Local and Wide-Area Network Protection Systems Improve Power System Reliability

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LOCAL AND WIDE-AREA NETWORK PROTECTION SYSTEMS IMPROVE POWER SYSTEM RELIABILITY

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ABSTRACT

Increasing demands on electricity supply, with the need for system economic optimization and power system growth limitations, have a significant impact on power system reliability. Because of these system demands, the power system operates closer to its stability limits.

When the system operates in extreme conditions, load shedding, generation shedding, or system islanding must occur to prevent total system collapse. Typical causes of system collapse are voltage instability or transient angle instability. These instabilities can occur independently or jointly. In most cases, system wide-area disruptions begin as a voltage stability problem. Because of a failure to take proper actions for the system to recover, this voltage stability problem evolves into an angle stability problem. New monitoring, protection, and communications technologies allow us to implement economical local- and wide-area protection systems that minimize risk of wide-area system disruptions or total system collapse.

This paper provides examples of actual system disruptions and historical wide-area protection system (WAPS) solutions that use such traditional approaches as underfrequency and undervoltage load shedding. The paper also presents solutions that use programmable logic capabilities, faster communications, and synchronized phasor measurements available in meters and protective relays to prevent system disruptions.

INTRODUCTION

Geographically speaking, power systems are probably the largest interconnected networks in service today and offer interesting engineering challenges. Generating sites are far away from big load demand regions. Some power plants are close to natural resources, while others are in areas with fewer environmental restrictions. Because of this generation/load separation, a reliable power transmission network is necessary. Unfortunately, transmission networks are not easy to build. Right-of-way restrictions limit transmission line construction. In general, almost nobody wants to live close to a power plant or a transmission line. This limited network growth requires optimization of available resources. Engineers achieve this optimization by adding technologies such as series compensation, static var compensation (SVC), and phase shifters that increase network power transmission capability. As a result of this optimization, the power system operates closer to its stability limits. Additionally, the power industry is splitting generation, transmission, and distribution into separate operating regions, which complicates implementation of network-wide policies.

A reliable power system maintains frequency and voltage excursions within acceptable limits under normal and abnormal operating conditions. In addition, the thermal limits of the power system components (lines, transformers, generators, etc.) must not be exceeded. Typical frequency limits are f_{NOM} ±0.1 Hz, while typical voltage limits are V_{NOM} ±5 percent.

Fink and Carlsen [1] identified five system-operating states (Normal, Alert, Emergency, Extreme, and Restoration), as illustrated in Figure 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.

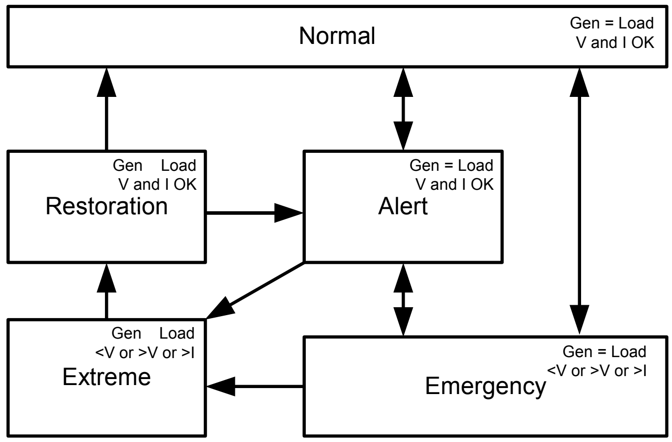

Figure 1 Fink and Carlsen Diagram Showing All Possible Power System Operating States and Normal/Emergency State Transitions Added

The system enters an alert state for 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 [2].

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 [3] minimizes system disturbance. When the system enters the emergency state without a system fault, automated control (fast valving, SVC, etc.) is necessary to reestablish the normal or alert operating state and 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 occurs 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 operate to avoid system voltage collapse. WAPS schemes [4], [5] that monitor power flows, system configuration, and voltage levels, etc. actuate to separate the system into islands or shed generation to maintain the load-generation balance and prevent total system 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.

Ideally, we want the system to avoid reaching the extreme state. Unfortunately, there are many occasions in which power systems operate in this state. This paper discusses local- and wide-area protection systems that minimize the risk of wide-area disruptions. First, we discuss the main causes of wide-area system disruptions. Second, we provide an example of a voltage system collapse in which the lack of prompt action created a voltage collapse operation condition [6]. Third, we present historical examples of local- and wide-area protection systems. Finally, we present technologies that use time-synchronized phasor measurement units, protective relays, and data concentrators to improve power system reliability.

WIDE-AREA SYSTEM DISRUPTIONS

There are two main causes of wide-area disruptions:

- Voltage collapse
- Rotor angle instability

These events can occur independently or jointly. In most cases, system disruptions begin as voltage instability problems that evolve 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.

Voltage Collapse

Taylor [7] refers to voltage collapse as follows:

> "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.

Rotor Angle Instability

When there is a reduction in transmission capacity because of transmission line disconnections or low-voltage operating conditions, power system generators cannot deliver predisturbance power to the system. Generator loss of synchronism can result from these abnormal system operating conditions if there are no actions to maintain proper generation/load balance.

The oscillogram in Figure 2 shows voltage at an EHV node while the system operates in the extreme state. In this case, the disturbance began as a voltage collapse problem where the voltage decayed below normal operating limits, and no system actions were taken. Actions such as undervoltage load shedding could have restored the system to normal operation. At approximately 0.33 seconds (in this oscillogram), transmission lines tripped, reducing the network transmission capacity. After the transmission lines tripped, generators 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 stability problem.

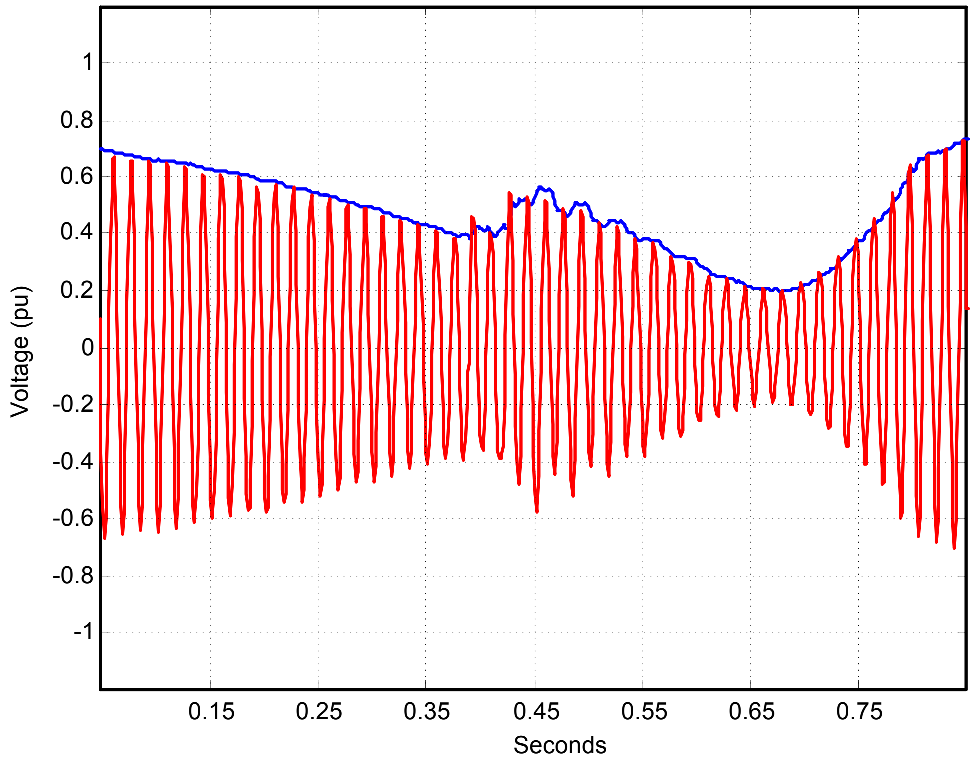

Figure 2 Voltage at an EHV Node While the Power System Operates in the Extreme State. This Event Shows How a Voltage Instability Problem Evolves Into an Angle Instability Problem for Lack of Proper Action to Return the System to the Normal or Alert State.

Examples of Power System Disruptions

Voltage Collapse in West Tennessee

Bullock [6] describes a case of voltage system collapse in West Tennessee. The problem began with a breaker fault while the breaker was interrupting a capacitive load (Figure 3). The subtransmission substation had neither breaker failure protection nor bus protection at the faulted bus. Remote backup had to operate. The transformer backup inverse-time overcurrent relay tripped the transformer high-side breakers. Zone 2 distance relays tripped the remote terminals feeding the fault. The overall fault clearing time was longer than one second. Voltage magnitudes in the nearby area dropped below 75 percent of nominal. Hot weather caused motors to begin stalling, which resulted in increased reactive power draw from the system. The predisturbance undervoltage condition lasted longer than 10 seconds. The system lost more than 700 MW during this voltage collapse.

Air-Conditioner Motors Delayed Voltage Recovery

The combination of low-voltage conditions with random motor restarting delayed voltage recovery. A depressed voltage condition reduces the motor torque characteristic (Figure 4). The air conditioning compressor load characteristic depends on operating conditions. When the compressor load characteristic is the “hot” curve, the compressor cannot return to normal operating speed during depressed voltage conditions. The motor will not restart until the load characteristic returns to the “cold” curve or voltage returns to normal. Random motor restarts prevent fast system recovery.

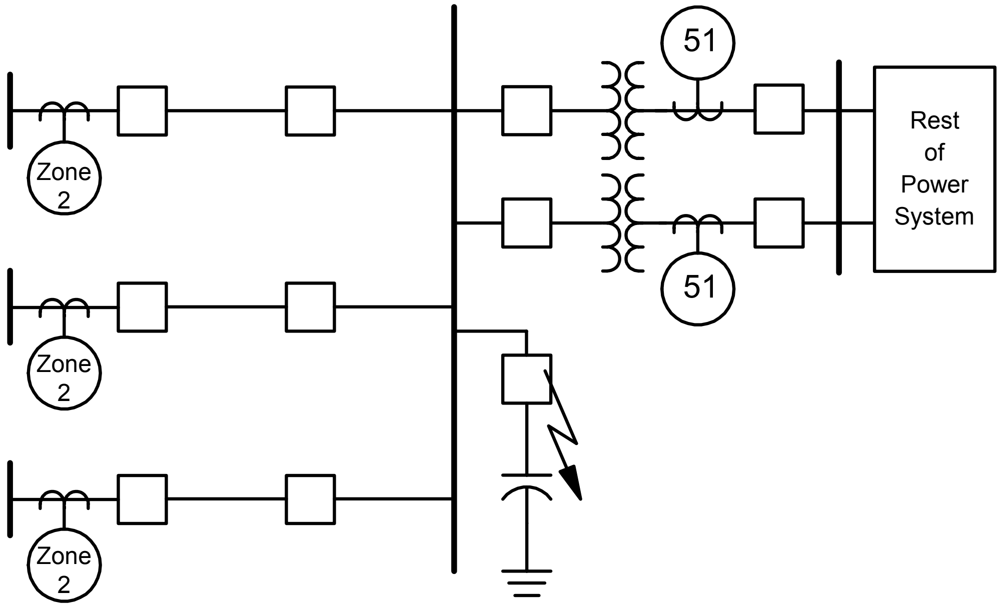

Figure 3 Lack of Breaker Failure and Busbar Protection Slows Fault Clearing, Initiating Voltage Collapse

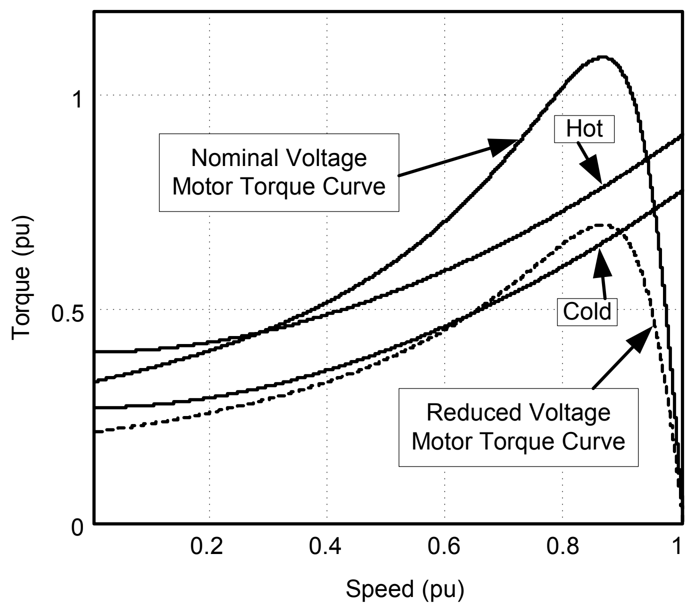

Figure 4 The Combination of Low-Voltage Conditions With Random Motor Restarting Delayed Voltage Recovery

Zone 3 Operations Reduced the Transmission Network Capability

In the West Tennessee system, reverse-looking Zone 3 distance elements provided backup protection at the time of the disturbance. Time-delayed Zone 3 distance elements operated during the low-voltage condition and high reactive current flow (Figure 5). In this case, the Zone 3 element operation reduced the transmission network capability. Use breaker failure protection and direct transfer trip instead of Zone 3 elements to provide backup protection and prevent this type of misoperation.

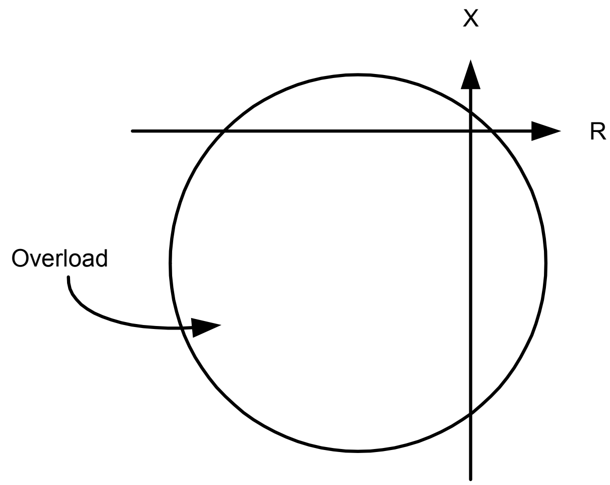

Figure 5 Reverse Zone 3 Distance Elements Operated During Low-Voltage Conditions. Zone 3 Operations Reduced Transmission Network Capacity.

West Coast System Separation on Aug 10, 1996

This outage is well known and documented [8]. Underlying conditions included high heat in the West, which caused large loads in California and heavy power exports from the Pacific Northwest (NW), a region with abundant hydroelectric resources. Several lines sagging into trees in the NW shifted flows to fewer lines. This loss of transmission capacity eventually resulted in a need for more var support than the available system reactive power reserve, particularly when a relay problem caused generation from a large hydroelectric plant to trip. Without sufficient transmission capacity, the Pacific NW and Southwest became synchronously unstable. The resulting oscillation grew large enough to enter the distance relay trip zone at the California-Oregon AC Intertie (COI), and the system separated. With a large amount of imported power suddenly lost, significant generation in California tripped, causing a large blackout.

After months of piecing the event together, engineers found that the model used to plan system protection did not predict this event correctly. Figure 6 shows actual COI power flow compared with the COI flow the model predicted. The growing oscillation of the actual flow looks like classic angle instability with a slightly positive damping factor. Engineers made extensive changes to the model to make it match the actual event. Now, improved dynamic measurement systems provide better measurement of actual system responses. Engineers now compare model results to system measurements and update the system model for any discrepancy.

