the iterative method are randomly generated by choosing vectors from a uniform distribution on an *m* dimensional hypercube corresponding to *m* distinct parameters of a slow varying load parameter vector λ. The iterative method is run for each of these initial directions. The closest bifurcation point corresponds to the minimum stability margin.

Continuation methods: The continuation methods determine the bifurcation point x* and the load margin, from the load flow equations, augmented by the continuation variable parameter(s). There are many variations of continuation methods, and the widely used are of the predictor-corrector type [24], [25]. A continuation algorithm starts from a known solution and uses the corrector-predictor scheme to find the subsequent solutions at different parameter values λ. It gives a continuum of power flow solutions for different values of parameter λ. The main advantage of the method is that it does not require good initial guess.

In the predictor step, it is assumed that load λ can be parametrized as a scalar. Suppose we are at the *i-th* step of the continuation process and the *i–th* solution (x^i, λ^i) are known. Then, we attempt to find an approximation of the next solution (x^{i+1}, λ^{i+1}) by taking an appropriate step in a direction tangent to the solution path. In the corrector step, a slightly modified Newton-Raphson algorithm is used to find the next iterative operatiung point after the predictor produces an approximation $(\bar{x}^{i+1}, \bar{\lambda}^{i+1})$ of the next point (x^{i+1}, λ^{i+1}). Since the predictor gives an approximation in a close neighborhood of the next point (x^{i+1}, λ^{i+1}), a few iterations of the corrector usually suffice to achieve the needed accuracy. The only task left to do after the predictor-corrector step is to check whether the critical point has been overreached. The tangent component corresponding to the direction of load λ is zero at the critical point, and is negative beyond the critical point. Thus, once the tangent vector has been calculated in the predictor step, a test of its sign will reveal whether or not the critical point has been reached. Continuation methods are the most computationally economical way to obtain information about voltage stability in power systems. The overview of wide area protection and emergency control techniques for voltage stability protection is provided in the subsequent sections, as well as in [1], [2].

Applications of Expert systems

Application of Expert System (ES) to protection engineering has been a research topic for several years. Working Group C-4 on “application of Intelligent Systems in Protection Engineering” was formed to continue the activity initiated by [28]. According to the working group C-4 report [29], the majority of the reported applications are related to the theoretical concepts tested, evaluated and justified by way of digital simulation. Only a few in-service applications have been identified.

Wide area protection is a highly complex task. If a disturbance occurs in any one of the interconnected systems, it is very difficult to arrive at a diagnosis in a short period of time. The system-wide knowledge is essential in resolving the problem. Due to the nature of the complexity, isolated ES is not suitable for diagnosing the wide area disturbance. There is a need for cooperating Expert System (ES), which can assist the local experts during emergencies and help solve routine work (overall system status report, individual system status report, etc.) that needs to be carried-out during the system wide disturbance. Significant reasons why we need cooperating ES to resolve various contingencies are:

- Complexity of the inter connected power system with ever growing power demand
- Large number of possible operating contingencies
- Lack of better and faster communication facilities
- Inefficient use of past history data and data management
- Deregulation, power marketers, affiliated power producers and regulatory bodies

An ES scheme capable of performing diagnosis to wide area disturbance is proposed in this report and is briefly discussed.

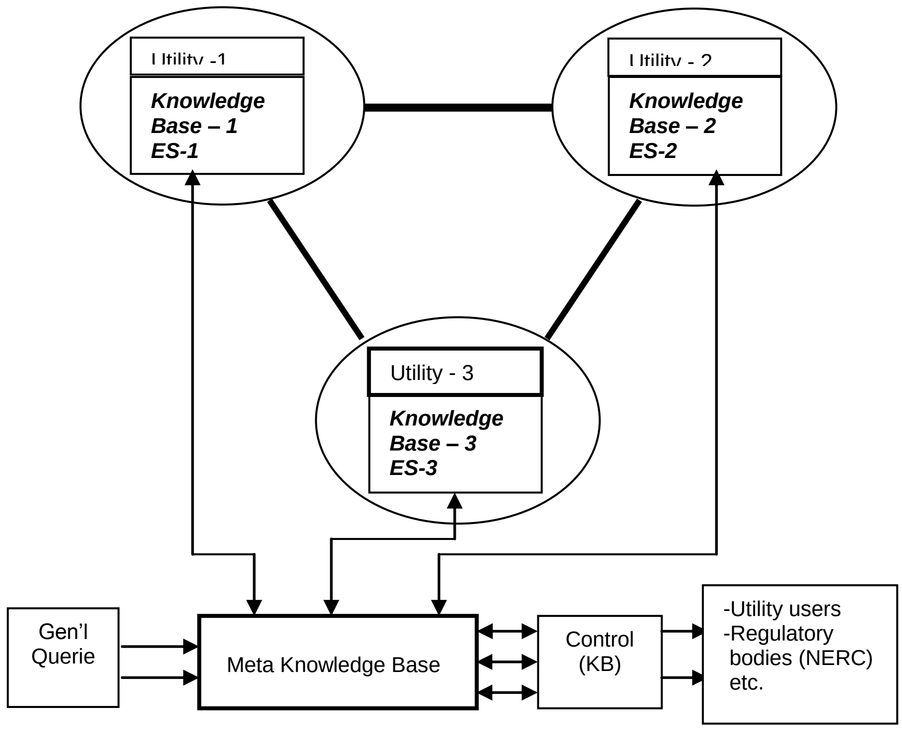


Figure. Schematic view of the proposed multi agent cooperating ES for wide area protection.

The goal of any ES is more ambitious than the conventional techniques. Expert System basically relies on the "Knowledge" and the "Inference" mechanism. In the complex environment like the wide area protection, it is very difficult to narrow down the scope of the ES. Careful guidelines are required in the design and development of the ES.

For simplicity, a typical wide area power system with two utilities interconnected is shown in the Figure. Each utility has its own Knowledge base and an ES.

The strategy that is proposed is to divide the wide area knowledge into several knowledge bases using multi agent model, which are distributed throughout the protection system. The notion of joint responsibility or cooperation in solving the problem during the disturbance is a key aspect needed to arrive at an expert solution to the problem. Common subdivision (Generation, Transmission and Distribution) in the utility environment is taken into consideration in narrowing down the knowledge base (Figure). Each subdivision has "Agents" responsible for providing the knowledge about their domain.

The term "Agent" used here has context (Power System), goals and intentions, knowledge and intelligence. The "Knowledge Base Agent" is the data base of several "Agents" which has ability to interpret the data (transform data into information), elaborate the data (derive new information) and ability to learn (acquire new knowledge). The multi agent model allows the information to be shared between them and also through out the wide area network via the "Meta Knowledge Base". Experts from all the utilities of the wide area protection system jointly formulate the Meta knowledge base. The "Meta Knowledge Base" enables other utilities to instigate cooperation for diagnosing disturbances beyond their domain or knowledge base. Output from the "Meta Knowledge Base" is further qualified via a "Controller" before it is delivered to the outside environment such as different utility users, regulatory bodies etc. The "Controller" also helps in validating the results and updating the current Meta knowledge.

In the event of a disturbance in one of the utilities, say Utility-1, the knowledge "Agents" for the Generation, Transmission and the Distribution report the status of their system hierarchically to the upper "Knowledge Base Agent –1". The "Knowledge Base Agent – 1" reports the nature of the problem to the "Meta Knowledge Base", which in turn propagates the information to all other utilities and waits for their contribution with a time limit as agreed jointly by the experts from all utilities. Later, the "Meta Knowledge Base" and the "Controller" qualifies the report and the nature of the problem and sends necessary queries to all the utilities seeking their cooperation in resolving the disturbance.

In order to prevent the cascade tripping, a Backup Protection Expert System (BPES) as proposed in [30] can be used in conjunction with the proposed scheme. The salient features of the BPES are:

- Precise location of a fault and exclude unfaulted elements so that only the circuit breakers necessary to isolate the fault are tripped.
- Avoid unnecessary trips due to hidden failure, current reversing or overloading by blocking the trip signals of conventional back-up protection relays.

The essential element required to implement wide-area backup protection is the availability of system-wide information which requires inter- and intra-substation communications. The BPES implemented in the UK consists of a data acquisition and communication system, a monitoring system, an inference mechanism (Expert System) and breaker tripping system, which operates in normal or emergency modes. The BPES monitoring system stays active and monitors the operational response of conventional protection relays. On the detection of a fault, a timer will be set and the expert system will be invoked after a pre-set time delay of 200ms has expired. The expert system, which usually is in an inactive state, analyses the action factors of the lines that are likely to be affected by the fault and decides on the best way to isolate the fault that has failed to be cleared by the main protection. The BPES blocks the trips that are additional to the fault isolation if blocking is allowed.

Multiple Contingencies & Fast-evolving Blackouts

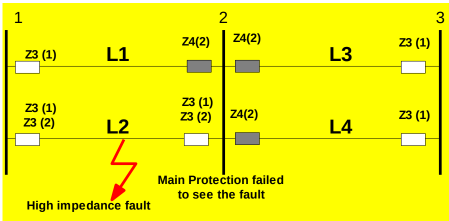
Transmission systems are designed to interconnect generation stations and distribution utilities and to transmit bulk power from generation stations to major load centres. An adequately designed transmission system operating with a sufficient security margin is capable of withstanding single or multiple contingencies without causing instability and cascading outages. The most commonly used reliability criteria for transmission planning and operation is the N -1 criterion[1], which requires a transmission system to be developed and operated at all load levels and meet the most severe single contingency in additional to any scheduled outages. As multiple contingencies are beyond the planned and operational limits of a power system, the occurrence of any multiple contingencies, may lead to overloading and cascading trips on the network.

Causes of multiple contingencies

- Evolution of a localised fault by trips initiated from conventional back-up protection, or false trips of protection relays, or due to hidden failures of relays.
- Sequential faults.
- Severe weather or geomagnetic induced currents
- Natural disasters such as earthquakes

Backup Protection & Multiple Contingencies

Conventional back-up protection is designed to protect a region of a network and is required to operate only when the main protection has failed to clear a fault. It is heavily skewed towards dependability as faults on the network must be cleared to maintain the operation of the power system. With a limited view of the protected network from the inputs measured locally, conventional back-up protection generally takes action to protect the local equipment without considering the impact on the entire network. It may trip a circuit breaker remotely (no-selectivity) and may operate under heavy loading conditions (maloperation). The example shown in Figures demonstrates a high impedance fault occurs on one of the double circuit lines, where all protection relays operated correctly and as a consequence of the trips initiated from back-up protection relays, the four lines are disconnected from the network. The fault in Figures is seen as a zone 2 and a zone 3 fault, and protection relays at one end of the faulted line totally failed, back-up protection trips the four lines after the zone 2 time delay has expired. Multiple contingencies are the consequence of tripping initiated by conventional back-up protection relays. The interesting issue here is that conventional back-up protection has operated as designed and multiple contingencies do occur, which push the power system beyond the planned limit. As loads on the disconnected lines will be transferred to their adjacent lines, this may overload them and casting cascading trips on the network leading to a widespread blackout. This issue is further aggravated in a competitive environment as transmission lines are pushed to operate close to their limit. It is more likely that overloading of lines leading to the trip of the associated circuit breakers will happen more frequently in a deregulated power system.



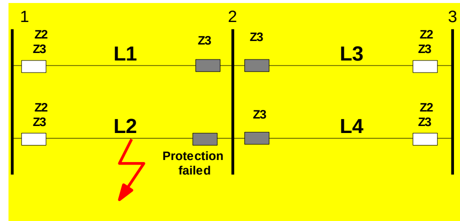


Fig.1 High impedance fault

Fig.2 Protection failed at one end

To prevent the occurrence of cascading outages on the network, it is necessary to vertically review and harmonize protection design practices in power system planning, operation and protection, particularly back-up protection. It is essential to ensure a power system is planned and operated in a way in which the power system can withstand contingencies caused by the designed protection actions, or that the protection system is designed and applied in a way in which it will not, at least in principle, push the power system beyond its design limit. Therefore, the protection system applied including back-up protection will not cause any multiple contigencies during a single localised event.

