General Electric Advanced Technology Manual

Chapter 4.5

Loss of All AC Power (Station Blackout)

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4.5 LOSS OF ALL AC POWER (STATION BLACKOUT)

Learning Objectives:

1. Define the term station blackout.

2. Describe the impact a station blackout would have when combined with an accident.

3. Describe the primary method available to mitigate the consequences of a station blackout.

4. List the two major classifications Boiling Water Reactors have been divided into for discussing station blackouts.

4.5.1 Introduction

The general design criteria (GDC) in Appendix A of 10CFR50 establish the necessary design, fabrication, construction, testing and performance requirements for structures, systems, and components important to safety; that is, structures, systems and components that provide reasonable assurance that the facility can be operated without undue risk to the health and safety of the public. GDC 17 "Electric Power Systems" requires that an onsite and offsite electric power system shall be provided to permit functioning of structures, systems and components important to safety. These structures, systems and components are required to remain functional to ensure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences. The GDC goes further to specify additional requirements for both the onsite and offsite electrical power distribution systems to ensure both their availability and reliability.

The establishment of GDC 17 was considered sufficient to ensure that commercial nuclear power plants could be built and operated without undue risk to the health and safety of the public. The likelihood of a simultaneous loss of offsite and onsite sources of ac power was considered incredible and therefore did not have to be considered in plant design or accident analysis. Evaluation of plant data and events, along with insights developed from PRA analysis, have led to the development and implementation of additional regulatory requirements addressing station blackout.

4.5.2 Description of Electrical Distribution System

A diagram of a typical offsite power system used at a nuclear plant is shown in Figure 4.5-1. During plant operation, power is supplied to the Class 1E (onsite) distribution system from the output of the main generator. In the event of a unit trip, the preferred source of power to the onsite distribution system would be the offsite grid. If offsite power is available, automatic transfer to the preferred power source will ensure a continuous source of ac power to equipment required to maintain the plant in hot standby and remove decay heat from the core. If offsite power is not available due to external causes such as severe weather or equipment failure, the onsite distribution system would sense the undervoltage condition and initiate a transfer to the onsite (standby) power source. Figure 4.5-2 shows a typical onsite emergency ac power distribution system. In the event that an undervoltage condition is sensed on the emergency buses following a unit trip, the system is designed to open all supply breakers to the buses, disconnect all unnecessary loads, start the emergency diesel generators and reconnect all loads necessary to maintain the plant in a stable hot shutdown condition. If the onsite emergency ac power source is not available to re-energize the onsite system, a station blackout has occurred.

4.5.3 Offsite Power Systems

On November 9, 1965, the northeastern U.S. experienced a power failure which directly affected 30 million people in the U.S. and Canada. On July 13, 1977, New York City experienced a blackout, following lightning strikes in the Indian Point 3 switchyard causing the reactor to scram and the plant to lose offsite power. No Federal regulation of the reliability of the bulk power supply was provided by the Federal Power Act of 1935 and none was subsequently approved following either the 1965 or the 1977 incidents. The National Electric Reliability Council (NERC) was created in 1968 as a result of the 1965 blackout; however their operations criteria and guides were voluntary. On August 14th 2003 over 50 million people in the northeastern and Midwestern United States and Ontario, Canada were without power due a blackout. The U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" that would span North America, with FERC oversight in the U.S. The legislation stated that compliance with reliability standards would be mandatory and enforceable. On July 20th 2006, FERC certified NERC as the electric reliability organization for the United States. The reliability of the bulk power supply (interconnections) is the responsibility of the North American Electrical Reliability Corporation (NERC) through its member Reliability Councils. These Councils are made up of members representing the electric power utilities which engage in bulk power generation and transmission in the United States, Canada, and Mexico.

Figure 4.5-3 shows the geographic locations of the member councils throughout the United States and the various interconnection sections. Interconnections are a strategy for providing power from the plants via an interconnected transmission network to the entities that resell it to the consumer via a distribution network. The Western Interconnection is composed of one reliability Council, Western Electricity Coordinating Council (WECC). The Eastern Interconnection is comprised of Florida Reliability

Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFO), SERC Reliability Corporation (SERC), and the Southwest Power Pool, RE (SPP). The Texas Interconnection is composed of one reliability Council, Texas Reliability Entity (TRE).

The objectives for each Reliability Council vary but, whether explicitly stated or implied in context, the Reliability Councils' operating philosophy is to prevent a cascading failure, provide reliable power supplies, and maintain the integrity of the system. Long-term and short-term procedures are in place nationwide to project demand, to provide for reserves to meet peak demand, and to provide for both likely and unlikely contingencies when demand exceeds capacity and other emergencies. These procedures include a load reduction program and automatic actuation to prevent collapse of the grid. The load management procedures for the Florida Reliability Coordinating Council consist of:

- Curtailment of nonessential power company station light and power (power plants)
- Reduction of controllable interruptible/reducible loads
- Voltage reductions (brownouts)
- Reduction of nonessential load in power company buildings (other than power plants)
- Voluntary customer load reduction
- Radio and television load reduction appeal
- Manual load shedding (rotating blackouts)
- Automatic actuation of underfrequency relays which shed 10 percent of load at 59.3 Hz, and additional 10 percent at 58.9 Hz, and an additional 10 percent at 58.5 Hz.