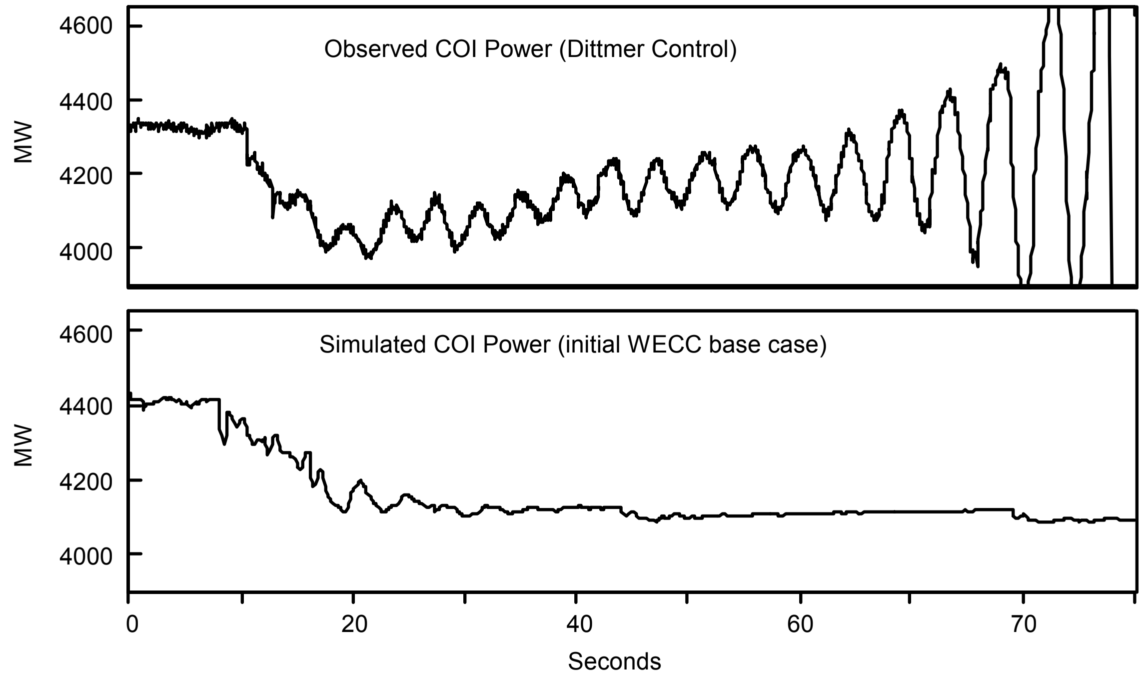

Figure 6 Actual Oscillation Compared With the Model Prediction of Power Flow at Malin in the 1996 Blackout

Transmission Line Tripping During System Oscillations in Idaho

A January 17, 1994, earthquake near Los Angeles, California caused a massive loss of transmission lines, which caused a severe power system disturbance in the western United States. The oscillogram in Figure 7 shows the start of a power oscillation that the distance relay of the Borah-Jim Bridger 345 kV line saw at Borah Substation in Idaho as a result of the system disturbance. The Borah-Jim Bridger Line is 239.68 miles long and has 42.5 percent series compensation. The oscillation began slowly with slip frequencies between –0.1 and –0.5 Hz. Figure 8 shows the positive-sequence impedance that the relay saw for these conditions. The relay out-of-step logic detected this swing condition and blocked the Zone 1 distance element.

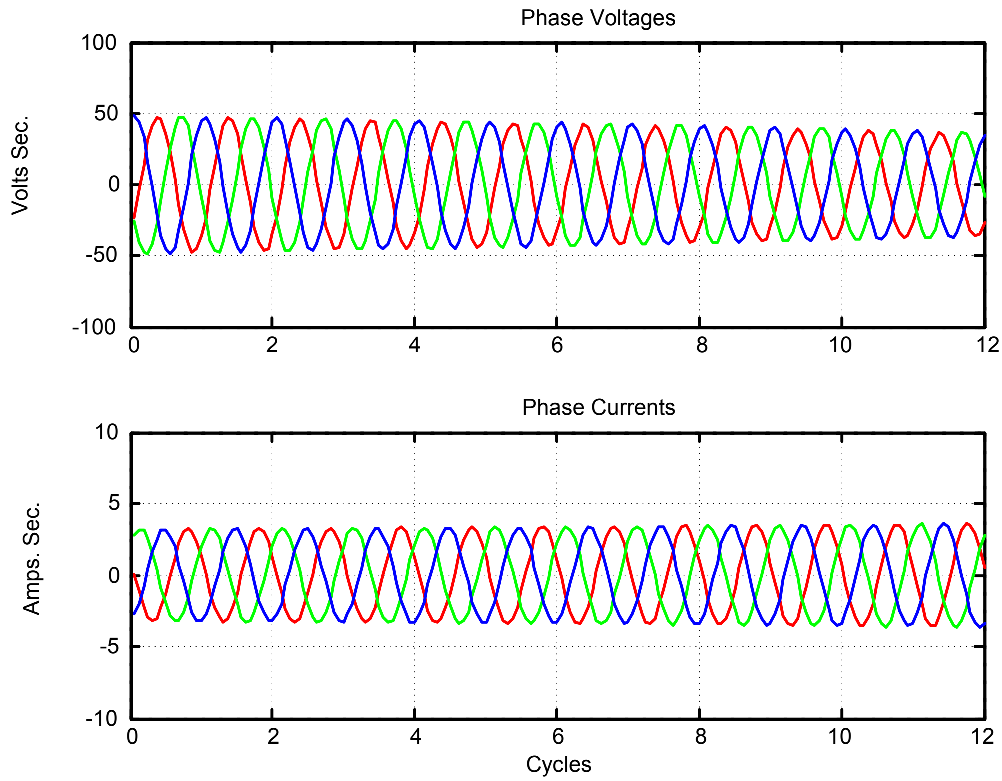

Figure 7 Oscillogram that Shows the Start of an Out-of-Step Condition in the Idaho Power 345 kV Network

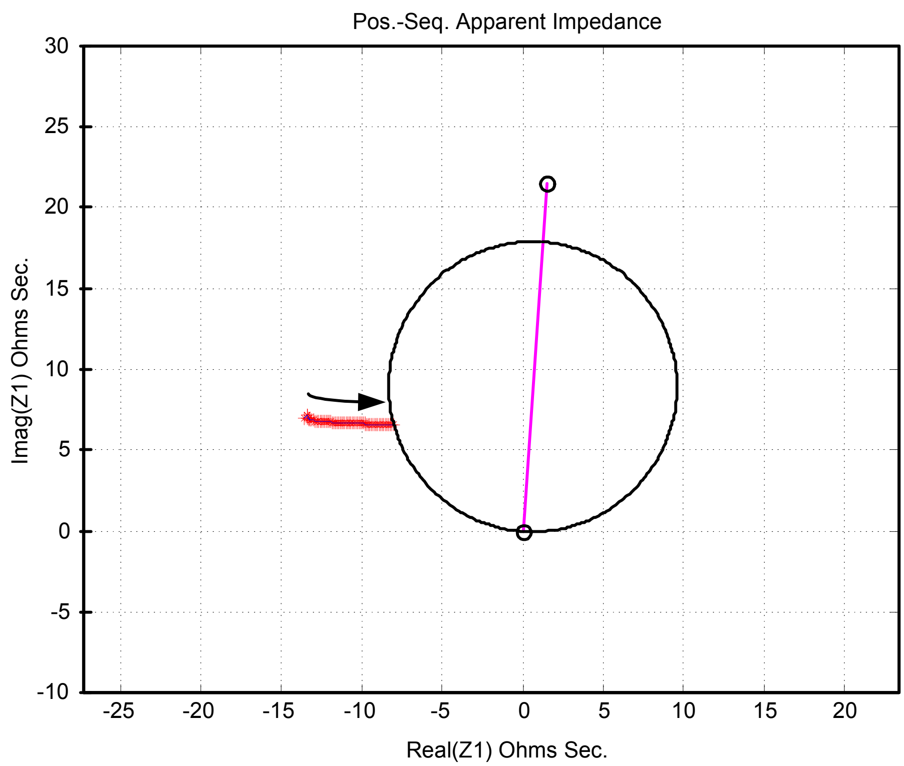

Figure 8 Out-of-Step Detection Logic Avoids Zone 1 Tripping During the Slow Oscillation Condition

The relay triggers a second event record a few milliseconds later (Figure 9). Meanwhile, the system slip frequency changed from –0.5 Hz, at the end of the first event (Figure 7), to –5 Hz at tripping time. Figure 10 shows the slip frequency calculations for this event according to [9]. The apparent impedance went through one slip cycle, plotting a circle in the impedance plane (Figure 11). The apparent impedance left the Zone 1 characteristic at the right of the characteristic and entered Zone 1 at the left of the characteristic. The out-of-step detection logic was unable to detect the out-of-step condition the second time that the apparent impedance entered the Zone 1 characteristic because of the high slip frequency operating condition. The relay activated the trip signal when the apparent impedance entered Zone 1. The trip occurred when the angle between the two systems approached 180 degrees. The breaker opened when the two systems were completely out-of-phase, imposing additional stress to the breaker. The line opening occurred in an uncontrolled fashion because the out-of-step detection logic failed to detect the out-of-step condition. Protection engineers can use improved out-of-step detection algorithms to cause trips at the time and location the power system requires for minimal system disturbance and reduced primary equipment stress.

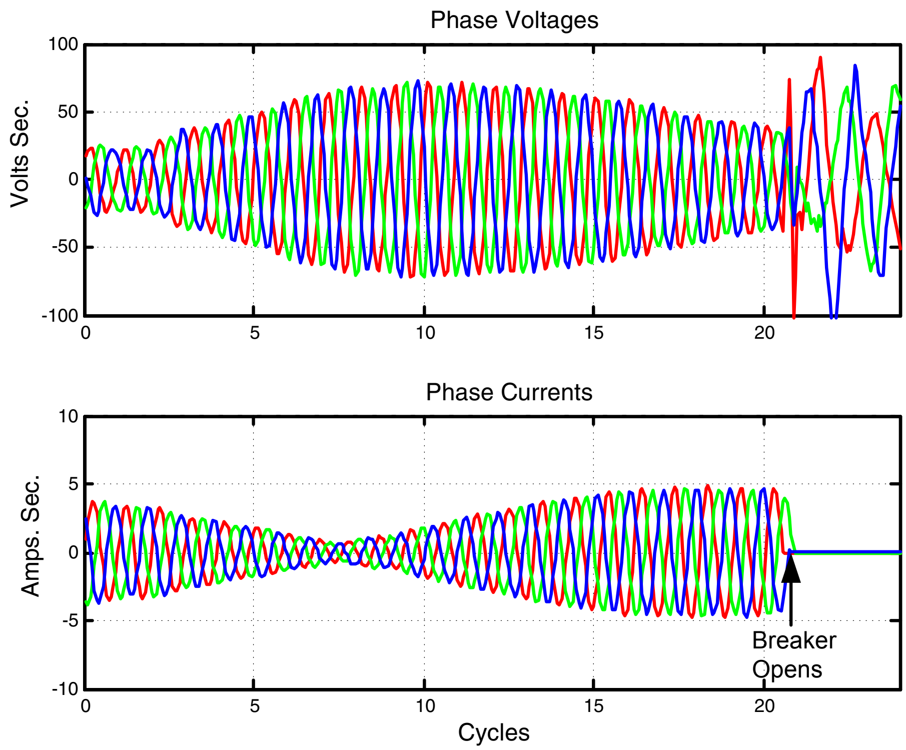

Figure 9 Voltages and Currents at Borah Before the Borah-Jim Bridger Line Opens

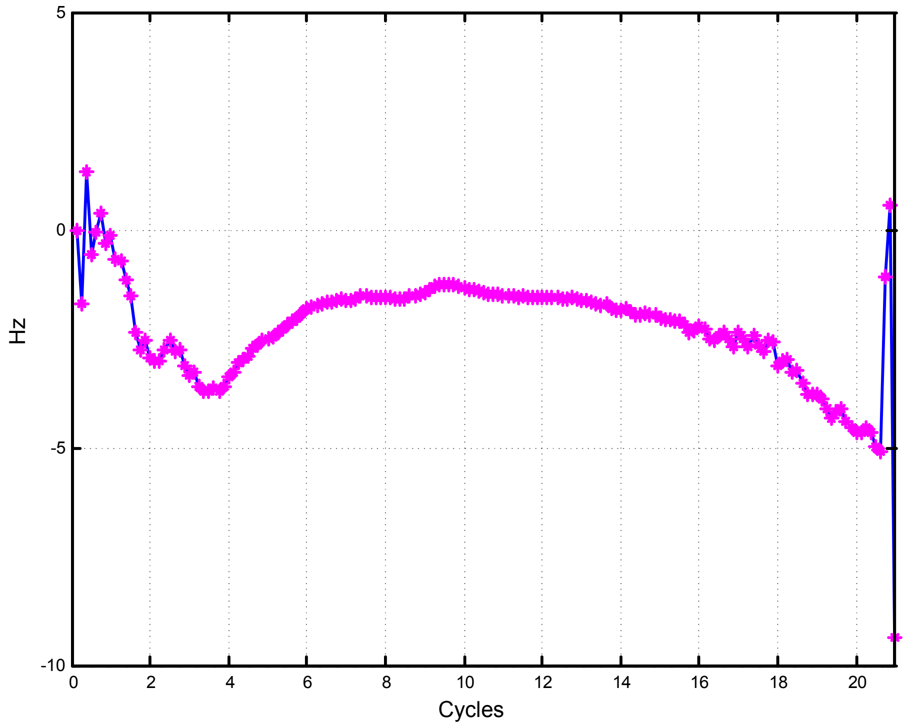

Figure 10 The System Slip Frequency Changes From –0.5 Hz at the End of the Event Shown in Figure 7 to –5 Hz at Tripping Time

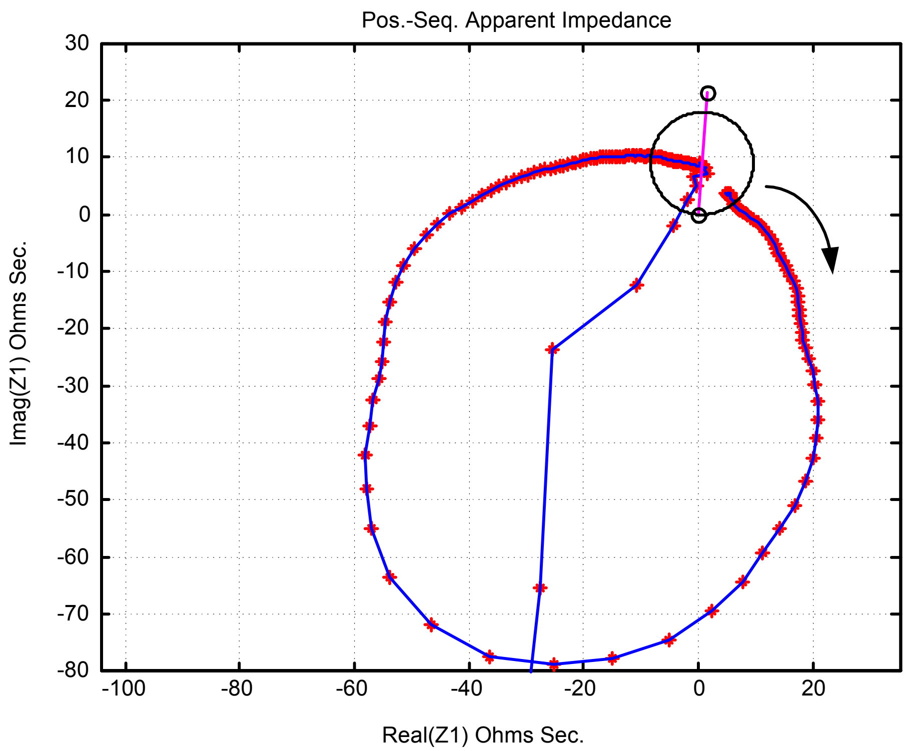

Figure 11 Zone 1 Operates When the Apparent Impedance Enters the Characteristic Because the Out-of-Step Detection Logic Fails to Detect the Out-of-Step Condition During the Fast Swing Condition

Historical Examples of Local- and Wide-Area Protection Systems

Local-Area Protection Systems

Underfrequency Load Shedding

When available generation is unable to supply the load demand, the system experiences a frequency decline. Rapid action is necessary to maintain the generation-load balance. If there is no rapid response, additional generation could be lost because of underfrequency relay operation to trip steam turbine generating units. Traditionally, load shedding restores the generation-load balance. The traditional load-shedding scheme consists of underfrequency relays located at critical feeder locations. When the frequency drops below a preset value, the critical feeders are disconnected from the system. If the frequency continues to drop, other load-shedding stages are activated. Some underfrequency load-shedding schemes have as many as five underfrequency stages set at, for example, 59.2, 59, 58.8, 58.6, and 58.4 Hz. Ideally, all underfrequency load-shedding schemes should have the same operating characteristic so that the schemes act simultaneously across the power system when the frequency drops below the predefined frequency.