Wide-Area Back-up Protection as a Preventive Measure

There are two ways in which wide-area backup protection can prevent cascading outages [32], [33]: (1) Precise location of a fault and thereby so as to exclude unfaulted elements so that only the circuit breakers necessary to isolate the fault are tripped. (2) Avoidance of unnecessary trips, due to hidden failure, current reversing or overloading, by blocking the trip signals of conventional back-up protection relays. The essential element required to implement wide-area backup protection is the availability of system-wide information which requires inter- and intra-substation communications. The back-up protection expert system (BPES) implemented in the UK consists of a BPES data acquisition and communication system, a BPES monitoring system,an expert system and breaker tripping system, operates in a normal or an emergency modes. The BPES monitoring system stays active and monitors the operational response of conventional protection relays. On the detection of a fault, a timer will be set and the expert system will be invoked after a pre-set time delay of 200ms has expired. The expert system, which usually is in an inactive state, analyses the action factors of the lines that are likely to be affected by the fault and decides on the best way to isolate the fault that has failed to be cleared by the main protection. The BPES blocks the trips that are additional to the fault isolation if blocking is allowed.

Remedial Actions Against Wide Area Disturbances

Special Protection Systems (SPS)

The following definition of a special protection system comes from a NERC planning standard.

"A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance". Note that this definition specifically excludes the performance of protective systems to detect faults or remove faulted elements. It is system oriented both in its inception and in its corrective action. Such action includes, among others, changes in demand (e.g. load shedding),changes in generation or system configuration to maintain system stability or integrity and specific actions to maintain or restore acceptable voltage levels. One design parameter that sets these schemes apart is that many of them are "armed" and "disarmed" in response to system conditions. For example, a watchdog type of scheme may be required and armed at high load levels, but not at lower load levels. Some SPSs are armed automatically by the system control center computer, others require human operator action or approval, others are manually operated and some are armed all the time [1].

NERC further defines the standards to which an SPS shall adhere. In part, they are:

- An SPS shall be designed so that cascading transmission outages or system instability do not occur for failure of a single component of an SPS which would result in failure of the SPS to operate when required.
- All SPS installations shall be coordinated with other system protection and control schemes.
- All SPS operations shall be analyzed for correctness and documented.

Reference [1] reports on the experience of 111 SPSs and lists the most common schemes being used as follows:

• Generator rejection	21.6%
• Load rejection	10.8%
• Underfrequency load shedding	0.2%
• System separation	6.3%
• Turbine valve control	0.3%
• Stabilizers	4.5%
• Load and generator rejection	0.5%
• HVDC controls	3.6%
• Out-of step relaying	2.7%
• Dynamic braking	1.8%

- Discrete excitation control 8.0%
- Generator runback 1.8%
- VAR compensation 1.8%
- Combination of schemes 1.7%
- Others 12.6%

The preponderance of the first three schemes is not surprising. The fundamental cause of wide-area outages, almost by definition, is the unbalance between generation and load following the loss of a line or generator due to correct operation following a fault or incorrect operation by human error, hidden failure, etc.. Therefore, an SPS seeks to correct this unbalance by removing load or increasing generation. In this survey, a distinction was made between direct load rejection, i.e. removing pre-planned customers through controls, and automatic under-frequency load rejection if the unbalance results in decreasing frequency. The underfrequency tripping of load may not be considered by everyone as an SPS since it is installed by many utilities as a normal protective measure.

An increasingly popular SPS is the separation of the system into several self-sufficient islands, leaving the faulted area to fend for itself, thus greatly reducing the impact of an outage. The use of the Global Positioning Satellite to synchronize relays across the system and adaptive digital relays makes this scenario particularly attractive.

The concept of out-of-step relaying has been known for some time. However, the specific setting philosophy has been a major problem in applying it. This has not changed very much as indicated by the low (2.7%) experience level.

Combining all of the schemes applied to the turbine-generator results in a respectable experience factor (36.9% from Reference 1). This has become feasible by the introduction of reliable and fast-acting electronics. Fast valving and dynamic braking are particularly noteworthy as methods to reduce generator output without removing the unit from service and thus allowing for rapid restoration.

The reliability of SPS was addressed in reference 1 and indicates that the equipment and schemes perform very similarly to traditional protective schemes. System conditions requiring action does not occur often, but when it does occur, the SPS usually performs its function correctly. The most common failure (43% of those responding) was hardware failures with human failure (20%) next. Inadequate design accounted for about 12% of the failures and incorrect setting less than 10%.

In this section all possible protective actions against wide area disturbances that we have been able to find during the work have been listed, commented, and evaluated. Here are mainly dealt with curative actions.

Generator Rejection Schemes

Generator rejection schemes are an effective means of maintaining system stability and avoiding wide area disturbances. They are based on the principle that rapidly disconnecting some generation can significantly reduce the amount of power that flows through a transmission path that suffers reduced capacity (due to a local disturbance such as a short circuit) while having relatively small effect on the load/generation balance in a large interconnected system. The rapid reduction in power flow through a path with suddenly reduced capacity reduces the probability of large power swings leading to instability.

Generator rejection schemes are clearly wide area schemes since the location of the transmission disturbance that requires generation rejection may be several hundreds or even a few thousand kilometers distant from the generation plant. The need for the schemes and amount of generation that needs to be shed for various contingencies depends significantly on the transmission load flow pattern, therefore the schemes are usually capable of being armed and/or adjusted by operators at the transmission control center.

The type of generation rejection scheme depends to a large extent on the type of prime mover that drives the generators. Shutdown of large steam turbine generators can be extremely costly, may result in very long restart times, and also subjects the turbogenerator set to significant thermal stresses. On the other hand, most hydroelectric generators can be relatively easily shut down and quickly restarted. There is however some detrimental effect on a hydro generator that may be subjected to severe overspeed if the unit breaker is opened under high load conditions.

Generator rejection schemes could be classed into three categories as follows.

a) <u>Schemes that depend on the status of the transmission paths.</u> These schemes rely heavily on direct transfer trip signals from the various substations that terminate the circuits in the relevant transmission path(s). The transfer trip signals are initiated by line terminal status, and/or by transmission line protection. The signals may be routed through a control centre where the generation rejection patterns are set up, with rejection trip signals going from the control centre to the generating stations. Conversely, the direct transfer trip signals may be routed directly to the generating stations and the generation rejection patterns set up there, by supervisory control and data acquisition (SCADA) equipment. Figure 1 shows a number of transfer trip signals keying generation rejection at a major hydro electric generating station. It is not intended that the reader try to understand the reason for all the signals shown in Figure 1. This figure is provided only as an example of the complexity that may be required for a transmission status based scheme. In the Figure on next page, generation rejection may be initiated by

- line status
- number of phases in service (for circuits where single phase tripping and reclosing protection schemes are applied)
- Series capacitor bypass

Schemes based on line status usually have to be set up with sufficient generation rejection to retain stability in the event of the worst threat to stability (usually a three phase fault that prevents all power flow throughout the transmission path). Since most disturbances on EHV transmission are not usually multiphase faults, the scheme usually rejects more generation than necessary to retain stability. This type of scheme is better applied to generation equipment such as hydroelectric that can be restarted relatively economically.

b) Schemes that determine the approach of transient instability. These schemes measure the acceleration and speed of the generating plant with respect to the system frequency and reject sufficient generation to ensure that stability will be retained. If this scheme is properly adjusted, only the minimum amount of generation will be shed for each specific disturbance. This type of scheme is relatively complex compared to the schemes that simply depend on the status of transmission paths. This type of scheme is more likely to be applied when there are significant costs associated with shutting down more generators than necessary (eg. When steam turbine driven generators are being rejected).

c) Hybrid schemes that depend on transmission path status and the type of disturbance. This type of scheme is initiated by line status similar to type a) described above, but the amount of generation shed depends on the type of fault that caused the transmission path outage. If the short circuit is caused by a multiphase fault, more generation will be shed than if it was caused by a single line to ground fault. The scheme depends on the type of protection that sensed the fault (phase to phase or phase to ground. This type of scheme is limited in application. The fault detectors may only be at a limited number of locations, or the number of direct transfer trips to indicate the different types of fault associated with the various changes in line status need to be transmitted to the generator rejection set up facility.

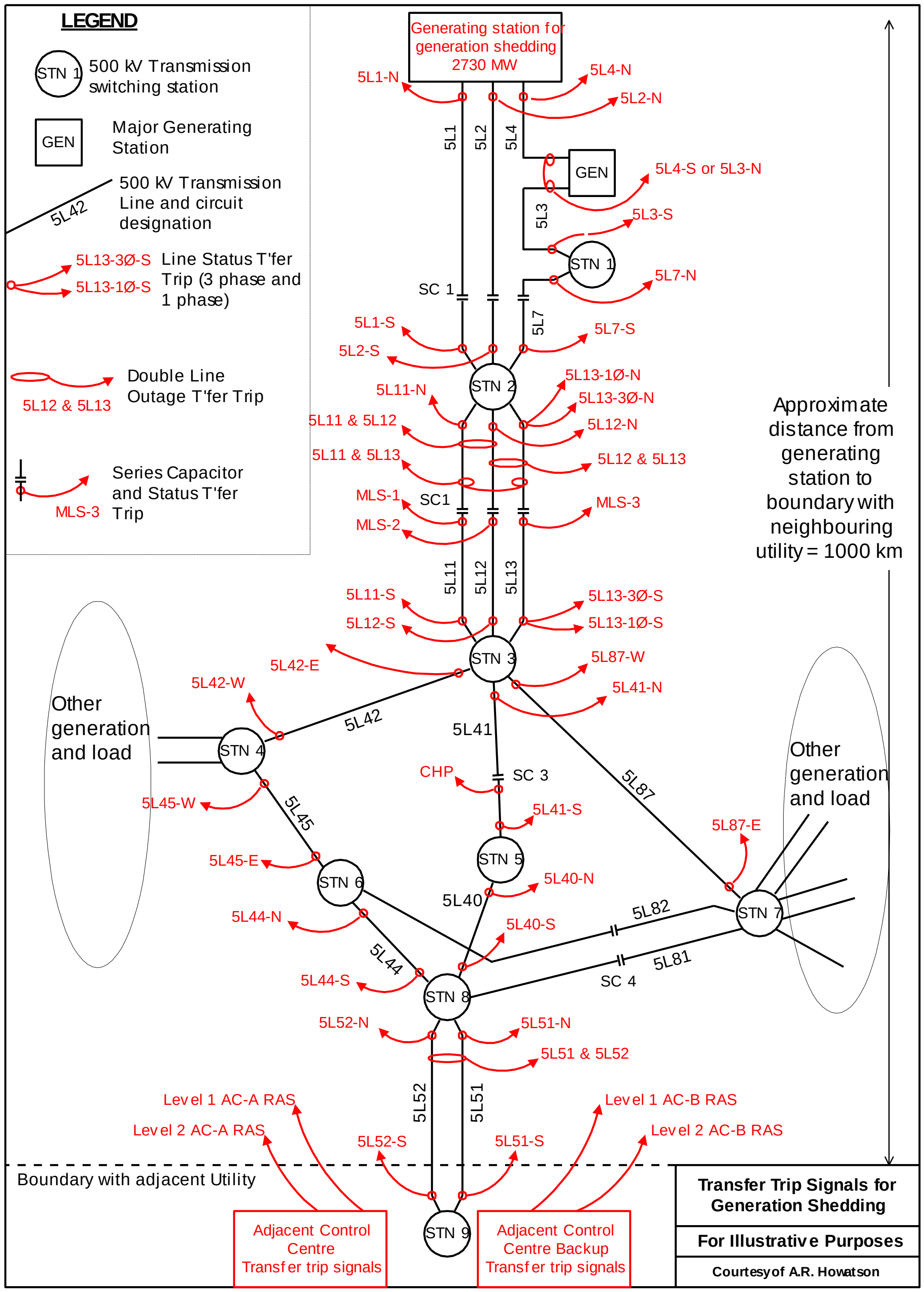


Figure. Wide area generator rejection scheme.

