Relay Performance During Major System Disturbances

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***Abstract*—Power systems in the United States and abroad experienced several wide-area disturbances in the last 15 years including the largest blackout on August 14, 2003, in the Midwest and Northeast U.S. and Ontario, Canada, which impacted millions of customers. On September 28, 2003, the Italian network was separated from the rest of Europe, and the whole country of Italy fell into darkness. The July 2, 1996, and August 10, 1996, major system disturbances in the western U.S. impacted millions of customers. All of these disturbances caused considerable loss of generation and loads and had a tremendous impact on customers and the economy in general. Typically, these disturbances take place when power systems are heavily loaded, are operated outside their intended design limits, and experience multiple outages within a short period of time. These wide-area disturbances are typically characterized by large power oscillations between neighboring utility systems, low network voltages, and consequent voltage or angular instability.**

The aim of this paper is to explain which relay systems are most prone to operate during stressed system conditions, and why relay systems operate, to share experiences and lessons learned from the past, and to suggest protection system improvements to lessen the impact of blackouts and hopefully lead us toward their prevention in the future.

I. INTRODUCTION

Power system blackouts have occurred since the initial development of power systems. Most blackouts are caused during stressed power system conditions followed by a sequence of low-probability outages. Power system blackouts are rare events, however, during the past 15 years and particularly since 2003 we have experienced an increased frequency and severity of power system failures. These failures led to major blackouts with large economic penalties on a society that depends heavily on the availability of high-quality electric power. The August 14, 2003, major system blackout in the Midwest and Northeast U.S. and Ontario, Canada, affected approximately 50 million people in eight states and two Canadian provinces. During the blackout, over 400 transmission lines and 531 generating units at 263 power plants tripped [1]. Power to New York City and other affected areas was restored approximately 30 hours later.

Recent regulatory developments, environmental constraints, limited power system growth, increased demands on the electricity supply, and the need for system economic optimization have a significant impact on power system reliability. Because of these demands, power system operators are forced to operate the system closer to its stability limits and not in its most robust state. In addition, system operators cannot always anticipate and predict the sequence of events of low-probability disturbances that render the power system more vulnerable to blackouts. The power system is designed to operate reliably under one major contingency (N-1), that is, loss of one major power system element: a major generation source, a critical transmission line, or a large transmission transformer, and not for a sequence of additional low probability outages. Most power system blackouts occur following the loss of successive unscheduled power system element outages in a very short period of time during which a system operator cannot respond quickly to prevent the occurrence of the blackout. In recent blackouts, the unscheduled power system outages occurred because lines were overloaded and sagged into trees causing faults in the power system that were cleared by relay systems, or because of inadequate reactive power support that caused extremely low voltages, line overloads, and subsequent operation of distance or other types of protective relays.

Recent blackouts in the U.S. and Europe over the last few years have led to much discussion of the role played by protective relay systems during emergency or extreme power system operating conditions. Protective relay systems are designed to quickly detect faults and other abnormal conditions in the power system, take quick action to isolate only the faulted elements of the power system, and allow continuity of service to electric utility customers. Protective relay systems are often involved during major system disturbances, and in most cases, they prevent further propagation of the disturbance. Sometimes, however, unwanted relay system operations caused by unexpected system loading and emergency operating conditions during major power system disturbances have contributed to cascading blackouts that affected millions of people.

Many power system experts recognize that it is not feasible to design the power system to completely prevent the occurrence of wide-area disturbances and future blackouts. However, by understanding the phenomena involved during major disturbances, learning from past incidents, using good design practices and proper relay settings, and applying new protection system technologies, we can minimize the impact of future disturbances.

The frequency of major blackouts around the world in the last few years is quite alarming. Adequate analysis of the events and further research are needed to better understand the phenomena involved, identify triggering events and mechanisms, and deploy the latest technology to lessen the impacts and possibly eliminate future blackouts. It is unfortunate and alarming that three years after the major blackouts of 2003, the data captured during those blackouts are not available to researchers and experts in the industry to study the response of

protection and control systems to advance the art and science of protection.

This paper discusses the performance of relaying systems during major power system disturbances. It presents the reasons why certain relaying systems are prone to operate and their impact on the system, using relay and digital fault recorder data captured during power system disturbances. In addition, the paper addresses design and setting considerations to avoid relay misoperations during disturbances and discusses application of existing and emerging technologies, such as synchrophasors, to monitor and control power systems and aid in the mitigation of future wide-area disturbances. An attempt has been made not to disclose the source of the data used to generate the plots that illustrate the phenomena discussed in this paper.

II. Common Theme of major System Disturbances

Analysis of most recent blackouts, such as the August 14, 2003, U.S. and Canada event, the September 23, 2003, blackout in Sweden and Denmark, and the September 28, 2003, event in Italy, indicates a common theme and points to similar causes and outcomes [1]–[4]. The common theme in all of the above-referenced blackouts is summarized below:

1. All of the blackouts occurred when the power system was stressed the most, i.e., during times of heavy power demand.
2. A number of transmission line and generator outages occurred prior to the disturbances, including equipment being out-of-service for maintenance reasons, that further weakened the power systems.
3. Operators did not detect the resulting weakening of the power system, even though the reasons were different for each one of the major blackouts
4. The end results were the same in all of the events
   - Transmission line overloading
   - Reactive power deficiencies
   - Low power system voltages
   - Line overloading and sagging into trees
   - Line and generator tripping
   - Relay operations
   - Voltage instability
   - Angular instability
   - Underfrequency load shedding (UFLS)

The primary and common causes of the most recent blackouts were:

- Inadequate level of vegetation management (tree trimming)
- Inadequate understanding of the system
- Inadequate level of situational awareness
- Inadequate sense of urgency regarding line overloads and inadequate counter measures
- Inadequate coordination of relays and other protective devices or systems

III. Phenomena During Stressed System Conditions

Before we discuss relay performance during major system disturbances, we will discuss observed power system phenomena common to the most recent disturbances. One of the main reasons for this review is to learn from these incidents and hopefully not repeat the mistakes. Analysis, conclusions, recommendations, and lessons learned from the 1996 disturbances in western North America on July 2 and August 10, 1996, were quickly forgotten and overlooked by many in the power industry in the U.S. and abroad as if such outages would not happen at their own power systems [5] and [6].

The two main phenomena observed during wide-area disruptions were:

- Voltage collapse and
- Rotor angle instability

These events can occur independently or jointly. Most recent power system disturbances began with reactive power deficiencies, line overloading, voltage instability and collapse problems, that later evolved into angle-instability problems because of a failure to take proper actions to return the system from the emergency state to alert or normal states.

Fink and Carlsen [7] identified five system-operating states (Normal, Alert, Emergency, Extreme, and Restoration), as illustrated in Fig. 1. The power system operates in normal state when system frequency and voltages are close to nominal values and there is sufficient generation and transmission reserve.

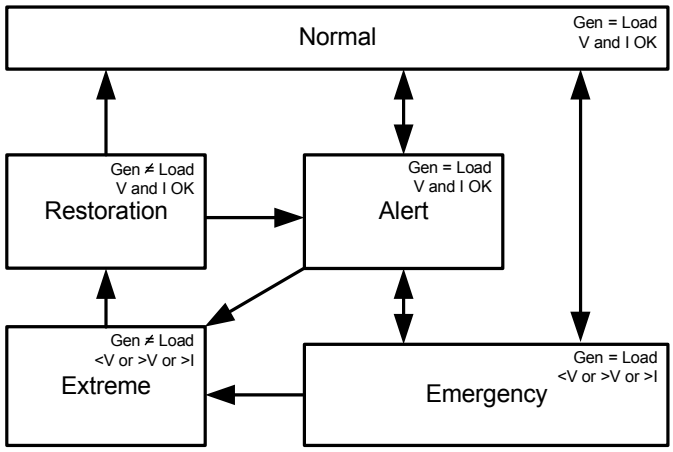


Fig. 1. Diagram showing possible power system operating states

The system enters an alert state because of a reduction or elimination of reserve margins, or for a problem with one or several system components as, for example, when one or several lines are overloaded. In the alert state, automated and manual system controls operate to restore the system to the normal state. Adequate power system monitoring and metering are necessary to promptly detect power system problems and accelerate system recovery.

The system enters an emergency state for system operating conditions that cause voltage or thermal limits to be exceeded or when a fault occurs. In the case of a fault, fault detection, clearance, and system restoration should cause minimum system disturbance. High-speed protective relays and breakers are necessary; speed and proper execution of corrective actions

are critical in preventing the system from entering the extreme state. For example, high-speed transmission line protection with single-pole tripping and adaptive reclosing capabilities minimizes system disturbance. When the system enters the emergency state without a system fault, automated controls (fast valving, SVC, etc.) are necessary to prevent the system from entering the extreme state.

If the system cannot maintain the generation-load balance or maintain voltage within desirable limits, the system enters the extreme state. In the extreme state, load shedding, generation shedding, or system islanding must take place to balance generation and load or to restore voltage to acceptable levels. Underfrequency load-shedding schemes operate to restore load-generation balance across the system; undervoltage load-shedding schemes (UVLS) operate to avoid system voltage collapse. After load and/or generation shedding, the system enters a system recovery state. In this state, manual or automated reinsertion of generation and load occurs.

In the next two subsections, we discuss system voltage and angular instability and show oscillographic data illustrating both system phenomena.

A. Voltage Stability

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

Taylor [8] refers to voltage collapse as: "A power system at a given operating state and subject to a given disturbance undergoes voltage collapse if post-disturbance equilibrium voltages are below acceptable limits." Voltage collapse can extend across the whole power system or be limited to a certain system area.

Voltage instability can occur in heavily loaded systems when the available reactive power from capacitors, generators, synchronous condensers, line charging, and static VAR compensators falls below or does not greatly exceed the system reactive losses and load. Typically, voltage instability can occur following the loss of several equipment outages, or when the system is heavily loaded following a lesser system disturbance. Reactive reserves are quickly exhausted when the system lacks the required reactive power and system voltages start to decline.

Distinguishing features of voltage instability and voltage collapse are:

- Low system voltage profile
- Heavy reactive power flows
- No substantial frequency change
- Inadequate reactive support
- Heavily loaded power systems

Low system voltage profile is one of the most distinguishing features of voltage instability and collapse. Fig. 2 shows the voltage at an EHV network bus, shown as Station C in Fig. 5, while the system operates in a voltage collapse state.

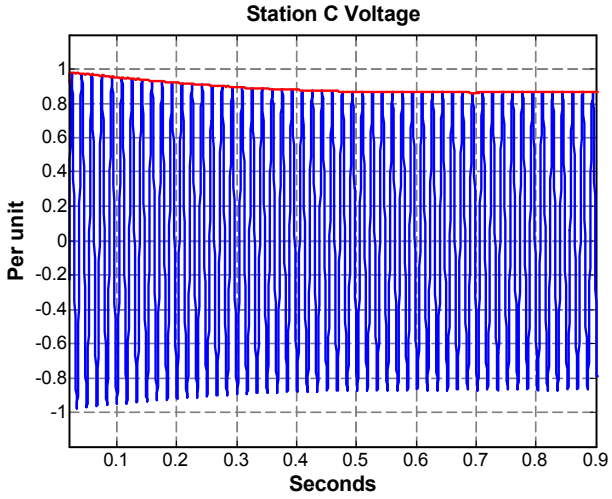


Fig. 2. Power systems operating in a voltage collapse state

The voltage decayed below normal operating limits, close to 0.8 per unit, and no system actions such as undervoltage load shedding were taken to restore the system to normal operation. The voltage during this disturbance decayed even further and reached a magnitude of 0.4 per unit, shown in Fig. 6, before Units 1 and 2 slipped poles and lost synchronism with the main network.