Undervoltage Load Shedding

The Protection Aids to Voltage Stability PSRC Working Group [10] describes the undervoltage load-shedding scheme shown in Figure 12. The scheme sheds the breaker load when the voltage in the three phases drops below 87 percent of nominal (27-2 undervoltage element). The scheme requires system-balanced operating conditions to operate. The 27-1 undervoltage element is connected in the open-delta potential transformer connection to detect zero-sequence voltage. The U/V scheme operates only when there is no zero-sequence voltage present. Instantaneous overcurrent elements at the feeder location provide additional supervision to prevent U/V scheme operation during feeder fault conditions. If a three-phase undervoltage condition exists, there is no zero-sequence voltage, and there is no feeder fault, the timer starts and, after a certain time (one second, for example), the scheme sheds the feeder load. Schemes with different delays provide staggered load shedding to minimize voltage overshooting conditions after the load is shed.

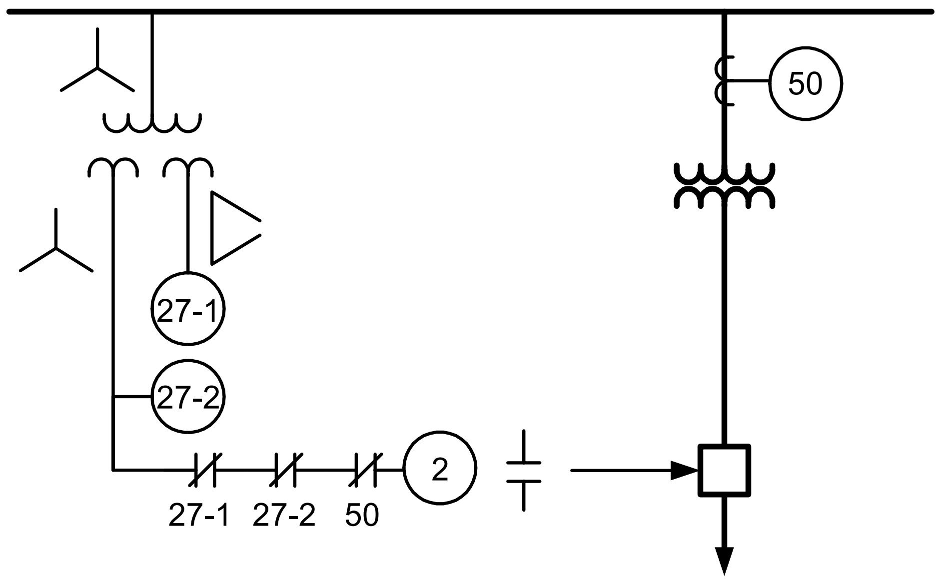

Figure 12 Undervoltage Load-Shedding Scheme That Operates Only During Balanced System Conditions and During No Feeder Fault Conditions

Wide-Area Protection Systems

WAPS schemes are designed to detect abnormal system conditions and take pre-planned, corrective actions intended to *minimize the risk of wide-area disruptions and to increase system power transfer capability*. Most typical WAPS actions include automatic tripping of generators and interruptible loads. To improve system reliability, WAPS schemes can be implemented through the use of new monitoring, protection, and communications technologies. Three application examples of these protection systems follow.

Undervoltage Load-Shedding Scheme

BC Hydro implemented an undervoltage load-shedding scheme that monitors undervoltage conditions in three system areas on Vancouver Island [10]. Figure 13 shows undervoltage monitoring in Area 1, Area 2, and Area 3. The scheme also monitors the MVAR output of four synchronous condensers. The synchronous condensers are located in Area 3. The voltage measurements are taken from 230 kV buses.

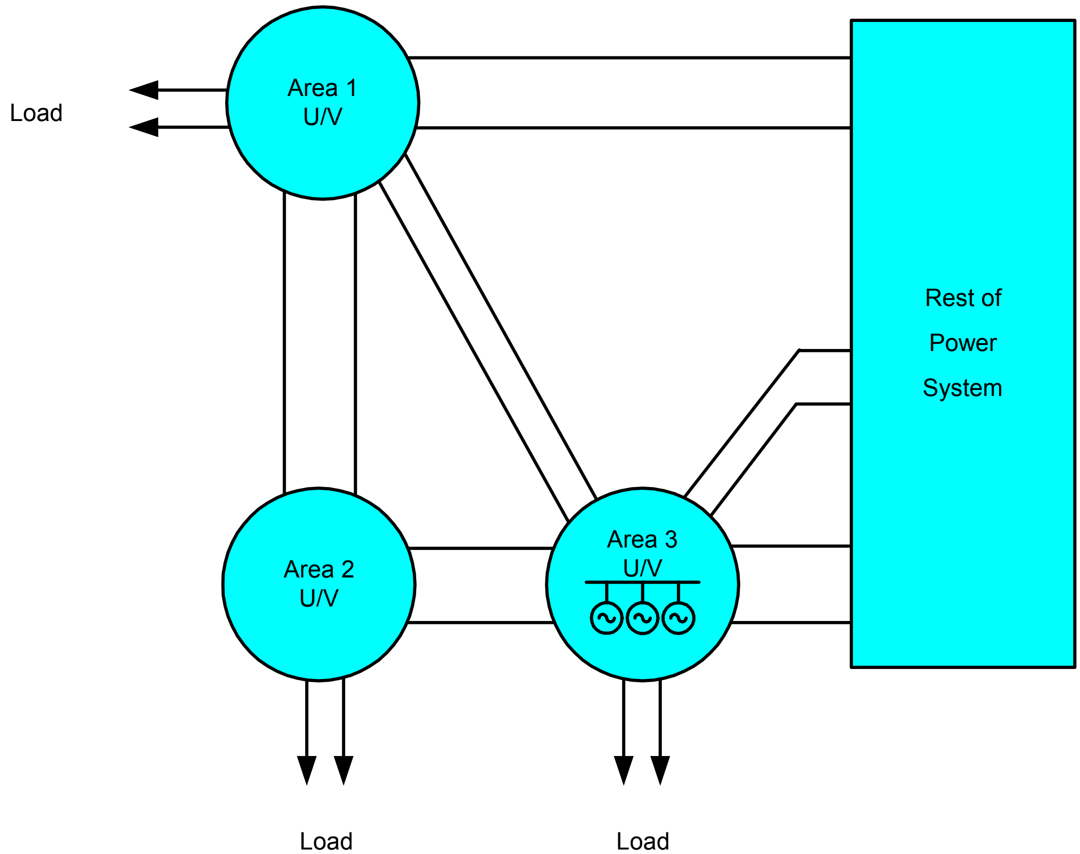

Figure 13 Wide-Area Network Undervoltage Load-Shedding Scheme That Monitors Voltage and Synchronous Condenser MVAR Output

The total MVAR output of the four synchronous condensers enables and disables the undervoltage load-shedding scheme (Figure 14). The scheme is enabled when the synchronous condensers operate close to their rated output. In the event of a system disturbance, the synchronous condensers will not be able to provide the reactive power necessary for the system. If voltage drops below 97 percent of the minimum normal voltage in Area 1 and Area 3 or in Area 2 and Area 3 for longer than 10 seconds (t1), the scheme sheds load Block 1. The scheme sheds Blocks 2 and 3 two and four seconds later to provide staggered load shedding.

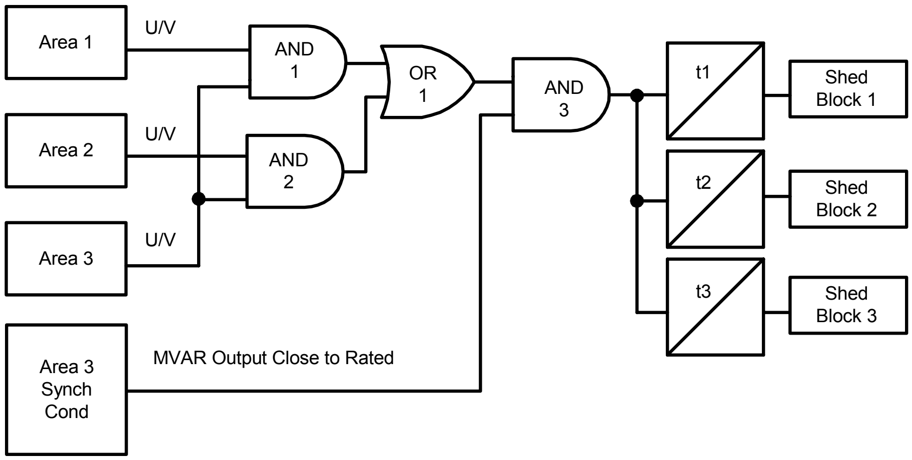

Figure 14 The Undervoltage Load-Shedding Scheme Is Enabled Only if the Synchronous Condenser Output Is Close to Rated Capacity

Two-Contingency WAPS

Leon et al. [5] describe a two-contingency remedial action scheme that prevents the system from near voltage collapse operation. In this description, the power system consists of three areas (see Figure 15):

- Area 1: Heavy load concentration
- Area 2: Heavy generation concentration
- Area 3: Light load concentration

Areas 1 and 2 are interconnected with three transmission lines; Areas 2 and 3 are interconnected with two transmission lines. The remedial action scheme to avoid voltage collapse is enabled when the transmitted power from Area 2 to Area 1 is greater than 1,100 MW, as Figure 16 illustrates. If two lines open under these conditions, the scheme sheds excess generation in Area 2 in a timely manner (less than one second). Multifunction relays can execute these tasks to prevent the system from collapsing.

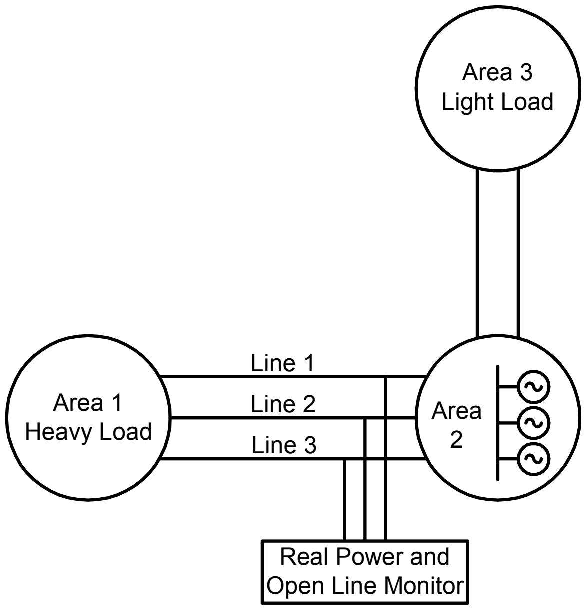

Figure 15 Area 2 Generation Depends on the System Real-Time Power Transmission Capability

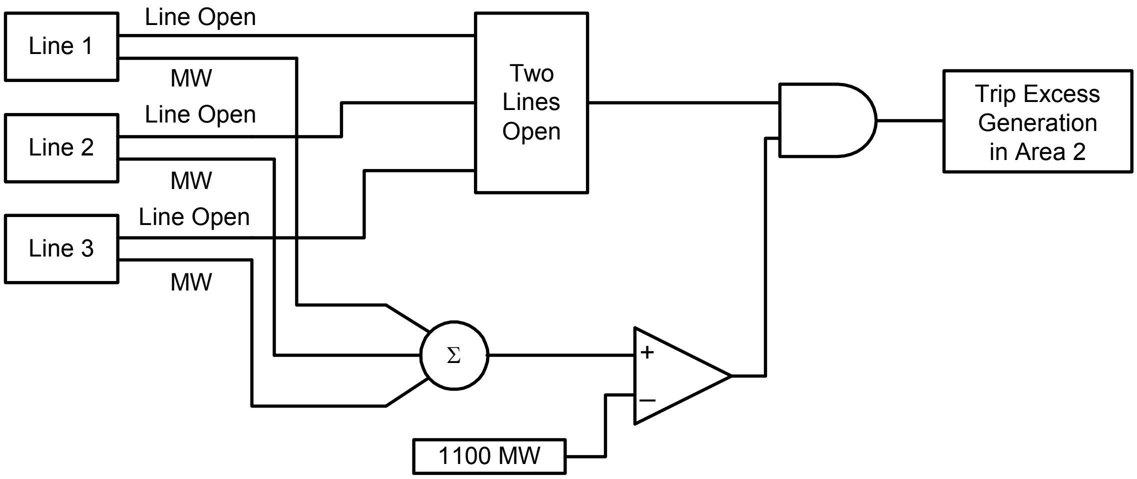

Figure 16 WAPS to Shed Area 2 Excess Generation When Two of the Transmission Lines Between Area 1 and Area 2 Are Open and the Transmitted Power From Area 2 to Area 1 Is Greater Than 1100 MW

WAPS Use in the Western United States

The interconnected transmission network of the Western Electricity Coordinating Council (WECC) encompasses nearly 1.8 million square miles and serves more than 71 million people. WECC service territory extends from Canada to Mexico and includes the Canadian provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 states west of the Rocky Mountains. EHV transmission lines span long distances to connect the Pacific NW with its abundant hydroelectric resources and the Southwest with its large coal-fired and nuclear resources to the large load centers of southern and northern California. WECC and nine other regional reliability councils in the U.S. were formed as a result of national concern regarding the reliability of interconnected bulk power systems, the ability to operate these systems without widespread failures in electric service, and the need to foster the preservation of reliability through a formal organization.

Abundant hydroelectric generation from the Pacific NW and Canada is transmitted over long distances to central and southern California load centers through the California-Oregon AC Intertie (COI, shown in Figure 17), which consists of three 500 kV transmission lines, and the Pacific DC Intertie (PDCI). The north-to-south transfer capability is 4,800 MW on the COI and 3,100 MW on the PDCI. Generation from Utah, Colorado, Arizona and New Mexico is transmitted to southern California load centers by two main transfer paths: the Arizona-California or East of the River (EOR) transfer path, which consists of five 500 kV and one 345 kV ac transmission lines, and the Intermountain Power Project (IPP) bipolar +/- 500 kV dc line. The rated transfer capability of the EOR path is 7,750 MW, and the IPP dc line transfer capability is 1920 MW. Another major path in central California (Path 15) consists of two 500 kV and four 230 kV lines that limit the north-to-south and south-to-north transfers within the state of California. The Path 15 ratings are 1,275 MW north to south and 3,300–3,900 MW south to north.

Planning studies have indicated that single-, double-, or three-line loss in the COI or bipolar PDCI line loss occurring when the system is heavily loaded can cause instability, cascading outages, WECC system separation, and islanding. To reduce risk of such events, WAPS schemes were designed in the Pacific NW and northern California to detect 500 kV line outages and initiate appropriate remedial actions to prevent overloads, low voltages, and out-of-step conditions in the WECC system.

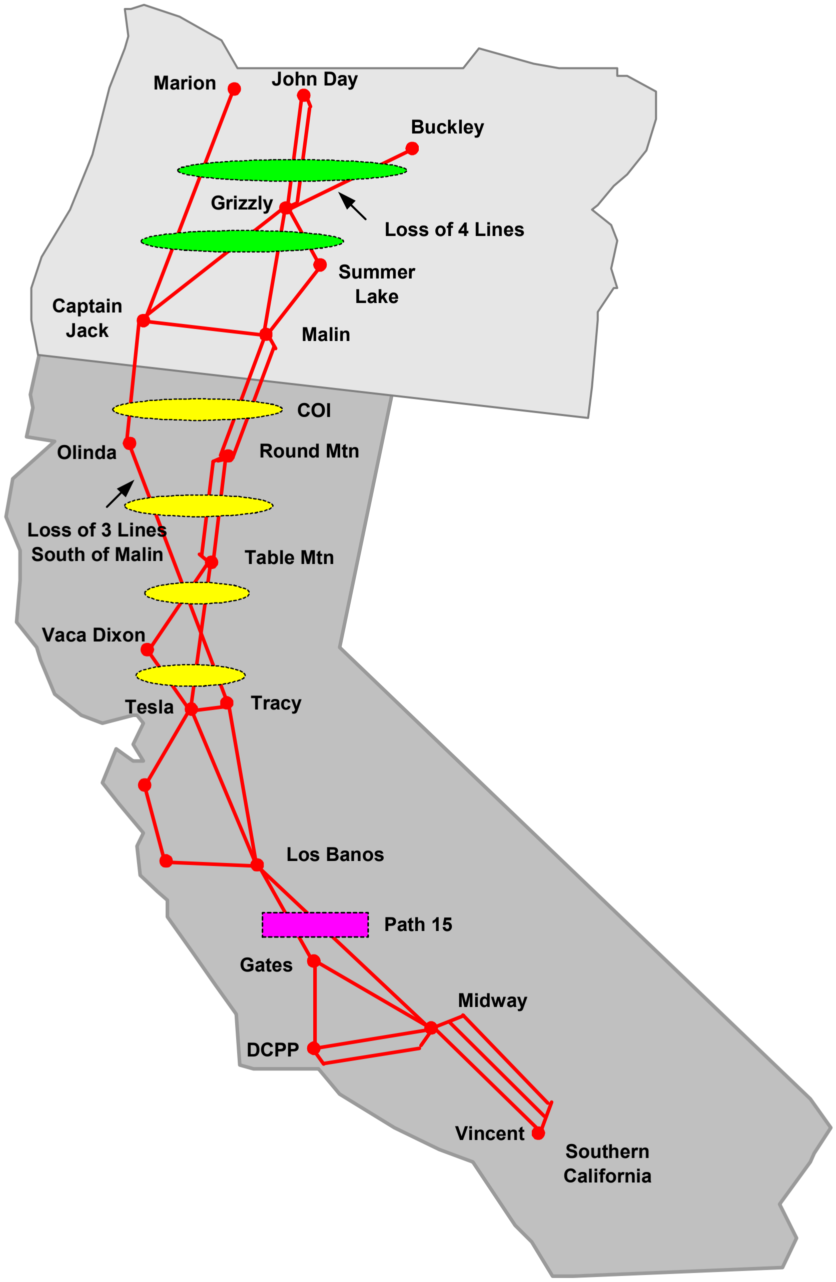

Figure 17 California-Oregon AC Intertie–COI. Ellipses Indicate Regions in Which the System Detects Three- or Four-Line Outages. Path 15 is a Region in Which the System Detects Two-Line Outages.