Load Rejection Schemes

Load rejection is a protection system designed to trip load following the loss of a major supply to the affected power system area. The major supply deficiency may be caused by the loss of generation or key transmission facilities. Load rejection may be also initiated to alleviate overload conditions of power system elements. It can also be initiated when certain power flow thermal interfaces are exceeded. LR systems redundancy may be required if a potential inter-area impact can be initiated by a normal contingency. Regional Reliability Councils usually have requirements involving such protective or control schemes. They may be considered as part of the Special Protection Systems (SPS) or Remedial Action Schemes (RAS) discussed in the report. Load rejection systems are completely separate from automatic under frequency load shedding programs.

Load rejection schemes are usually analyzed and initiated from a central location. A reliable communication network is required to collect the needed input information upon which to base the decision and then issue the required tripping commands. The arming of the Load Rejection systems may be based on power system conditions and recognized contingencies analyzed off-line and can be either automatic or manual via an operator. An alternative is to arm the scheme based upon system studies and take action in real-time if the contingency develops.

Load rejection schemes can also be implemented from local information such as the loss of a generator or transmission line to a generating source. This action may be automatic, based upon the actual loads and generation or it can be the result of an alarm, followed by local operator or central system control room command.

Stabilizers

The addition of power system stabilizers (PSS) to the automatic voltage regulators on generators in the power system to damp low-frequency oscillations is common. Conventional PSS design uses feedback of local measurements to damp the oscillations. When inter-area oscillations are involved, tuning the feedback gains of the PSS can be challenging. Occasionally stabilizers have had to be retuned as system conditions evolve. A proposed improvement in PSS design [Snyder] is to include remote phasor measurements in the input signals to the PSS. Even with conventional PSS there are questions concerning the optimal location of the PSS to damp inter-area oscillations. With both the PSS location and the choice of remote measurement it is possible to effectively damp the desired inter-area oscillation.

In [14] an adaptive tuning technique was used to design both a conventional PSS and a remote feedback controller (RFC) for a small system. The accelerating power of a local and a remote machine were used as inputs to the RFC. The RFC was robust over a broad range of operating points of the model system.

Out-of-step relaying [9], [10], [11]

A loss of synchronism condition occurs when generators in one part of the network accelerate while other generators somewhere else decelerate thereby creating a situation where the system is likely to separate in 2 parts.

The conventional relaying approach for detecting loss of synchronism is by analyzing the variation in the apparent impedance as viewed at a line or generator terminals. Following a disturbance this impedance will vary as a function of the system voltages and the angular separation between the systems.

Out of step, pole slip or just loss of synchronism are equivalent designations for the condition where the impedance locus travels through the generator. When the impedance goes through the transmission line the phenomenon is also known as power swing. However, all of them refer to the same event: loss of synchronism.

For a *stable* swing the apparent impedance moves fast at first, slowing down as a new equilibrium is reached, with system voltages not going beyond 90 degrees approximately. If the system voltages continue to drift apart a non-return point is attained where the system becomes *unstable.* When the impedance locus intersects the total system impedance line (in the RX plane) the system voltages are 180 degrees or out of phase. This point is called the system electrical centre.

The philosophy behind the use of out-of-step relaying is simple and straightforward. When two areas of a power system or two interconnected systems lose synchronism, the areas should be separated in order to avoid equipment damage or a system-wide shutdown.

Ideally, the systems should be separated at such points as to maintain a balance between load and generation in each of the separated areas. To accomplish this, out-of-step tripping must be used at the desired points of separation and out-of-step blocking used elsewhere to prevent separating the system in an indiscriminate manner. Where a load-generation balance can not be achieved in a separated area and there is excess load as compared to generation, some means of shedding non-essential loads will have to be used in order to avoid a complete shutdown of the area.

While this philosophy may be simple and perhaps obvious, it is often difficult to implement an out-of-step relaying program. This is primarily due to the difficulty in obtaining the necessary system information to set the relays. To apply out-of-step relaying on any system, the following information is required.

1. Impedance swing loci for various system conditions.
2. The maximum slip (max. angle) between systems or system areas.

On small, simple systems, it is possible to obtain the impedance loci using an approximate graphical procedure(1). On other systems, especially for large networks, it is not possible to use this simplified procedure and complete transient stability studies are required covering all possible combinations of operating conditions.

The maximum rate of slip can only be obtained from transient stability studies. Only the maximum slip is of importance and need be determined. Knowing the swing loci and the maximum slip, it will be possible to obtain reasonable settings for the out-of-step relaying equipment.

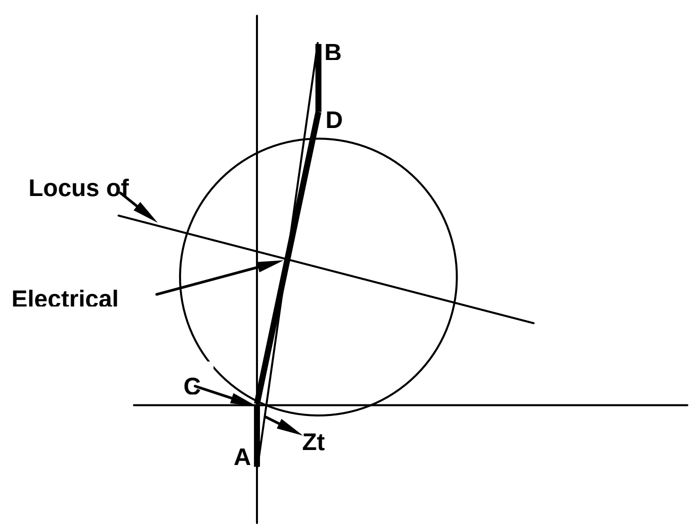


Figure. – Principle of out-of-step relaying.

Underfrequency Load Shedding [7], [8]

During severe system emergencies, which result in insufficient generation to meet load, an automatic load shedding program throughout the affected area can prevent a total system collapse. It also helps to achieve fast restoration of all affected loads. The application of underfrequency relays in substations throughout the load area, preset to drop specific percent magnitudes of load at predetermined low system frequency values, provides the simplest automatic load shedding program. Relay settings can be developed to drop the minimum load to arrest system frequency decay at a safe operating level. Additional underfrequency relays can also be applied to initiate a safe and orderly separation or shutdown if the emergency is beyond the capabilities of the load shedding program.

The load shedding relays may be electromechanical, solid-state or computer-based. The measuring element senses a frequency equal to its setting and will operate after a certain amount of time has elapsed after the frequency passes through its setting on its way down. The load shedding relays are installed in distribution or subtransmission stations, where feeder loads can be controlled. Loads throughout the system are classified as being critical, or non-critical. The order of priority of shedding is determined by the relative criticality of the load.

The load-shedding program must be coordinated with equipment operating limitations under low-frequency operation. These limitations or restrictions are primarily associated with operation of steam turbines or powerhouse auxiliaries. In general, continuous steam turbine operation should be restricted to frequencies above 58.5 Hz (60 Hz system base), and operation below 58.5 Hz should be for a limited time only, e.g. 10 minutes or less. The controlling parameter is the fatigue of turbine blades at low frequencies, which is a limitation determined by the specific turbine manufacturer. Tests on power plant auxiliary performance indicate that a limit of approximately 53-55 Hz, below which plant output begins to reduce and motors, driving constant Kva load, will see an increase in current, increasing heating and approaching overcurrent relay settings.

Following the Northeast blackout of 1965, interest in underfrequency load shedding became a dominant concern of utilities in the U.S. A PSRC survey of their plans in this regard was made in 1966. The use of such relays was accepted by a large majority of utilities but the specific application varied widely. Most utilities planned to use three frequency levels with a definite time delay over and above the operating time of the frequency sensing element of three to ten cycles (60 Hz base) although one company reported nine frequency levels. The majority selected seven to ten percent of total connected load at each frequency level. The most popular tripping frequencies were 59.1 to 59.5 Hz as the highest level and 58-59 Hz as the lowest.

A follow-up survey was conducted by the PSRC in 1974, which revealed that underfrequency relays for system preservation was universally accepted. The experience reported indicated that these relays were effective in achieving system preservation although there were some instances of malfunctioning of the relay scheme resulted in unnecessary load interruptions. These incidents were caused by connected motor or cable loads where the natural frequency was below the relay settings. The most common solution was to increase the time delay.

Of the 108 companies reporting, only one did not have a program to interrupt load during underfrequency conditions. All companies carried out the program automatically. Supplemental control was provided by 41 companies to interrupt load also by manual operation of a remote supervisory control system. Approximately 65% of the companies shed 25% or 30% of their load by underfrequency. These values were generally dictated by pool agreements. All except four companies used multiple frequency levels with a fixed time delay. The most popular was 3 levels, then 2 levels, followed by 5-15 levels. The most common time delays were six cycles.

An modification to the underfrequency scheme is to determine the rate of change of frequency decay. A relay responding to this quantity would then anticipate the final low frequency value and begin shedding load to arrest this decay. The calculations and the relays are more complex but two utilities reported their use in the 1974 survey, with a total of 96 relays in service. These relays were being eliminated as a result of pool policy.

Load that has been shed must be restored when the system frequency returns to normal. Automatic load restoration systems are in service, which accomplish this function. There are differences in the practice of restoration. Some utilities restore as the frequency increases toward normal; others restore after the frequency has returned to normal. In either event, restoration must also be done in steps, with sufficient time-delays, so that hunting between load shedding and load restoration does not occur. The restoring steps should be significantly below the shedding steps so restoration will not result in a repeat of the generator-load imbalance. There is also some concern about the priorities assigned to the loads in the program. On the face of it, the most critical loads would be public safety and welfare related such as hospitals or airports and should be the last to be shed and first to be restored. On the other hand, they are usually the installations equipped with house generators and are self-sufficient in this regard so they might be candidates for the first step to be shed and the last to be restored. This, however, may not be a popular decision. From the technical point of view, however, the last to be shed because of its priority position is also at the lowest frequency and would be the first to be restored. If the generation-load imbalance has not been corrected, than the frequency must return to the lowest level before shedding the restored load.

Underfrequency relays are also used for reasons other than tripping load as follows:

- Alarms to the operators
- Automatic loading of hydro plants
- Separation from neighboring utilities
- Permissive interlocks in generating stations
- Isolation of selected loads with matched generation
- Supervision of generator manual emergency trips
- Protection of large motors and generators
- Protection of generators during start-up
- Starting oscillographs

Undervoltage Load Shedding

Undervoltage load shedding is an option that is sometimes used as a final means of avoiding a wide area voltage collapse when all other effective means are exhausted. The action of shedding load is no different from other load shedding schemes including underfrequency load shedding and overload load shedding. The initiation by low voltage, possibly in combination with other parameters provides the unique characteristic of this type of scheme.

Detection of low voltages on the transmission system may indicate the lack of sufficient reactive power to maintain system stability. If other emergency control actions such as reactive switching, are not effective in restoring system voltages, it may be necessary to shed load in order to maintain system voltage stability. Undervoltage load shedding operates when there is a system disturbance and the voltage drops to a certain pre-selected level for a certain pre-selected time period. It is expected that the voltage will then stabilize or recover to normal levels. Loads with high absorption of reactive power are especially suitable for shedding to prevent voltage collapse.

A complicating factor in load shedding schemes is that voltages may be very close to normal at the onset of voltage collapse. It is the inability of available reactive support to maintain the voltages that lead to the imminent wide area voltage collapse and blackout. Because voltage levels may be so close to normal levels at the onset of collapse, the low voltage parameter may be supplemented by other parameters, such as transmission circuit status, and/or availability of reactive power reserve. The need to measure parameters and initiate load shedding in diverse locations may require a true wide area protection system.

Many power utilities offer special tariffs for customers, who allow some loads to be disconnected in certain circumstances. If this type of volunteered tripping of low priority load can be initiated automatically, it can also be included in a protection system against voltage collapse. A final measure to avoid a system blackout, can be to shed high priority load. In most cases it is enough to shed a very small part of the total system load, in the affected area.

Turbine Fast Valving [6]

The purpose of turbine fast valving is to reduce the generator output without removing the unit from service. This is desirable when the system is stressed, e.g. upon some occurrence which would result in a transient stability problem. By reducing the generator output, the stability is not endangered and the unit can be returned to full output, maintaining system security.