Another distinguishing feature of voltage instability is heavy reactive network power flows. Fig. 3 shows the real and reactive power of one of the transmission lines between Station C and Station E to illustrate the heavy reactive flow during a voltage collapse. We observe in Fig. 3 that Station C is receiving about 1000 MW on line 4 from System B and is delivering an increased amount of MVARs after 0.3 s (an increase of 300 MVAR in 0.6 s). Similar flows are also observed in lines 5 and 6. It is quite clear from these plots that the system is operating in an abnormal state.

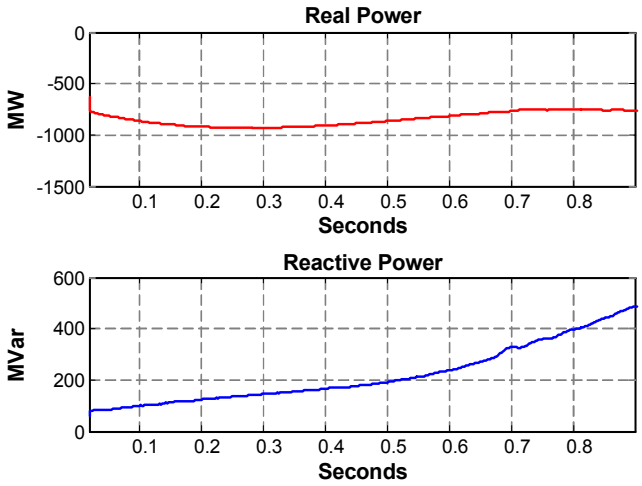


Fig. 3. Real and reactive power flow in line 4 of Fig. 5

Another feature of voltage instability and subsequent voltage collapse, before the system experiences angular instability, is that network frequency remains very close to the nominal power system frequency. The phenomenon of no substan-

tial system frequency change is shown in Fig. 4. The network frequency even starts to recover after 0.7 seconds.

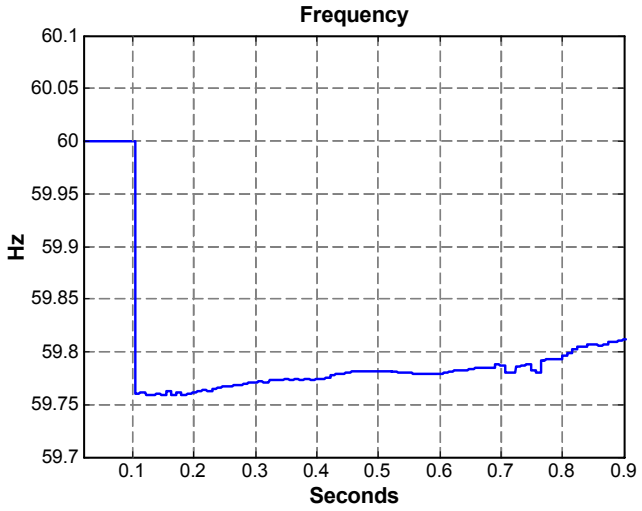


Fig. 4. Power system frequency at Station C during voltage collapse

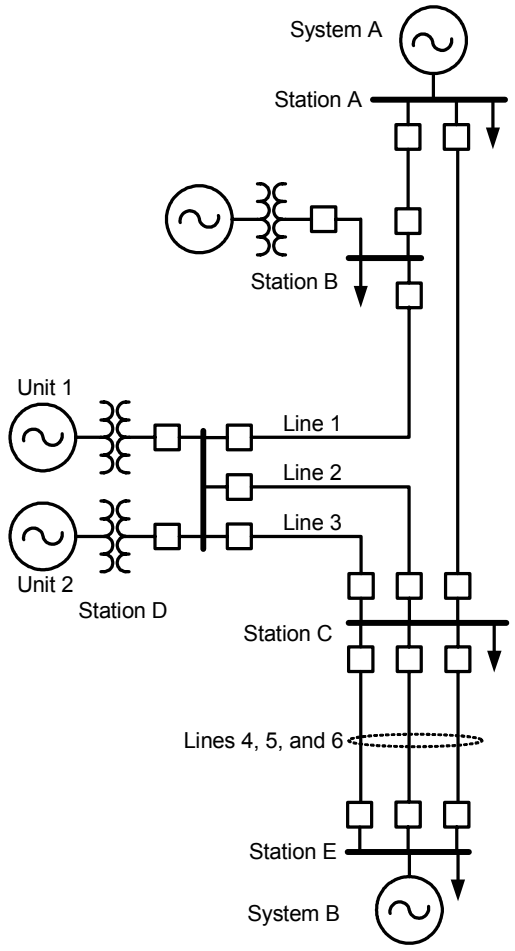


Fig. 5. Interconnected power systems

B. Angular Instability

Power system stability is the ability of an electric power system to regain a state of operating equilibrium after being subjected to disturbances such as faults, load rejection, line switching, and loss of excitation. Power systems under steady-state conditions operate very near their nominal frequency. Under steady-state conditions, there is equilibrium between the input mechanical torque and the output electrical torque of each generator.

Power system faults, line switching, generator disconnection, and the loss and application of large blocks of load result in sudden changes of the electrical power, whereas the mechanical power input to generators remains relatively constant. Major system disturbances cause severe oscillations in machine rotor angles and severe swings in power flows. Loss of synchronism can occur between one generator and the rest of the system, or between interconnected power systems. Synchronism could be maintained within each group of generators, assuming a timely separation occurs, and at such points in the power system where a good balance of generation and load exists.

Power system integrity is preserved when practically the entire system remains intact with no tripping of generators or loads, except for those disconnected by the isolation of the faulted elements, or by the intentional tripping of some elements to preserve the continuity of operation of the remaining part of the power system.

Distinguishing features of angular instability are:

- Large power oscillations
- Large voltage variations
- Zero voltage at the system electrical center when the two systems are 180 degrees out of phase
- Loss of synchronism

Fig. 6 shows the voltage at the same network location, Station C, as the power system moved into the extreme operating state and Units 1 and 2 lost synchronism with the rest of the network. At approximately 0.40 seconds (in Fig. 6), transmission lines 4, 5, and 6 tripped, reducing the network transmission capacity.

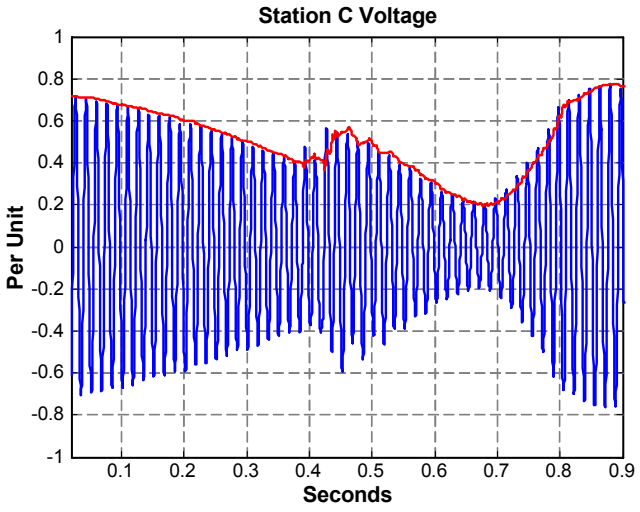


Fig. 6. Voltage collapse results into an angular instability

Generating Units 1 and 2, shown in Fig. 5, were unable to deliver predisturbance power to the system, and a rotor angle instability condition developed. This event is a clear example of how a voltage stability problem can evolve into an angle instability problem.

Fig. 7 shows the real and reactive power in line 2 as calculated from data captured at Station C. The figure clearly shows

that the units were supporting the system voltage, providing about 200 MVAR per line, just before they lost synchronism with the system. The main reason the units lost synchronism was because of their inability to provide their scheduled power into the system because of the extremely low voltage, almost 0.4 per unit, at the receiving Station C. Real power flow is given by (1):

$$P = \frac{E_S \bullet E_R}{X} \bullet \sin\delta \qquad (1)$$

From (1) we observe that the real power transmitted from the sending to the receiving bus is proportional to the voltage magnitudes at the sending and receiving buses and inversely proportional to the total impedance between them.

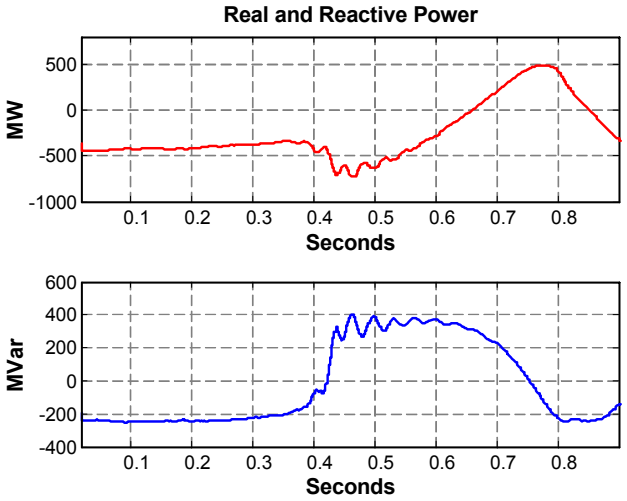


Fig. 7. Real and reactive power of line 2 at Station C

In the disturbance shown in Fig. 6, the voltage at the receiving bus reached 0.4 per unit. This reduction in voltage magnitude caused the same amount of reduction in the real power delivered into the system. Assuming that the sending voltage was at approximately 1.0 per unit, we can conclude that the remaining mechanical power, 0.6 per unit, was converted into generator kinetic energy, which caused rotor acceleration and subsequent loss of synchronism.

Fig. 8 shows the positive-sequence voltage magnitude of line 2 at Station C and the angle difference between the positive-sequence voltage and the positive-sequence current. We observe in Fig. 8 that the positive-sequence angle difference between V_1 and I_1 keeps increasing after 0.4 s and increased beyond 360 electrical degrees, indicating generator pole slipping.

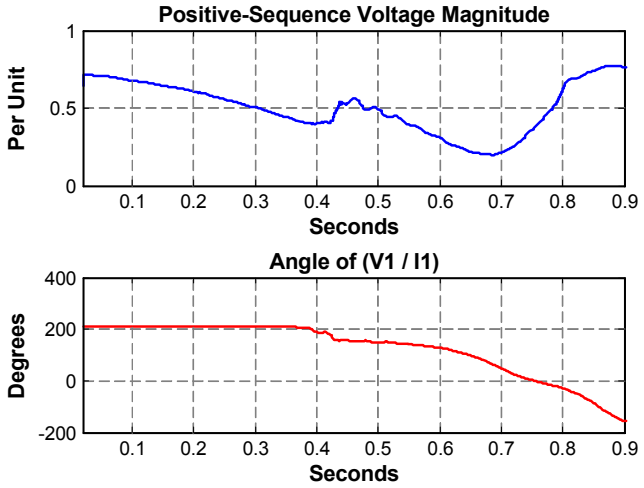


Fig. 8. Positive-sequence voltage magnitude and angle of V1/I1

IV. Relay Performance During Major Disturbances

In this section we will discuss the performance of relays that are most likely to operate during major disturbances, and explain why they operate. The data we use was captured during a number of major system disturbances in North America and Europe over the last 15 years. We review the performance of high and extra high voltage transmission system relays and generator protection relays.