The Bonneville Power Administration (BPA) and California WAPS schemes shown in Figure 18 monitor the status of the 500 kV transmission system in their respective areas, the load flow levels and direction at the California-Oregon border, and the MW output of two major generating units in central California. The two systems then send appropriate signals back and forth during an outage to determine the level of necessary remedial actions.

Depending on the lines that trip between the Pacific NW and northern and central California, 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
- Bypass series capacitors
- Transmission of transfer trip signals to separate the WECC system into two islands
- Application of a dynamic breaking resistor at a Pacific NW generation site

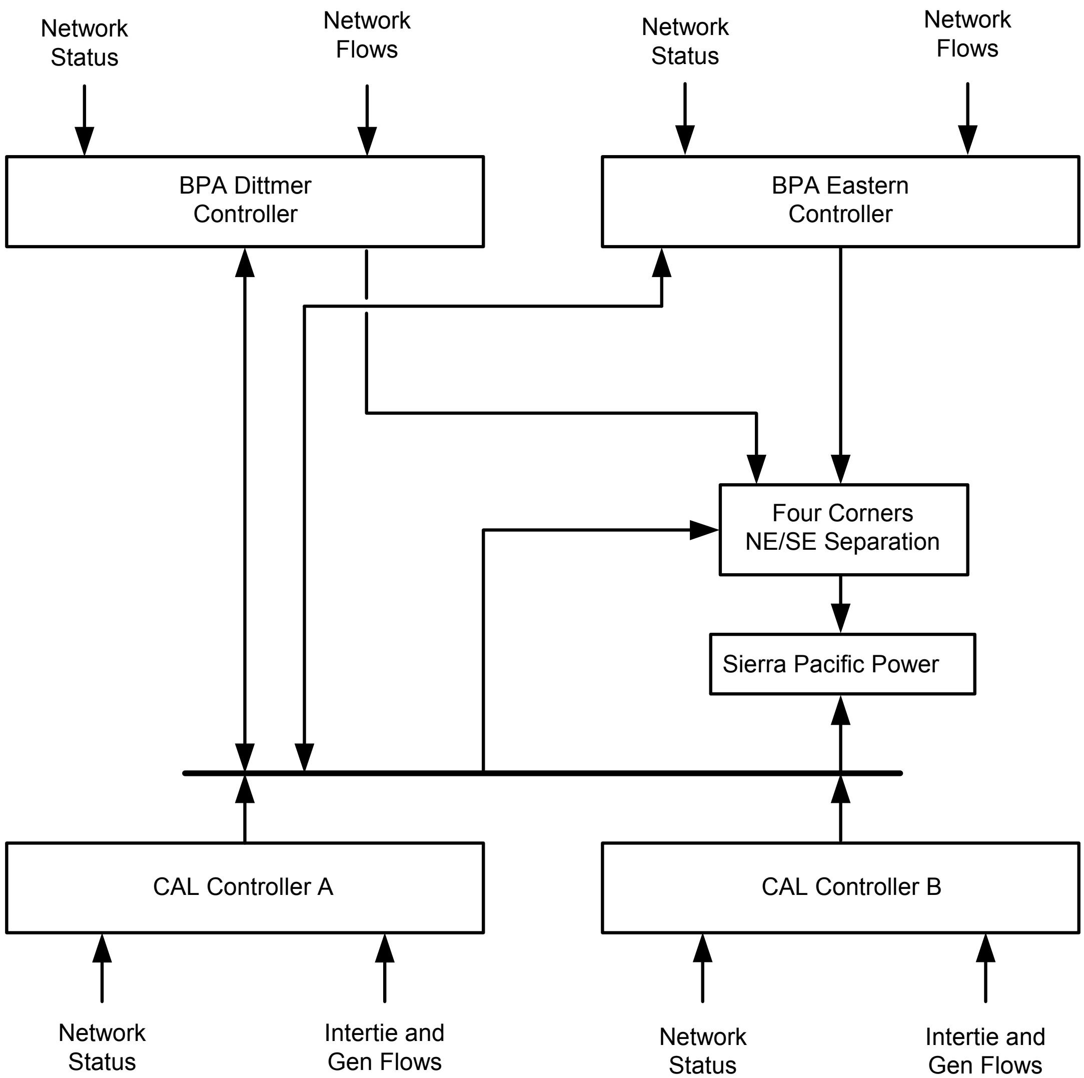

Figure 18 California and BPA Remedial Action Scheme Controllers

Complete loss of the COI in northern California detected by the California WAPS controllers, i.e., three-line loss south of Malin substation to Tesla substation, initiates a WECC system islanding that separates the WECC system into two islands (such as in Figure 19):

- A southern island includes California, Arizona, and New Mexico in the United States and Baja California, Mexico.
- A northern island includes the rest of the WECC system.

WECC islanding also occurs if the BPA controllers detect a four-line loss north of Malin and Captain Jack substations.

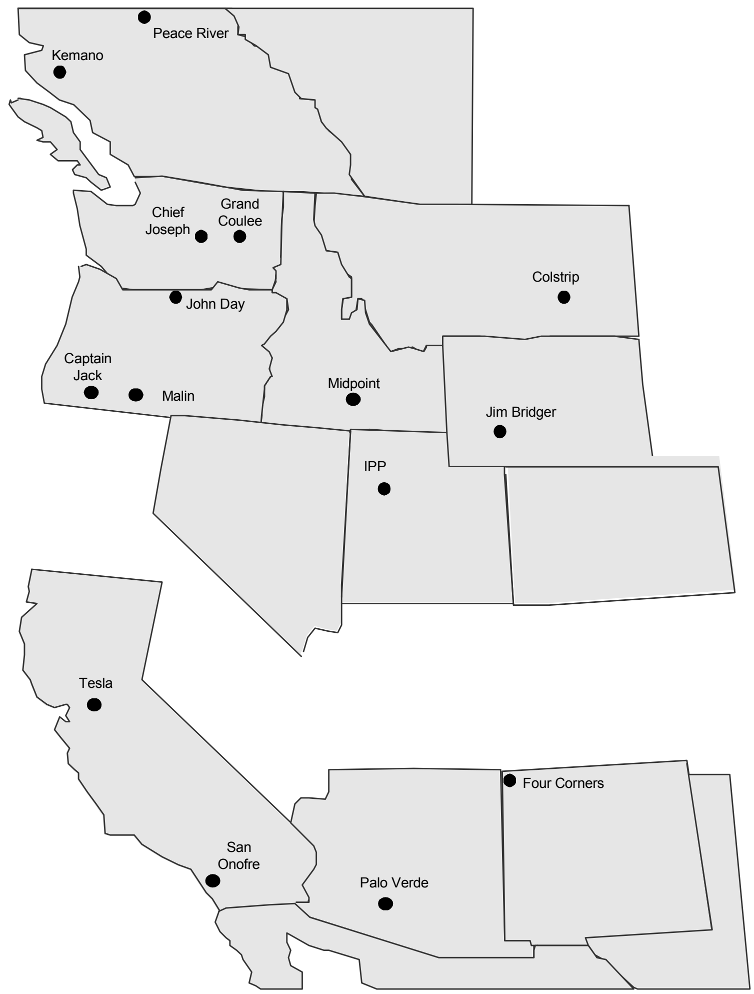

Figure 19 WECC System NE/SE Separation

There are many other outages for which the WAPS takes actions to prevent widespread outages and maintain system stability. For example, double line loss on the COI initiates generator tripping, switching of shunt capacitors, and insertion of a 1,400 MW dynamic brake in the Pacific NW. The most critical outage for Path 15 is a double 500 kV line loss. To maximize power transfer capability during double line loss in Path 15, while the system is operating according to Set V (see Figure 21), the WAPS initiates bypassing of series capacitors and generator tripping in northern California and load shedding in central California.

Figure 20 shows the interconnected generation/load areas in the western United States protected with a WAPS to maintain high power transfer levels from Area 1 (Pacific NW) to Areas 2 (northern and central California) and 3 (southern California, New Mexico, and Arizona). Let us look more closely at the WAPS in Area 2. The system monitors the following operating conditions:

- Real-power flow between Area 1 and Area 2 and between Area 2 and Area 3
- Real-power output from two large power plants in Area 2
- Transmission line open conditions throughout the 500 kV network in Area 2 and the intertie lines connecting Area 2 with Areas 1 and 3

Depending on system operating conditions, centralized wide-area protection controllers take different sets of control actions to protect the system from angular instability in the event of single, double, or triple line outages in Area 2 and between Area 2 and Areas 1 and 3.

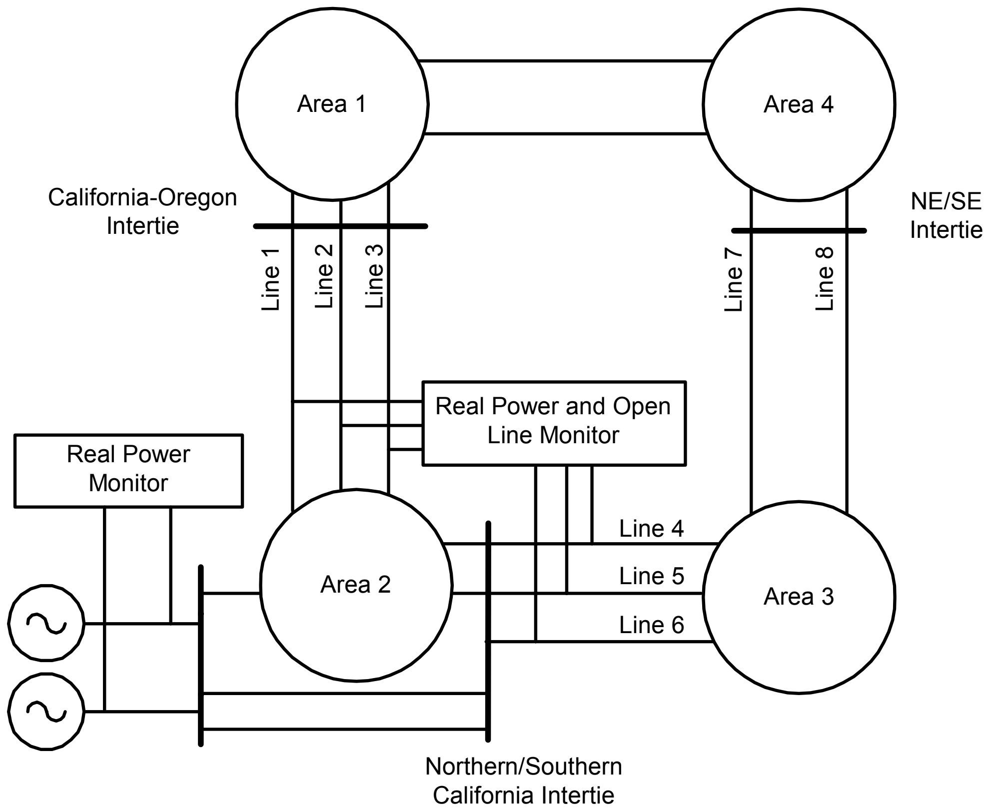

Figure 20 WAPS to Enhance Network Power Transfer Through Wide-Area Network Monitoring of System Operating Conditions

Inter-area real-power flow levels and whether one or two of the large generators monitored in Area 2 are in service determine a different set of control actions that occur for transmission line outages to prevent system angular instability and minimize the extent of potential system disturbances. Figure 21 represents an adaptive WAPS with a higher level of design sophistication. The figure shows five sets of control actions that can occur depending on real-time operating conditions in Area 2. The protection scheme takes no action when the system operates in the center area. This area represents operating conditions where small amounts of real-power exchange exist between Area 2 and Area 1, and between Area 2 and Area 3.

When Area 2 imports power from Area 1 and exports power (greater than 900 MW) to Area 3, the scheme enables Set I or Set II actions. Set I is active if one of the large power plants in Area 2 is in service, and Set II is active if both large power plants are in service in Area 2. Set IV is active if Area 2 is importing power from Areas 1 and 3, or when Area 2 is importing power from Area 1 and exporting power (as much as 900 MW) to Area 3.

Let us look at some actions the WAPS takes for different operating conditions when Set IV is active and the system detects a three-line outage between Areas 1 and 2. The system is at a high risk of a major blackout if such a scenario develops and no control actions occur to prevent propagation of the disturbance. The protection system must take severe actions in this situation. Such actions include the following:

- Area 2 informs Area 1 of a three-line-open condition south of Malin substation.
- The Pacific NW WAPS controllers trip generation and send a NE/SE separation signal.
- The system separates into two islanded networks, as shown in Figure 19: Areas 1 and 4 form a northern island, and Areas 2 and 3 form a southern island.
- The protection system sheds water irrigation pump load in Area 2 and other noncritical loads. Water irrigation pumps are not considered critical loads, and shedding of these noncritical motors reduces both real and reactive power requirements.
- The protection system inserts a dynamic brake resistor in Area 1.

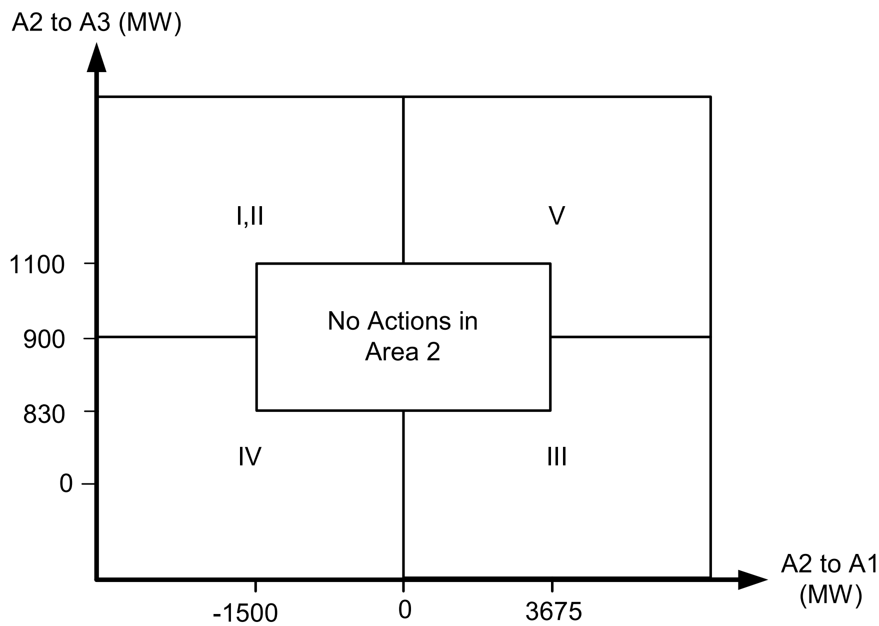

Figure 21 Inter-Area Power Flow Determines Set of Actions to Avoid System Disruption

BPA provides transmission for a large number of hydroelectric generators in the Pacific NW. The BPA WAPS monitors the network status through the use of line loss logic, which is included in relay trip schemes to provide a fast indication of line loss. Other BPA WAPS triggers include a power rate relay, described in the following paragraphs, and error conditions (such as commutation failures, restrikes, etc) on the Pacific NW-SW dc intertie. The WAPS sends trigger indications by transfer trip to a triple-redundant control computer. Control inputs to this computer arm and disarm the various remedial actions. Other transfer trip circuits carry outputs from the WAPS controller to initiate the required actions. The remedial actions may include shunt reactor tripping, shunt capacitor insertion, tripping of generators, reclose blocking, dynamic brake insertion, transient voltage boost, dc power ramp, and islanding. Most WAPS actions occur in less than 100 ms.