There are two concepts in use. TVA, for example, closes the turbine valves to a predetermined position and stays there until the operator returns the unit to a desired load level. This procedure requires a turbine bypass system to allow the trapped steam to escape until the boiler pressure matches new load level. AEP has opted to use a momentary fast valving (MFTV) scheme, which closes the turbine valves momentarily, and then allows them to return to a predetermined position. The scheme reduces the turbine mechanical power about 50% within one second. The valves then reopen automatically to their original positions, restoring mechanical power to the pre-disturbance level in less than 10 seconds.
The installation of this MFTV at AEP's Rockport plant has several advanced protection schemes as well as the special protection scheme. The plant started out as a single 1300MW coal-fired unit connected to the AEP 765kV system through a single line to Jefferson Station. To prevent loss of the unit for a single-phase-to-ground fault, single phase tripping and reclosing was installed. This is not a new scheme being used in Europe but it is not a general practice in the U.S. Since its inception it has been invaluable in maintaining vital generation at AEP's westernmost boundary. Subsequently, a second 1300 MW unit was installed, together with a second 765 kV line to the west, a tie to Sullivan station and a relatively weak interconnection to a neighboring utility.

This system configuration resulted in several unusual stability problems. The most striking was the fact that a three-phase opening of the Rockport-Jefferson line, without any fault, is more severe with respect to plant stability than a three-phase opening resulting from a fault. This is because, in response to a voltage depression due to a nearby fault, the excitation level of the Rockport units is boosted via voltage regulator action, which increases the internal generator voltage and, in turn, improves the plant's stability performance.

Another special control was the Quick Reactor Switching (QRS) scheme. For selected disturbances, a 150 Mvar shunt reactor bank at Rockport on the Rockport-Sullivan line is automatically opened in about 5 cycles and reclosed in about 2.5 minutes. In addition, a Rapid Unit Runback (RUR) is installed on both Rockport units. This scheme automatically reduces the output of each unit by about 50 MW within 30 seconds and by 200 MW within 3 minutes following selected disturbances. This maximizes plant production since plant output curtailment is deferred until after a disturbance, rather than prior to anticipated contingencies. Finally, an Emergency Unit Tripping (EUT) scheme for both Rockport units provides an intentional turbine trip of one of the units following selected disturbances.

Each of the supplementary controls requires that three input conditions be met in order to operate: 1) pre-contingency Rockport area transmission status, 2) pre-contingency Rockport plant output; and 3)type of contingency. The supplementary controls are asymmetric, i.e. the controls act differently in response to events on one line than they do in response to events on the other line. All of the schemes have arming switches for personnel to be able to activate or disable these controls based in system needs. Historically, the MFTV scheme is armed about 99% of the time, the RUR and EUT schemes only 1% of the time. The QRS control is disabled only when the Rockport-Jefferson line is out of service.

Emergency Control Schemes

Secondary Voltage Control

Secondary voltage control is mainly used for controlling the overall system voltage profile in a region in such a way that maximum robustness against voltage collapse is achieved. The secondary voltage control system derives voltage set-point values for a number of pre-defined so called pilot nodes, chosen to be well representative of voltage in the region. The primary voltage control systems (tap-changer controllers and AVRs of generators, synchronous condensers and SVCs) then keep the voltage at these pilot-nodes at the desired value. By distributing the reactive power generation in a suitable way, reactive power margins in the synchronised units can be optimised.

Deployment Of Reactive Power Reserves

Reactive power support in the emergency area can be achieved by:

- shunt capacitor bank connection and shunt reactor disconnection;
- shunt capacitor ”boosting” by temporarily decreasing the number of series groups in a shunt capacitor bank;
- increased Mvar output from reactive power controlled machines;
- temporary reactive power overload of synchronous machines;
- decrease of real power generation to enable increased reactive power generation for generators in the emergency area, can be efficient under certain circumstances.

Actions Of OLTC Transformers

The action of the on-load tap-changers (OLTCs) operating on the power transformers at various voltage levels has the main goal to supply the load at a voltage kept within a given range, as close as possible to the rated value. For a voltage collapse scenario the bulk system voltages are slowly decreasing while the OLTCs are restoring the distribution system voltages.

The simplest method to eliminate the OLTC as a contributor to voltage collapse is to block the automatic raise operation during any period where voltage collapse appears to be a concern. The decision to temporarily block the tap-changer can be made using locally derived information or can be made at a central location and the supervisory system can then send a blocking signal to the unit. A co-ordinated blocking scheme can be utilised to block operation of OLTCs in an area where voltage instability is imminent. The co-ordinated scheme can be accomplished with undervoltage schemes acting independently in a co-ordinated fashion at various stations within a region, or it can be a centralised scheme that recognises a pattern of low voltages at key locations.

A more sophisticated use of the OLTCs, than just blocking them, could be to reduce the voltage set-point. A larger load relief can be achieved in this way. As for the blocking of OLTCs the effectiveness is largely dependant on the characteristics of the supplied system, such as type of load, degree of shunt compensation, number of OLTCs on lower levels, etc.

ENEL, Italy, describes an interesting strategy for controlling OLTCs:
- In a secure state, all OLTCs are controlled as usual. HV voltage set-points are chosen to minimise active losses in the subtransmission networks.
- In emergency conditions, EHV/HV and HV/MV OLTCs are blocked, keeping the minimum possible transformer ratio for EHV/HV transformers.
- In alert state, where credible contingencies would lead to voltage instability, the MV voltage set-points of HV/MV OLTCs are decreased while EHV/HV OLTC set-points are *increased*. The objective is to reduce reactive losses and get more reactive support from shunt elements in subtransmission networks.

Active Power Support, Gas Turbines, HVDC Lines, Etc.

Normally active power support by gas turbine start up and emergency power from HVDC lines in the critical area, are very efficient in a stressed situation. HVDC active power support can be achieved in the time scale of seconds, while the gas turbine start up process takes some minutes. A large amount of the critical situations are however of long term type and the gas turbines will have a reasonably good chance to contribute to the system stability.

Rate Of Voltage Variation As A Local Collapse Criterion

The receiving end voltage as a function of time can be used to identify, or predict, a voltage collapse situation. Since the voltage profile includes step-changes from shunt reactor and shunt capacitor switchings, as well as tap-changer operations, faults and fault clearance processes, the signal needs proper low pass filtering. On the other hand the voltage profile is affected by the slow (and even sudden) load variations and therefore also requires some sort of high pass filtering. The filtering process will introduce an unavoidable delay with respect to the original signal and therefore increase the detection time of the collapse criterion.

Interfaces Among Utilities, Co-Ordination

The degree of interconnection of the power systems around the world is increasing, and the systems tend to be larger and larger and stronger and stronger. On the other hand competition on the electricity market is splitting the system on different owners and operators, resulting in less exchange of information. In this environment it is extremely important to use the strengths of the interconnected system, for abnormal operation conditions, such as severe faults and voltage instability. Detailed agreements between all relevant parties involved in the power system process have to be established and accepted. The operators should also be trained in correct use of these agreements, in order to be able to use the full capability of the system in stressed situations.

Decision Making For Curative Actions

Regarding the decision to take curative actions, it may be difficult to choose a simple criterion that accommodates the large numbers of possible system conditions (topology, load level, etc.) and incidents.

If system wide collected measurements are available more elaborate criteria may be thought of to trigger the curative action. In this respect a statistical methodology may help the protection designer to choose the appropriate criterion. Statistical methods and large data bases of system scenarios are built off-line, using numerous numerical simulations, and automatic learning methods to extract the relevant decision criterion.

Protection Systems Already In Operation

In this section a number of systems, specially designed for protection against voltage collapse, will be described. Both systems already in operation and systems planned are addressed. This section is structured in such a way that results of the actions are more and more severe to the customers.

Secondary Voltage Control Within EDF

In order to co-ordinate the primary regulators, and also to deal with the slower and/or high amplitude variations, the French power system has been fitted with Secondary Voltage Control at regional level. This control performs a corrective action automatically, by modifying the set-points of the primary regulators of a set of generators (the *regulating generators*) which are located within a *control zone*. The time constant of the system is about three minutes. For that purpose, the French EHV power system is divided into *control zones*, which are chosen so as to be homogeneous from the point of view of voltage, and as independent as possible. The voltage is controlled in each zone by an automatic regulation of the reactive power supplied by the regulating generators belonging to the zone. This action is performed so as to control the voltage at a special point in the zone, called *pilot node*; this node is chosen so as to be well representative of the voltage fluctuations throughout the control zone.

A new generation of secondary voltage control is now going to be implemented. This new scheme is called the Co-ordinated Secondary Voltage Control, because the control signals for neighbouring zones will no longer be calculated on an independent basis, as it was until now.

Operator Aid Based On Load/Power Margin (Evarist, EDF France)

Before reaching the stage of curative actions, EDF considers that it is very important that the operators in the control centres should be able, through preventive tools, to detect liable contingencies to come, by means of indicators of the risk of voltage profile instability. Evariste is based on a sensitivity technique, initially proposed by N. Flatabø for network planning. The principle is to provide the margin of active and reactive power from the current operating point to voltage instability, through successive linearizations of the algebraic equations describing the power system behaviour. The successive linearizations make it possible to take into account the major non-linearities, which occur when one of the generators reaches its reactive output limit. The Evariste indicator may give a prediction for a time horizon of about 30 minutes, which enables the operators to order efficient actions.

Protection Against Voltage Collapse In The Hydro-Quebec System

The Hydro-Québec system is characterised by long distances (up to 1000 km) between the northern main generation centres and the southern main load area. The peak load is around 35,000 MW. The long EHV transmission lines have high series reactances and shunt susceptances. At low power transfers, the reactive power generation of EHV lines is compensated by connecting 330 Mvar shunt reactors at the 735 kV substations. At peak load, most of the shunt reactors are disconnected while voltage control on the lower side of transformers implies connection of shunt capacitors. Both effects contribute to a very capacitive characteristic of the system.

Automatic shunt reactor tripping was implemented in 1990, providing an additional 2300 Mvar support near the load centres. This amount is likely to triple in 1996 after an upgrade of the present devices. The switching is triggered by low 735 kV bus voltages or high compensator reactive power productions. Another emergency control used is the automatic increase in voltage set-points of SCs.

Blocking Of Tap-Changers On Distribution Transformers (EDF Experience)

The effect of tap-changer blocking depends highly on the load characteristic, if all the taps all the way down to the customer level can be blocked. It is also important to keep a high voltage in systems with a large amount of shunt capacitors and cables. The automatic blocking of EHV/HV OLTCs was implemented in France after the voltage collapse of January 1987. The choice of blocking EHV/HV OLTCs was taken among different strategies which were simulated from the reconstruction of the incident, with a long term dynamic program. The decision to implement automatic blocking of EHV/MV and HV/MV OLTCs has recently been taken. As modifications are needed at different levels of the control centres, this implementation should began in 1997.

Reduction Of Set-Point Voltages In An Area Depending On Voltage Criteria

The set-point value in France may be reduced by 5% at the MV voltage level of the HV/MV or EHV/MV OLTCs. This reduction may be ordered manually from the special emergency system situated in each regional control centre. Different field tests and analysis of operation within EDF have shown that this 5% MV voltage reduction leads in fact to an effective load reduction by 2 to 3%; the effect of the reduction is exhausted after a delay of about 2 hours because of the action of the regulators, at load level, and also because of the manual actions of the consumers who try to find means to restore their needs of consumption.

Special Protection System Against Voltage Collapse In Southern Sweden

The objective of the special protection system is to avoid a voltage collapse after a severe fault in a stressed operation situation. The system can be used to increase the power transfer limits from the North of Sweden or to increase the system security or to a mixture of both increased transfer capability and increased security. The special protection system was commissioned in 1996. The system is designed to be in continuous operation and independent of system operation conditions such as load dispatch, switching state, etc.

A number of indicators such as low voltage level, high reactive power generation and generator current limiters hitting limits are used as inputs to a logical decision-making process implemented in the Sydkraft SCADA system. Local actions are then ordered from the SCADA system, such as switching of shunt reactors and shunt capacitors, start of gas turbines, request for emergency power from neighbouring areas, disconnection of low priority load and, finally, load shedding. Shedding of high priority load also requires a local low voltage criterion in order to increase security. The logic is shown in Figure 5.