Previous figures in this paper show the large variations in power flows and system voltages when the power system enters the emergency or extreme state. Power system frequency excursions, large variations in system voltages, and power flow oscillations could cause unwanted relay operations that will probably contribute to the severity of the disturbance.

Analysis of previous blackouts indicates that the power system can experience overloads, voltage collapse, angular instability, under- and overfrequency, and under- and overvoltage conditions. These abnormal system conditions will cause many types of relay systems to operate during major system disturbances.

Protective relays monitor the power system voltages and currents and are designed to operate during faults or other abnormal system conditions. Protective relay elements are designed to respond to overcurrents, over- or undervoltages, over- or underfrequency, and underimpedance. The relays most likely to operate during disturbances are:

- Zone 1 distance relays
- Overreaching distance relay elements
- Directional comparison pilot relaying systems
- Instantaneous directional and nondirectional overcurrent relays
- Under- and overvoltage relays
- Underfrequency relays
- Loss-of-field relays
- Volts/Hz overexcitation relays
- Generator backup relays
  - Distance relays
  - Voltage restraint overcurrent relays
  - Voltage controlled overcurrent relays

Modern numerical line current differential and phase comparison relaying systems, applied for transmission line protection, are immune to stable and unstable power swings, because of their principle of operation.

A. Relay Performance During Power Swings

Power swing is the variation in three-phase power flow that occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances [9]. Power swings can, for example, cause the load impedance, which under steady-state conditions is not within the relay's operating characteristic, to enter into the distance relay-operating characteristic. In addition, unstable power swings can generate high currents during part of the swing cycle that may impact the performance of phase directional or nondirectional instantaneous overcurrent relays. On the other hand, low voltages during part of the swing cycle may impact instantaneous or short-time undervoltage relays in power plants.

Frequency excursions, during unstable power swings and after the separation of interconnected systems, can cause errors in the phasor measurement of numerical relays if they do not track the system frequency. In addition, numerical distance relays with long memory time constants may operate during large frequency excursions.

1) Distance Relay Performance

To understand why distance relays operate during power swings, we first need to determine the impedance measured by a distance relay during an out-of-step (OOS) condition in the simple two-source network shown in Fig. 9.

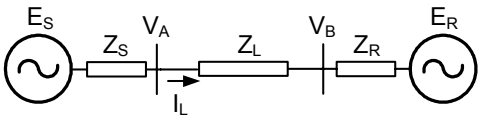


Fig. 9. A simple two-source power system

The impedance measured by a distance relay at bus A would be:

$$Z = \frac{V_A}{I_L} = \frac{E_S \cdot (Z_S + Z_L + Z_R)}{E_S - E_R} - Z_S \tag{2}$$

Let us assume that E_S has a phase advance of δ over E_R and that the ratio of the two source voltage magnitudes E_S/E_R is k. We would then have:

$$\frac{E_S}{E_S - E_R} = \frac{k\left[(k - \cos\delta) - j\sin\delta\right]}{(k - \cos\delta)^2 + \sin^2\delta} \tag{3}$$

For the particular case where the two sources' magnitudes are equal or k is 1, (3) can be expressed as:

$$\frac{E_S}{E_S - E_R} = \frac{1}{2}\left(1 - j\cot\frac{\delta}{2}\right) \tag{4}$$

Finally the impedance measured at the relay will be:

$$Z = \frac{V_A}{I_L} = \frac{(Z_S + Z_L + Z_R)}{2}\left(1 - j\cot\frac{\delta}{2}\right) - Z_S \tag{5}$$

Fig. 10 shows a geometrical interpretation of (5).

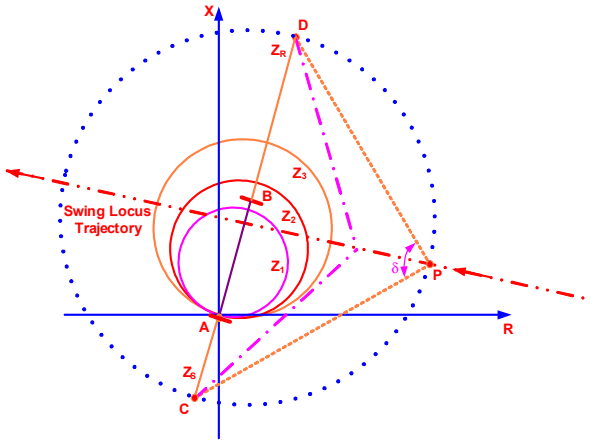


Fig. 10. Swing locus trajectory when the magnitude of E_S/E_R = 1.0

The trajectory of the measured impedance at the relay during a power swing when the angle between the two source voltages varies corresponds to the straight line that intersects the segment C to D at its middle point. This point is called the electrical center of the swing. The angle between the two segments that connect P to points C and D is equal to the angle δ. When the angle δ reaches the value of 180 degrees, the impedance is precisely at the location of the electrical center. Thus, the impedance trajectory during a power swing will cross any relay characteristic that covers the line, provided the electrical center falls inside the line.

In situations where k, the ratio of the sources' magnitudes, is different from 1, the impedance trajectory will correspond to circles. This is shown in Fig. 11. The circle's center and radius values as a function of the k ratio can be found in [10].

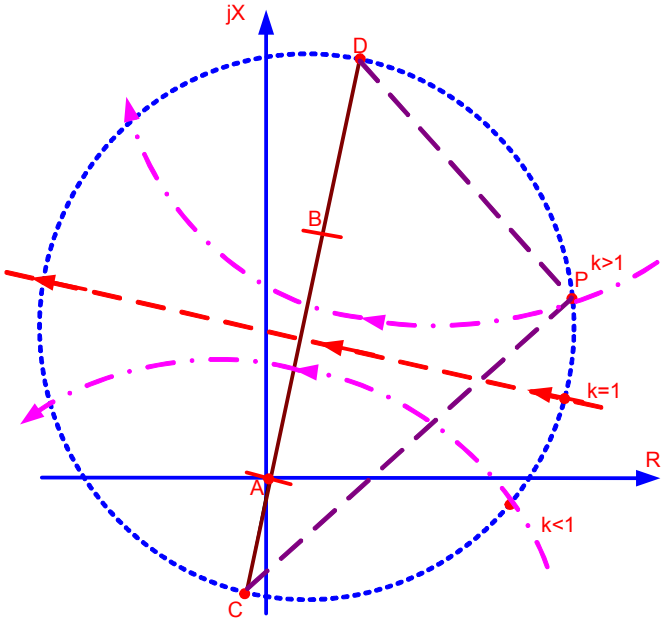


Fig. 11. Generalized swing locus trajectory

Phase distance relays respond to positive-sequence quantities. The positive-sequence impedance measured at a line terminal during an OOS condition varies as a function of the phase angle separation, δ, between the two equivalent system

source voltages. Zone 1 distance-relay elements with no intentional time delay are the distance elements most prone to operate during a power swing.

Fig. 12 shows the operation of a Zone 1 distance relay when the swing locus passes through its operating characteristic.

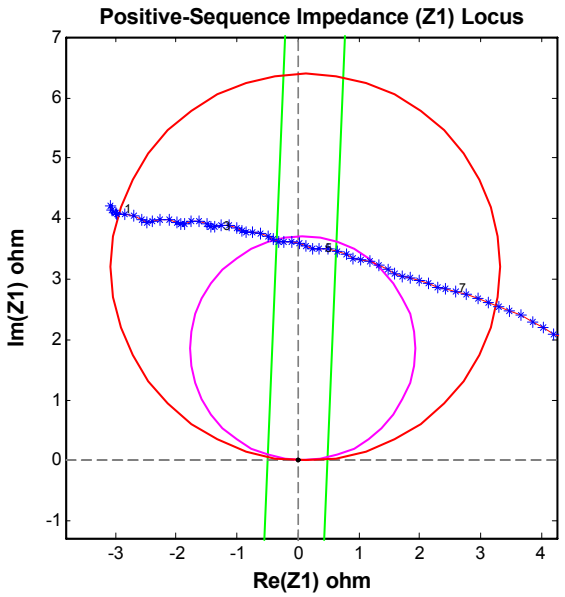


Fig. 12. Zone 1 distance operates when Zapp enters its characteristic

The power swing blocking (PSB) relay function in this application was not enabled, which caused the Zone 1 distance relay to operate. Proper application and setting of the PSB elements would have prevented this line operation. Fig. 13 shows the raw data and selected digital relay element data of the previous example to illustrate the Zone 1 distance element operation.

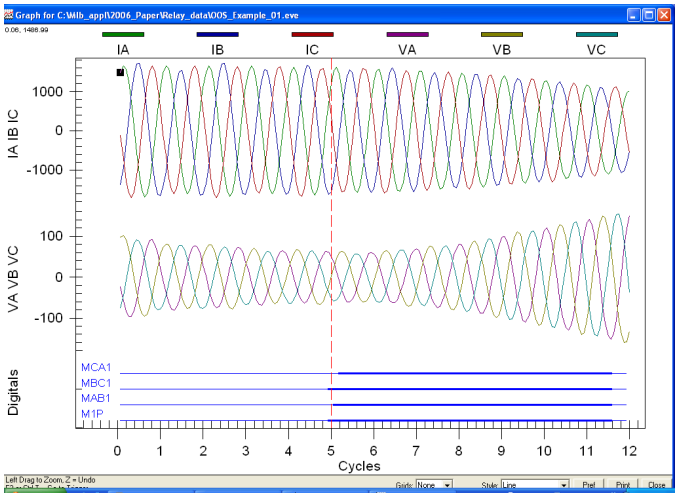


Fig. 13. Zone 1 distance relay operation during an OOS condition

Directional comparison pilot relaying systems, for example blocking or permissive types, are also very likely to operate during power swings. Backup zone step-distance relay elements will not typically operate during a swing, depending on their time-delay setting and the time it takes for the swing impedance locus to traverse through the relay characteristic.

The next couple of plots illustrate another operation of a Zone 1 distance relay element during an OOS condition. This event differs from the previous one because in this particular case, the PSB logic was enabled. Fig. 14 shows the voltage and current waveforms captured during an OOS condition by a numerical distance relay. In Fig. 14 we also plot the distance relay internal digital elements to show how the PSB function, asserted OOS trace, prevented Zone 1 distance element operation during the first slip cycle.

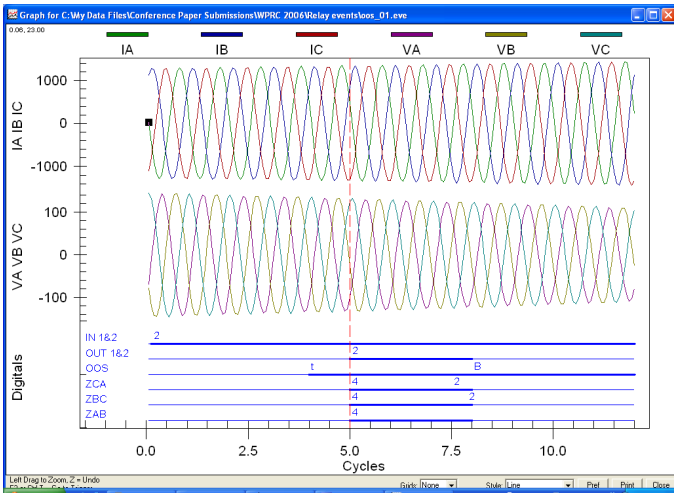


Fig. 14. PSB logic blocks operation of distance relay elements

Fig. 15 shows the continuation of the previous example and illustrates Zone 1 distance relay tripping caused by PSB function failure to maintain blocking of the distance elements on the subsequent power swing.