BPA built a power rate relay (PRR) to detect transmission loss outside the BPA system during high export conditions. This device uses Hall effect power transducers with a less than 1 ms response time to detect sudden loss of power flow. The PRR arms for power flow that exceeds a minimum power flow threshold and then triggers for any sudden power loss exceeding another preset threshold. The PRR sends the trigger indication to the WAPS controller, resulting in system initiation of the appropriate action to rapidly shed generation exceeding transmission capability and prevent over-speed and out-of-step conditions. Without this type of protection, high power exports from the Pacific NW would be severely limited.

BPA also built a 1400 MW dynamic brake, shown in Figure 22 and Figure 27, to help stabilize the large concentration of generating units at Grand Coulee and Chief Joseph Dams. The dynamic brake consists of three single-phase resistors created from several hundred feet of wire strung on towers. During high power exports, transmission system faults and opening of line breakers reduce the electrical power transfer capability of the system and threaten system stability by causing subsequent acceleration of these generating units. The dynamic brake, applied for 0.5 seconds, slows down these generating units and keeps these units in service, in anticipation of a successful line reclosing. If a line remains open because of a permanent fault, the generating units trip and the dynamic brake helps to limit unit over-speed.

Figure 23 displays actual system reaction to a WAPS-triggered brake insertion resulting from a bus fault. The large voltage dip resulting from the bus fault is followed by an incomplete system voltage recovery and subsequent voltage overshoot caused by the brake insertion.

Figure 22 1400 MW Dynamic Brake at Chief Joseph Substation (K. E. Martin photo)

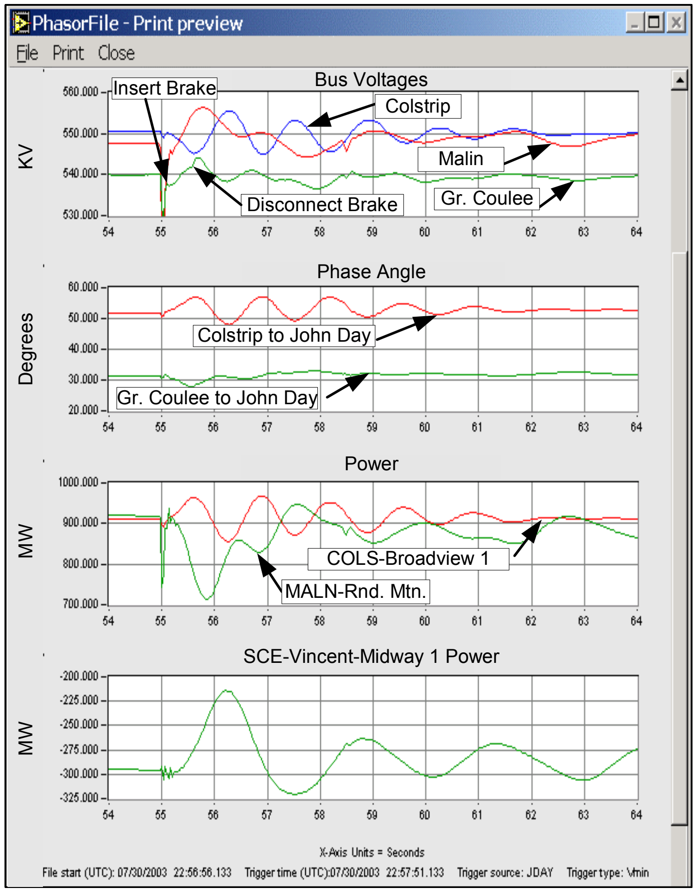

Figure 23 System Response to 1400 MW Dynamic Brake at Chief Joseph Substation

WAPS Requirements

As we have discussed, WAPS schemes must act quickly and correctly to protect the power system from major disruptions. For this reason, the design requirements of WAPS schemes are very demanding. Although WAPS schemes can cover vast areas, such as the WECC system, and use different equipment and procedures of many different operating entities, they are designed to meet certain requirements.

One of the most important and common system requirements is redundancy, which provides a high degree of dependability so that a single component failure of any one component will not cause a failure of the WAPS. Most system components can be removed from the scheme for testing or repairs while the rest of the scheme remains in service. WAPS systems require duplicate central programmable logic controllers (PLCs) located in different geographical locations and duplicate communication paths and equipment so that no single failure of any device or facility will adversely impact the operation of the system.

WAPS schemes must also include a high level of security designed into the system to avoid any false system operations, because WAPS schemes take drastic remedial actions to preserve system stability and service continuity. One of the most important features in these systems is a requirement for triple redundant programmable logic controllers where two out of three voting schemes are implemented to ensure a high level of security. Even if one CPU fails, the two remaining CPUs must agree before any actions take place. System security is also ensured by additional means, such as manual or automatic arming of the system, when power flow levels exceed a certain threshold, or after the loss of a particular system element. Additionally, transfer trip signals that take severe remedial actions, such as system separation, are supervised with additional inputs such as from rate-of-change of power or current devices that are installed at key interconnection paths.

A major requirement for these systems is fast and redundant communication paths. We discussed previously the need for redundancy of the communication paths for WAPS schemes. In most cases, privately owned communication facilities and paths, for example analog or digital microwave or fiber-optic networks, are used for these systems to ensure a high degree of availability and to meet strict time requirements. The time necessary from the initiation of a disturbance to the time the system completes a remedial action is on the order of 100–200 ms, especially if the WAPS is designed to preserve angular stability among neighboring utility systems.

Highly reliable control equipment is another important requirement in the design of WAPS schemes. WAPS schemes are installed to ensure high levels of power transfers among interconnected networks. Therefore, extended equipment down time is not tolerated, even though these systems have a high degree of built-in redundancy. These systems must use control equipment with a high mean time between failures (MTBF) and extensive self-diagnostics to alert operating and maintenance personnel of equipment component failures.

WAPS schemes require accurate and fast metering because, in many cases, the arming of remedial actions depends on intertie power flow levels and power flow direction. Additionally, many WAPS designs require local measurements, such as rms volts, amperes, watts, vars, and frequency to supervise remote WAPS var support requests. In new WAPS schemes, synchrophasor data from remote sites will be transmitted via communication links to a data concentrator for processing and implementation of protection and control algorithms. In such systems, there is a need not only for accurate and fast metering but also for accurate time-synchronized measurements that use an accurate GPS system time reference.

Very important for WAPS schemes in service today is the ability to monitor and record the input and output status of the PLC with a sequence-of-events (SOE) recorder. Such records are valuable for post-event analysis by operations engineers in determining the proper response of a WAPS to a particular disturbance. The SOE recorder is typically connected to a GPS clock that provides accurate timing for time tagging the data with a minimum resolution of one millisecond.

WAPS schemes typically are tested annually, with some more critical facilities and equipment tested semi-annually. The design of the WAPS should include test switches for ease of input/output isolation to accommodate testing and troubleshooting by maintenance personnel.

Technologies to Improve Power System Reliability

Synchronized Phasor Measurement System for Improved Monitoring

A number of phasor measurement systems have been implemented in the WECC area in western North America. The primary purpose of these systems is to improve disturbance monitoring and system event analysis. These measurements have been sited to monitor large generating sites, major transmission paths, and significant control points. Synchronized phasor measurements provide all significant state measurements including voltage magnitude, voltage phase angle, and frequency. Most installations also calculate current phasors so power flow and generator interactions can be accurately assessed. Figure 24 shows the approximate coverage of phasor measurements in the US portion of the WECC. Several new sites are being added every year.

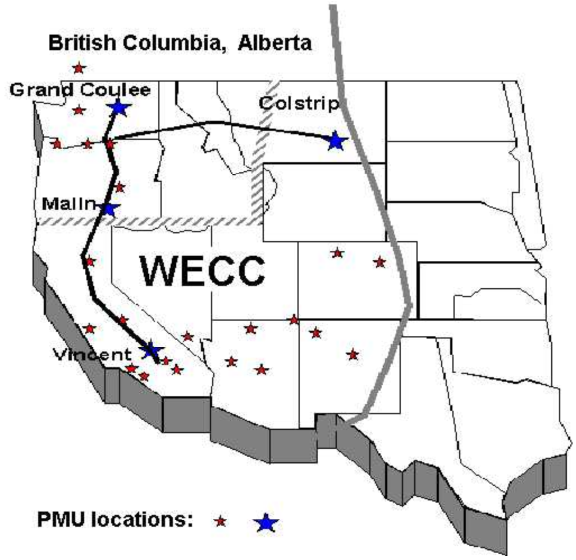

Figure 24 Phasor Measurements in the WECC. PMU Locations Denote Actual Units or Groups of Nearby Units in Service by Jan. 2003.

Most of these phasor measurement systems have been implemented as real-time systems. With these systems, phasor measurement units (PMUs) installed at substations send data in real time over dedicated communications channels to a data concentrator at a utility control center. This approach allows the data to be used in operations and control systems as well as being recorded for system analysis. Figure 25 is a block diagram of this type of system as implemented at BPA [11]. PMUs measure the bus voltage(s) and all the significant line currents. These measurements are sent to a Phasor Data Concentrator (PDC) at the control center. The PDC correlates the data by timetag to create a system-wide measurement. The PDC exports these measurements as a data stream as soon as they have been received and correlated. Multiple applications can receive this data stream and use it for display, recording, and control functions. Total time delays are in the range of 100 ms or less. The elements of this system are described in the following subsections.

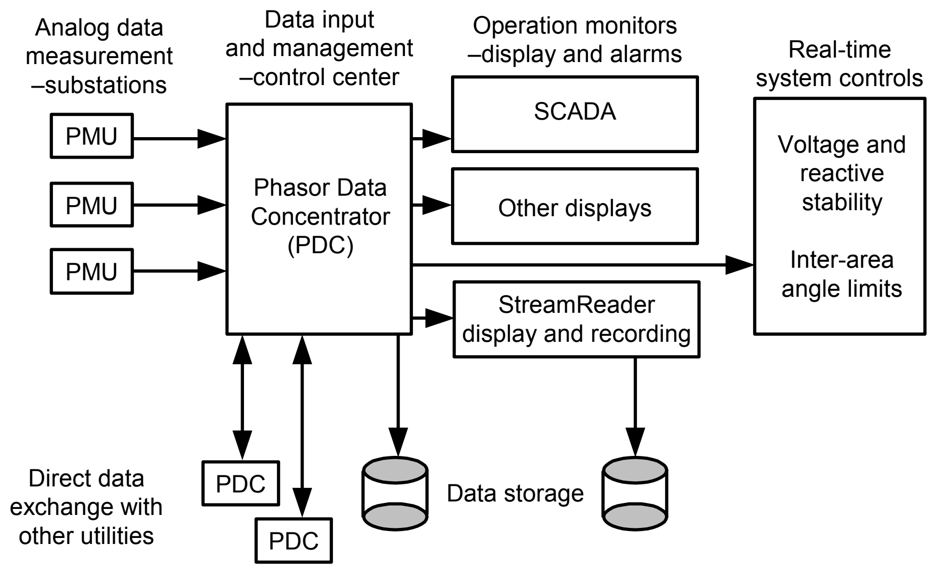

Figure 25 Phasor Measurement System at BPA

Phasor Measurement Unit

The basic phasor measurement process is that of estimating a positive-sequence, fundamental frequency phasor representation from voltage or current waveforms. The phasor measurements are calculated using a UTC time reference. A number of techniques have been used for this purpose [12], [13]. The IEEE standards 1344 and PC37.118 [14], [15] describe reporting and measurement requirements for synchronized phasor measurements. Phasor measurements are combined with frequency measurements, status information, and a precise timetag into a data frame that is sent to the PDC. Present phasor systems in the WECC transmit phasor measurements at a message rate of 30 messages/s.

Communications and Phasor Data Concentrator

Standard communication systems are adequate for most phasor data transmission. The issues for data communications include speed, latency, and reliability. Communication speed (data rate) depends on the amount of phasor data being sent and the number of messages/s. A PMU sending 10 phasors at 30 messages/s has an actual data rate of about 17 kbps. A V.34 analog modem operating at 33.6 kbps is fast enough for this application. However, if the rate increases to 60 messages/s, a faster system, such as a 56 kbps digital link, is necessary. Many stations in the WECC are still only accessible by some kind of analog communications, so the 30 messages/s rate is more suitable for easy station integration.

Reliability in this application includes both error rate and component failures. Infrequent single-frame errors can be easily compensated for. Dropouts longer than about 0.3 seconds begin to cause difficulty in system analysis and operation applications. The biggest problem is sustained failures; these failures should be infrequent. Redundant measurements with automatic switchover are essential for real-time applications. A good system monitor that alerts maintenance personnel is important to keeping the system in full operation.

Latency, the delay time between occurrence of an event and execution of an action command, is critical in control applications. It is often the dominant factor in determining overall control loop performance. BPA has measured system latency including PMU measurement, data communications, and PDC processing. Total latency ranges from 45 to 200 ms (or longer). The biggest factor contributing to system latency is measurement filtering within the PMU that can range from less than one cycle to longer than 0.5 second (3 dB response level). With minimal filtering, communications channels account for the largest system delay. Direct digital communications with high bit rates and high data frame rates (60 messages/s or faster) can reduce overall latency to less than 35 ms. In the WECC, typical digital systems have a 40–60 ms latency; while analog systems have a latency of 80–120 ms. All present systems use dedicated, private communication systems. Internet connections may be used in the future.

The PDC brings together data from many sources, including both PMUs and other PDCs, and concentrates these data into a single measurement set. It sends the full set or selected subsets of the correlated data out to other applications. It provides system management by monitoring all the input data for loss, errors, and synchronization. It can be used also for data recording, continuous or only during disturbances. The PDC at BPA accepts input data, using a number of protocols that use serial or Ethernet communications. It uses a real-time operating system that provides low latency processing. This operating system allows the PDC to input and output data with only a few milliseconds of delay.

Application Programs

Phasor measurements are useful as long as there are applications that use these measurements. BPA and other users in the WSCC have developed a number of software utilities for processing and using phasor data. These include phasor system monitoring, data analysis, continuous data recording, and real-time observation of power system operation.

PDCs perform the primary system monitoring function. It checks for data errors, PMU time synchronization, and system failures. It sends status information to a monitor program that provides an operation display and operational statistics. This monitor program runs on a standard PC and connects to the PDC through a serial cable or TCP/IP over Ethernet.

StreamReader is a real-time application that plots user-selected data quantities and records data continuously (Figure 26). This display is useful for observing real-time power system operation. It also is useful for detecting phasor data system problems. *StreamReader* runs on a standard PC and connects to the PDC through UDP/IP over Ethernet.

