



**New Section VII
approved by Operating
Committee**

July 16 – 17, 2003

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

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Electric System Restoration Reference Document

by the

North American Electric Reliability Council

April 1993

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Foreword

On November 9, 1965, a cascading failure of the electrical system left 30 million people in the dark and caused economic losses estimated at over \$100,000,000. Major portions of the northeastern United States and Canada were without electricity. Hundreds of thousands of people were inconvenienced for days. The Federal Power Commission investigated the blackout and recommended ways to ensure that it would not likely happen again. Instead of a mandatory federal program to coordinate electric power, electric utility representatives from 12 regional and area organizations signed an agreement creating the North American Electric Reliability Council (NERC) on June 1, 1968.

The NERC organizational structure provides the mechanism by which electric utilities work together to prevent blackouts. A strength of this structure lies in NERC's ability to call on unmatched expertise and experience from member utilities to serve on its various committees. These people work together to critique the past, monitor the present, and assess the future. NERC establishes and updates Criteria and Guides for reliably operating the bulk electric system. Reliability is NERC's sole mission, and these criteria are based on coordination, cooperation, communication, and commitment.

The NERC and Regional Criteria and Guides present characteristics of a well-planned and operated electric network and describe adequacy and security tests necessary to evaluate its performance. The interconnected electric network is designed and operated such that uncontrolled, widespread interruptions are unlikely. However, building and operating an electric system, which provides 100% reliability is impossible.

I. Introduction

This document provides general guidelines to be followed in the event of a partial or complete collapse of any of the interconnected electric systems in the North American continent. Quick implementation of each control area's restoration plan, compiled in accordance with the suggestions and recommendations contained in this document, will facilitate coordination between member control areas and ensure the earliest possible restoration of the electric system.

It is impossible to predict all the possible combinations of problems, which may occur after a major electric system failure. It is, therefore, the responsibility of system operators to restore the electric system BY applying the general guidelines outlined in this document and in their respective detailed system restoration plans. Mutual assistance between member control areas is highly encouraged.

A. Principles

Each control area should have a readily accessible and sufficiently detailed current system restoration plan to guide in an orderly recovery. System restoration will be aided by communicating to neighboring control areas, and to Regional offices, an accurate assessment of system conditions throughout the restoration process. Communication must be established with power plants, critical substations, and neighboring operation centers. Mutual assistance and cooperation are essential and beneficial to prompt system restoration and to avoid the recurrence of a partial or complete electric system collapse.

In the event of an electric system collapse, each control area should use the following as guiding principles for the restoration process:

1. Take immediate steps to initiate internal system restoration plans.
2. Restore a high percentage of internal load in as little time as possible.
3. Provide assistance to any and all control areas as system conditions allow.
4. Supply neighboring control areas and Regional offices with information on electric system status.
5. Coordinate with neighbors the reconnection of control areas and/or islands.

B. Plan Elements

Actions required for system restoration include identifying resources that will likely be needed during restoration, determining their relationship with each other, and training personnel in their proper application. Actual testing of the use of the strategies is seldom practical. Simulation testing of plan elements, major plan sections, or the overall plan are essential preparations toward readiness for implementation on short notice.

Control area restoration plans include the following elements:

1. Philosophies and strategies for control area restoration
2. Selection of critical alarms from the alarm information available
3. Identification of the relationships and responsibilities of the personnel necessary to the restoration
4. Identification of blackstart resources including:
 - a. generating unit resources
 - b. sufficient fuel resources
 - c. transmission resources
 - d. communication resources and power supplies
 - e. mutual assistance arrangements

5. Contingency plans for failed resources
6. Identification of critical load requirements
7. Provisions for training of personnel
8. Provisions for simulating and, where practical, actual testing and verification of the resources and procedures
9. General instructions and guidelines for:
 - a. system operators
 - b. plant operators
 - c. communications personnel
 - d. transmission and distribution personnel
10. Provisions for public information

The body of this document contains more details on items to be considered in the restoration process, which may be used in the development or review of individual control area system restoration plans.

C. *Priorities*

Establishing priorities can be subjective and even change from one incident to another or one area to another. Starting units with blackstart capability and providing auxiliary power to units that have just been shut down is clearly a very high priority.

The following actions for system restoration should be considered by each control area and assigned proper sequence and priority:

1. Stabilization of generating units
2. Restoration and maintenance of intra- and inter-system communication facilities and networks
3. Assessment of control area condition and bulk electric system conditions
4. Contact local police and fire departments concerning the extent of the problem
5. Contact with public information agencies to request the broadcasting of pre-distributed appeals and instructions
6. Restoration of units with blackstart capability
7. Providing service to critical electric system facilities
8. Restoration of the control area's transmission system
9. Connection of islands taking care to avoid recurrence of a partial or complete system collapse and equipment damage
10. Restoration of service to critical customer loads
11. Restoration of service to remaining customers

If it becomes apparent that the emergency is a Regional one, the focus of restoration action should shift from individual control area priorities to bulk electric network priorities. Giving priority to a neighboring system's generation and/or load may be necessary in order to benefit the rapid restoration of the bulk electric system. As generation and transmission facilities become available, systematic restoration of network load should proceed using established priorities.

D. *Responsibilities*

Each control area should train associated personnel (system operators, power plant operators, etc.) in the implementation of its detailed internal system restoration plan. Non-control area electric utilities should prepare a plan, in cooperation with their responsible control area, designed to assist and coordinate with the control area's plan. This applies to cogeneration facilities and independent power producers. Where appropriate, a copy of these plans should be on file at the

Regional offices. System restoration plans should be verified by as much simulation testing as possible, although actual physical testing is highly encouraged where feasible. Simulation also can help determine the feasibility of parallel activities, sequential activities, and avoidance of unnecessary loss of equipment life. Control areas should report significant testing activities of system restoration plans to their Regional Reliability organization and summarized Regional activity should be presented to the NERC Operating Committee.

II. Conditions That May Result in Major Area Blackouts

A. Definitions

A blackout is a condition where a major portion or all of an electrical network is de-energized with much of the system tied together through closed breakers. Any area whose tie lines to the high voltage grid cannot support reasonable contingencies is a candidate for a blackout. The area will become electrically isolated if a *critical contingency* should occur. The identification of these areas, as indicated in Figure 1, should be a high priority for minimizing blackouts.

Separation of an island from the grid will take place under two general scenarios:

1. Dynamic instability
2. Steady-state overloads and/or voltage collapse

System separations are possible at all loading levels and all times in the year. Changing generation patterns, scheduled transmission outages, off-peak loadings resulting from operations of pumped storage units, storms, and rapid weather changes among other reasons can all lead to blackouts. Systems must always be alert to changing parameters that have the potential for blackouts.