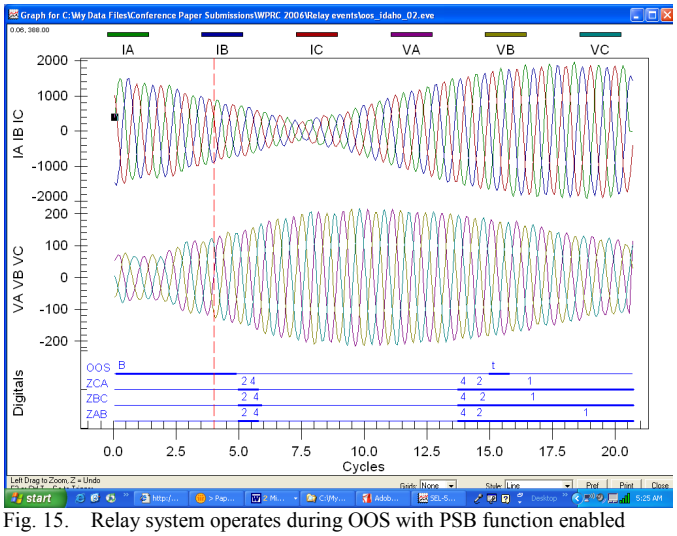


Fig. 15. Relay system operates during OOS with PSB function enabled

The PSB element blocked the operation of distance elements during the first slip cycle and failed to block during a subsequent slip cycle because the slip frequency reached approximately –5 Hz. Fig. 16 shows the slip frequency of this particular event.

Further analysis of the previous example indicates that fine-tuning of the PSB concentric impedance elements and power swing blocking timer settings could have avoided the line trip on the second slip cycle. However, setting conventional PSB and out-of-step tripping (OST) functions can be

very difficult on long overloaded lines, depending on source strengths, and requires extensive stability studies to determine the proper relay settings

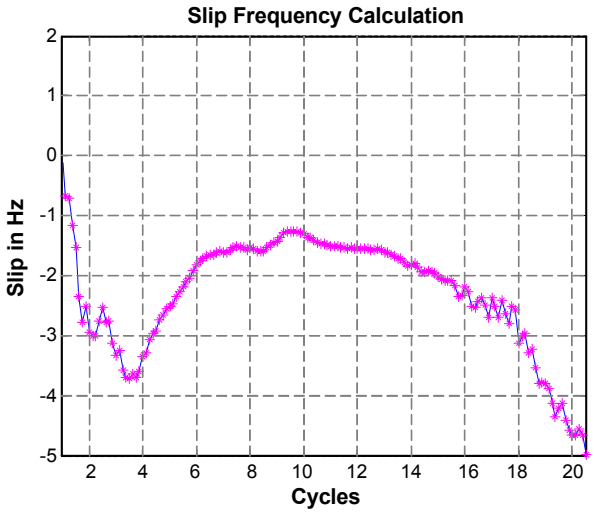


Fig. 16. Slip frequency reaches –5 Hz

Conventional PSB schemes use the difference between impedance rate of change during a fault and during a power swing to differentiate between a fault and a swing [11] [12]. To accomplish this differentiation, one typically places two concentric impedance characteristics, separated by impedance ΔZ, on the impedance plane and uses a timer to time the duration of the impedance locus as it travels between them. If the measured impedance crosses the concentric characteristics before the timer expires, the relay declares the event a system fault. Otherwise, if the timer expires before the impedance crosses the inner impedance characteristic, the relay classifies the event as a power swing.

There are a number of issues one must address with regards to properly applying and setting the traditional PSB and OST relaying functions. To guarantee that there is enough time to carry out blocking of the distance elements after a power swing is detected, the PSB inner impedance element must be placed outside the largest distance protection characteristic one wants to block. The PSB outer impedance element must be placed away from the load region to prevent PSB logic operation caused by heavy loads, thus establishing an incorrect blocking of the line mho tripping elements.

Another difficulty with traditional PSB systems is the separation between the PSB impedance elements and the timer setting that is used to differentiate a fault from a power swing. The above settings are not trivial to calculate and, depending on the system under consideration, it may be necessary to run extensive stability studies to determine the fastest power swing and the proper PSB impedance element settings. The rate of slip between two systems is a function of the accelerating torque and system inertias. By performing system stability studies and analyzing the angular excursions of systems as a function of time, one can estimate an average slip in degrees/s or cycles/s. This approach may be appropriate for systems where slip frequency does not change considerably as the systems go out of step. However, in many systems where the slip frequency increases considerably after the first slip cycle and on subsequent slip cycles, a fixed impedance separation between the PSB impedance elements and a fixed time delay may not be suitable for providing a continuous blocking signal to the mho distance elements. Detailed guidelines for setting PSB and OST functions are discussed in [11]–[14].

Fig. 17 illustrates the performance of a no-setting PSB function for the previous example, where the conventional PSB function failed to block the distance elements on the second slip cycle. The PSB element in Fig. 16 is asserted from cycle 4 in this event and blocks distance elements from operating.

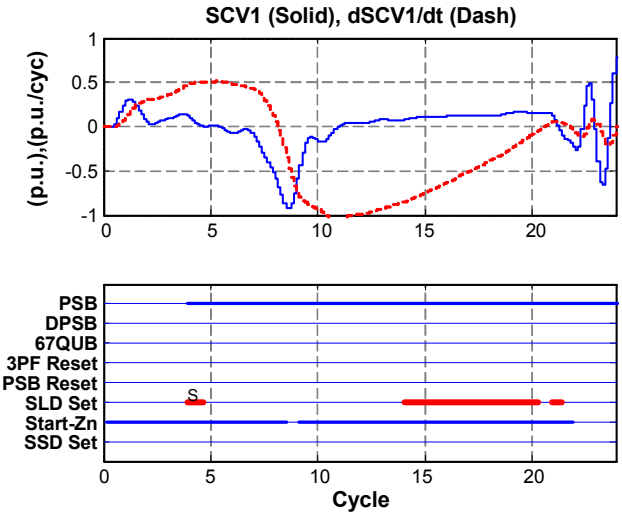


Fig. 17. Swing-center voltage and power-swing blocking elements

A new no-setting PSB algorithm has recently been developed. It will be part of future advanced numerical relays and will offer tremendous help to protection engineers in the application of PSB and OST functions [12]. Fig. 18 shows the positive-sequence impedance trajectory for the previous example, which starts at cycle 1 and ends at cycle 17, to illustrate the traversing of the positive-sequence trajectory for a second slip cycle through the Zone 1 distance relay element characteristic.

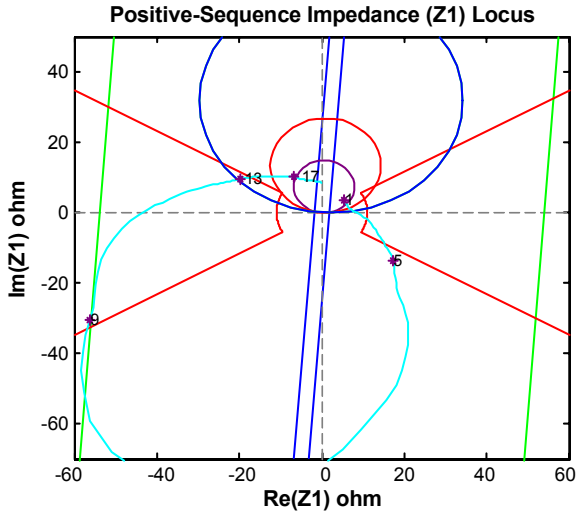


Fig. 18. Positive-sequence impedance trajectory

2) Polarizing Voltage Memory

Comparator-based mho distance elements require a polarizing quantity to provide a reliable angle reference. When a fault occurs, this angle reference should be stable and last long enough to guarantee that the protection element consistently picks up until the fault is cleared. The memory voltage supports several functions of the distance protection device:

- Allows the distance protection relays to operate for zero voltage three-phase faults in front of the relay
- Prevents the relay from operating for zero voltage three-phase faults behind the relay
- Allows the relay to maintain directionality during voltage inversion in series-compensated lines

The maximum duration of the memory voltage can be fixed, user settable, or adaptive. One possible problem with fixed memory time involves faults beyond the reach of the Zone 1 function. On lines with high source-to-line ratios, the magnitude of the steady-state fault voltage at the relay location for three-phase faults at the remote end of the line may be less than the voltage required for the relay to operate. For these conditions, the overreaching step distance backup functions may not operate if the time delay is greater than the fixed memory time.

Voltage inversion in series-compensated lines endangers the directional security of the Mho distance elements. In such applications, the polarizing memory should be long enough to provide correct and consistent distance element operation until the fault is cleared, the spark-gap protection operates, or the capacitor bypass switch operates to clear the voltage inversion.

Long polarizing memory helps to detect faults in difficult system and fault conditions like those just mentioned. However, longer memory also comes with a serious security drawback when there is a system frequency excursion. When a frequency excursion occurs, because of the memory effect, the polarizing voltage phase angle starts to slip away from the input voltage phase angle, resulting in a phase angle difference as shown in Fig. 19.

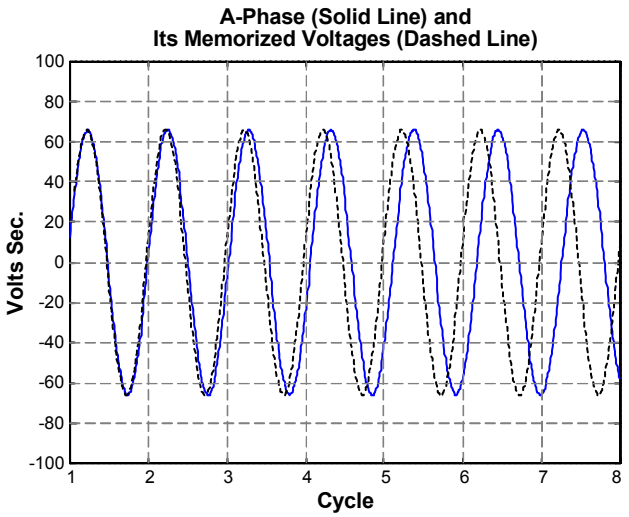


Fig. 19. Polarizing quantity slips away from the voltage inputs

If this frequency excursion persists long enough, the angle difference between the operating and polarizing signals becomes less than 90 degrees and the relay inadvertently trips because of the frequency excursion and the use of a long polarizing memory.

To overcome the long polarizing memory problem and at the same time provide a reliable polarizing quantity for zero-voltage faults and faults with a voltage inversion, modern distance relays use an adaptive polarizing scheme. The relay normally uses the positive-sequence voltage V_1 with little or no memory for the polarizing quantity. This polarization is satisfactory for all faults other than zero-voltage three-phase faults and faults with a voltage inversion. When the relay detects that V_1 magnitude is less than a predetermined value or the relay detects a voltage inversion, it switches to a long memory V_1 polarizing quantity.