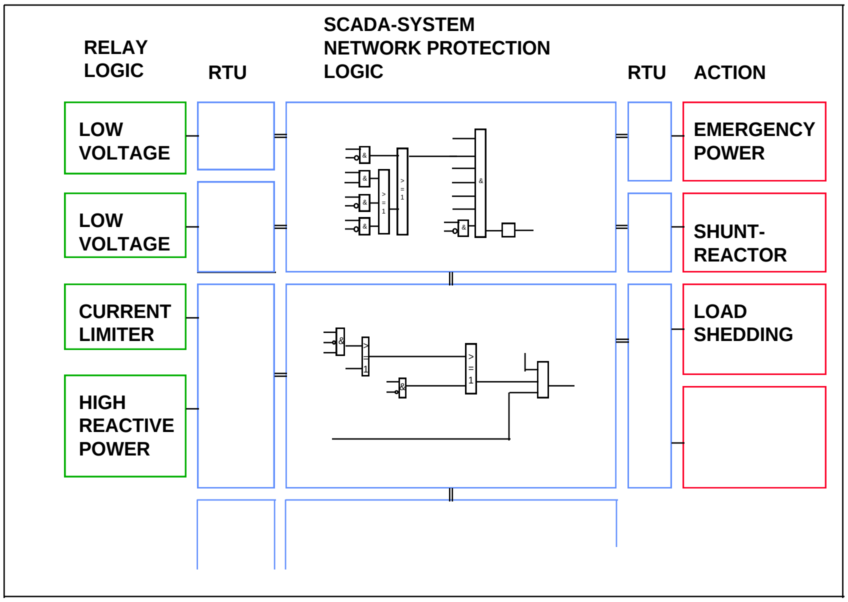


Figure: SCADA system network protection logic in the Swedish system.

The special protection system is designed to have a high security, specially for the load-shedding, and a high dependability. Therefore a number of indicators are used to derive the criteria for each action.

Wide Area Undervoltage Load Shedding (BC Hydro System)

BC Hydro has developed an automatic load shedding remedial action scheme to protect the system against voltage collapse. The voltage collapse may be caused by a second or multiple sequential contingencies such as the forced outage of a critical major transmission line while the system is already weakened by another outage. Closed loop feedback scheme will monitor the system condition, determine the need of load shedding, shed appropriate blocks of pre-selected loads in 10 to 120 seconds with sequential time delays, and stop when proper system voltage and dynamic VAr reserves are restored.

The scheme is based on a centralised feedback system which continually assesses the entire system condition using the actual dynamic response of the system voltages at key buses and dynamic var reserves of two large reactive power sources in the load area to identify impending voltage instability and then sheds pre-determined loads in steps recursively until the potential for voltage collapse is eliminated. The use of both low voltage and low var reserve provides an added security against possible voltage measurement errors and allows higher than usual undervoltage settings to protect against conditions where collapse starts at near normally acceptable operating voltage levels. The key voltage buses are selected based on their sufficiently high fault levels and having multiple low impedance connections to load centres so that local system outages or var equipment operations will not affect the voltages significantly to cause misoperation. The var sources are selected based on their large capacity relative to the total load area dynamic var capacity. In addition, they must have multiple connections to the load centre so that their reserves can be reliably used to reflect the system reserves. Since the low voltage and low var reserve occur for system voltage instability irrespective of the cause such as different line outages, major reactive support equipment outages, increased loading and intertie flows, transformer tap movement, or shifted generation patterns, this scheme will provide a safety net against voltage collapse from such causes.

Ontario Hydro System

A co-ordinated undervoltage protection scheme is employed consisting of:

a) Short-time automatic reclosure on major 230 kV lines supplying areas with voltage collapse risk.
b) Automatic load shedding of different areas in two time steps. If in reference substations the voltage measurement gives voltage drops below a certain reference value the areas are shed in 10 s.
c) Automatic capacitor switching for maximum reactive power infeed and voltage support.
d) Automatic OLTC-blocking.

Load Shedding Based On Topology Data (Tripping Of Lines) (Eda, Enel Italy)

The structure of the Italian network together with the considerable foreign exchanges and with the high power transmitted, mainly from North to South due to the lack of production in the central and southern areas, determine "critical sections" defined as ideal lines dividing the network in not interconnected parts along where the splitting is more likely to happen. Control actions, such as load shedding, to avoid network splitting are justified by the fact that the objective of an operation under security conditions cannot always be fulfilled against any credible disturbance. The reasons may be a weakness of intrinsic type or due to outages for maintenance or repairs purposes of generators, lines and stations equipment.

Future Trends and Realization Structures in Wide Area Protection

The meaning of wide area protection, emergency control and power system optimization, may vary dependant on people, utility and part of the world, although the basic phenomena are the same. Therefore standardized and accepted terminology is important. Since the requirements for a wide-area protection system vary from one utility to another, the architecture for such a system must be designed according to what technologies the utility possesses at the given time. Also, to avoid becoming obsolete, the design must be chosen to fit the technology migration path that the utility in question will take. The solution to counteract the same physical phenomenon might vary extensively for different applications and utility conditions. A certain utility might wish to introduce a complete system to take care of a large number of applications in one shot, while others want to move very slowly with small installations of new technology in parallel with present systems. Some utilities want to do large amount of the studies, design and engineering themselves, while others want to buy complete turn-key systems. It is important for any vendor in this area to supply solutions that fit with different utility organizations and traditions.

The potential, to improve power system performance using smart control instead of high voltage equipment installations, seems to be great. The introduction of the Phasor Measurement Unit (PMU) has greatly improved the observability of the power system dynamics. Based on PMUs different kinds of wide area protection, emergency control and optimization systems can be designed. A great deal of engineering, such as power system studies, configuration and parameter settings, is required since every wide area protection installation is unique. A cost effective solution could be based on standard products and standard system designs.

The intentional automatic control action that can be taken to save the power system or restore sufficient reserve margins, can be divided into preventive and corrective actions. During normal operation, the focus is on economic aspects of power system operation, and economic operation is hence playing the more important role. While during more stressed network operational conditions, such as in an alert state, and in particular during emergency situations, the focus for control objectives shifts towards stability considerations. The ultimate objective here is keeping as much as possible of the network intact and generators connected to the grid. The breakdown normally results in one or more severe problems in the power system. The main concern in the emergency state is of course system security. System protection schemes form in this respect a last line of defense in case of severe disturbances. The aim of actions taken by SPS is to provide uninterrupted power supply by use of sometimes rather ruthless methods, i.e. by taking actions that could be referred to as measures of last resort (and which would not be used during normal operational conditions). The objective of the system protective scheme is hence to retain power system operational security.

Tailor-made wide area protection systems against large disturbances, designed to improve power system reliability and/or to increase the transmission capacity, will therefore most likely be common in the future. These systems will be based on reliable high-speed communication and extremely flexible protection devices, where power system engineering will become an integrated part of the final solution. This type of high performance protection schemes will also be able to communicate with traditional SCADA systems to improve functions like DSM, DA, EMS and state estimation.

As the electricity market is restructured all around the world, the nature of utility companies is changed. In particular, the downsizing of the staff makes it difficult or impossible for the utility to perform many R&D functions. As a result, there is a trend in the industry where utilities collaborate with vendors to cope with issues related to the grid. The utility can view its partnering vendor as a substitute for its vanishing R&D department to perform tasks that its existing staff cannot handle. The vendor sees the partnering utility as the "sounding board" for its product development and the place to demonstrate its latest products. This closed-loop collaboration, which already exists in the form of pilot projects in wide-area protection, is found to be fruitful to both parties.

Enhancements to SCADA/EMS

At one end of the spectrum, enhancements to the existing EMS/SCADA can be made. These enhancements are aimed at two key areas: information availability and information interpretation. Simply put, if the operator has all vital information at his fingertips and good analysis facilities, he can operate the grid in an efficient way. For example, with better analysis tool for voltage instability, the operator can accurately track the power margin across an interface, and thus can confidently push the limit of transfer across an interface.

SCADA/EMS system capability has greatly improved during the last years, due to improved communication facilities and highly extended data handling capability. New transducers such as PMUs can provide time-synchronized measurements from all over the grid. Based on these measurements, improved state estimators can be derived.

Advanced algorithms and calculation programs that assist the operator can also be included in the SCADA system, such as "faster than real time simulations" to calculate power transfer margins based on contingencies.

The possibilities of extending the SCADA/EMS system with new functions tend to be limited. Therefore it might be relevant to provide new SCADA/EMS functions as "stand alone" solutions, more or less independent of the ordinary SCADA/EMS system. Such functions could be load shedding, due to lack of generation or due to market price.

Multilayered architecture

A comprehensive solution, that integrates the two control domains, protection devices and EMS, can be designed as in Figure below.

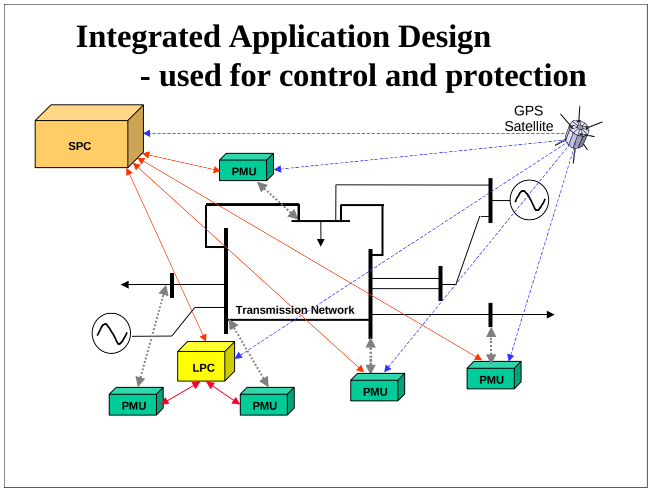


Figure. Multilayered wide area protection architecture.

There are up to three layers in this architecture. The bottom layer is made up of PMUs, or PMUs with additional protection functionality. The next layer up consists of several Local Protection Centers (LPCs), each of which interfaces directly with a number of PMUs. The top layer, System Protection Center (SPC), acts as the coordinator for the LPCs.

Designing the three-layered architecture can take place in several steps. The first step should aim at achieving the monitoring capability, e.g., a WAMS (Wide Area Measurement Systems). WAMS is the most common application, based on Phasor Measurement Units. These systems are most frequent in North America, but are emerging all around the world. The main purpose is to improve state estimation, post fault analysis, and operator information. In WAMS applications a number of PMUs are connected to a data concentrator, which basically is a mass storage, accessible from the control center, according to Figure below.

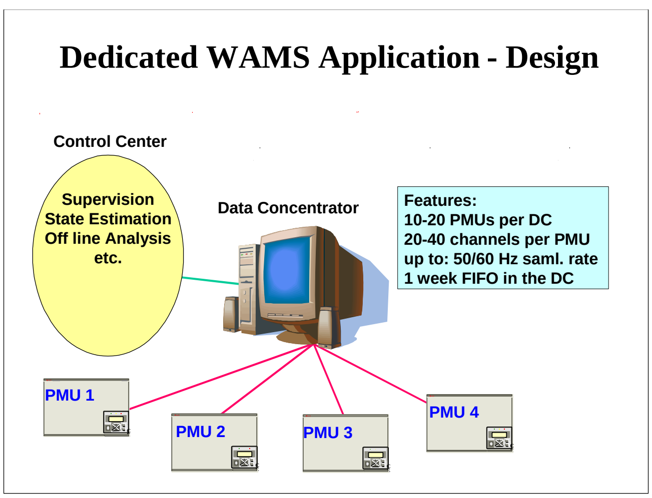


Figure. WAMS design.

Starting from a WAMS design, a data concentrator can be turned into a hub-based Local Protection Center (LPC) by implementing control and protection functions in the data concentrator, Figure below.