B. Separation Due to Dynamic Instability

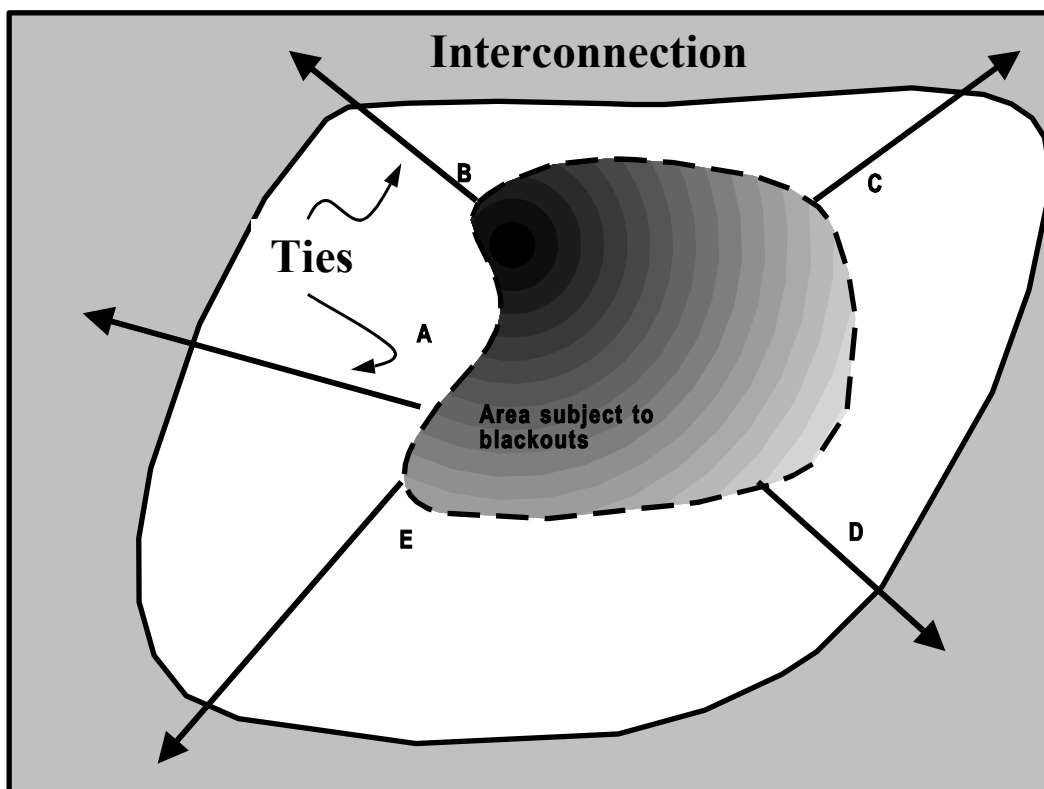
The transmission system should be able to sustain any single contingency without loss of load. If the steady-state response to a single contingency does not drive loadings beyond facility capabilities, it should be expected that the dynamic response to the single contingency will be stable. The damping of the system should be adequate. Except in very special cases, the steady-state response will be more constraining than the dynamic response to a single contingency. For this reason, separations due to dynamic instability are typically initiated by multiple contingencies such as loss of corridors, several transmission circuits, several generating units, or delayed fault clearing. These contingencies were referred to before as a *critical contingency*.

Following the *critical contingency*, a tie line of Figure 1 will approach an out-of-step condition. Cascading of the other ties will isolate the area from the grid. There will be no time for operator intervention. If possible, isolated areas should be automatically established with good generation to load ratios. Early detection of unstable conditions may be possible in some parts of the system.

In these cases, selective use of transfer trip relaying can isolate an area with a favorable generation to load ratio. In general, there may be no clearly defined area that will separate. In such cases, the extent of the affected area will only be known after-the-fact.

If the isolated area is generation deficient, underfrequency relays should shed the necessary load to match load and generation in the island, and the operation should become stable at or near 60 Hz. If not, load should be shed to restore stable operation near 60 Hz. If the isolated area has excess generation, the total area generation must be reduced immediately to approximate the area load for 60 Hz operation. When possible, schemes for islanding as well as frequency correction programs should limit the consequences of stability contingencies. Controlled islanding action is preferred to blackouts.

Figure 1 – Area isolated from the Interconnection



C. Collapse Due to Steady-State Overloads and/or Voltage Collapse

The system just prior to a blackout may not be dynamically unstable but in an overloaded condition. At such loadings, the collapse may come about due to damage to thermally overloaded facilities, or circuits contacting underlying facilities or vegetation. When an overloaded facility trips, other facilities will increase their loadings and may approach their thermal capabilities or relay trip settings. There may be some time to readjust system conditions (generation shifts, load shedding, transfers, etc.). If not, the overload will lead to electrical isolation.

Voltage collapse, as currently defined by the IEEE Working Group on Voltage Stability, is the process by which voltage instability leads to the loss of voltage in a significant part of the system. This condition results from reactive losses significantly exceeding the reactive resources available to supply them. Circuits loaded above surge impedance loadings and reduced output of shunt capacitors as voltages decline can lead to accelerating voltage drops. It is possible that impending voltage collapse can be detected by slowly dropping voltages in an area of concern. However, heavy use of shunt capacitors or reactors can maintain near normal voltage up to the point that voltage support resources run out. Thus, voltage collapse can look like both a steady-state problem with time to react and a problem where no effective operator intervention is possible. The NERC *Survey of the Voltage Collapse Phenomenon* provides more insight into this problem.

It is very hard to predict the area that will be affected or electrically isolated from the grid. Adequate models of load variation with voltage are not available, and there is an undeterminable variety of sequential circuit operations that can lead to wide area collapses.

The characteristics of a steady-state voltage collapse are different from those of a separation due to dynamic instability:

1. The *critical contingency* may be a single contingency if a heavily loaded circuit exceeds its capability or gets close enough to material objects to flash over.
2. The process of voltage collapse is usually slow enough to permit operator intervention to reverse the process if adequate information and resources are available.

The prevention of the voltage collapse is usually accomplished by shedding load or by rapid generator response to quickly relieve the overloads. These remedial actions do not form an electrical island as may be attempted for dynamic stability problems.

D. Blackout Causes

Blackouts originate from power system disturbances resulting in loss of service to all loads within an area. System disturbances are reported when they turn into large service interruptions.

The DOE criteria for reporting major bulk power system disturbances for systems with peak load greater than 3,000 MW is:

1. Loss of 300 MW load for greater than 15 minutes
2. Loss of service to over 50,000 customers for more than three hours

In addition, CIGRE Study Committee 39, Group 05 AOperational Performance of Power Systems[≅] has performed a worldwide survey on power system disturbances. The severity of the disturbances was measured in terms of System Minutes:

Degree 1 X From 1 to 9 System Minutes
Degree 2 X From 10 to 99 System Minutes
Degree 3 X From 100 to 999 System Minutes
(One System Minute is equivalent to an interruption of the total load of a system for one minute.)