3) Phasor Measurement Error Caused By Frequency Change

Numerical relays are designed to measure the fundamental frequency component of their voltage and current inputs. In practice, the frequency of the power system is constantly varying to some degree around the nominal system frequency, 50 or 60 Hz, depending on network conditions or circuit breaker switching. Power systems with weak frequency stability can have wide range shifts in the network frequency. When the fundamental frequency of the power system changes, numerical relays adapt their phasor estimation algorithms to minimize the phasor measurement error. Numerical relays typically either apply frequency-tracking algorithms by estimating the system frequency and changing their sampling interval to obtain a fixed number of samples-per-power-system-cycle, or use a fixed sampling frequency and mathematically compensate the phasors for the difference between the nominal and actual power system frequency.

The errors in phasor estimation are typically small, for small deviations of system frequency from nominal frequency. The rate of change of the frequency is limited by the system inertia. During major disturbances where the system may experience a large rate of change of frequency, different implementations of frequency tracking algorithms may perform differently. Some numerical relays may not be able to track the system frequency in some situations, some can only track the frequency up to plus or minus a few Hz from the nominal system frequency, and there are also a number of numerical relay implementations that may not perform any frequency tracking.

The phasor measurement errors caused during frequency excursions are present only during the time period that the frequency-tracking algorithm lags the system frequency. Once the system frequency is measured accurately again by the relay, the phasors are estimated accurately.

Power system component reactances are proportional or inversely proportional to system frequency and vary as a function of system frequency. Therefore, during frequency excursions, the actual reactance X of a protected transmission line varies proportionally according to the floating network frequency. For example, the varying line reactance is given by:

$$X = \omega L = (\omega_{nom} + \omega_{\Delta})L = \omega_{nom} L + \omega_{\Delta} L = X_{nom} + X_{\Delta} \quad (6)$$

$$X = X_{nom}\left(1 + \frac{\omega_{\Delta}}{\omega_{nom}}\right) = X_{nom}\left(1 + \frac{f_{\Delta}}{f_{nom}}\right) \quad (7)$$

If the nominal frequency of the power system is f_{nom} = 60 Hz, a deviation of the actual network frequency of f_{Δ} = 6 Hz causes a deviation of 10 percent of the actual line reactance compared to the line reactance in case of the nominal network frequency. The distance protection device measures the line impedances continuously and compares the calculated impedances with its tripping characteristic; however, its tripping characteristic was calculated using the nominal network frequency. The continuous measurement of the network frequency could be used to adapt the reactive reach settings of the distance relay to the actual measured network frequency; however, this is not typically performed by distance relays today.

During major system disturbances, the system frequency will most likely stay within the relay frequency tracking design limits and its measurement will not be impacted drastically. Numerical relays that support frequency tracking or frequency compensation methods will perform better than electromechanical and solid-state analog ones.

4) Instantaneous Phase Overcurrent Relay

Instantaneous directional or nondirectional phase overcurrent relays, in addition to distance relays, may operate during OOS conditions. Two large generators were tripped by directional instantaneous phase overcurrent relays after slipping poles during the August 10, 1996, WSCC disturbance [15]. The directional instantaneous phase overcurrent relays were located on the high side of the unit step-up transformer and set to look into the unit step-up transformer. The generators were not equipped with OST relaying and tripped uncontrollably during this event. Uncontrolled tripping of large units is not desirable. Damages to generator, shaft, and high-voltage breakers could be sustained because of OOS conditions during uncontrolled tripping. The loss of these major units, totaling 2600 MVA, was caused by misapplication of an instantaneous phase directional overcurrent function in an attempt to provide high-speed tripping for faults on the short section of line between the switchyard and the high side of the step-up unit transformers. These relays were subsequently removed from this location and were replaced with digital line current differential relays. In addition, OST relays were also installed at these two generators and recommendations were made to install OST relaying at all power plants with output equal or greater than 100 MVA.

B. Generator Protection Performance

Major disturbances produce abnormal system conditions that impact the performance of generator controls and generator protection relay systems. Voltage and frequency excursions during these major disturbances have a great impact on generator excitation and governor control system performance and on protective relays designed to protect the generators. Abnormal plant or grid conditions could cause catastrophic damage to these most expensive assets of a utility or plant owner. Many generator protection relays and excitation control protective functions are prone to operate during major system disturbances. The relaying systems that are most likely to operate are:

- Underfrequency protection
- Loss of excitation protection
- Undervoltage protection
- Overexcitation protection
- System backup protection
  - Backup distance relay
  - Voltage restraint overcurrent relay
  - Voltage controlled overcurrent relay

The Rotating Machinery Protection Subcommittee of the IEEE Power System Relaying Committee produced recently a transactions paper that addresses in great detail the performance of generator protection during major disturbances [16]. In addition, the IEEE Power System Relaying Committee has produced several other guides and a tutorial on the protection of synchronous generators that cover the subject of generator protection extensively [17]–[19]. Therefore, based on the wealth of available information in the above references, we will only share some additional experiences from generator protection system performance during major disturbances. The reader can check [16]–[19] for more complete generator protection application and setting details.

Past disturbances have taught us that the proper coordination of protective relays with generator excitation control systems is of paramount importance. Undesired loss of generation during stressed system conditions can further aggravate the disturbance and lead to total system blackout.

During the August 10, 1996, WSCC disturbance, approximately 8000 MW of generation and about 11600 MW of load was lost in the northern California island. Two large generators totaling 2600 MW were tripped during loss of synchronism by instantaneous directional phase overcurrent relays looking into the step-up transformer. The remaining generators were tripped by loss-of-field relays, overexcitation V/Hz protection relays, undervoltage, and underfrequency relays.

Most of this generation loss was undesirable for two main reasons:

- Misapplication of a relaying function in the case of the instantaneous directional phase overcurrent protection
- Inability of voltage control devices to reduce system overvoltages to normal operating conditions after the northern California island formation

At least 263 plants with 531 generating units, totaling approximately 62 GW, shut down during the August 14, 2003, Midwest and Northeast U.S. and Ontario, Canada, blackout. A high number of generators were tripped during this event before the formation of islands, which is one of the main reasons why so much of the northeast area blacked out during August 14. It appears that some of these generators tripped to protect the units from conditions that did not justify their protection, and many others tripped because they were not coordinated with the region's underfrequency load-shedding scheme design, rendering the UFLS schemes less effective [1]. The re-

maining generators tripped because of overexcitation, loss of field, undervoltage and underfrequency protection, and about 40 percent of the generators that tripped during or after the cascade did not provide useful information on the cause of tripping in their response to the NERC investigation data request.

For the remaining part of this section we discuss some experiences from past disturbances to illustrate why generator protection relays and control systems operate during these disturbances. We also identify areas where improvements are needed in order to keep generators online for longer periods to support the system during stressed conditions.

Fig. 20 shows the voltage magnitude, at Station D in Fig. 5 during a major system disturbance, to illustrate the swings in magnitude during Units 1 and 2 loss of synchronism with the system. The voltage swings are quite severe and the voltage magnitude is 0.09 per unit during the first swing and approximately 0.25 per unit during the second swing. The period of oscillation is approximately 2.8 Hz, which is very close to the 5 Hz critical shaft torsional mode of this particular unit. The low voltages observed during loss of synchronism could cause undervoltage protection relays of auxiliary plant equipment to operate, depending on pickup and time delay settings associated with undervoltage protection. This particular unit tripped by a reactor coolant pump (RCP) undervoltage relay for similar undervoltage conditions during the December 14, 1994, WSCC disturbance [20]. Further investigation at the time revealed that the RCP undervoltage relays would operate in approximately 2.5 cycles with no additional time delay. A time delay of approximately 0.4 s was implemented to allow the undervoltage relay to coordinate with breaker failure operating times at the switchyard and with system low voltages during system stressed conditions.

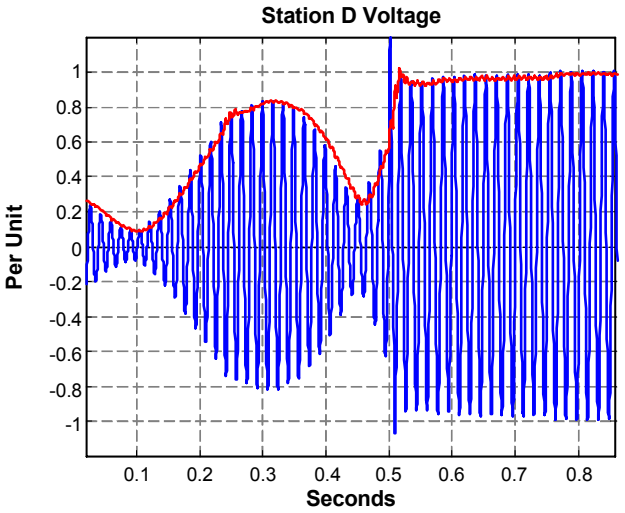


Fig. 20. Voltage at Station D during loss of synchronism

Fig. 21 shows the MW and MVAR output of Unit 1 as seen from Station D and indicates that the unit tripped from 1500 MW and about 600 MVARs. This is at least 1.3 per unit MVA and could cause severe torsional forces in the shaft, and end-winding forces.

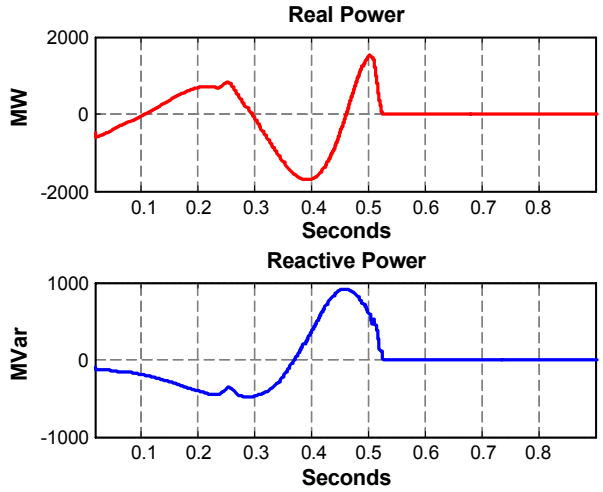


Fig. 21. Unit 1 three-phase MW and MVAR output

Units 1 and 2 were both tripped by directional phase overcurrent instantaneous relays as was discussed previously. These relays were subsequently removed from service and modern numerical line current differential relays were applied to protect the short 500 kV line section from the switchyard to the high-voltage bushings of the step-up transformer. Further investigation revealed that these major units lacked pole-slipping or OST protection functions.

Pole slipping causes high currents and forces on the generator windings and high levels of transient shaft torques. If the slip frequency of the unit with respect to the power system approaches a natural torsional frequency, the torque exerted on the shaft can be high enough to break the shaft [17]. Pole-slipping events can result in abnormally high stator-core-end iron fluxes that can lead to overheating and shorting at the ends of the stator core. Pole-slipping events can generate high currents that could result in arcing at the retaining ring fits, or between the rotor wedges to the rotor body at the ends of the wedges, where current is interrupted as it attempts to flow along the rotor axially. Pole slipping also generates high voltage spikes in the field circuit that can affect the exciter fuses and diodes.

Pole slipping or OST tripping should be applied to large steam-turbo generators and it should be coordinated with system OST schemes. Whether units are tripped during the first slip cycle, or after a number of slip cycles, should be part of an interregional design philosophy and the particular requirements of certain plants, like nuclear power plants. However it is desirable to trip steam power plant units by OST function in the first or second slip cycles, if the swing center passes through the generator, to avoid considerable damage. On the other hand, hydro units can cope much better during pole slipping and could be allowed to operate for a number of slip cycles to give a chance to the generator controls and operators to reduce mechanical input and resynchronize with the system.