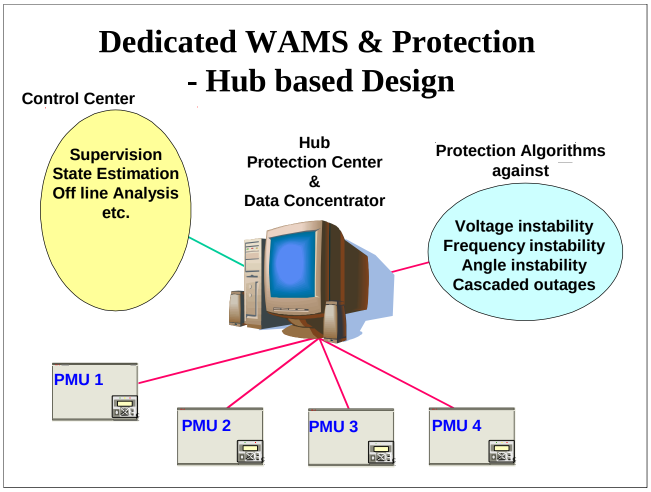


Figure. Hub based wide area protection design.

A number of such local protection centers can then be integrated into a larger system wide solution with a System Protection Center (SPC) at the top. With this solution the local protection center forms a system protection scheme (SPS), while the interconnected coordinated system forms a defense plan [39].

"Flat Architecture" with System Protection Terminals

Protection devices or terminals are traditionally used in protecting equipment (lines, transformers, etc.). Modern protection devices have sufficient computing and communication capabilities to be capable of performing beyond the traditional functions. When connected together via communications links, these devices can process intelligent algorithms based on data collected locally or shared with other devices.

Powerful, reliable, sensitive and robust, wide area protection systems can be designed based on de-centralized, especially developed interconnected system protection terminals. These terminals are installed in substations, where actions are to be made or measurements are to be taken. Actions are preferable local, i.e. transfer trips should be avoided, to increase security. Relevant power system variable data is transferred through the communication system that ties the terminals together. Different schemes, e.g. against voltage instability and against frequency instability, can be implemented in the same hardware.

The solution with interconnected system protection terminals (SPT) for future transmission system applications is illustrated in Figure below for protection against voltage instability; similar illustration can be done for angular instability.

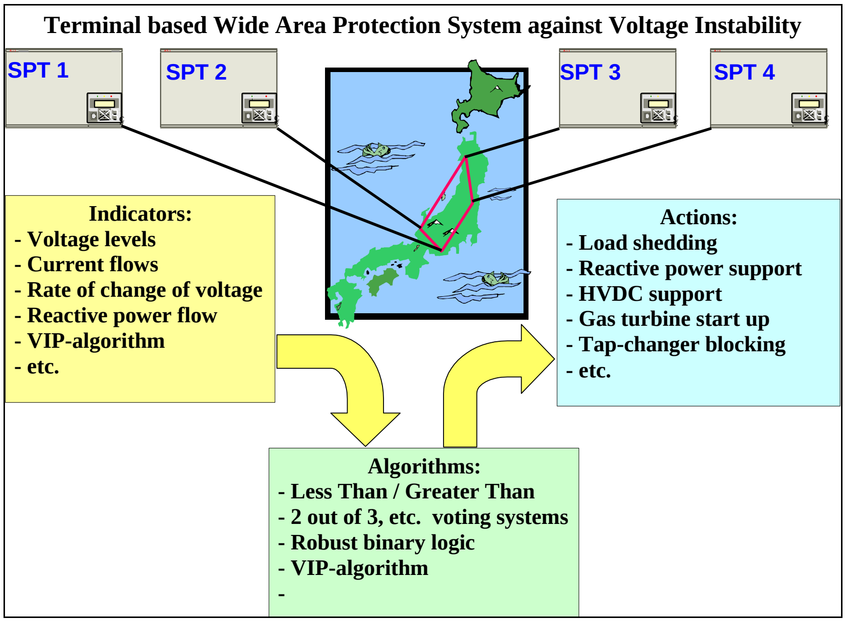


Figure. Terminal based wide area protection system against voltage instability.

Different layers of protection can be used, compare with the different zones of a distance protection. The voltage is for example measured in eight 400 kV nodes in a protection system against voltage instability. In a certain node, a certain action is taken if:

- 6 of the 8 voltages are low (e.g. <380 kV), or
- 4 of the 8 voltages are very low (e.g. <370 kV), or
- the local voltage is extremely low (e.g. <360 kV).

Using the communication system, between the terminals, a very sensitive system can be designed. If the communication is partially or totally lost, actions can still be taken based on local criteria. Different load shedding steps, that take the power system response into account – in order not to over-shed, can easily be designed.

Based on different criteria and algorithms, voltage stability indicators can be derived. These indicators can be used for pure information to the system operator, decision support to the operator or automatic actions to counteract a pending voltage instability. The criteria could be simple undervoltage detection or high reactive power flow in combinations, or more advanced local criteria, such as the VIP (Voltage Instability Predictor) [40], or system wide criteria, such as minimum singular value [41]. The sensors have to be placed at different critical locations all over the power system, see Figure x. In this way an overview of the overall system condition can be achieved and appropriate actions to mitigate a voltage collapse can be taken. Both protective actions, such as shunt capacitor switching or load shedding, and emergency control, such as request for HVDC emergency active power support or SVC reactive power support, can be implemented.

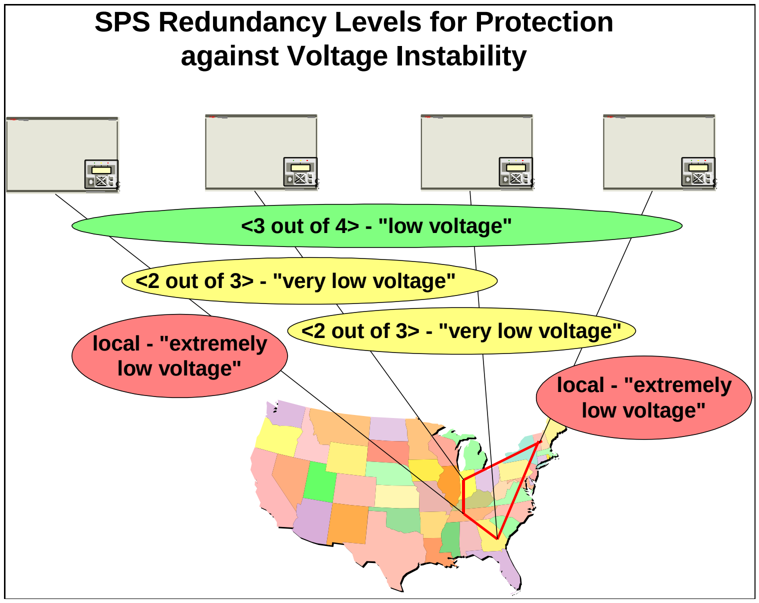


Figure. Wide area voltage stability control.

Based on time synchronized measurements of voltage and current by PMUs at different locations in the network, real-time values of angle differences in the system can be derived with a high accuracy and a high sample rate, e.g. half the system frequency (25/30 Hz), see Figure below. With this new type of real-time measurements, efficient emergency actions, such as PSS control, based on system wide data, load shedding, etc., can be taken to save the system stability in case of evolving power oscillations.

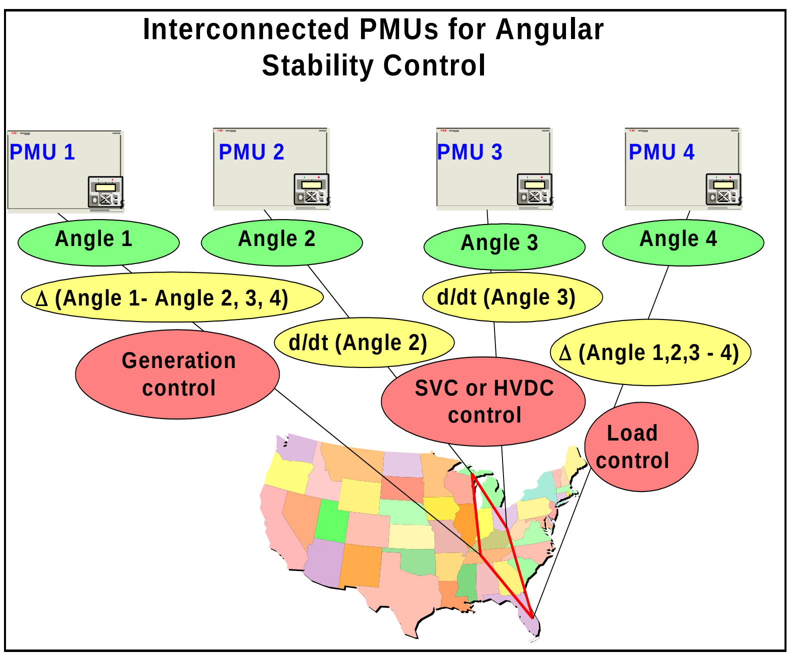


Figure. Wide area angular stability control.

System Protection Terminal

Traditionally, remedial action schemes have been hub based, i.e. all measurements and indicators are sent to a central position, e.g. a control center, for evaluation and decision. From this central position, action orders are then sent to different parts of the power system. Such a centralized system is very sensitive to disturbances in the central part. With the ring based (or WAN) communication system, a more robust system can be achieved. One communication channel can for example be lost without any loss of functionality. If one system protection terminal fails in a flat de-centralized solution, a sufficient level of redundancy can be implemented in the neighboring terminals. In other technological areas the decision power is moving closer to the process, with increasingly more powerful sensors and actuators, for decisions based on rather simple criteria. Such an independent system protection scheme, based on powerful terminals, can also serve as a backup supervision system, that supplies the operator with the most critical power system data, in case of a SCADA system failure.

The system protection terminal will probably be designed from a protection terminal to fulfill all requirements concerning mechanical, thermal, EMC, and other environmental requirements for protection terminals. Design and interfaces of a system protection terminal is shown in Figure:

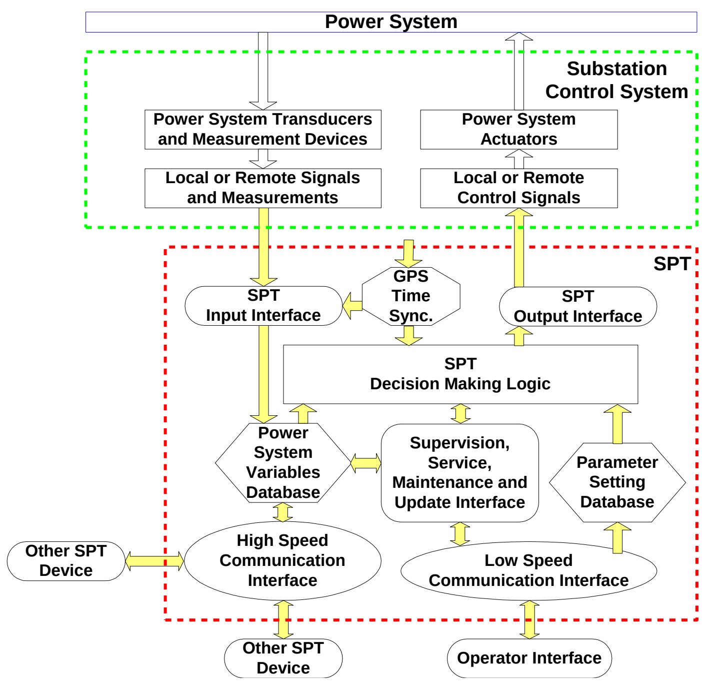


Figure. System protection terminal, design and interfaces.

The terminal is connected to the substation control system, CTs and VTs as any other protection terminal. For applications that include phasors, i.e. phase angles for voltages or currents, a GPS antenna and synchronization functions are also required. The system protection terminal comprises a high-speed communication interface to communicate power system data between the terminal databases. In the data base all measurements and binary signals recorded in that specific substation are stored, and updated, together with data from the other terminals, used for actions in the present terminal. The ordinary substation control system is used for the input and output interfaces towards the power system process. The decision making logic contains all the algorithms and configured logic necessary to derive appropriate output control signals, such as circuit-breaker trip, AVR-boosting, and tap-changer action, to be performed in that substation. The input data to the decision making logic is taken from the database, and reflects the overall power system conditions. A low speed communication interface for SCADA communication and operator interface should also be available. Via this interface phasors can be sent to the SCADA state estimator for improved state estimation. Any other value or status indicator from the database could also be sent to the SCADA system. Actions ordered from SCADA/EMS functions, such as optimal power flow, emergency load control, etc., could be activated via the system protection terminal. The power system operator should also have access to the terminal, for supervision, maintenance, update, parameter setting, change of setting groups, disturbance recorder data collection, etc.