The CIGRE study committee only reported the main cause of disturbances. For instance, a system disturbance resulting from a circuit fault and a subsequent failure of a breaker to clear would be reported as caused by breaker failure if the system should have been able to withstand the original fault. The main causes are listed as follows:

Faulty conventional protection and control equipment
Faulty special protection (i.e., generation rejection scheme)
Lightning
Weather other than lightning
Solar magnetic disturbances
Faulty high-voltage equipment
Personnel error
Other causes
Unknown

There were 295 disturbances reported for the period 1982 to 1989. Of these, there were 271 disturbances with an identified main cause. Over 22% of the disturbances were caused by lightning, other weather and solar magnetic disturbances, over 47% were caused by faulty equipment, and 7% were the result of personnel errors.

Since power system disturbances appear to occur at random, remedial schemes should be considered when possible and appropriate. These schemes will detect the disturbance early enough to avoid the total outage of an area.

III. Determine Blackout Extent and System Status

A. Communication

A functional communication system is critical for the assessment of the extent of a blackout and determining the status of generation and transmission facilities. Utilities should review their communication systems, regardless of whether it is a private carrier (telephone company) or electric utility owned. The assessment is essentially the same for a private carrier or electric utility owned. It should be determined that there is an adequate power source to the communication equipment in order to handle the duration of the blackout conditions. Battery capacity, standby generation availability, enough fuel, or adequate refueling plans also need to be studied. For utilities sharing communications equipment and networks with their neighboring utilities, both users should assess the impact of equipment failure.

B. Customer Calls

In the early stages of system restoration, utility dispatch centers will be bombarded with phone calls from employees and customers. From the utilities perspective, continual calls inquiring into the status of service serves no useful purpose. In fact, continual customer calls may be a detriment by degrading the public telephone system to a point that it is not functional for the utility. Some of the ways of mitigating problems are:

1. Automatic dialing system to notify employees of the status
2. Immediate notification of customer service representatives
3. Public appeal to limit phone system use
4. Priority call system for utility dispatchers' phone systems

Dispatch centers that do not handle customer calls should consider establishing a center or desk for communicating with governmental and public agencies. Dispatchers will then be able to focus directly on operations.

C. RTU Operation Without AC Power

In order to be functional in a blackout, RTUs should not be dependent on ac power. RTUs, in general, are designed to be powered by dc from the station battery. The RTU interface equipment with the telephone system, such as amplifiers and equalizers, also should not use ac-powered equipment. Telephone companies generally try to use ac-powered equipment throughout their system, but utilities have a special need. Utilities should include periodic monitoring of RTU communication equipment as part of their routine inspections to ensure that it is not dependent on ac power.

D. Units Available for Service

The system restoration sequence and timing will be directly impacted by the various sizes, types, and state of operation of the system generating units prior to the blackout. The operating fossil, hydro, and combustion turbine units prior to the disturbance will likely be the most desirable units for the restart effort with the non-operating blackstartable units included among this group. The system operators will need to know throughout the restoration process the status and

availability of the system generating units. They also need to be alert to the influences of the weather and temperature and understand their potential to alter the availability of these units as well as their fuel supplies.

Determining the proper sequence for returning generating units to service also requires the gathering of known facts about the specific units beforehand. Having a tabulation of the individual unit characteristics and capabilities will be beneficial when selecting the order and fit of the units for the restoration sequence. This data will need to be compared to the actual serviceability of these units soon after the disturbance has occurred, with special emphasis placed on defining any changes to ramp rates, restart times, minimum or maximum load and var generation, or damage that occurred which might constrain unit operation. As many units as possible should be startable in parallel, although some will have to be done sequentially. Connected loads at plants and along circuits between plants also must be taken into consideration.

Auxiliary power should be restored to the generating sites as soon as possible to improve their availability. Relatively short delays in restoring auxiliary power can result in delays of several hours (or even days) in restoring the affected units. Station emergency generators and backup batteries may provide power for only the most essential safety systems but cannot be counted on as a source for a unit start-up.

E. Units Operating With Local Load

Units that have become isolated or islanded will not have the stability they would have if the system were normal. Units that have separated from the system, supplying their own auxiliary load or local area loads, will be at greatest risk of having frequency control problems if the actual unit load is less than the minimum load for the unit. Adding more station or distribution load or substituting fuels may increase the stability of the unit. However, any load added should be in small increments to prevent the unit from tripping and to better control the voltage and frequency fluctuations.

In some cases, the system operator may not be able to identify units that have separated from the system but are continuing to supply some load either to their own station auxiliaries or local areas. These units may appear to have tripped off-line based on observations of system control center generation stripcharts, frequency meters, load meters, and the like. Knowledge of the size and locations of these islands needs to be communicated to the system operators to enable them to choose the best strategy for the restoration effort and unit stabilization. When islanded areas can be identified, they should become the basis for connecting with adjacent islands as they become available.

F. Units With Blackstart Capability

The sources of start-up or cranking power, regardless of their type, need to be of adequate capacity to provide for the largest anticipated load plus any line charging requirements. For a remote combustion turbine or hydro site providing blackstart capability to another unit, line voltage between the source and load should be monitored and controlled close to the normal operating values. Adding shunt reactors may be necessary for var control if the reactive limits are exceeded on the generator(s) providing the cranking power.

At blackstart sites having multiple sources with which to provide remote cranking power, parallel unit operation will be required if the load is more than the output of one unit. Controlling these multiple units at no-load and then combining them into a single synchronized source will be necessary. As the cranking power path leaves the blackstart site, possibly entering substations or switchyard, breaker configuration will need to be examined to prevent unwanted loads from using power intended for units to be started or causing a trip-out of the blackstart sources.

G. *Scrubbers Availability After a Period Without Power*

The waste stream, thickening and transport sections of a “wet” flue gas scrubbing system, will be susceptible to rapid sludge thickening and solids set-up upon loss of power. For system equipment such as tanks, piping, rake drives, and pumps installed in unheated or outdoor locations, particular attention should be given to their sensitivity to low temperatures and freezing if not kept heated or drained of liquids. Spray lines and spray pumps would be recommended for draining and flushing as well. Creation of a solids settling time-line and a time-temperature curve might well serve as guidance to develop procedures.

An “dry” scrubbing system will typically have residual fluids and solids in its treatment/sorbent slurry, the atomizing system and recycle lines. A flushing and draining of these sections would be recommended even if installations are in heated areas. The ash transport lines for the associated bag house should be purged as well.

The power requirements to operate a unit’s scrubber system can demand a significant portion of the total station auxiliary power even under normal conditions. At some power stations, scrubbers can consume as much as 30 MW. During a system restoration, especially in the early stages, the power to operate a scrubber may better be directed to serving customer or other system needs. Operating temporarily without some portion of environmental controls also may be in the public’s best interest. An examination of the specific effects and risks of shifting these power uses to the customer should be considered.

H. *Nuclear Plant Status*

When a nuclear unit trips off-line and simultaneously the auxiliary power from the outside sources is lost, their site emergency generators are designed to start and supply the emergency or safeguard busses with power. Off-site power should be restored as soon as possible even though the unit start-up will be delayed. Upon the availability of off-site power to the non-safeguard busses, and assuming no equipment damage has taken place nor any radioactive leakage has occurred, a restart of the unit is possible.