Pole-slipping protection was installed on both of these units after the August 10, 1996, WSCC disturbance and a recommendation was made to install OST on all generators greater than 100 MVA if the swing center passes in the region between the high-voltage terminals of the step-up transformer

down into the generator [17]. According to [17] OST relays should also be applied if the electrical center is out in the transmission system and transmission line relays cannot detect the OOS condition or are set to block during OOS.

Fig. 22 shows the positive-sequence impedance trajectory to illustrate pole slipping of Unit 1 during this disturbance. This figure also illustrates that the swing center moves as the disturbance progresses and that it does not remain fixed in a particular system location. Note in Fig. 22 that the swing center during the first slip cycle was in the transmission lines leaving Station D, and later on it moved inside the step-up transformer during the second slip cycle. Fig. 22 was generated with voltages and currents captured at Station D's 500 kV switchyard.

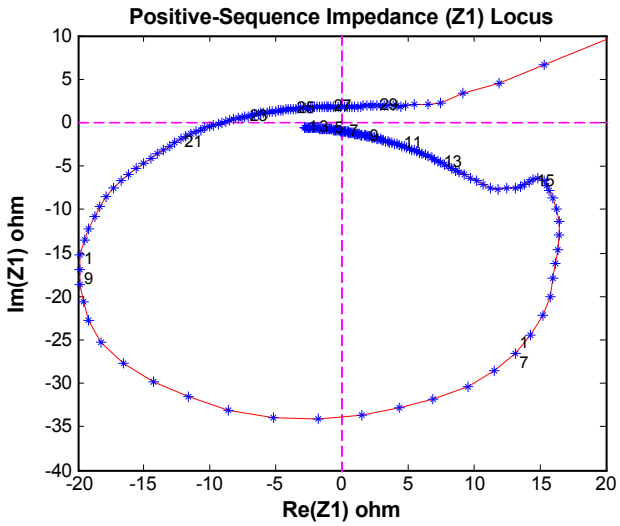


Fig. 22. Positive-sequence impedance trajectory

Fig. 23 shows the same pole-slipping event as seen from line 2 at Station C. Note that the positive-sequence impedance trajectory traverses through the Zone 1 distance relay characteristic which is set at 85 percent of the line positive-sequence impedance.

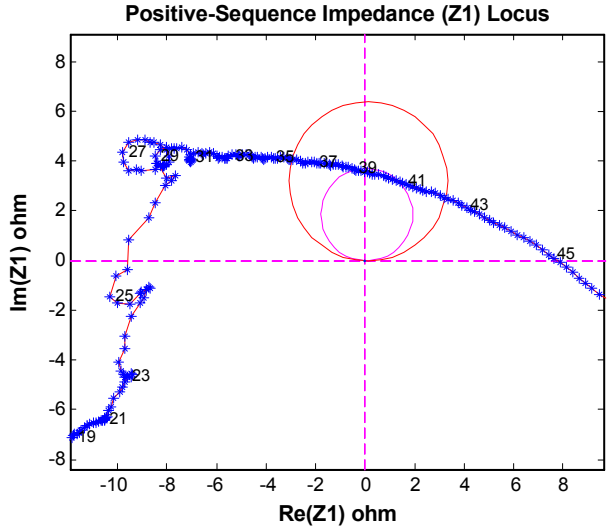


Fig. 23. Z1 impedance trajectory as seen by line 2 at Station C

The practice in China is to only trip steam turbo-generators if the swing center passes through the generator and not to trip if the swing center passes into the transmission system. However, if the swing center passes through the step-up transformer the practice is to allow the generator to operate for a number of slip cycles to allow resynchronization. Note that their specification states that the generators should be able to sustain 20 oscillation cycles for OOS-initiated events by close-in line faults and for numerous times. In addition, hydro generators are usually not equipped with OST protection because their experience and tests have shown that hydro units can withstand OOS operation [21].

Loss of field and V/Hz protection played a large part in removing major units from service during the August 14, 2003, Midwest and Northeast U.S. and Ontario, Canada, blackout and in northern California during the August 10, 1996, WSCC system disturbances. It is worth discussing why this happened.

Loss-of-field protection is designed to protect the generator from losing synchronism with the system. Generators and transformers can only operate for a short period of time during overexcitation conditions. Core flux is directly proportional to voltage and inversely proportional to frequency. Excessively high flux can cause rapid thermal damage to generator and transformer cores. Modern static excitation control systems are typically operated in the automatic voltage regulator (AVR) mode and have a V/Hz limiter to prevent a high-voltage/low-frequency condition from causing damage to the generator and step-up transformer cores. In addition, modern static excitation systems have maximum and minimum excitation limiters. The minimum excitation limiter (MEL) prevents the AVR from reducing the excitation to a very low level that could cause generator loss of synchronism. The MEL must prevent reduction of current to a level where the generator loss-of-field relay may operate.

V/Hz relays are typically applied at thermal generating plants to provide overexcitation protection of the generator and step-up transformer. This provides the same type of protection as the V/Hz limiter and also serves as a backup to the V/Hz limiter if there is one. Generator units with older voltage regulators most likely do not have a V/Hz limiter and the V/Hz generator protection relay is the only device providing overexcitation protection. The V/Hz limiter in modern excitation systems can override the signal from the MEL and force the excitation low enough to allow the loss-of-field relay to operate if it is necessary based on system conditions.

During the August 10, 1996, disturbance, the northern California island experienced high system-overvoltage conditions, approximately 10–20 percent overvoltage, because of excessive reactive power from the unloaded 500 kV transmission system and inability of system controls to maintain acceptable system voltages. High system voltages, combined with low frequency, caused the generators to operate in their underexcited region, trying to control the system voltage by absorbing large amounts of VARs from the system. As a consequence of this, V/Hz limiters overrode the MEL and played a major role in the tripping of a number of large generating units. A study of which type of protection tripped the units revealed that units with modern excitation systems with V/Hz limiters

tripped by loss-of-field protection. The units that were equipped with older voltage regulators without V/Hz limiters tripped by generator V/Hz protection relays.

Backup protection relays for generators can also operate during major disturbances caused by long periods of depressed system voltages. Phase backup protection for generators is provided either with a distance backup relay or voltage-controlled or voltage-restrained overcurrent relays. Typically these relays are connected to generator terminal-voltage and generator neutral-current transformers.

Operation of voltage-restrained overcurrent relays depends on the voltage drop at the generator terminals during a fault or a stressed system condition. Typically the pickup of a voltage-restrained overcurrent relay is set above the generator rating. The pickup is lowered proportionately to the reduced voltage at the machine terminals during faults or abnormal system conditions. The pickup of voltage-controlled relays is set below machine rating, and its operation is controlled by an undervoltage element. This undervoltage element must be set below the lowest credible generator terminal voltage at which the power system may operate. It is difficult to compute the settings for both relays for all credible operating conditions. In addition, if the high-voltage substation that the generator step-up transformer is connected to is not equipped with breaker failure protection, the relays are typically set to provide backup for faults at the end of the longest transmission line with infeeds available from all other sources, and consequently one has to make more sensitive settings that could expose the relays to a misoperation during stressed system conditions and trip the generator.

The operation of the backup generator distance relay is more predictable than the voltage-controlled or voltage-restraint generator backup relays and they should be preferred. However, generator distance backup relays have also operated during stressed conditions, depending on their settings. The safest solution, to avoid misoperations by the generator phase backup protection relays, is to apply local breaker failure protection at the high-voltage switchyard, including direct transfer trip to remote line terminals if it is necessary, and set the relays to provide backup only for faults up to the switchyard. Note that you may still have to set the relays to detect faults at the remote end of the line, if the high-voltage bus is of a ring or a breaker-and-a-half configuration. However, the generator backup relay settings will not be as sensitive, since you do not have to take into consideration the infeed from the other sources on the high-voltage bus. Reference [17] offers a more complete discussion on the application of generator backup protection, recommended settings, and trade-offs between sensitivity and security.

C. Overreaching Distance Relay Performance During Stressed System Conditions

Stressed system conditions are characterized by low voltages, high transmission-line power flows, power swings, and abnormal system frequencies. Many of the operations of Zone 3 distance relays, during major disturbances, were caused by line overloading conditions and low system voltages. The undesired operation of Zone 3 distance relays caused by low voltages and line overloads is the most obvious distance relay characteristic that has been addressed after the August 14, 2003, blackout in North America [22]–[24]. Because Zone 3 distance relay operations (or other overreaching zone operations) have contributed to the extent of blackouts, a lot of effort has been placed into reviewing their settings and development of loadability requirements and standards. Reference [24] provides a tutorial on the application and need for the Zone 3 distance relay function.

Distance relays are monitoring the line voltage and current conditions and will operate if the apparent impedance measured by the relay falls within its operating characteristic. Fig. 24 shows the potential of loading encroachment to the Zone 3 distance relay function during a stressed system condition. Note that in Fig. 24 the load encroachment function is set to ±30 degrees. The Zone 3 distance relay will operate for this condition since it will not be blocked by the load-encroachment function. Note also that the radius setting of the load-encroachment function is very critical because in this example, even if we increase the angle setting to ±45 degrees, the relay could still operate, given the load trajectory shown for this particular stressed system condition.

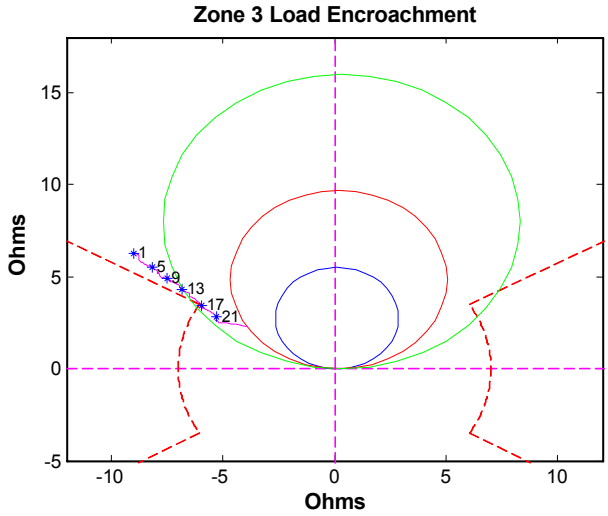


Fig. 24. Zone 3 distance relay load encroachment

The impedance of loads can be actually less than the impedance of some faults during stressed system conditions, or in very long heavily loaded transmission line applications. Loadability problems of Zone 3 distance relays and of other overreaching distance elements have been recognized for many years. Yet, the protection must be made selective enough to discriminate between load and fault conditions. Unbalance during line-to-ground and phase-to-phase faults is used to identity all faults except three-phase faults.

For better load rejection, traditional methods used lenticular or elliptical shape characteristics. Unfortunately, these characteristics reduce the fault-resistance coverage. Alternatively, one can use additional comparators to make blinders parallel to the transmission line characteristic, to limit the impedance-plane coverage, and exclude load from the tripping characteristic, or build quadrilateral characteristics, which box out load. All traditional solutions have the same common ap-

proach: shape the operating characteristic of the relay to avoid load. The traditional solutions have two major disadvantages:

- Reducing the size of the relay characteristic desensitizes the relay to faults with resistance
- Avoiding a small area of load encroachment often requires sacrificing much larger areas of fault coverage

Modern digital design approaches do not modify the relay characteristic shape directly. Instead, they define the load-encroachment regions in the impedance plane, and block operation of the three-phase distance elements if the positive-sequence impedance lies within the defined load region, as shown in Fig. 25.