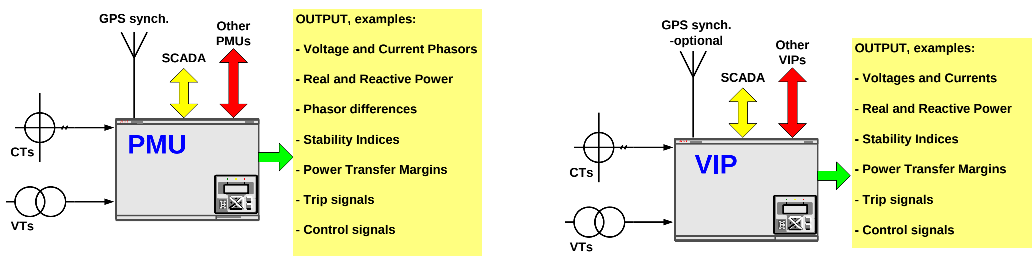


Figure. PMU and VIP terminal interfaces and outputs.

In Figure above, system protection terminals for phasor measurements and voltage stability applications are shown, with respect to interfaces and output signals. By using a well-established and accepted protection terminal as the base for a system protection scheme, all requirements concerning CT-/VT-connections, binary inputs and outputs, etc., are immediately fulfilled. The development cost will also be quite moderate, and time to market for a full system will be rather short.

It can be concluded that there seems to be a the great potential for wide area protection and control systems, based on powerful, flexible and reliable system protection terminals, high speed, communication, and GPS synchronization in conjunction with careful and skilled engineering by power system analysts and protection engineers in co-operation.

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Appendix A

Historical Examples of Wide Area Disturbances

Wide area disturbances may be triggered by wide area causes such as severe weather or geomagnetic induced currents. They may also be triggered by cascading results from localized disturbances. By virtue of their impact on a wide area, they usually affect a large amount of load and generation. Some historical examples of wide area disturbances will be briefly discussed to demonstrate the scope and impact of such disturbances.

Hydro-Quebec Blackout, 13 th March, 1989

This event was triggered by a geomagnetic disturbance that affected reactive support sources over a wide area. Harmonics flowing in the system caused seven static var compensators that were supporting the 765 kV transmission system to trip off line within seconds of each other. The static var compensators were actually tripped off line sooner than necessary because the individual protection systems were not designed for exceptional harmonic distortion of load currents. The massive loss of reactive power over a wide area resulted in instability and collapse of the backbone transmission system and blackout of the majority of the Hydro-Quebec system. Load was affected over an area of 1500 x 1000 km.

This event is an example of a disturbance that needs to be addressed by design of the power system (to prevent generation of large amounts of harmonics during geomagnetic events) and design of individual static VAr compensation protection systems to allow their full temporary overload capability to be realized even in the presence of high harmonic currents. A wide area protection or emergency control system would have had to have been extremely fast and sophisticated to have prevented a total system break-up. The event illustrates the limitations of protection and control systems in their ability to prevent uncontrolled break-up of a power system in the presence of massive crippling of the primary transmission system.

Northridge Earthquake Disturbance - January 17, 1994

The initiating cause of this equipment was a severe earthquake in the Northridge area of Los Angeles. This could be classified as a relatively localized initiating event. Initial relay operations were correct, in general, though some relay contacts may have been closed by violent ground accelerations.

The Pacific Northwest was importing power from the mountain states and the Southwest. Los Angeles generation was at a minimum. There was a net flow of power from South to North. The Rinaldi Station, about 3 miles from the epicenter had 15 lines including two 500 kV lines, terminating there.

Out of ste p relays tripped on the initial swing resulting from loss heavily loaded 500 kV transmission lines. The WSCC broke up into islands, which experienced both under and over frequency. The frequency controller on the Intermountain HVDC line attempted to correct frequency by increasing power delivered north to south. Since both ends of the line were in the same island the correction only served to produce a 2900 MW loop flow, which ultimately tripped the HVDC system. Many IPPs in the North, which could have helped restore service were tripped by underfrequency relays. Underfrequency protection tripped loads in Western Canada, more than 3000 km from the initiating event.

Correct operation of underfrequency load shedding protection systems kept most networks except those close to Los Angeles, intact. The inability of utilities to determine the connectivity of their own or neighboring systems and poor communication between control centers hampered restoration.

WSCC Interconnection Disturbance - December 14, 1994

The initiating event was a single phase-to-ground fault which caused all three terminals of Idaho Power Company's (IPC) 345 kV Midpoint-Borah-Adelaide No. 1 line to trip, properly clearing the fault. About the same time, on end of an adjacent three-terminal 345 kV line improperly tripped and open-ended this line. See comments in appendix related to this relay miss-operation, which is catalogued as hidden failure. Loss of the two 345 kV lines resulted in substantial redistribution of transmission power flow with severe results. This localized initiating event cascaded throughout the WSCC system.

Just prior to the disturbance, several of the major WSCC transmission paths were operating at or near their capacities. The effects of the disturbance spread due to several factors. About nine seconds into the disturbance, additional transmission lines opened due to overload. Oscillations of 200 MW peak-to-peak were observed on the 500 kV system between Canada, the US Pacific Northwest, and California in the US Southwest.

About 52 seconds into the disturbance, additional transmission lines tripped due to high loads and low voltages. As electricity flows automatically redistributed throughout the WSCC system, frequency out-of-step conditions occurred. The WSCC system split into several islands, and the eastern portion of Nevada was blacked out. Several major transmission lines opened due to out-of-step conditions. Some of these line openings may have increased the severity of the disturbance, while other line openings may have reduced the severity.

Numerous generating plants throughout the WSCC system tripped out of service interrupting a total of 11,300 MW of generation for various reasons (underfrequency, overfrequency, boiler instability, low voltage, etc.)

There were several opportunities for wide area protection and control systems to mitigate the effects of this disturbance.

WSCC Disturbance - 2 July, 1996

This disturbance was triggered by a fault on a 345 kV line bringing power from the Jim Bridger plant in Wyoming to Eastern Idaho. Line protection operated correctly to switch off the faulted line. However line protection in the parallel 345 kV line misoperated and switched off that unfaulted line. See comments in appendix related to this relay miss-operation, which is catalogued as hidden failure. The loss of the two lines caused loss of 1000 MW import from Wyoming to Idaho. As power flow patterns were redistributed, a 230 kV line in Oregon, more than 500 km away from the initial disturbance, also tripped due to high load and a faulty relay. See comments in appendix related to this relay miss-operation, which is catalogued as hidden failure. Loss of this line decreased power flow from Oregon to Northwestern Idaho. The system remained intact for an additional 21 seconds, until another 230 kV line supplying power from Montana to Northeastern Idaho, tripped due to the heavy load causing the apparent impedance to enter into the line protection relay characteristic. Three seconds later, four more 230 kV lines bringing power from Oregon to Western Idaho, tripped due to excessive load and low system voltage.

Thus in the space of 24 seconds, the state of Idaho lost important sources of power from Wyoming, Oregon, and Montana. There remained insufficient reactive power to support the voltage in Idaho, and most of the state blacked out due to voltage collapse. About 400,000 customers were interrupted, for a load loss of about 3400 MW.

The severe disruption to power flow in the Western US area and low voltages resulted in loss of angular stability across the California Oregon Intertie, and automatic tripping of the three ac lines that tie the Pacific Northwest to the Southwest. The flow of 4000 MW of power from North to South was interrupted. Underfrequency load shedding in California, Arizona, Southern Nevada and New Mexico tripped about 1 million customers (4500 MW load) to restore the generation/load balance. About 3300 MW of load (serving 600,000 customers) in the region to the South and East of Idaho (Colorado, Wyoming, Utah, Western Nebraska and South Dakota) was also lost.

The Northern region was left with excessive generation, and some generators were automatically disconnected. During attempts to reduce the frequency in the North, about 7000 customers became disconnected for a load loss of about 100 MW. In all, about 1.7 million customers lost nearly 8000 MW of load in an area stretching 2500 km North to South, and 2000 km East to West.

A Wide area protection scheme to detect the loss of reactive power support in the Idaho area could have helped prevent blackout of that state.

Appendix B

Protection System Miss-Operations Catalogued as Hidden Failures

From the list of wide-area disturbances, this appendix describes a number of wide-area disturbances in which protection system failures, particularly hidden failures, have been found as key contributors in the disturbance degradation. In other words, the occurrence of hidden failures caused detrimental effects in the power system parameters, and the initial single contingency terminated in a wide-area disturbance. Some background on hidden failures is also included.

Hidden Failures Theory

Hidden failures are defined as: “a permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove a circuit element(s) as a direct consequence of another switching event [34].” From the definition, it can be emphasized that hidden failures bring as a result the disconnection of a circuit element. Then, a "failure to operate" will not be considered a hidden failure due to the fact that some other protection systems will react and finally eliminate the abnormal condition. Power systems are biased towards dependability, and, sooner or later, all "events" should be cleared by the existing protection systems.

Hidden failures are defects from which any of the protection system elements may suffer and they are applicable to potential transformers (PT), current transformers (CT), cables, lugs and connectors, all kind of relays, communication channels, transmitters, receivers, etc. The fundamental difference is that these defects, by themselves, will not produce an immediate action in the system, but they will remain undetected.

The first element in a hidden failure mechanism is a Protection Element Functionality Defect (PEFD) [35]. However, having a PEFD does not guarantee that a hidden failure will occur. In general, a PEFD takes place when the protection devices are unable to perform their designed and expected actions. This defect can be present on any of the protection system elements, and may take the form of hardware failures, outdated settings and human negligence or errors.

Examples of PEFD can be a relay’s contacts that are always opened or closed, a timer that operates regardless of its pre-assigned time delay, an outdated setting in a relay, a human error in relays coordination, etc. PEFD related to hardware failures are referred to as PEFD-A, and PEFD related to relay settings, human errors or negligence are defined as PEFD-B.

The second and last element in the hidden failure mechanisms is the logic involved around the PEFD, which will determine if this first element will result in a hidden failure. It is important to note that the determining factor for an undetected PEFD is the logic sequence of events required for a switching action in a power system, such as a line or generator trip.

WSCC Interconnection Disturbance - December 14, 1994

This wide-area disturbance occurred on the Western Systems Coordinating Council (WSCC) system on December 14, 1994, having a total generation lost of 11,300 MW [36]. Figure 1 shows the physical arrangement for the three-terminal 345 kV transmission lines, Midpoint-Borah-Adelaide #1 and Midpoint-Borah-Adelaide # 2.

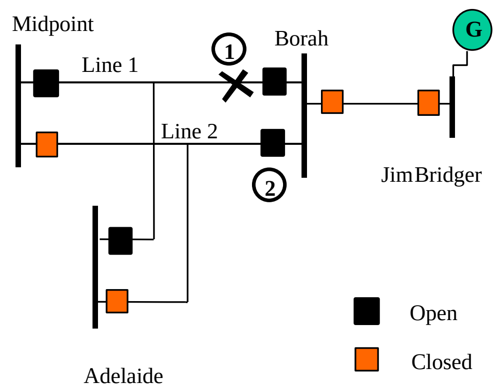

Figure 1: WSCC System, hidden failure location.

The first event was a line to ground fault on the 345 kV transmission line Midpoint-Borah-Adelaide # 1, occurred at 0125:41.25 MST, see number 1 in Figure 1. All three terminal circuit breakers were tripped and the fault was cleared. At about the same time, an unwanted trip took place, opening the Borah breaker only of the Midpoint-Borah-Adelaide # 2, see number 2 in Figure 1. This event is identified as a hidden failure, it occurred when the power system was under stressed conditions due to the line-ground fault on the 345 kV transmission line Midpoint-Borah-Adelaide # 1, and it was an unwanted trip, a transmission line disconnection.