Nuclear units require special treatment. NRC start-up checklists generally do not permit hot restarts and their diesels would not be permitted to supply auxiliary power to other stations. Nuclear units that are taken off line on a controlled shutdown can be restored to service in about 24 hours; more likely 48 hours after a scram. While restoring off-site power to nuclear units requires attention, restoring power to service area load will normally need to be without the help of nuclear units.

I. *Neighboring Systems*

In today’s operation of generation and transmission systems, few utilities are autonomous. Knowledge of the neighboring utilities’ status can enhance restoration through pooling restart sources, sharing reserves, and interconnecting transmission. Utilities should have functional communications to gain timely knowledge of the overall system status. Data links for system conditions in neighboring systems will aid in limiting the amount of verbal communications required. Special coordinating efforts will be necessary for facilities that are jointly owned or operated between two or more utilities.

J. *Personnel Availability*

System restoration requires utility personnel to complete an enormous amount of tasks in a relatively short time (less than 24 hours). It is essential for utilities to promptly get appropriate

off duty personnel notified to report to duty. Automatic notification systems can provide system and plant operators necessary relief of this burden. For effective use of extra personnel, utilities should consider defining responsibilities in advance of the event. Standing instructions for personnel expected to be involved should be to report to a designated site under blackout situations on their own initiative. Consideration must also be given for rotating personnel to keep fresh system and plant operators. Lists of contractors and the location of special tools and equipment should be available.

K. *Transmission Breaker Status and Connectivity*

After a system has blacked out, the system operators should perform a quick survey of the system status. Circuit breaker positions will not provide a reliable indication of faulted versus non-faulted equipment. Breakers will be found open from:

1. Permanent faults (storm related or equipment degradation), which may have initiated the system shutdown
2. Out-of-step conditions: As the system collapses, power flow on some lines may swing through the impedance characteristics of the line relays and trip the line. These lines will be usable in the restoration plans.
3. Temporary faults: As the system cascades into shutdown, some lines may overload, allowing the conductor to sag into underbuild or other right-of-way obstructions. After the fault is cleared and the conductor has cooled, the conductor will regain adequate clearance and will be serviceable.

Breakers can be found in the closed position, but the associated transmission facility is faulted. If the system blackout is storm-initiated, this condition is quite possible. The storm can continue to damage equipment after the system is de-energized.

Utilities operating in cold weather should be concerned about breakers= serviceability. In cold weather, breakers with leaks tend to leak more. After prolonged periods without ac power to compressors and heaters, enough pressure may not be available for circuit breaker operation. SF6 gas may condense into a liquid causing the breaker to lock out until heaters and compressors are restored. Clearly, station service should be restored as soon as possible.

L. *Transmission Facilities Unavailable for Service*

Because breaker positions cannot be relied on as an indicator of facility availability for service, the system operator should rely on field verified data (such as oscillographs) to determine whether or not equipment is faulted. Also, equipment with neutral connections, such as reactors, transformers, and capacitors, may be locked out from the neutral overcurrent conditions during system shutdown. These facilities may be in perfectly serviceable condition.

M. *Station Battery Effective Availability*

The station battery is one of the most critical pieces of equipment in the restoration process. Most utilities have standards for specifying the battery size. A common battery standard is to have enough battery capacity to handle an 8 to 12 hour outage of ac power to the battery chargers and still be able to serve all of the following:

1. All normal dc loads
2. The largest credible substation event at the beginning of the 8 to 12 hour period
3. One open-close-open operation on each substation device during the 8 to 12 hour period with some margin

The main concern with this specification is whether a blackout event will result in a greater initial dc load than the largest substation event. Also, will more than one operation be needed on each device before ac is restored to the substation?

Utilities may periodically test station batteries based on a substation theoretical load profile in a system blackout, not based on design criteria or manufacturer specifications. Testing based on design criteria of manufacturer specifications can mislead utilities as to their actual battery performance. Also, proper, routine battery maintenance is essential to battery performance in emergencies.

Utilities should periodically review the station battery loads to check for added loads, such as dc lights or dc heaters, that the battery was not designed to handle without an ac power source.

N. *Expected Relay System Reliability*

Most relay systems will remain reliable and secure during restoration, provided there is adequate fault current available to activate the relaying. The most questionable relay reliability issues come from reclosing relays. Utilities should review their restoration plans for impacts of inadvertent reclosure of breakers during energization. Restoration plans also should be reviewed for reclosing schemes that allow reclosing in a manner that is only suited for normal operation. Some examples are:

1. Station hot bus-dead line reclosing requires the main bus to be hot before a transmission line is reclosed. In a blackout, this scheme may prohibit energizing from a blackstart generator into a transmission station.
2. Peaking plants that tap a transmission line may require a hot line before allowing closure to the line. If this is a blackstart generator, energizing of the line may be prohibited until the relay is bypassed.
3. Motor operated air-break switches that may inhibit circuit restoration.

O. *Underfrequency Relaying Load Status*

Utilities should make the status and control of underfrequency relays available for the system operator through SCADA. The underfrequency relay operation indication should be identified and segregated by trip frequency so that the system operators know what underfrequency protection has activated and what is remaining.

Any block restoration of underfrequency load shed by underfrequency relays should be sequenced so that the entire block of load is not restored simultaneously, resulting in re-activating underfrequency, or in the worst case, causing the system to shut down again. Distribution circuits with capacitors and/or underfrequency relaying may want to be energized later in the restoration process to avoid voltage problems or automatic trips.

During much of the early stages of system restoration, customer service may be rotated, giving more customers an opportunity for some amount of service. The SCADA system load shed program should be designed to allow previously restored underfrequency load to be shed, and shed load restored.

P. *Generators Tripped by Underfrequency*

A unit separated from the system due to an underfrequency trip may have islanded and continue to generate power for its station auxiliary load. With no system load on the generators, the station

auxiliary demand will be quite small, and the steam generators output may be difficult to control. Immediate load addition may be required to keep the steam generator from tripping or having the steam turbine trip out on overspeed. Other units may be able to operate indefinitely on their auxiliary load.

For the units tripped and unable to maintain generation for their own auxiliary load, a complete restart would be necessary. Restart could commence with the return of station auxiliary power from an external source.

IV. Restoration of Auxiliary Power to Operable Generation

A. Evaluate Transmission System Status

A system blackout will generally cause much initial confusion and create a large number of SCADA alarms and reports. Efforts should be made to ensure that only essential alarms are given to operators under these and other emergency situations. Before generating units can be restarted, an accurate picture of the transmission and generation system should be developed. The first step of the restoration process should be an evaluation of the transmission system. Energy Management System (EMS) SCADA indications should be confirmed by dispatching field personnel or verify equipment status from other sources as required. This EMS SCADA data will be used during the restoration process and must be accurate if the process is to be successful. All known and/or suspected transmission damage should be identified. Work can then be initiated on damaged transmission facilities that are involved in the blackstart process, to either isolate or repair the damaged facilities, or to use alternate paths.