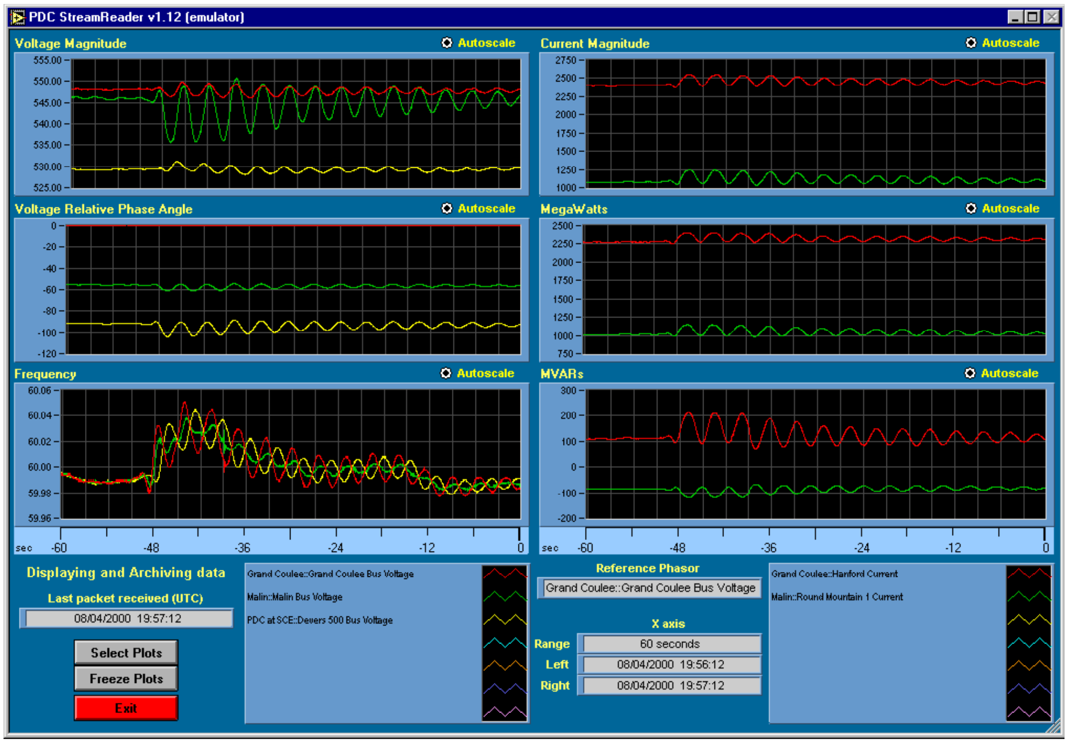

Figure 26 StreamReader Real-Time Data Display
Showing Sustained System Oscillation After a Line Outage

Both the PDC and the *StreamReader* program record phasor data in files. These files are in a simple raw data format with a header that can be machine read for data parsing. An auxiliary file is provided for scaling and labeling data items. Several utilities are available for viewing, plotting, and analyzing these data. These utilities include *PhasorFile* (BPA), DSI Utilities (Pacific Northwest National Laboratory/BPA), and Power System Outlook (Southern California Edison). The parenthetical note following each program title indicates the developer of that program. Through the use of these analysis programs, data from these systems locate and correct errors in power system models.

System Performance

The PDC records statistics including data loss, signal loss, and PMU time-synchronization failures. Table 1 summarizes typical performance during a randomly chosen two-month period in 2002. A PDC failure will cause a complete system failure. BPA uses two units in parallel for this contingency. The PDC has a hardware watchdog that reboots the system if a core program fails. There have been very few recorded failures in the seven years BPA has used the system.

Table 1 Phasor System Performance For a Random Two-Month Period in 2002

Station	**Reliability (%)**		**Notes**
PMU	Signal[1]	Sync[2]	
GCoul	97.52	99.974	PMU fail 2 days
JDay	99.929	99.996	Normal, modem
Malin	99.997	93.74	PMU clock failure
Colstrip	99.82	100	Comm sys problems
BigEddy	99.99	99.988	Normal, fiber, digital
MValley	99.983	99.74	PMU clock problems
Keeler	99.996	99.95	Normal, modem

[1] Signal Reliability is the percent of time the system continuously received data from the PMU.

[2] Sync Reliability is the percent of time the PMU was synchronized with a global positioning system (GPS).

Synchronized Phasor Measurement-Based WAPS

As this paper discussed previously, present WAPS actions are based on studies that show how the system reacts with certain system configuration and loading levels. It is not possible to model every loading and system configuration, so these models group typical loading and system configurations so that a WAPS action handles an appropriate range of situations. Consequently, WAPS actions take care of worst-case scenarios and usually take more action than necessary. Consider also that actual system loading changes constantly, so a model is an approximation of this system. A WAPS that acts on actual system responses rather than preset conditions would potentially take only the actions necessary to maintain system stability. Such a WAPS would minimize outages, increase system reliability, and increase power transfer limits [16], [17].

BPA is developing a response-based WAPS that uses phasor measurements as the basic input (Figure 27, Figure 28). PMUs at substations transmit phasor measurements in real time to a data concentrator (PDC) at the control center. The PDC sends the combined data to a Wide-Area Control System (WACS) controller that analyzes power system stability based on these data. If the power system swings close to its stability limits, the controller takes the proper action through a WAPS to avoid system collapse. Figure 27 is a block diagram of this plan.

BPA is presently developing two control approaches for this system and has considered a third. The first approach is a fast transient detection algorithm that drops generation to maintain synchronous stability. This scheme takes advantage of the high accuracy of phasor measurements and low latency of the measurement system to take action in less than one second. The second approach is a voltage support system that inserts capacitors to supplement var output from generators. This second approach uses both voltage and current phasors to monitor var flow and is slower than the first scheme, with operating times from one to five seconds. A third approach based on phase angle and frequency measurements shows promise as a wide-area protection control scheme. BPA is not currently developing this third approach.

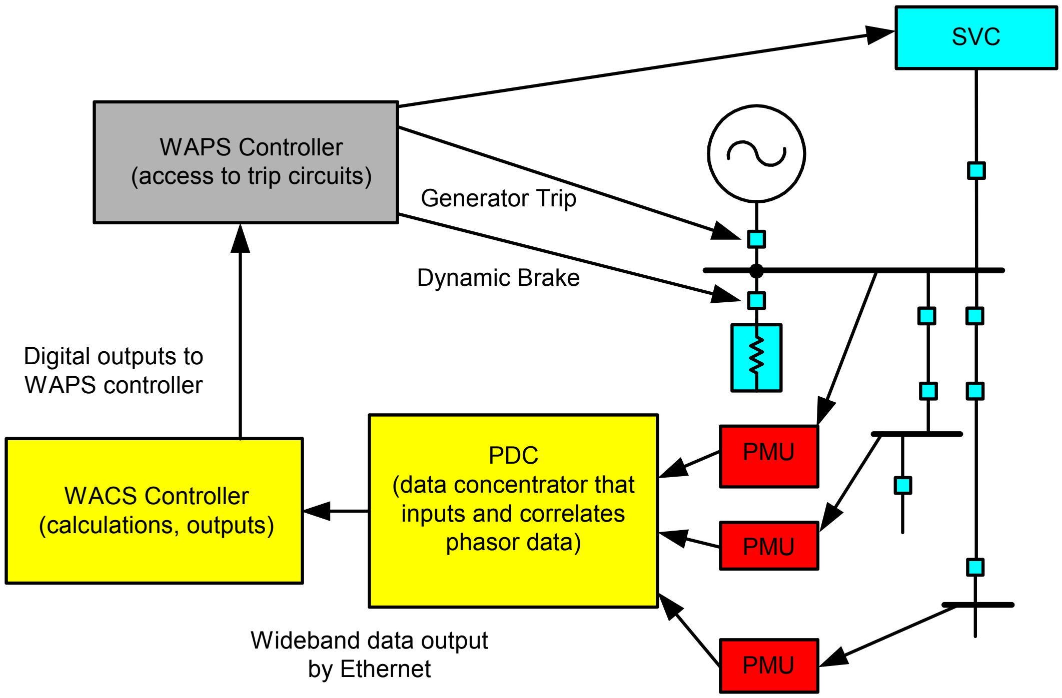

Figure 27 WAPS Control Using Phasor Measurement Input

First Approach: High-Speed Stability Control

The high-speed stability control approach detects a large voltage swing such as would result from loss of generation outside of the BPA transmission area. In particular, a double Palo Verde (see Figure 19) outage at full load (2,700 MW) is a limiting factor for the NW-SW intertie loading. If the intertie loading were too high, the intertie would be unable to transfer enough power to keep the NW and SW in synchronism, and the systems would separate. By monitoring intertie voltages, the high-speed stability control scheme can detect the voltage swing created by a large outage fast enough to initiate remedial action. The scheme calculates a weighted average of 10 bus voltage phasors and feeds it into a volt-time accumulator. When the accumulated value exceeds a preset threshold, the controller scheme sends a trip signal to generating stations in the NW and inserts capacitors on the intertie. These actions optimize the power flow between the two regions and maintain both regions in synchronism. Figure 28 [17] shows the voltage swing that the model predicted after a double Palo Verde outage with this control scheme in place. Using this control scheme, stable intertie loading increased from 4,700 to 5,000 MW.

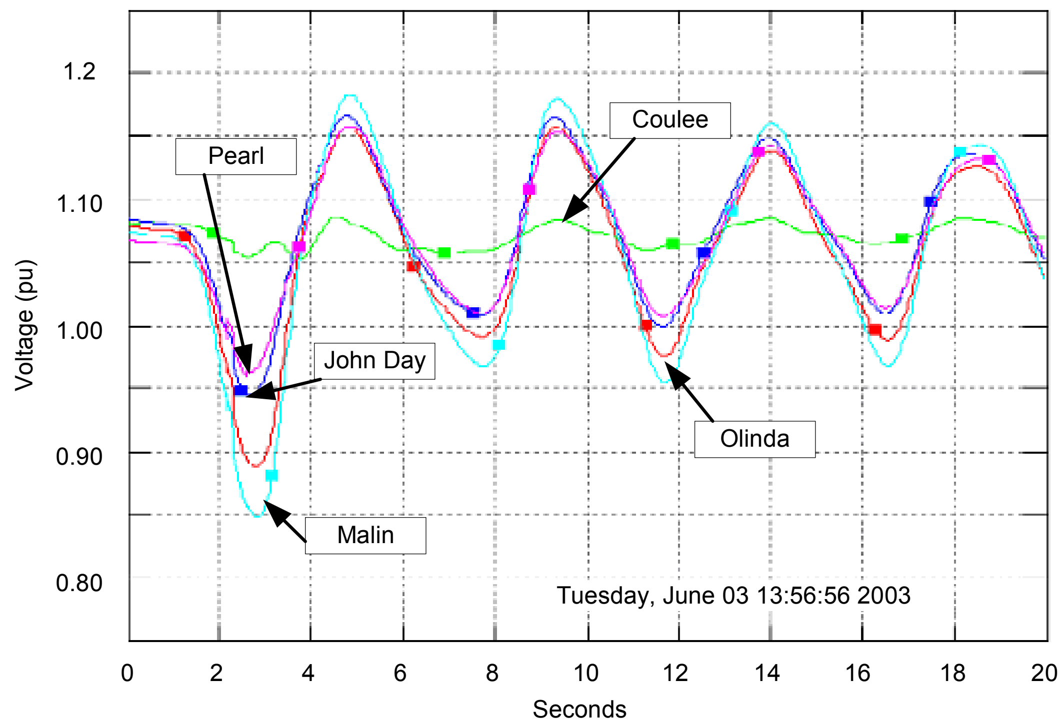

Figure 28 BPA Voltage Swing for a Double Palo Verde Outage (2,700 MW) With 5,000 MW Pacific NW-SW Intertie Loading and WACS Control Action

The NW-SW inter-area mode of oscillation is about 1/3 Hz, or 3 seconds/cycle. The oscillation frequency decreases as damping decreases. The oscillation frequency was about 0.22 Hz when the system separated in 1996. A step response, such as with a generator loss, will reach a peak in about 1.5 seconds. Remedial action ideally would be well before the response peak, perhaps at 0.75 seconds. BPA has performed a number of tests on delay in phasor measurements. At the 30 messages/s data rate, these times total 50 to 150 ms, depending on data communications and PMU filtering. Data communication links are generally responsible for the greatest delay, so BPA is moving all critical measurements to direct digital communications, limiting total latency to about 60 ms. One must then consider time necessary for the controller decision, sending the control system commands, and control system execution. For a trip action, transfer trip commands are one cycle or less, and breaker opening is typically two cycles. Total system delays are about 170 ms outside of the control algorithm. The accumulator threshold in the control algorithm can be set to a fairly long response time for higher security from false actions. It should be fairly easy to take a control action within 0.3 seconds after a system disturbance.

Second Approach: Voltage Support System

The voltage support system monitors MW and MVAR output from five large generating plants in the lower Columbia River area, the northern end of the intertie. We can estimate the number of units on line from the generator outputs, so we need no additional status information. Var capability is entered into the controller along with high-side reactive curves (phasor monitoring is on the 500 kV side of the step-up transformers). A fuzzy logic inference engine compares var output with var capability and bus voltages. When voltage sags and the power system approaches its var limits, the system initiates reactor and capacitor switching. The fuzzy logic approach should be capable of handling this situation where there are many lines to monitor and many combinations of generators, reactors, and capacitors in service.

Third Approach: Phase Angle And Frequency Measurement (not yet implemented)

A large loss of load or generation, such as the Palo Verde loss, creates a sharp local frequency swing. Phase angles across interconnecting lines will change as power transfer rebalances among generators. There will be some power swings as areas stabilize to new loading conditions. A control that combines detection of rapid frequency changes with accurate phase angle measurements can provide high-speed triggers for actions to stabilize wide-area disturbances.

Faults, switching actions, and data errors can all cause an apparent large change in frequency at one location. A controller must monitor the frequency data from several stations and for several successive samples for measurement assurance. Once the frequency trigger threshold is reached, the controller must compare frequency with corresponding changes in phase angle. If the change exceeds predicted criteria for interregional stability, the controller should issue appropriate control actions, such as generator drop or capacitor insertion.

Figure 29 and Figure 30 illustrate this concept showing a wide-area system reaction to a loss of 750 MW of generation near Grand Coulee in the state of Washington. The frequency drops immediately at measurement sites closest to the location of the loss of power and propagates through the system. Power flows from north to south, so the phase angle decreases as less power flows, confirming the event. Figure 29 shows frequency deviation from 60 Hz at Grand Coulee, Malin, and Vincent. Using –20 mHz as a reference, one can see that Grand Coulee, which is near the power loss, reaches this level 0.3 seconds before Malin and 0.9 seconds before Vincent. Figure 30 shows the Grand Coulee frequency again and also includes Coulee-Vincent phase angle and generation power output in the Los Angeles area. The phase angle begins decreasing immediately as less power flows over the intertie and as local generation ramps up to compensate for the reduction of power flow over the intertie. The controller, monitoring the sudden changes in frequency beyond a threshold and steady change in phase angle, can take action before the area remote from the problem exceeds stability thresholds. Addition of previously discussed delays to those from longer telecommunications delays [18] results in a measurement-to-controller action time within about 120 milliseconds, which is much faster than progress of the incident.
The –20 mHz trigger point is not critical; it is used here as an example based on this incident. A control would use frequency thresholds and the system phase angle rate of change based on studies of critical events.

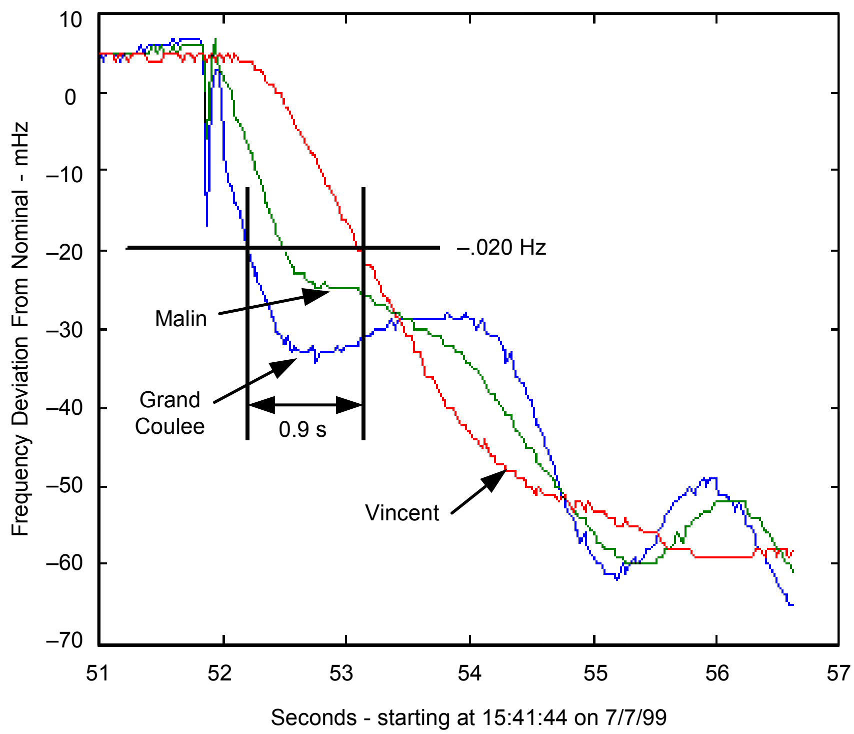

Figure 29 Response to 750 MW Generation Loss in NE Washington. Reaction Progress From Grand Coulee to Malin and Finally to Vincent.