This hidden failure was caused by a PEFD-A acting on a pilot ground relay. According to the hidden failure occurrence, the sequence of events may be summarized as follows. The pilot ground relay at Borah had a PEFD-A. Having this PEFD-A, the only required condition to initiate the tripping of the Borah breaker (see Figure 1 number 2) was the presence of a current of sufficient magnitude. From Figure 1, it is clear that the fault was not in Midpoint-Borah-Adelaide # 2 transmission line. However, due to the Borah station layout and configuration, the pilot ground relay of this station reacted to the current increment, in a similar way that it would react for a fault inside its protection zone. Since the pilot ground relay at Borah had a PEFD-A, this condition was enough to send a tripping command to the Borah breaker. The line to ground fault on the 345 kV transmission line Midpoint-Borah-Adelaide # 1, did uncover the PEFD-A of the Borah pilot ground relay and is considered the hidden failure triggering event.

The impact of the hidden failure is quite considerable. The Borah side of the 345 kV transmission line Midpoint-Borah-Adelaide #1 tripped due to a correct protection system operation. While the Borah side of the 345 kV transmission line Midpoint-Borah-Adelaide #2 was an unwanted trip, a hidden failure.

The disconnection of the Borah side of the Midpoint-Borah-Adelaide # 1 and # 2 345 kV transmission lines, resulted in the open ended of the Borah-Jim Bridger

345 kV transmission line, due to the bus configuration in Borah. See Figure 2, number 1. This fact interrupts the power flow, and a transfer trip was sent to the Jim Bridger end of the Borah-Jim Bridger 345 kV transmission line, see Figure 2, number 2.

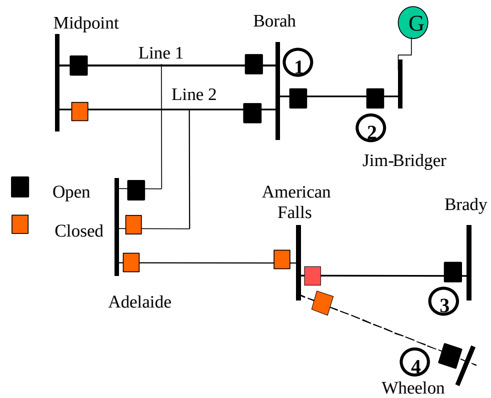

Figure 2: WSCC System, hidden failure Impact

The previously described events added overload through the Adelaide station side. At 0125:50.891, about nine seconds after the initial event, the Brady end of the Brady-American Falls 138 kV transmission line tripped due to overload, see number 3 on Figure 2. Thirty seconds later, the Wheelon end of the American Falls – Wheelon 138 kV transmission line also trip on overload, see number 4 on Figure 2. 200 MW peak-peak power oscillations were observed and other lines were tripped due to the stressed power system parameters and out of step conditions, the WSCC system was separated in 5 islands.

WSCC Disturbance - 2 July, 1996

The wide-area disturbance occurred on the Western Systems Coordinating Council (WSCC) system on July 2, 1996. A single phase to ground fault at the Jim Bridger-Kinport 345-kV line ultimately resulted in system separation and electric service interruption to more than 2 million customers.

Table T- 1 shows that the first event was a phase to ground fault. Twenty milliseconds after the Bridger-Kinport 345-kV line trip (correct operation), the Bridger side of the Bridger-Goshen 345-kV line was also tripped due to a hidden failure. This event is identified as hidden failure 1, (HF1).

Table T- 1: WSCC-07/02/96, Sequence of initial Events.

Event	Time	Comment
Jim Bridger-Kinport 345-Kv, Phase to ground fault.	1424:37.180 MAST	Line Sag to close to a Tree.
Jim Bridger-Goshen 345-kV trip.	1424:37.200 MAST	HF1, Faulty ground element at Bridger, PEFD-A.
RAS started, JB loose 2 lines.	1424:37.200 MAST	RAS was correct, 1040 MW off...
All Generators respond to Generation lack…		Freq. Went to 59.9 Hz.
Round Up-LaGrande 345-kV trip.	1424:39.200 MAST	HF2, bad connectors in a distance relay, PEFD-A.
MillCreek-Antelope Trip	1425:01.052 MAST	HF3, unwanted operation of Back-up relay, PEFD-B

Figure 3 shows the first fault on the Bridger-Kinport 345-kV line (see number 1), and the circuit breaker unwanted trip caused by HF1 (see number 2).

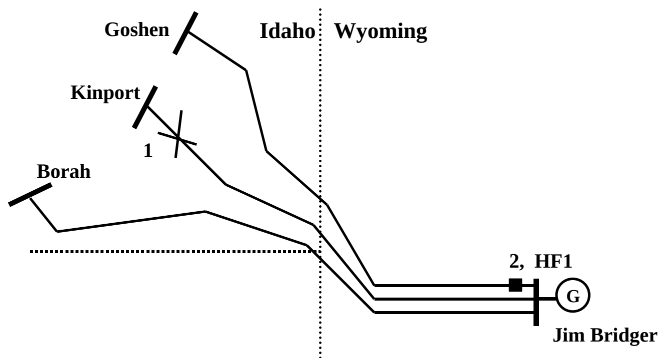

Figure 3: WSCC-07/02/96, HF1 localization.

The relay involved with the Bridger-Goshen 345-kV line unwanted trip was a segregated phase comparison, solid state relay. The relay had a PEFD-A, a faulty ground element - local delay timer - had failed in the "closed" position. Technical staff confirmed that Jim Bridger-Goshen relay mis-operation is a hidden failure sequence of events. The logic of the phase comparison relay is shown in Figure 4.

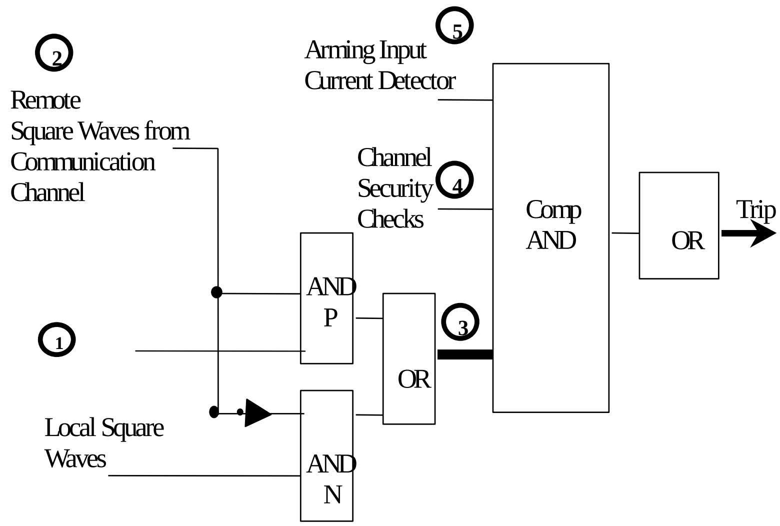

Figure 4: Phase comparison relay internal logic schematic.

The single phase comparison protective scheme receives as inputs the local and remote wave forms, which are compared in order to determine if the fault is external or internal and decide if a trip signal will be sent to the circuit breaker, see numbers 1 and 2 in Figure 4. The biggest rectangle shown in the sketch represents an AND gate, which receives as inputs three signals. One of these signals is the element with a PEFD-A (failed in the closed position) shown in bold, see number 3. The remaining two signals are a channel security check and an Arming Input Current Detector; see numbers 4 and 5 respectively.

A PEFD-A, the timer which failed in the closed position, remained hidden until the fault at Bridger-Kinport line forced a current high enough to satisfy the condition for the Arming Input Current Detector to operate, providing its “positive signal” to the AND gate. Since the channel security checks were verified, all three inputs to the AND gate were satisfied, the Arming Input Current Detector, the sanity checks, and the PEFD-A (which was already with “positive signal”). Consequently the relay system sent a trip signal to the Jim Bridger circuit breaker, and second contingency was caused by the hidden failure in the protection scheme.

The Jim Bridger SPS was immediately activated, due to the fact that Jim-Bridger generation plant had lost 2 transmission lines. This SPS operation was appropriate and did work as designed, disconnecting 2 units from the Jim-Bridger plant. Generators from the entire WSCC interconnection responded to the frequency deviation, 59.9 Hz. Almost 2 seconds after the first event, another relay-unwanted trip disconnected the Round Up-LaGrande 230 kV transmission line. This event is catalogued as HF2.

The defective relay was identified as an electro-mechanical distance relay. Figure 5 describes HF2 sequence of events. The relay operation is based upon a balance between operating and restraining forces created by the current and voltage inputs [38]. For distance relays, the restraint force overcomes the operating force during out-of-zone faults. In the present instance, corrosion under the voltage restraint crimp-on lug produced a poor connection, reducing the restraint force. In time the corrosion was complete and the restraint force was practically eliminated and the distance relay (mis)operated, closing its contacts.

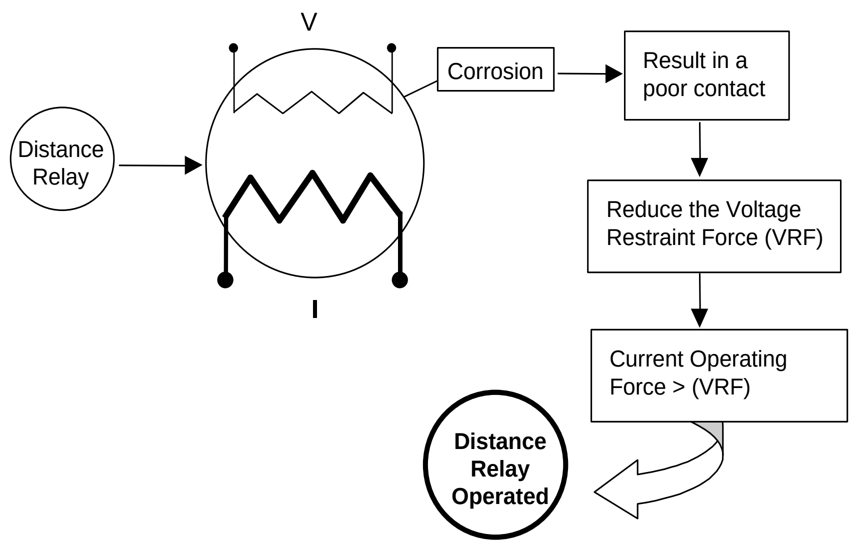

Figure 5: HF2, Sequence of Events.

The time when the corrosion caused the distance relay to operate is unknown. This relay condition remained undetected due to the fact that a fault detector supervises this relay, i.e., some others conditions are required before sending a tripping signal to the circuit breaker. From the time when the distance relay was defective due to corrosion until the time the Round Up–LaGrande 230 kV line was tripped, the system conditions were “normal”. As mentioned before hidden failures are triggered or uncovered by some another “event” which could be a fault, overload, under-voltage, etc. On July 2, 1996 the system did not have normal conditions since two lines were tripped, initiating a SPS, dropping 1040 MW of generation. HF2 was triggered by these abnormal conditions. This hidden failure event conforms to the PEFD-A definition and in this case it is related to the relay connectors and lugs.

An excerpt from [39] states “Jim Bridger Remedial Action Scheme should have ensured stability and prevented further outages. Several near simultaneous switching events, however, had some detrimental effects: A 230 kV line relayed in Eastern Oregon”. This 230 kV line is the Round Up – LaGrande, which was tripped due to HF2.

HF3 will be described next, which is related to the MillCreek-Antelope 230 kV transmission line, where the MillCreek station breaker had an unwanted trip. This is a hidden failure occurring over a Back-up protection system; in fact it can be catalogued as an unwanted operation of a Back-up relay. An excerpt from [39] states: “Relays installed to detect short circuits must not operate for mild overload and mild voltage depression". The relay did not do anything wrong, it tripped because the Power System conditions changed and the apparent impedance encroached under the zone 3 of the distance relay. The relay reacted to the low apparent impedance resulting from the Power System conditions.

The PEFD associated with HF3 is a PEFD-B. This hidden failure is related to human error in relay settings, in the sense that these power system conditions presented on the July 2, 1996 disturbance were not previously considered in the contingency analysis studies. This line trip and the 300 MW interruption caused power swings leading to rapid overload, voltage collapse and angular instability.