B. Evaluate Generation Resources

Generation resources in any system are constantly changing. This will be especially true following a partial or complete system blackout. The units that were on line during the event are now off line and in an unknown condition. Plant personnel should begin an immediate assessment and, as soon as possible, communicate unit status to the control center. This must be complete before the full restoration process can be initiated. This information will be used to develop a blackstart process based on actual unit availability. Enough units must be provided with auxiliary power to assure capacity to serve all customer load.

C. Fuel Supply Considerations

In a blackout event, especially a wide spread event, natural gas transmission facilities should be considered for priority power restoration if they are required as a fuel source for generation. Most, if not all, of those facilities do not have on-site emergency power. Transmission paths supplying start-up power for generating units also should support fuel delivery to those units.

D. Blackstart Process

Each system should have a blackstart plan including specific transmission and generation procedures to implement that plan. In an actual system blackout, the generation and transmission resources could be significantly different than anticipated. The primary focus of a restoration process is to connect available generation to a start-up power source. The information accumulated during the transmission system and generation resources evaluation should be used to develop a blackstart process utilizing actual available resources. The process should include the following:

1. Establish off-site power for nuclear units, both those that had been operating and those already off line. This is required without regard to using these units for restoring load.
2. Units with blackstart capability should begin the restart process for use in supplying start-up power to other units.
3. Priority access to start-up power should be given to hot units that can be returned to service immediately.
4. Priority access to start-up power also should be given to other units that can be started within a few hours.

5. Consideration should be given to connecting shunt reactor devices to help stabilize generating units being brought on line.
6. Transmission corridors for supplying start-up power should be identified and switching procedures determined, taking extra care to isolate damaged facilities.
7. Units without blackstart capability should be prepared to begin the start-up process when start-up power becomes available.
8. Transmission system corridors to support the start-up process should be established but not energized until needed.
9. As units with blackstart capability come on line, *energize* appropriate transmission system corridors supplying start-up power for units that are ready to return to service.

E. Procedure Testing

For blackstart units to achieve their maximum benefit, they should be tested periodically under realistic conditions. In addition to demonstrating that the units can in fact be started using designated facilities, this also provides training for the people involved with the process. Similar testing and training also is needed for units with load rejection capability. Isolating these units from the system when conditions permit and using the actual sources to start them is a worthwhile and revealing exercise. Problems that could seriously impact an actual restoration can be revealed under controlled conditions and corrected before they can impact an emergency. Similar testing and training also is needed for units with load rejection capability.

V. Preparation for the Transmission System Restoration

A. Restoration Switching Strategies

After determining the extent of the blackout and assessing the status of system equipment, the switching operations necessary for system reintegration represent a significant portion of the restoration process. Depending on the specific utility's requirements, there are two general switching strategies, which may be used to sectionalize the transmission system for restoration. The first is the "all open" approach where all circuit breakers at affected (blacked out) substations are opened. The second strategy is the "controlled operation" where only those breakers necessary to allow system restoration to proceed are opened.

The "all open" strategy can be effectively accomplished by local station operators or by automated EMS supervisory control. This approach has the advantage to the system operator of presenting a simpler and safer configuration to re-energize. Only breakers involved in the restoration process will need to be closed. System collapse or voltage deviations due to inadvertent load pickup or circuit energizing are less likely to occur. Drawbacks of the "all open" approach are that restoration time may be longer and more stored energy is required for the greater number of breaker operations. Stored energy in the form of compressed air or gas, springs, or station batteries is used to operate the breaker mechanism. Unless this energy is lost due to leakage or discharge due to operations during the blackout event, circuit breakers should be capable of one open-close-open operation without ac station service.

The Acontrolled operation≡ switching strategy imposes less (stored) energy requirements since breakers not involved in the initial sectionalization and restoration remains closed. However, the system operator must be continually aware of the isolation between the restored and de-energized systems. Studies should be conducted to examine steady state and transient voltage response if multiple transmission circuits are to be energized by the "controlled operation" strategy. Either strategy requires an extensive amount of switching operations, except that "controlled operation" will hopefully postpone some breaker operations until after station service is re-established.

B. Cold Weather Switching Concerns

In addition to the limited number of breaker operations during a blackout, switching operations can be further compromised following an interruption in cold weather. The proper operation of many transmission breakers (particularly air-blast and SF6) depends on maintaining the proper temperature and pressure within the breaker. This is normally accomplished by heating elements and compressors supplied by ac station service. A cold weather interruption reduces the time window for normal breaker conditions (as short as thirty minutes), after which operation may be blocked by electrical interlocks monitoring the breaker pressure. Although most breakers can be operated manually, this method normally requires the breaker to be de-energized for safety and restricts switching operations. If manual operation is required for energized breakers, breaker misoperation or damage may occur.

C. System Sectionalizing

Regardless of restoration switching strategy, system sectionalizing to disconnect load and capacitors from the transmission system is generally desirable. Unless load pickup is required when energizing transmission circuits for voltage control, loads should be disconnected and restored in small blocks for system frequency control. Opening of station and controlled distribution capacitors may help prevent high voltage and generator underexcitation conditions aggravated by charging current of unloaded transmission circuits. Shunt reactors are ideal

candidates for controlling high system voltage if studies show their use acceptable under weak system conditions. Transformer tap positions, especially load tap changers under automatic control, should be reviewed and moved if substantially off nominal. Generator voltage regulators should be in service to limit voltage deviations prior to load pickup or circuit energizing. Restoration of several subsystems in parallel and then tying them together may shorten the restoration process if manpower and facilities are available.

D. System Assessment

In preparation for an actual restoration, the effort to ascertain faulted system equipment will detract from the restoration process. Many transmission circuits may trip due to out-of-step relaying or temporarily sag and trip during the system collapse. These circuits may be serviceable for restoration, however, system operators should exercise care to avoid closing into a fault when energizing the transmission system. If possible, field personnel should check relay flags of tripped transmission circuits before energizing. Any verifiable failures must be factored into the restoration.

A utility restoration plan incorporating either the “all open” or “controlled operation” switching strategy must consider the impact of substation equipment availability following a blackout. Inoperable or failed equipment at key substations will require additional switching operations and may significantly delay the restoration effort. Utilities that rely on automatic restoration equipment at unattended stations not controlled by supervisory control must take operation of this equipment into account in developing restoration plans.

VI. Restoration of the Transmission System and System Loads

A. *Transmission Restoration*

1. Voltage Limitations

During restoration, the bulk power system should be operated so that reasonable voltage profiles (within the range 90% to 110% of nominal) can be maintained. Where possible, voltages should be maintained at the minimum possible levels to reduce charging currents.

When energizing transmission lines, care must be taken to make sure that nearby generators are on automatic excitation control and that enough Mvar reserve (or margin) is available at the generator to absorb the line charging. If the generator's underexcited capability is exceeded following the line energization, a voltage runaway situation may arise.