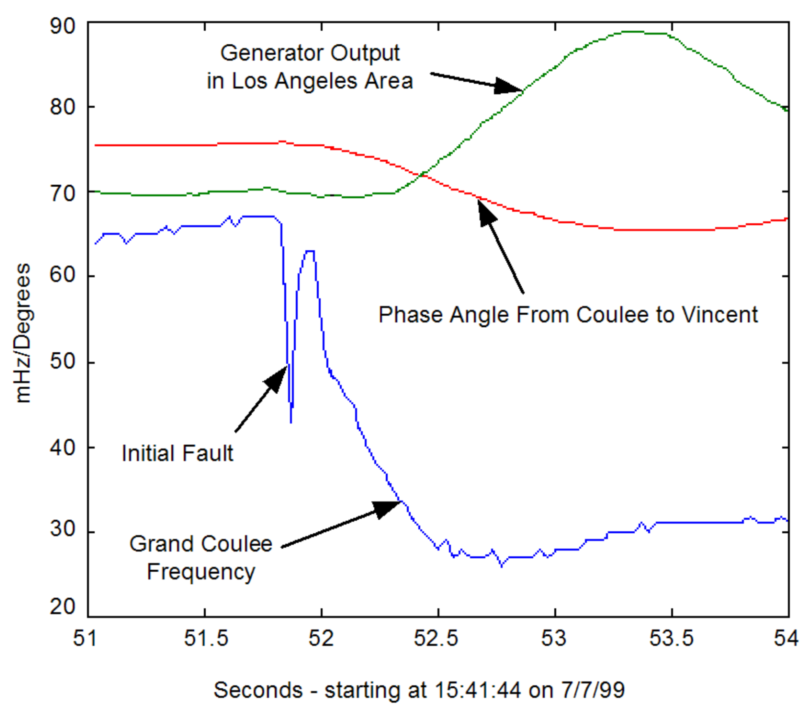

Figure 30 Response to 750 MW Generation Loss in NE Washington. Grand Coulee Frequency Is Compared With Phase Angle From Coulee to Vincent and Generator Output in the Los Angeles-Area (San Onofre Nuclear Generating Station).

Adaptive Underfrequency Load Shedding

Traditional underfrequency load-shedding schemes trip predetermined feeders when underfrequency conditions exist for a certain amount of time. The system has no information on the amount of power that has been dropped. Sometimes, more load is 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 underfrequency load-shedding 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. The scheme shown in Figure 31 reads the amount of power, P_{SD}, that the system must shed according to system operating conditions in real time. At the same time, the scheme has information about the power demand of all feeders, P_1 and P_2. Additionally, load priority can be programmed into the scheme to trip less critical loads first. Load shedding and system performance can be optimized with all of this information.

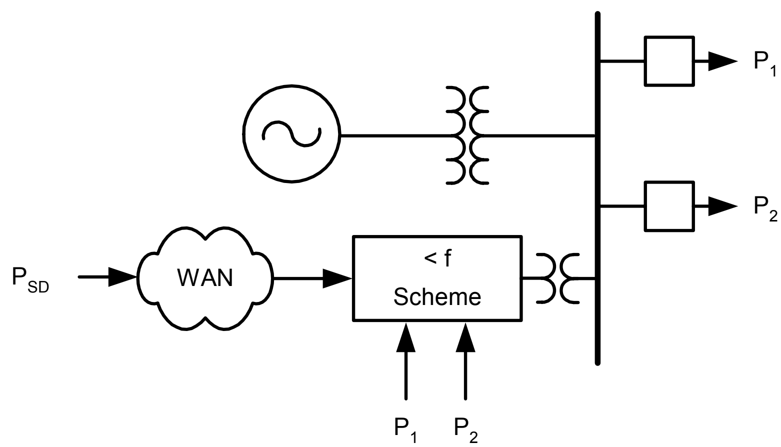

Figure 31 Adaptive Underfrequency Load Shedding Optimizes Power Supply

Figure 32 shows the flow chart of the proposed adaptive underfrequency load-shedding scheme. The scheme reads the system real-power load-shedding requirements, P_{SD}. When the underfrequency condition exists, the scheme trips Feeder 1 if Feeder 1 real power, P_1, is greater than P_{SD}. Otherwise, the scheme checks if the load in Feeder 2, P_2, is greater than P_{SD}. If P_2 is greater than P_{SD}, the scheme trips Feeder 2. If neither of the above loading conditions occurs, the scheme trips both feeders. This simplified scheme shows how one feeder, Feeder 2, could remain in service during the underfrequency disturbance when Feeder 1 load exceeds the load system load-shedding requirements for a specific substation. Similarly, Feeder 1 could remain in service during the underfrequency disturbance when Feeder 2 load exceeds the load system load-shedding requirements for a specific substation.

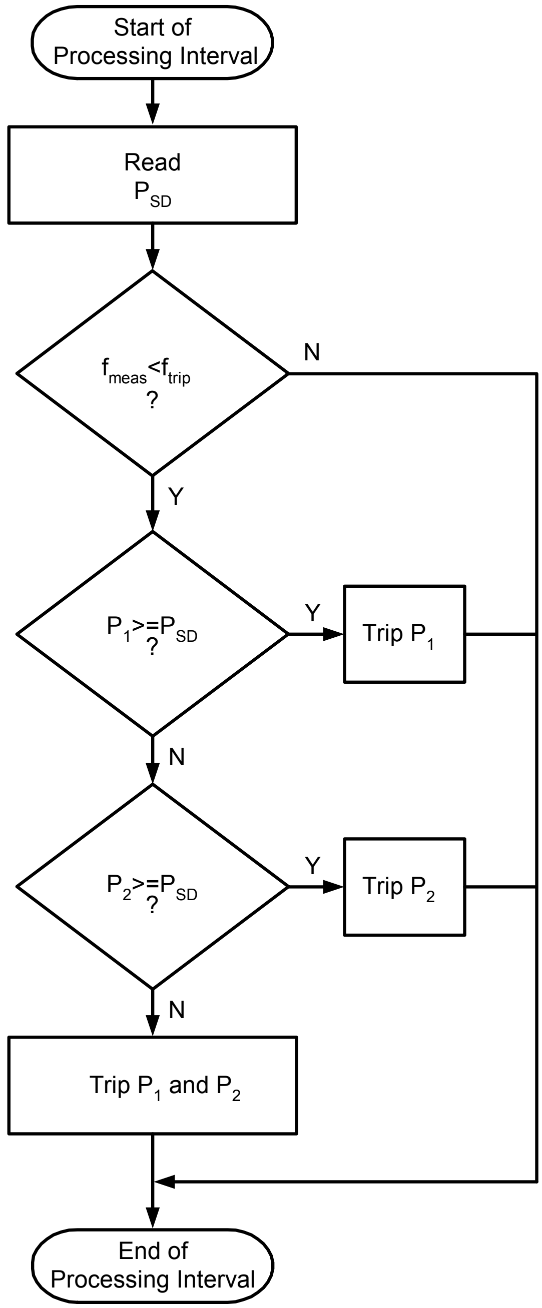

Figure 32 Adaptive Underfrequency Load Shedding Avoids Tripping Feeder 2 if Station Load-Shedding Requirements Are Met When Tripping Feeder 1

Load Shedding for Voltage Collapse Prevention

Load shedding is the last resort in preventing a system voltage collapse. This paper stated previously that definite time undervoltage elements are traditionally used in these types of schemes [19]. One disadvantage of this method is that the tripping time is fixed as long as the voltage magnitude is below the selected tripping threshold independently of the type of load. Voltage collapse is a dynamic phenomenon that depends among other things on the types of load. For example, dynamic loads such as induction motors, thermostatic loads, and under-load-tapchangers could demand more reactive power from the system than could some static loads. An ideal load-shedding scheme should identify loads demanding the most reactive power and shed these loads as soon as possible without affecting other load types in the system.

For illustration purposes, let us analyze the simple system shown in Figure 33. The system consists of two transmission lines that feed a constant power load. The PV curve of this system is shown in Figure 34 with a solid line [20]. Point A is the operating point during normal operating condition, and P_A is the real power that the load consumes for this operating condition. Let us open one of the transmission lines. The dashed line (in the same figure) shows the new PV curve of the modified system after the line has been opened. Point B is the operating point for the new system configuration. The voltage starts to drop after the line opens. To minimize the amount of load to shed, the load-shedding action must occur before the voltage drops below the critical operating point, C. To restore stable system operating conditions, although these conditions may not be acceptable, the amount of load to shed, P_{SD}, must be greater than P_A–P_C. If $P_{SD} = P_A$–P_B, which is greater than P_A–P_C, the new operating point is B. If the voltage drops below Point C, the amount of load to shed to restore the system to stable conditions must be greater than P_A–P_C. The operating voltage might drop to a point where the system cannot recover no matter how much load is dropped [21]. Therefore, rapid load-shedding action is necessary to minimize system disturbance.

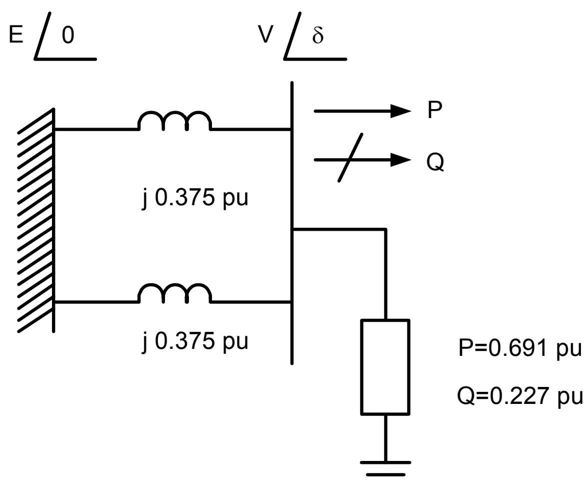

Figure 33 Two Transmission Line Power System Feeding a Constant Power Load

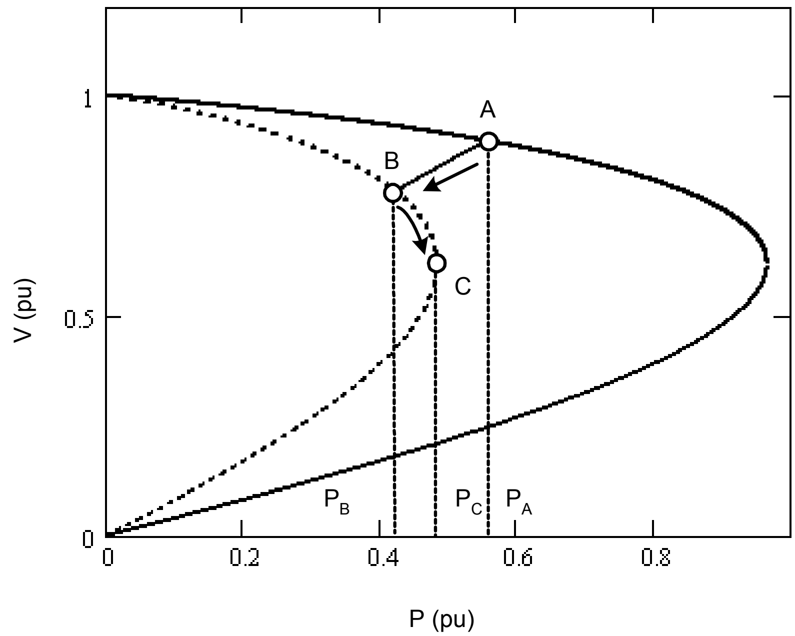

Figure 34 PV Curves During Normal Operating Conditions (Solid Line) and After One of the Transmission Lines Opens (Dashed Line)

A more elaborate model to study voltage collapse is the one shown in Figure 35 [22]. We used this model with increased load at Bus 8, as Figure 35 illustrates. The system has constant impedance load at Bus 8 and a combination of constant impedance and constant current loads at Bus 11. We opened two of the five transmission lines and observed the voltages at Buses 8 and 9. Figure 36 shows the rms voltage values at these buses after the two lines open. The voltage dropped at both buses immediately after the lines opened. The voltage magnitude at Bus 9 is about 4 percent lower than the voltage magnitude at Bus 8. The load at Bus 11 is the most critical one from the reactive power point of view, because of the underload tap changer (ULTC) action. Assuming that no actions are taken to block the ULTC, the ULTC operates to maintain the desired voltage at Bus 11. Because of the ULTC, the voltages at Buses 8 and 9 continue to drop. If we apply definite-time undervoltage relays with identical settings at Buses 8 and 9 and set them to 95 percent of nominal voltage, both loads might be dropped from the system unnecessarily after the undervoltage condition exceeds the preset definite-time delay. This type of undervoltage relay does not consider the fact that the voltage level at Bus 9 is lower than the voltage level at Bus 8.

Now, let us consider the application of an inverse-time undervoltage relay at Buses 8 and 9. Eskom has applied this type of relay to maintain power system voltage stability [23]. Figure 37 shows the corresponding inverse-time undervoltage element characteristic that starts timing when the voltage drops below 95 percent of nominal. The inverse-time undervoltage relay integrates the voltage with respect to time, according to Equation 1 [24]. The relay at Bus 9, the busbar with the lowest voltage, operates faster than the relay at Bus 8 because of the voltage integration with respect to time. After the system drops the load at Bus 11, the system returns to stable conditions, as Figure 38 illustrates, without dropping the load at Bus 8. Looking at the voltage magnitudes at both buses, we can observe the voltage magnitude decline with respect to time. We can use this additional information to provide faster time to trip and minimize system disturbance. We can modify the relay operating quantity, M, according to Equation 2. An additional advantage of this approach is that the inverse-time relay integration rate decreases during system voltage recovery because the voltage magnitude increases with respect to time.

$$\int_0^{T_0} \frac{1}{t(V)} \cdot dt = 1 \tag{1}$$

Where:

$$t(V) = \frac{A}{M^P - 1} + B$$

$$M = \frac{1 - V_{pu}}{1 - \text{Pickup}}$$

A, B, P	are constants that define the relay characteristic
T_0	is the operating time
M	is the relay operating quantity
Pickup	is the relay pickup setting, Pickup = 0, 0.01, ..., 0.95
V_{pu}	is per-unit voltage measured by the relay

$$M = \frac{1 - V_{pu}}{1 - \text{Pickup}} - k \cdot \frac{dV_{pu}}{dt} \tag{2}$$

Where:

k	is a weighting factor, k = 0.01, …, 0.5

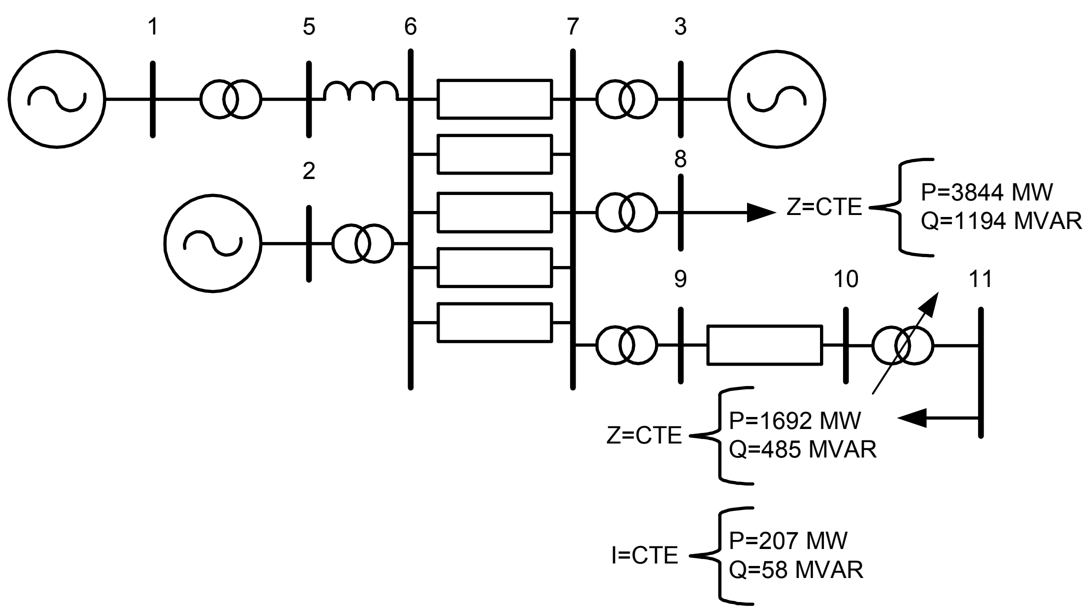

Figure 35 Classical Power System Model to Study Voltage Stability with Increased Load Conditions

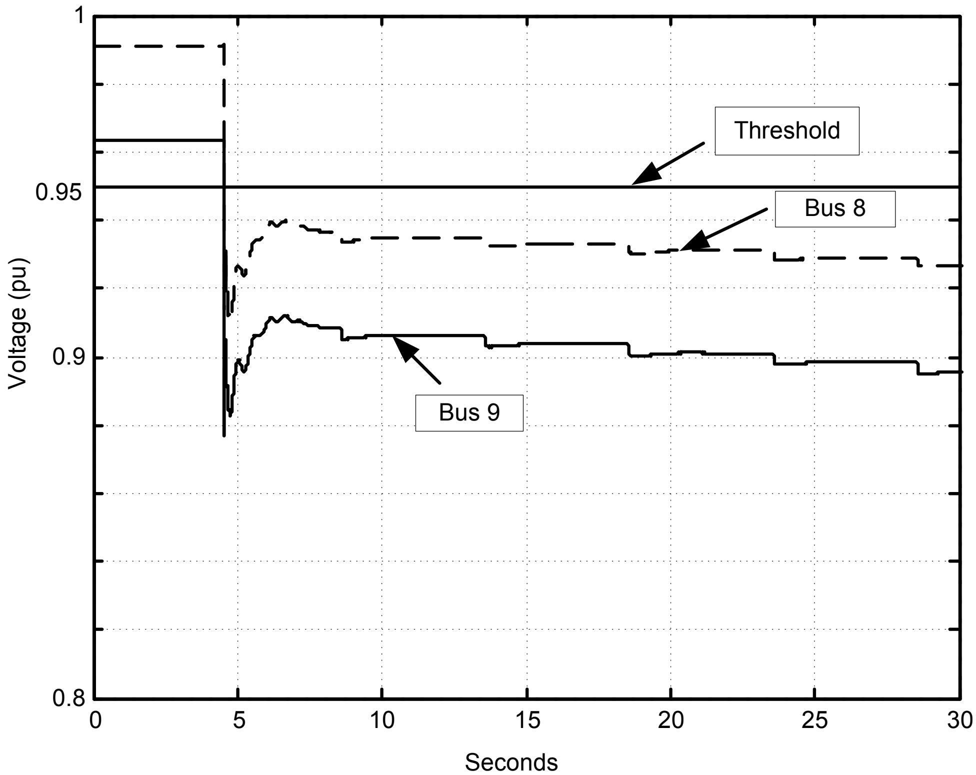

Figure 36 RMS Voltages at Buses 8 and 9. The Voltage at Bus 9 Is Approximately 4 Percent Lower Than the Voltage at Bus 8. Both Voltages Drop Below 95 Percent, the Definite-Time Undervoltage Element Threshold.