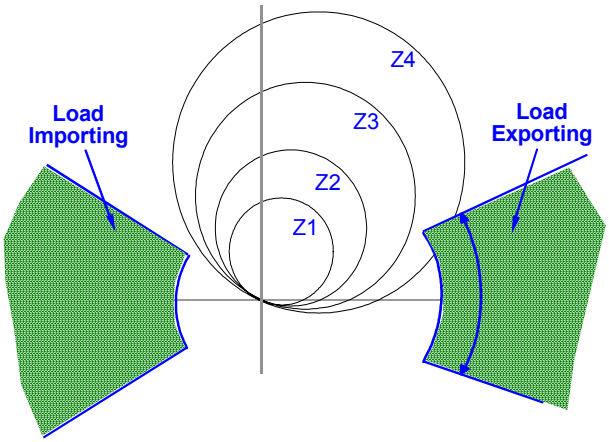


Fig. 25. Load-encroachment characteristic

Note that transmission line overloads are balanced phenomena. Therefore, the load-encroachment function only blocks the three-phase distance elements and does not impact the relay operation for phase-to-phase faults. The load region rejects only a small portion of the mho distance characteristic, as shown in Fig. 25. Reduced fault-resistance coverage for potential three-phase faults is not of great concern.

A further enhancement to the load encroachment function can be offered with a relay function that monitors the rate of change of the positive-sequence swing-center voltage (SCV1) and blocks overreaching distance zones during voltage instability and collapse. Monitoring the discontinuity caused by three-phase faults allows the overreaching zones to operate during these faults. A very fast three-phase fault detector can be implemented by evaluating the second derivative of SCV1 and the rate of change of SVC1 as discussed in more detail in [12].

Fault detection is accomplished by evaluating the second derivative of the swing-center voltage, and this is used to unblock the overreaching distance elements and allow them to operate in the event of a fault. Fig. 26 and Fig. 27 show the performance of the above function during system voltage collapse conditions. The starting zone element (Start-Zn) asserts on cycle 12 and the overreaching zone blocking element (ODZB) asserts on cycle 28 and remains asserted for the duration of the disturbance.

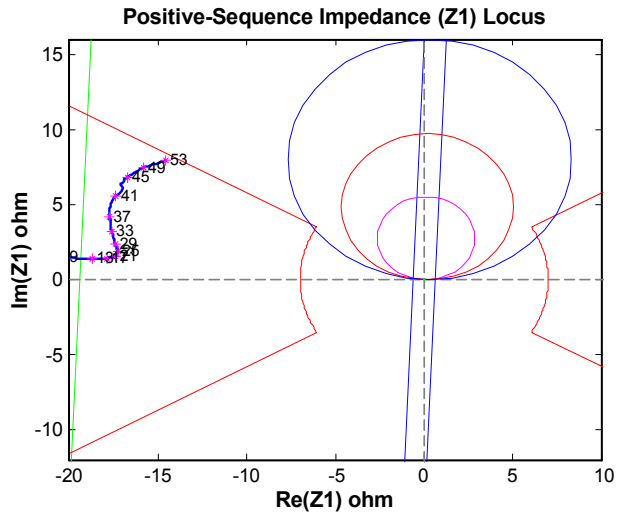
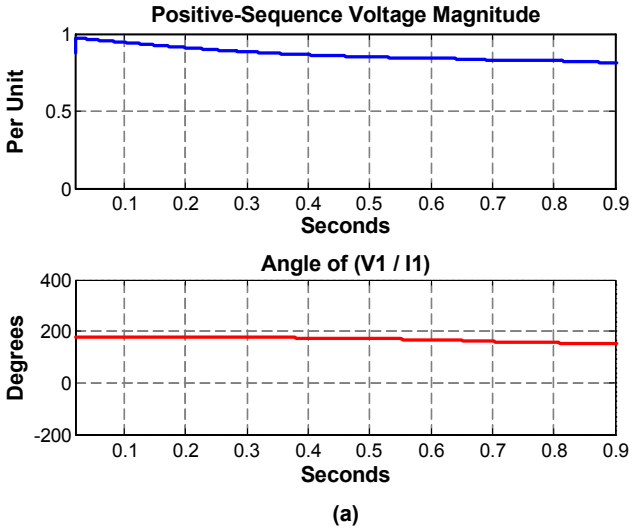


Fig. 26. Positive-sequence impedance during voltage collapse



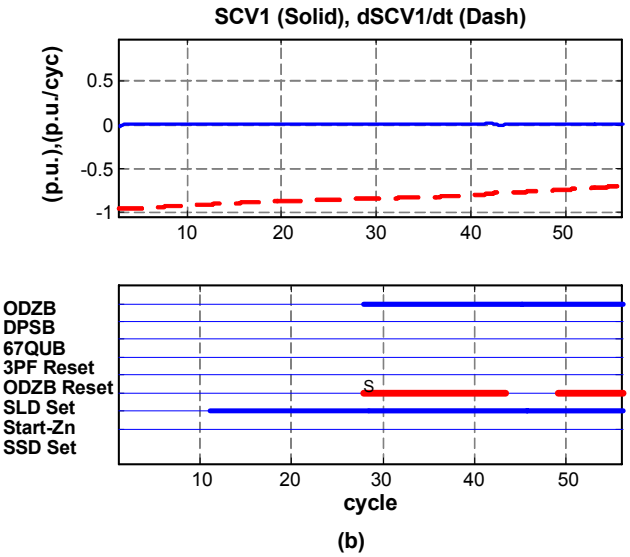


Fig. 27. Blocking of overreaching zones using SCV1

Analysis of the most recent disturbances indicates that overreaching distance relay zones have contributed to the extent of the blackouts and the application of overreaching zones in HV and EHV systems should be reassessed. Application of

dual pilot relaying systems, local breaker failure protection, and transfer tripping schemes can reduce to a great extent the need to apply overreaching zones. However, there are many other considerations, such as station battery collapse, structural damage of the substation caused by catastrophic events, and so forth, where the application of overreaching zones is still desirable. Applying the load encroachment function and other mentioned solutions helps in continuing the application of overreaching zones.

V. Protection System and Other Improvements

Analysis of recent disturbances teaches us that power systems are not immune to major blackouts and that such blackouts will probably reoccur in the future. However, it is the responsibility of all involved to implement necessary design changes and apply new technologies to prevent or lessen the impact of future blackouts. In this section we discuss some changes that are needed to improve the performance of relaying systems and the overall performance of the power system in general. These recommendations are based on analysis of major disturbances that the author performed during his 18-year career at the largest U.S. utility company [15].

A. Improvements in Transient Stability

Power systems should be designed to maintain angular stability for the duration of fault-clearing time, taking into consideration breaker-failure operating times. In addition, relay misoperations that may cause a line or another power system element to trip during a fault should be studied from a transient stability point of view and not be considered as a second contingency. Wide-area protection systems (WAPS) should be implemented to preserve system stability, and network islanding should be reserved as a last resort to save the power system from a complete collapse. Transient stability improvement methods should try to achieve one or more of the following effects [25]:

- Minimize fault severity and duration
- Increase the restoring synchronizing forces
- Reduce the accelerating torque by:
  - Control of prime-mover mechanical power, and
  - Application of artificial loads

The Western Electricity Coordinating Council (WECC) has WAPS in operation for many years to improve the transient stability of the western U.S. network [26]–[29]. Planning studies of the WECC system have indicated that single-, double-, or three-line loss in the California-Oregon Intertie or bipolar Pacific DC Intertie line loss occurring when the system is heavily loaded can cause instability, cascading outages, WECC system separation, and islanding. To reduce the risk of such events, WAPS schemes in the Pacific NW and northern California were designed to detect 500 kV line outages and initiate appropriate remedial actions to prevent overloads, low voltages, and OOS conditions in the WECC system [27].

The WAPS monitors the status of key 500 kV transmission lines, the load-flow levels and direction at the California-Oregon border, and the MW output of two major generating units in central California. The above information is used during an outage to determine the necessary level of adaptive remedial actions.

Depending on the lines that trip between the Pacific NW and northern and central California, adaptive remedial actions necessary to maintain system stability include various combinations of the following:

- Tripping generation in the Pacific NW and Canada
- Tripping generation in northern California
- Tripping aqueduct pump loads in California
- Suspension of automatic generation control in the Pacific NW
- Insertion or removal of mechanically switched capacitors or shunt reactors
- Insertion or bypass of series capacitor
- Transmission of transfer trip signals to separate the WECC system into two islands
- Application of a dynamic breaking resistor (artificial load) at a Pacific NW generation site

We discuss below a number of items to be considered that improve the transient stability of power systems.

1) High-Speed Fault Clearing

The amount of kinetic energy gained by the generators during a fault is directly proportional to fault duration and the positive-sequence voltage at the point of fault. Therefore, application of high-speed relaying systems and high-speed breakers is essential in HV and EHV systems when stability studies require it.

2) Local Breaker Failure Protection

Local breaker failure protection improves stability by minimizing the amount of time a fault remains on the system if a breaker fails to clear a fault. In addition, local breaker failure protection minimizes the number of power system elements that must be isolated, thereby keeping as much system capacity intact as possible. Application of direct transfer tripping in conjunction with breaker-failure protection should be an absolute requirement in EHV systems and other critical parts of the power system. This type of design change will reduce or eliminate the need for the application of time-delayed overreaching distance protection functions, such as Zone 3 backup distance functions.

3) Single-Phase Tripping

Most of the power systems in the U.S. were placed in service 50 to 60 years ago and the majority of them were designed using three-phase tripping. The power systems were designed to handle future load increases, and their stability was not impacted by the loss of one or more transmission lines during a system fault. Lack of investment in transmission and generation capacity in the U.S. utility industry, during the 1980s and 1990s, combined with large power transfers between interconnected systems, has caused an alarming increase of major disturbances and blackouts.

Single-phase tripping systems are designed to trip only the faulted phase, followed by fast reclosing between 0.5–1.5 seconds [30]. Single-phase tripping improves power system transient stability by interrupting only the faulted phase rather

than all three phases of the transmission line. During the open-pole period, approximately 50 percent of the prefault power is transferred over the remaining two phases. Since the majority of faults on HV and EHV systems are single line-to-ground faults, opening and reclosing only the faulted phase results in an improvement in transient stability over three-phase tripping and reclosing.

Single-phase tripping requires independent-phase operating breaker mechanisms for each phase of the circuit breaker that allows each phase to open and close independently from the other phases. As a result, failure of one pole does not restrict the operation of the other two poles. Failure of more than one pole at the same time is highly improbable. During multi-phase faults, independent operation of the breaker poles will reduce the fault to a single line-to-ground fault, thus significantly reducing the severity of the disturbance. Single-phase tripping requires the application of single-phase tripping relay systems that are able to discern the faulted phase and only trip and reclose the affected phase.

The application of single-phase tripping breakers and relay systems should be part of the planning process in all EHV power systems. During the 500 kV relay replacement projects at Pacific Gas and Electric Co. in the late 1980s and 1990s, we applied single-phase tripping in key 500 kV transmission lines. Relaying systems with single-phase tripping capability were applied at all 500 kV line terminals, even though in some locations the breakers were not yet capable of independent-phase operation. Using this approach made it very easy to convert future locations to single-phase tripping and reclosing if this was deemed necessary by the planning and operating departments.