Once a line has been energized successfully, it is best to energize some local load to reduce the voltages. Successive energization of a line followed by that of a load will be a good strategy to control the voltages to within acceptable ranges. The system operators should attempt to balance the reactive requirements using line charging, and loading of shunt capacitors, reactors, and unit Mvar reserve capabilities. Transmission shunt capacitor banks should be removed from service to prevent high voltage until sufficient load has been re-energized. Shunt reactors should be placed in service when initially restoring the system to help reduce system voltages. Static var compensators and condensers under automatic control should be placed in service as soon as practical. Voltages need to be continuously monitored on all the transmission circuits, particularly those that provide inter-area ties.

2. Synchrocheck Interconnection Relay Schemes

Automatic reclosing relays should initially be disabled in order to prevent premature, uncontrolled, automatic reclosure of individual interconnections. Isolated areas should be synchronized using the highest voltage line available. This procedure is desirable because of the lower impedance and higher relay load ability of the higher voltage lines. However, possible overvoltages or special considerations could prompt the use of lower voltage lines.

Control areas, which share common transmission or generation facilities, must develop prearranged plans for the priority operation of these facilities during restoration. Interconnection should only be attempted at a generating plant or at a station with a synchroscope. Substations, which have the capability of synchronizing two systems, which are isolated, should be identified and included in each system restoration plan.

Where possible, field personnel should be used to verify breaker positions. When synchronizing, both phase angle across the breaker and the voltage on each side of the breaker should be measured. If possible, the phase rotation should be stopped and the phase angle reduced to ten degrees or less before interconnection is made.

3. Transmission Stability

Circuit energizations should be performed in a deliberate manner, checking the status of all associated facilities before and after energization. The system operator should aim low on voltage when energizing circuits to reduce charging currents. The energized

transmission must be monitored to control facility loadings and voltage conditions. Minimize the number of switching operations because: (1) excessive switching increased restoration time, and (2) until station service is restored to a substation, the breakers at that station can be operated only a relatively few times before they become inoperative due to loss of stored energy. Only energize transmission lines that will carry significant load. Energizing extra lines will generate unwanted Mvars.

Prior to energizing a line section, the system operator should attempt to keep the voltage on the source bus below its nominal value. Open shunt capacitors and close shunt reactors before re-energizing transmission lines. If minimum source requirements have been established for a transmission line, the system operator must ensure that those requirements have been met before energizing the EHV line. Minimum source requirements address the concerns associated with:

- a. Steady-state overvoltage caused by excessive var supply from the capacitive rise of EHV lines and aggravated by harmonics from transformer saturation.
- b. Transient overvoltage caused by traveling wave phenomena.
- c. Dynamic overvoltage caused by transformer magnetizing inrush and aggravated by harmonics from transformer saturation.
- d. Reduction in proper relaying protection reliability due to insufficient fault current and overvoltage failure of EHV equipment.

Where possible, ac load flow analysis should be used to examine steady-state voltage levels, and switching surge studies should be used to identify transient problems. These must be representative off-line studies prior to the incident until practical real-time analysis is developed.

If an EHV line is to be energized by closing the breaker on the low side of the transformer, consideration should be given to adjusting the tap changer to its studied position or in the absence of a specified setting to its lowest EHV tap setting. On an open-ended EHV transformer that will be energized with an EHV line, adjust the tap changer to the studied tap position, to its normal or midpoint position, or to match the energized line voltage. Ferroresonance may occur upon energizing a line or while picking up a transformer from an unloaded line.

4. Fault Availability for Proper Relay Operation

Low available short circuit current can hinder the performance of protective relaying. Because of a higher likelihood of overvoltage, and thus system faults during restoration, proper relay protection is imperative to prevent recollapse of a weak system. Primary and backup EHV relaying should be in service on all lines being returned to service. The system operator should assure that adequate underlying transmission capability is electrically connected at the interconnection point to provide adequate fault current (relay protection). Impedance relays that do not have out-of-step blocking may trip lines due to power swings during restoration.

5. Transient Problems in Energizing Transmission

Various factors affect the transient stability of a system, such as the strength of the transmission network within the system and of the tie lines to adjacent areas (if any), the characteristics of the generating units, including the inertia of the rotation parts, and the electrical properties such as transient reactance and magnetic saturation characteristics of the stator and rotor iron. The stronger (i.e., lower source impedance) and the more numerous the lines on a bus, the less severe the energizing transients become. In

addition, connecting shunt reactors to the line especially at the remote end of the terminal to be switched, will lower the energizing voltages.

Severe overvoltages resulting from switching surges may cause flashover and serious damage to equipment. Switching transients are fast transients that occur in the process of energizing transmission line and bus load capacitances right after a power source is connected to the network. The transient voltages or switching surges are caused by energizing large segments of the transmission system or by switching capacitive elements. The switching transients, which are usually highly damped and of short duration, in conjunction with sustained overvoltages, may result in arrester failures.

Transient overvoltages are not usually a significant factor at transmission voltages below 100 kV. At higher transmission voltages, overvoltages caused by switching may become significant because arrester operating voltages limits are relatively close to normal system voltage and lines are usually long so that energy stored on the lines may be large. In most cases, without sustained traveling wave transients, surge arrestors have sufficient energy absorbing capability to damp harmful overvoltages to safe levels without permanent damage. Also, circuit breaker closing resistors will provide enough damping of switching surges for closing long lines.

B. Generation

1. Unit Stability

As system restoration progresses and more generating units return to service, the more stable the system becomes. More units mean stronger sources in terms of synchronized inertia and control of frequency and voltage. Stronger sources will afford more circuit energizations, unit start-ups, spinning reserve, and load pickups. However, caution needs to be observed during this period. There should be sufficient time between switching operations to allow the generating units to stabilize from sudden increases in load.

Automatic governor controls on generators should be placed in the automatic position to ensure instantaneous governor response to changes in frequency. Generating units should be loaded as soon as possible to a load level above their minimum loading point to achieve reliable and stable unit operation.

2. Load/Frequency Control in Area Islands

Generation and load should be adjusted in small increments to minimize the impact on the frequency. Loads should be added in block sizes that do not exceed 5% of the total synchronized generating capability. Frequency should be maintained between 59.75 Hz and 61.00 Hz with an attempt made to regulate toward 60.00 Hz. Manual load shedding may need to be used to keep the frequency above 59.50 Hz. As a guide, shed approximately six to ten percent of the load to restore the frequency 1 Hz. Large segments of load should only be restored if the frequency can be maintained above 59.90 Hz, and it is certain that such action will not jeopardize the transmission system of other paralleled areas. It may be helpful to increase the frequency to slightly above 60.00 Hz before each load block addition in the early restoration stages.

Even with the advantages of load with underfrequency relays enabled, it is advisable to resist picking up this type of load unless normal load pickup has been demonstrated to not cause frequency decay below the applicable underfrequency trip level. When load with underfrequency relays enabled is being picked up, it may be advisable to restore the load by alternating load pickup at each of the various underfrequency steps.