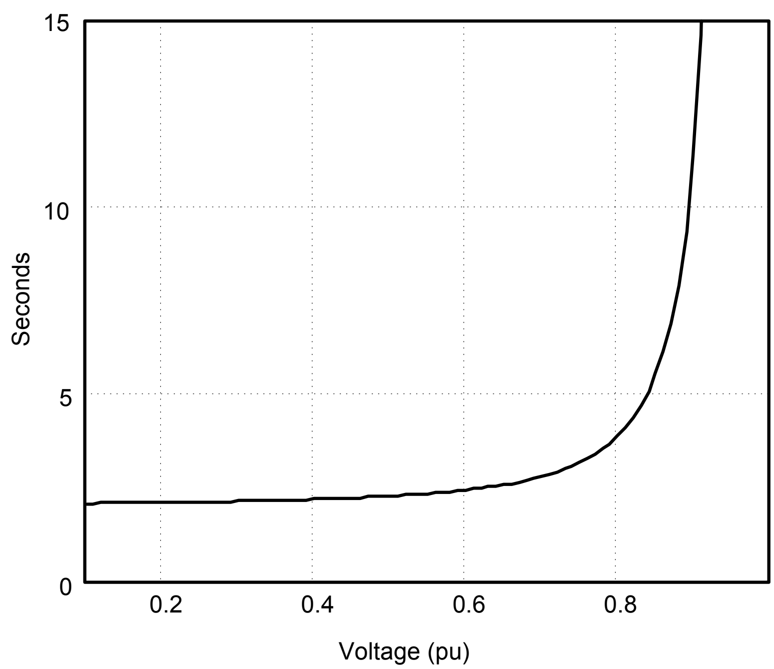

Figure 37 Inverse-Time Undervoltage Characteristic Trips Lower Voltage Loads First. A= 28.2, B=2, P=2, Pickup=0.95

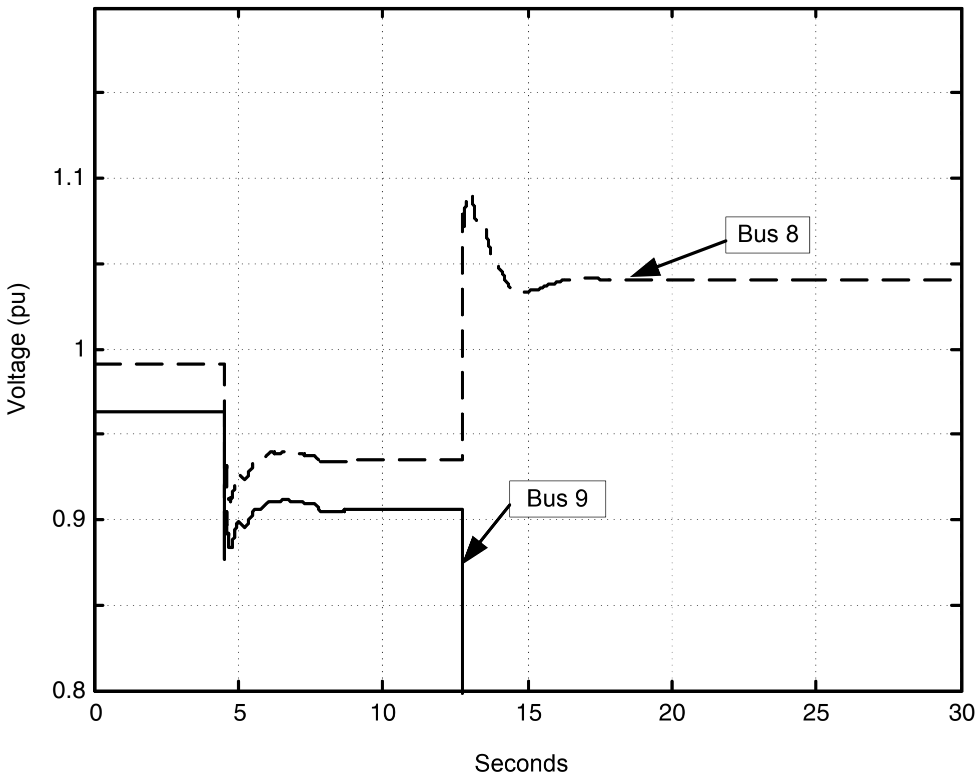

Figure 38 RMS Voltages at Buses 8 and 9. The Voltage at Bus 8 Recovers Immediately After the Inverse-Time Undervoltage Element Drops the Bus 9 Load.

Single-Pole Tripping

Transmission line single-pole tripping and reclosing is another way to increase power system reliability and reduce the risk of system disruptions. An example illustrates this use of single-pole tripping and reclosing. Let us look at the reactive power losses of two parallel lines for different operating conditions. Assume that 1,000 A flow in each of the phases of the two parallel lines shown in Figure 39 where the line phase impedance is 80 Ω.

The reactive power is a square function of the current (I^2X), and, in this case, the two line reactive losses are $6 \cdot 1000^2 \cdot 80 = 480$ MVARs. What happens to the line reactive power losses when one of the parallel lines is removed from the system, as Figure 40 shows?

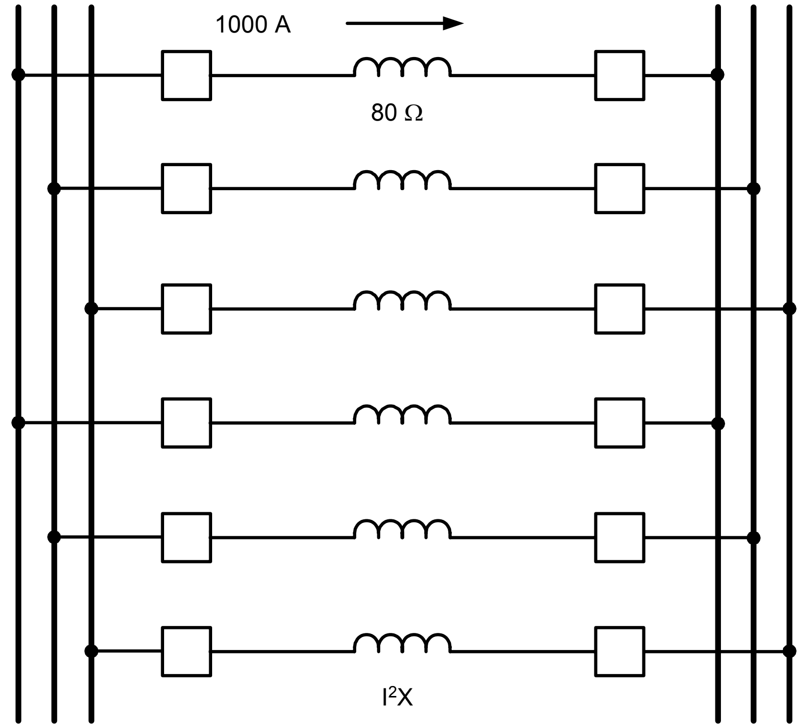

Figure 39 Reactive Losses Are Square Functions of Line Current. In This Case, the Two Line Reactive Losses are 480 MVARs.

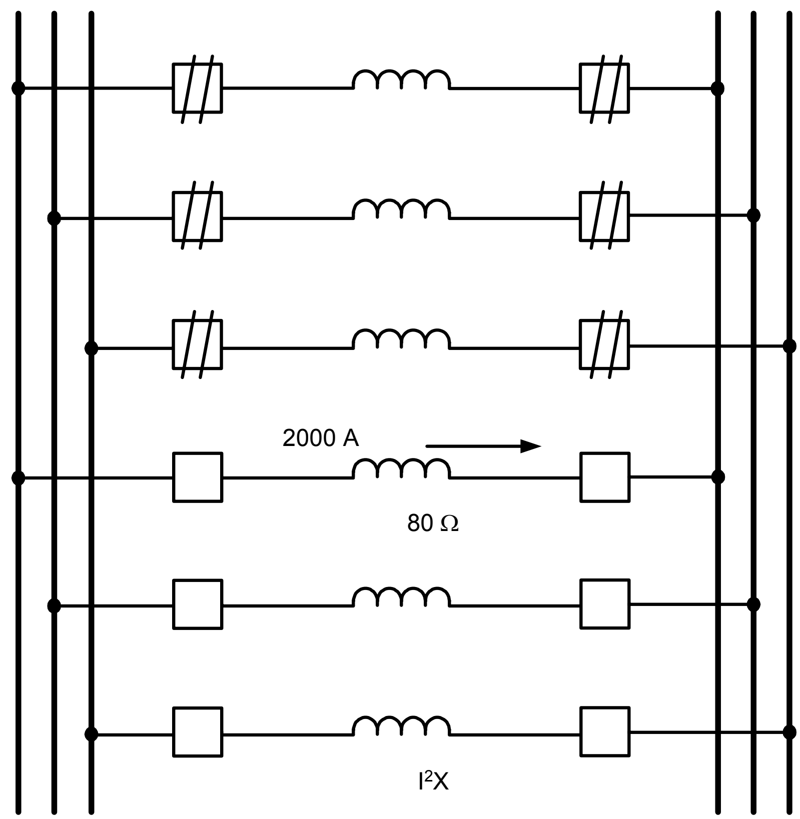

Figure 40 Reactive Losses Increase 100 Percent When the Parallel Line Opens

Let us assume now that 2,000 A flow in each of the phases of the remaining line in service. Now, the line demands $3 \cdot 2000^2 \cdot 80 = 960$ MVARs from the system. The reactive losses increased by 100 percent! So, what happens when only one phase is disconnected from the system as a result of a single-phase tripping operation (see Figure 41)?

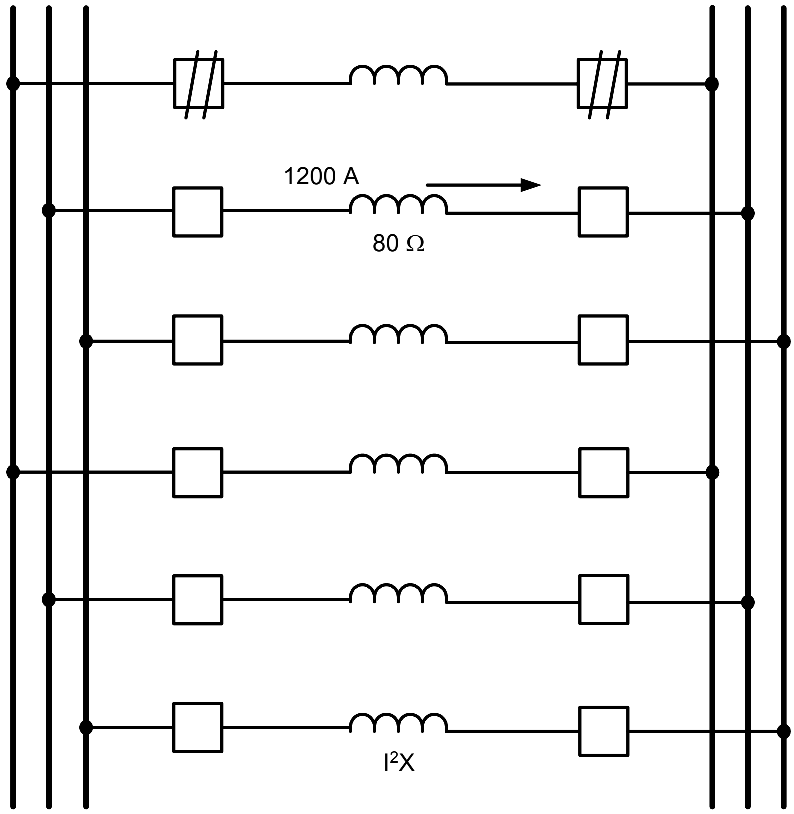

Figure 41 Reactive Losses Increase Only 20 Percent When One Phase Opens

Assume now that 1,200 A flow in each of the phases. Because we now have five phases still in operation, the reactive power demand from the system is 576 MVARs. The reactive losses increase only by 20 percent! Single-phase tripping and reclosing applications demand a smaller amount of reactive power from the system during the pole-open period. These applications also optimize real power transfer, thus improving power system reliability and performance.

Conclusions

1. Breaker failure protection together with direct transfer tripping schemes can be used instead of Zone 2 and 3 distance elements to provide backup protection and avoid unnecessary tripping of transmission lines during power system disturbances.
2. Improved system time-synchronized measurements provide better assessment of actual power system dynamic response. These measurements are used to improve system models.
3. Improved out-of-step detection techniques are necessary to minimize system disturbances and primary equipment stress.
4. WAPS schemes are designed to improve power system reliability, mitigate large disturbances, and/or to increase power system transmission capacity. Current trends indicate

that these systems should become more common. These systems will be based on extremely flexible and adaptive protection devices, as well as on reliable high-speed communication technologies.

5. There is a great potential for improving power system reliability through the use of intelligent local and wide-area protection systems and controls based on existing technologies. The introduction of phasor measurements in protection, control, and automation devices [25] has greatly improved the observability of power system dynamics. Synchronized phasor measurement-based design could lead to new kinds of adaptive wide-area protection, emergency control, and optimization systems.
6. Adaptive underfrequency load-shedding schemes respond to power system operating conditions to trip just the amount of load necessary for system recovery.
7. Inverse-time undervoltage elements take advantage of load dynamics to optimize load shedding to prevent system voltage collapse.
8. Single-pole tripping and reclosing minimize system disturbance, optimize power transfer capability, and increase power system reliability.

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Biographies

Armando Guzmán received his BSEE with honors from Guadalajara Autonomous University (UAG), Mexico, in 1979. He received a diploma in fiber-optics engineering from Monterrey Institute of Technology and Advanced Studies (ITESM), Mexico, in 1990, and his MSEE from University of Idaho, USA, in 2002. He served as regional supervisor of the Protection Department in the Western Transmission Region of the Federal Electricity Commission (the electrical utility company of Mexico) for 13 years. He lectured at UAG in power system protection. Since 1993 he has been with Schweitzer Engineering Laboratories in Pullman, Washington, where he is presently a Fellow Research Engineer. He holds several patents in power system protection. He is a senior member of IEEE and has authored and coauthored several technical papers.

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