B. Main 1 and Main 2 Protection System Design Changes

EHV transmission lines are typically protected by dual pilot (communications-assisted) relay systems, in other words, a Main 1 and a Main 2, with power-swing blocking (PSB) logic. A large number of transmission lines on HV networks, such as 230 kV, in the U.S. today are still protected with a Main 1 pilot relay protection system that may or may not have PSB blocking capability, and with a secondary nonpilot relay system consisting of phase distance and directional overcurrent relays that probably do not have PSB detection logic. Such secondary nonpilot relay systems could operate during stable and unstable power swing conditions by Zone 1 distance and instantaneous directional overcurrent elements.

During the last 15 years, many Zone 1 distance relays operated during power-swings and out-of-step conditions and removed transmission lines from service at undesired network locations [1], [6], and [15]. Therefore, in critical HV lines the application of two pilot protection relay systems, for instance a Main 1 and a Main 2, with similar functionality and with power-swing blocking and tripping capability should be practiced, just as it is practiced on EHV systems. After the December 14, 1994, and the July 2 and August 10, 1996, WSCC disturbances, Pacific Gas and Electric Co. implemented many transmission-line protection design philosophy changes, which are briefly discussed next [15].

During the December 14, 1994, WSCC disturbance, a third-level Zone 1 distance relay tripped a key 500 kV transmission line during an OOS condition at an undesired network location [31]. The day prior to this disturbance, one of the main protection systems was removed from service for repairs and the third-level relay system was placed in service for the duration of the repairs. The conventional third-level relay system did not have power-swing blocking capability and tripped the 500 kV transmission line by Zone 1 when an unstable power swing passed through its zone of protection. Note that the third-level relay system, as applied by this utility, consisted of Zone 1, Zone 2, and directional ground overcurrent relays, and is placed in service only if one of the main protection systems is removed from service for maintenance or repairs.

A protection design change was implemented after this incident to correct the shortcomings of the third-level relaying systems. All future third-level relay systems applied had equivalent functionality with the Main 1 and Main 2 protection systems, including a third pilot communication channel or the ability to switch communication channels with the Main 1 or Main 2 protection systems. This design change allows flexibility in operations to remove one relay system from service and at the same time maintain two pilot relay systems in operation at all times. These types of design changes can be easily implemented with today's modern relays that offer integrated digital relay-to-relay communications functionality.

High system overvoltage conditions during the August 10, 1996, disturbance in northern California, combined with low system frequency, caused failure of four large 230 kV distribution transformer banks. These transformer failures were caused by overexcitation conditions. Typically, overexcitation protection was only applied on generator step-up transformers and not on transmission and distribution transformers. Application of overexcitation protection on large transmission and distribution transformer banks was recommended after this incident.

C. Controlled System Separation

Certain system disturbances may cause loss of synchronism between interconnected power systems of neighboring utilities. If such a loss of synchronism occurs, it is imperative that the system areas operating asynchronously are separated immediately to avoid widespread outages and equipment damage. This separation is accomplished by well-planned and designed special protection systems that detect loss of major system elements, like the loss of a major AC interconnection, or unstable powers swings, and separate the network into subnetworks at preselected locations. This design accomplishes a controlled network separation that attempts to balance the generation and load in each subnetwork in order to maintain system stability and continuity of service to a majority of electric customers. Other actions such as load shedding and or generator tripping may be required in each subnetwork to maintain stability.

During the August 14, 2003, disturbance, the eastern U.S. and Canadian system experienced severe unstable power

swings and large generators slipped poles many times before the system collapsed completely. Transmission-line relays tripped uncontrollably and indiscriminately during these unstable power swings, anywhere in the power system that the center of the unstable power swing passed through. The eastern U.S. system lacked a preplanned controlled separation scheme using PSB and OST functions or other stability controls, in addition to a voltage collapse detection and UVLS schemes.

Controlled system separation, using special protection systems or OST and PSB functions, improves system reliability and security and should be a part of all interconnected power systems. Here we briefly discuss the application philosophy of OST and PSB for controlled system separation. Additional details on this topic and the design of wide-area systems to achieve controlled system separation can be found in references [11]–[14], [27]–[29], and [32]. The IEEE Power System Relaying Committee produced a comprehensive report, on the topic of power swing and out-of-step considerations on transmission lines, after the devastating impacts of the August 14, 2003, disturbance [9].

1) PSB and OST Application Philosophy

Detection of unstable power swings and controlled separation of interconnected power systems can be performed using OST and PSB integrated functions available in modern numerical relays. In this section of the paper we describe the philosophy and application fundamentals of PSB and OST in transmission systems and refer the reader to many recent papers written on this topic [21]–[24].

The philosophy of OOS relaying is simple and straightforward:

- Avoid tripping of any power system element during stable swings.
- Protect the power system during unstable power swings or OOS conditions.

There are basically two functions related to power-swing detection. One is the OST protection function that discriminates between stable and unstable power swings and initiates network sectionalizing or islanding during loss of synchronism. The other function is called PSB protection function. The main purpose of the PSB function is to differentiate faults from power swings and block distance or other relay elements from operating during stable or unstable power swings. In addition, the PSB function must allow relay elements to operate during faults or for faults that evolve during an OOS condition.

Out-of-step tripping schemes are designed to protect the power system during unstable conditions by isolating unstable generators or larger power system areas from each other with the formation of system islands. The isolation helps maintain stability within each island by balancing the generation resources with the area load.

To accomplish this, OST systems must be applied at preselected network locations, typically near the network electrical center, and network separation must take place at such points to preserve a close balance between load and generation. However, as discussed earlier, many relay systems are prone to operate at different locations in the power system during an OOS condition and cause undesired tripping. Therefore, OST systems must be complemented with out-of-step blocking functions to prevent undesired relay system operations, prevent equipment damage and shutdown of major portions of the power system, and achieve a controlled system separation.

Typically, the location of OST relay systems determines the location where system islanding takes place during loss of synchronism. However, in some systems it may be necessary to separate the network at a location other than the one where OST is installed. This is accomplished by applying a transfer-tripping type scheme. Another important aspect of OOS tripping is to avoid tripping a line when the angle between systems is near 180 degrees. Tripping during this condition imposes high stresses on the breaker and can cause restrikes and breaker damage.

D. Undervoltage and Underfrequency Load Shedding

Lack of detection for voltage instability and collapse, and lack of UVLS schemes, contributed to the blackout in North America on August 14, 2003, and during the July 2 and August 10, 1996, WSCC disturbances in the western U.S. The majority of blackouts in the last 20 years occurred because of voltage instability and collapse. Many papers and books have been written that brought awareness of these phenomena, and many UVLS schemes have been designed and installed to avoid system collapse [8], [28]–[29], and [33]–[34]. The design of UVLS schemes is quite complex and requires close cooperation between planning, operations, and protection departments. Most of these schemes are well thought out and well implemented using technology available at the time of implementation.

Recent developments in synchrophasor measurements and their availability in numerical relays creates new opportunities for designing more robust and intelligent voltage instability and collapse detection schemes that are critically needed in many power systems [35]. Recent research in this area offers hope in designing more robust wide-area voltage instability detection and control schemes that are needed to avoid future blackouts [36] [37].

Traditional UFLS schemes trip predetermined feeders when underfrequency conditions exist for a certain amount of time. The system has no information on the amount of load that was shed. Sometimes, more loads are shed than necessary. Ideally, we want to trip just the amount of load necessary for the system to recover and to optimize power delivery. We want an UFLS scheme that adapts to system operating conditions. Such a scheme can be designed with existing protection, control, and automation relays, taking advantage of relay programmability, mathematical calculation capability, and ability to communicate with other intelligent devices and systems. Reference [27] provides details on the design of an adaptive UFLS and an UVLS scheme to prevent voltage collapse.

E. Synchrophasor Measurements Technology

Protective relay sampling synchronization within 1 μs has been made possible with the advent of satellite-based timekeeping systems and advances in computer technology. For

some time now, stand-alone synchronized phasor measuring devices have been available. Modern protection relays are now available that include synchronized phasor measurement capabilities. These relays are applied widely, especially on HV and EHV systems, and the phasor measurement functionality is integrated, at no additional cost, into these modern numerical protection relays [35].

Over the last few years, many utilities in the U.S. and abroad have installed synchrophasor measurement relays in their systems to measure voltage, current, power flow, and the relative phase angle between various substation buses. Interest in this technology is based on the potential benefits derived from the use of synchrophasor measurements in a number of power system applications [36].

Synchrophasor measurements can be used to establish real-time wide-area transmission monitoring, analysis, and adaptive protection and control systems to:

- Improve the reliability of the interconnected systems
- Increase operator situational awareness
- Reduce the possibility of regional and interregional blackouts

Present methods for control and protection of power systems rely mostly on local measurements. Typically, these measurements are used to stabilize and enhance the dynamic performance of the power system via supplementary controls on generator excitation systems, static VAR compensators (SVC), thyristor-controlled series capacitors (TCSC), static synchronous compensators (STATCOM), unified power flow controllers (UPFC), and high-voltage direct current (HVDC) controls. Local measurements impose limitations on the control and protection functions because they lack adequate knowledge of the power system state at remote locations. The availability and use of synchronized phasor measurements permits advanced power system protection and control strategies.

Synchronized phasor measurements can be used in many power system applications, some of which are listed below:

- State estimation and real-time monitoring
- Transient and dynamic instability prediction
- Voltage instability prediction
- Disturbance analysis and power system monitoring
- System model validation
- Wide area protection and control
- Special protection systems
- Adaptive relaying
- Adaptive direct load shedding

A recent report to United States Congress identifies the steps necessary to establish and implement a real-time monitoring system for the Eastern and Western Interconnections [39].

VI. Conclusions

1. Relay systems have contributed to the extent of blackouts in the past and most likely will take part in future disturbances.
2. Good understanding of existing protection schemes, careful review of their settings, and implementation of proper design changes can minimize the extent of future disturbances.
3. Careful review of major system disturbances, lessons learned, and proactive implementation of recommended actions, provides continuous improvement in power system reliability and security.
4. Single-phase tripping and reclosing should be considered for all EHV transmission lines to improve stability, minimize system disturbances, optimize power transfer capability, and increase power system reliability.
5. Dual-pilot protection relay systems in all EHV and all critical HV lines, including local backup protection, and direct transfer tripping should be applied.
6. Well-designed controlled system separation schemes, using special protection systems and/or OST and PSB functions provide a safety net to lessen the impacts of major system disturbances.
7. Proper coordination of generator protection relays and excitation control systems is of paramount importance to providing needed system support during stressed system conditions.
8. Out-of-step tripping should be applied to large steam-turbo generators and it should be coordinated with system OST schemes. Whether units are tripped during the first slip cycle, or after a number of slip cycles, should be part of an interregional design philosophy and the particular requirements of certain plants, like nuclear power plants.
9. WAPS schemes based on extremely flexible and adaptive protection devices, as well as on reliable high-speed communication technologies, improve power system reliability and can mitigate large disturbances.
10. Synchrophasor measurements technology should be used to establish real time wide-area transmission monitoring, analysis, and adaptive protection and control systems to improve the reliability of the interconnected systems, increase operator situational awareness, and reduce the possibility of regional and interregional blackouts.
11. Application of voltage instability detection and UVLS schemes, and adaptive UFLS schemes that respond to power system operating conditions to trip just the amount of load necessary for system recovery, will mitigate the impacts of system disturbances and reduce the likelihood of future blackouts.
12. System overvoltages, after system islanding and deep load shedding, can cause damage to transformer banks because of overexcitation. V/Hz protection should be applied to critical transmission and distribution transformers and should be coordinated with the utility's overall system voltage control philosophy.

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VIII. Biographies

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