When interconnecting with another system, the frequency should be matched and maintained above 59.75 Hz and below 61.00 Hz. Anytime two or more isolated systems are operating in parallel, only one system should control frequency with the other system(s), controlling tie schedules unless load frequency control (LFC) is available. The best regulating units on the system should be used to regulate area or island frequency. The best units should be determined based on both the amount and quality of regulation provided. If the frequency regulation burden becomes too large for one unit, the frequency regulation should be shared by two or more units, preferably in the same plant control room for better coordination. If more than one area controls frequency, there would be a hunting effect without LFC. As a general guide, the regulation requirement to maintain frequency during system restoration should be about twice the normal requirement for the area load being carried at that time. Units not assigned to regulate frequency should be constantly redispached to keep each regulating unit's energy at the middle of its regulating range.

3. **Spinning Reserve**

During system restoration, each control area should carry enough operating reserve to cover its largest generator contingency in each isolated area. This reserve can either be on-line generation that can produce additional power within ten minutes or customer load that can be shed manually within ten minutes. Operating reserve is required to enable the control area to restore its area (or subsystems) to a pre-contingency state (both tie lines and frequency) within ten minutes of a contingency. The smaller the area, the more of this reserve should be spinning. Connecting two or more systems together may result in a lower combined operating reserve requirement. However, caution needs to be used to ensure that load is not added too fast and the system collapses again.

C. Load Pickup

1. **Cold Load Pickup**

Restoring customer load to service, which has been disconnected for some time, presents new challenges. The disconnected load will probably be much higher than its value at the time of interruption. The simultaneous starting of motors, compressors, etc., will cause high peak demands for power. These higher than usual load requirements are commonly referred to as cold load pickup. Cold load pickup can involve inrush currents of ten or more times the normal load current depending on the nature of the load being picked up. This will generally decay to about two times normal load current in two to four seconds and remain at a level of 150% to 200% of pre-shutdown levels for as long as 30 minutes. When restoring load, sufficient time must be allowed between switching operations to permit stabilizing the generation.

2. **Priority Customers**

Each control area should develop a priority restoration scheme for its customer load. These load restoration schemes need to address the control area's requirements as well as those of the community. Providing station service to nuclear power plants and providing service to facilities necessary to restore the electric utility system should be the highest priority.

As conditions permit, the system operator should consider providing service to critical loads such as generating plant fuel supply depots, military facilities, law enforcement organizations, facilities affecting public health, and public communication facilities.

3. **Automatic load Restoration Schemes**

The system operators need to control and remain in control of all aspects of the system restoration. Automatic devices, which protect the system (relays, voltage regulators, etc.) should be in service as quickly as possible. Other automatic devices such as automatic load restoration schemes should not be enabled until a sufficient portion of the system generation and load have been restored unless the possibility of automatic restoration is factored into the portion of the system being energized.

VII. Reliability Coordinator Responsibilities During Restoration

A. *Early Restoration Stages*

1. Communications

The Reliability Coordinator's primary role in the early stages of power system restoration is to coordinate the exchange of information among the systems under the Reliability Coordinator's purview (the Reliability Coordinators' "members"), other Reliability Coordinators, NERC, and the Regions. The Reliability Coordinator should initially endeavor to establish lines of communication with its members via normal systems or, lacking those, through any available means. As soon as practical, the RC should establish communications with other Reliability Coordinators and NERC via the NERC hotline and Reliability Coordinator Information System or, lacking those, through any available means. Communications with the Regions should be on an as-needed basis. Information to be gathered from members and exchanged with other Reliability Coordinators and NERC would typically include:

- The extent of the required restoration effort in the Reliability Area (transmission and generation facilities not available for service).
- High-level summaries of the members' initial plans to begin restoration.
- The progress being made to restore generation capacity (for example, key generating facilities restored, milestones achieved associated with generation, etc.).
- The progress being made in restoring transmission facilities (for example, a list of bulk power substations re-energized, milestones achieved associated with transmission, etc.).

2. Information Sharing

Information from other Reliability Coordinators or NERC to be shared with members would typically include:

- Status of power system restoration progress in adjacent Reliability Coordinator areas.
- Information regarding the cause of the system collapse.

B. *Later Restoration Stages*

As the power system restoration process progresses, the responsibilities of the Reliability Coordinator increase. The Reliability Coordinator should:

- Work with the Control Area Operators to review the power system data to facilitate the RC's real-time data acquisition in order to determine the overall state of the power system.
- Work with the Control Area Operators in order to ensure that sub-regional switching is coordinated as the system is restored.
- Work with the Control Area Operators and neighboring Reliability Coordinators to determine when interconnections in adjacent Reliability Coordinator areas can take place.

Throughout the restoration process, the RC should assess its ability to perform the RC functions required by NERC Policy 9. As system conditions and data availability permit, the RC should verify that it has successfully restored its ability to perform each function.

C. *Reliability Coordinator Training*

Reliability Coordinators should have knowledge of the restoration plans and procedures within their defined area of responsibility. Restoration drills plus other training as needed should take place on an annual basis.

VIII. Training and Testing

The development of training and testing for electric system restoration requires careful consideration and is specific to each utility. From a global perspective, however, the utilities within a control area should share common objectives. In order to enable each utility to develop an effective training plan, this section will focus on presenting a training schematic. Employee input and involvement are the prime catalysts in all aspects of training.

A. Goals

The area utilities should first develop training goals by listing the objectives specific to each utility. The goals should encompass conditions, concerns, contingencies, post-outage generation resource forecast, automatic circuit breaker operations, training needs of personnel, and procedures specific to the area.

Typical area goals might be expressed as follows:

1. “Provide electric system restoration training for system operations personnel in order to build confidence, optimize effectiveness, and nurture teamwork.”
2. Provide a basis for better communications concerning electric system restoration between utilities and groups within utilities.≡

B. Decision Making and Priority Setting

Training priorities should be set in order to make tough decisions regarding the depth and focus of training. The backgrounds and needs of utilities vary, so the training program of each also may vary from that of a neighboring system.

Training tasks should be identified which will help attain the goals. The training tasks identify the nature of training, but do not say how to do it. Priorities must be established for the training tasks. The tasks and priorities should be developed and scrutinized by employees closest to the daily operations.

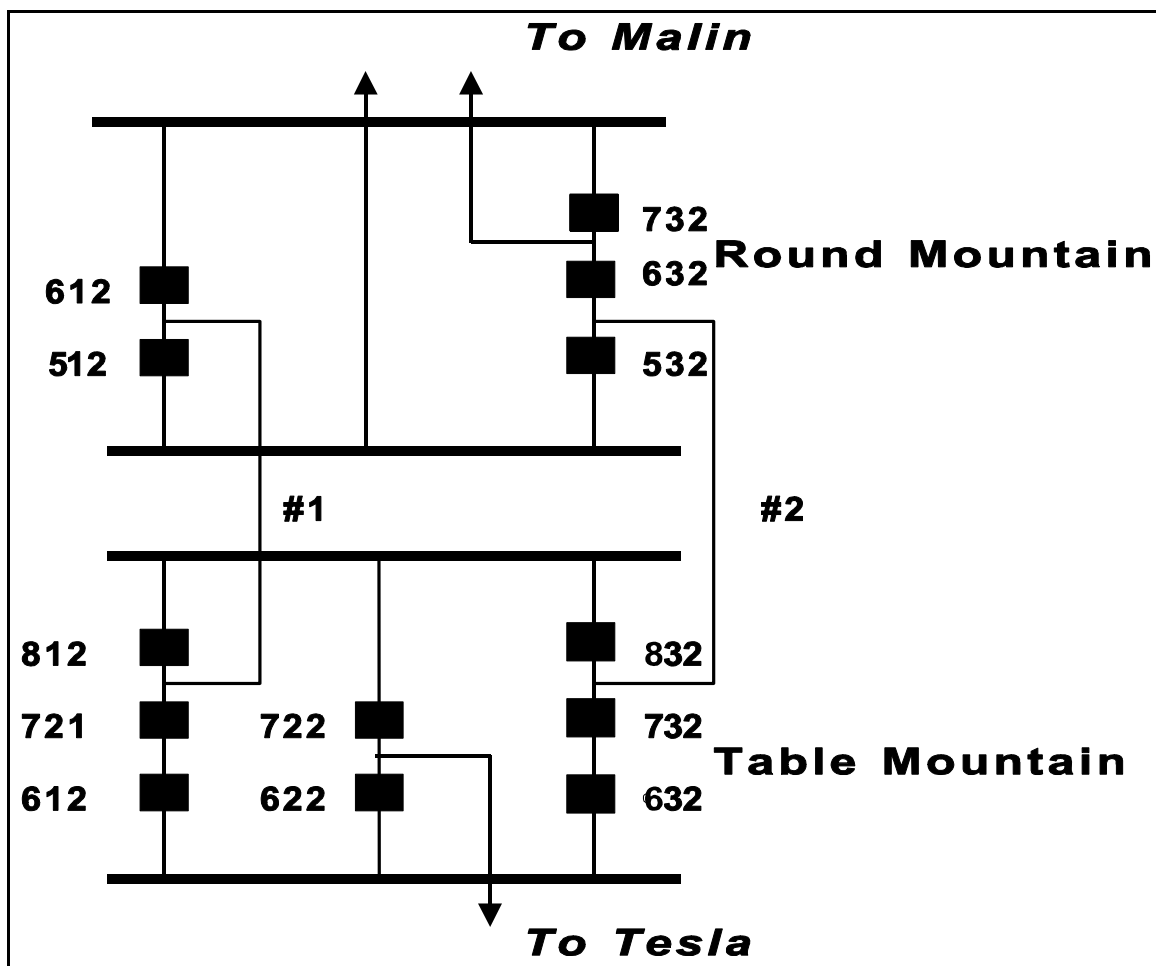
Typical restoration training priorities include the following:

1. Enhance understanding of anticipated post-collapse system conditions and alarms.
2. Review existing dispatching instructions and procedures.
3. Develop and be prepared to use a functional restoration diagram for tracking system restoration down to and including major 115 kV, such as the example shown in Figure 2.
4. Refine and update system restoration procedures using simulation if available.
5. Study and project response to restoration procedures regarding generation sources, interconnections, AGC control mode, frequencies, governor bandwidth, voltage rise, relaying parameters of potential impact, backup control center, and voltage change anticipated from reactive changes at substations with little or no power flow.
6. Promote increased awareness of problems arising from picking up load with isolated generation, including frequency deviation anticipated, potential distribution underfrequency relay action, potential generation overspeed trips in response to distribution load trips, frequency control methods, reactive control, maintaining unit stability, increasing frequency by 0.5 to 1.2 Hz before incremental load pickup, and control of electrical system load being restored.
7. Knowledge of problems associated with attempting to pick up portions of the system while avoiding restoration of uncontrolled loads by automatic controls or field personnel actions when necessary.

8. Familiarization with specific devices for use in controlling line voltages: EHV line shunt reactors, tertiary shunt reactors, unloaded banks, banks with controlled amounts of load, synchronous condensers, static var compensators, bypassing series capacitors, and the anticipated magnitude of the voltage change to be realized from each action.
9. Encourage teamwork within each control center and between control centers.
10. Promote coordinated response and understanding across corporate cultural lines of plants, divisions, regions, and business units or other organizational boundaries.

C. Methodology

Each utility should construct a plan for implementing restoration training, outlining how the training will be done. The methods developed should be focused upon providing the training tasks, which serve to accomplish training goals. In addition, the methods proposed should be subjected to a review to ensure the methods can be supported. Suggested prerequisites to consider for checking to ensure that training can be supported include practicality, human resources required to accomplish, support by involved parties, and budget allocation.



Some training methods might include the following:

1. Classroom review of critical technical information and reference to procedures, including automatic generation control (AGC) modes, frequency sources for AGC, coordination, power pool or coordinating council notification procedures, loading or stability

- constraints, detailed procedures for specific plants or portions of the system, and equipment voltage limits.
2. Simulator demonstrations involving isolated system response.
 3. Simulator demonstration of voltage changes by various voltage control methods.
 4. Guest speakers for classroom PC slide show presentations on remedial action, special protection schemes, contingency studies, and protective relaying impact on restoration.
 5. Simulator or classroom work group assignments to respond to total system blackout and take actions up to and including total system restoration. Suggested scenarios should include both with and without outside sources of generation or supply.
 6. Simulator restoration or work group assignments may be combined into contiguous segments:
 - a. System analysis
 - b. Assignment of responsibilities
 - c. Determination of plan(s) to implement linking resources with critical needs, such as nuclear plants and control centers
 - d. Restoration and express routes for linking first resources with power plants
 - e. Bulk load restoration
 - f. Subsequent day's load reduction measures or rotating outage implementation if resources are insufficient at peak.

D. Testing Equipment and Procedures

In addition to training, possible simulation, and operations preparedness, the communication links and procedures within and between utilities should be tested by means of periodic use and, if possible, training drills or exercises.

E. Measuring Effectiveness

It is recommended that measurements be established to determine the effectiveness of restoration training. The measurements may be suited to individual needs, but may include:

1. Training results critique to be completed by the people being trained
2. Annual system restoration knowledge level questionnaire
3. On-the-job evaluation of restoration knowledge

Any demonstrated application in restoring smaller parts of the system also can be included. The desirability of measuring training effectiveness is now perceived by many as a preferred strategy rather than that of testing individuals. It is most difficult to test an individual's operating ability without simultaneously lessening the focus upon learning. Each utility must determine the best strategy in view of specific needs, goals, and resources.

All aspects of restoration are extremely important. However, the mere presence of procedures does not ensure optimum response. Training is an important element, which can bridge the gap between what we want to happen and what will really happen with respect to restoration. The NERC Operating Guides and associated appendices are excellent resources for training assessment and development.