Other procedures allow disconnecting from the grid areas which have generating units that are capable of supplying local loads, but would trip if connected to a degrading grid.

In addition, emergency procedures are provided for the safe shutdown and restart of the system. Because many plants cannot be restarted without external power, "black start" units are available at various locations as determined by the utility. The black start units are capable of self-excitation: therefore, they restart and produce power to restart other units. The typical black start capability is comprised of diesel generators, combustion turbine units, conventional hydro units, and pump storage units. Normal operating procedures for pump storage hydro plants require maintaining sufficient water in the upper reservoir at all times to provide for system startup power. Satisfactory tests have been conducted to prove the capability of black start of conventional hydro, pumped storage hydro, and some steam and combustion turbine units to provide system startup power.

4.5.3.1 Grid Characteristics

To more fully explain grid operation, the following concepts will be discussed: demand, capacity, reserve margin, age of power plants, and constraints on transmission lines.

Demand

Demand is the amount of electricity that the customer requires. The demand for electricity varies with the hour of the day, day of the week, and month of the year due to factors such as area temperature and humidity. When demand is greatest, it is said to "peak". Peak seasonal demand occurs in the summer for most areas of the country and in the winter in others.

To meet expected demand, utilities establish a base load (the amount of electricity they need to produce continuously) and an operating reserve for responding to increased demand. This operating reserve is called spinning or non-spinning reserve and can be loaded up to its limit in ten minutes or less. Spinning reserve is already synchronized to the grid, while non-spinning reserve is capable of being started and loaded within ten minutes. In addition to the spinning and ten minute non-spinning reserve some areas also have thirty minute reserve equipment.

Peak demand is the average or expected peaks estimated by combining such factors as previous use, the number of new customers, and weather forecasts. Demand forecasting is not done on a worst case scenario. It does not anticipate the demand during unusually severe weather or other unforeseeable factors which may affect demand.

An example of severe weather effects on demand (and capacity) occurred on January 18, 1994, in Pennsylvania, New Jersey, and Maryland as well as Delaware, the District of Columbia, and Virginia. The temperature began to drop from approximately 35°F, at 5 a.m. to 8°F, at midnight. Electric demand in the afternoon and evening increased inversely with the temperature when it was expected to drop with the change in usage from commercial to residential. Because the temperature decreased to atypical values, the increase in residential demand exceeded the decrease in commercial demand, peaking at 7:00 p.m., and remained higher than the daytime peaks through midnight of the following day.

Utilities began emergency procedures to reduce demand. Emergencies were declared in Pennsylvania, Maryland, and the District of Columbia. Government offices and many businesses closed early on January 19 and remained closed on January 20. The emergency ended by midday on January 21, though some voltage reductions continued into the evening.

When demand is projected to exceed supply as it did in the January 18, 1994 cold spell, utilities purchase power from adjacent systems. In this case, these systems were also strained by the same cold weather problems; but the New York Power Pool did reduce voltage to its customers and imported power from the New England Power Pool and Canada in order to assist the affected area.

Demand for electricity by nuclear power plants usually occurs when the unit is not producing enough power to supply house loads which may include the safety related systems. Power to start up must also be supplied to the nuclear unit's generator. Offsite power for nuclear plants is not included in the utilities load management program, but it may be affected by an automatic actuation in response to a grid fault. That is, a nuclear plant's voltage will not be reduced, nor will the plant load shed by the load management schemes; however, grid faults have caused nuclear plants to be isolated from the grid.

Capacity

Capacity is the amount of electricity that the utility can produce or buy. A utility generates electricity by various means: steam turbines, gas turbines, internal combustion engines, jet engines, hydro turbines, and number of other means. Additional electricity may be furnished by co-generation units and non-utility generators. Typically, co-generation units are run by a company that produces the electricity for its own use. Non-utility generators may be co-generators, but are usually power production facilities, built and run by companies which are not regulated utilities. They currently sell the power that they produce to a utility. The generating capacity for various areas can be seen on Figure 4.5-3.

Reserve Margin

Reserve margin is the extra electrical capacity that the utility maintains for periods when the demand is unexpectedly high. In mid-afternoon on a hot summer day in July about anywhere in the country, reserve margins are reduced. Utilities must then resort to demand management: urging conservation, reducing voltage (brownouts), and load shedding (rotating blackouts) if additional power cannot be purchased.

The ability to purchase power is limited by the availability and adequacy of transmission lines. Although transmission lines can carry current in excess of rated maximum, attempts to increase the current beyond the setpoint of the protective system would result in the protective system opening the breakers and isolating the lines.

Past events have shown that factors such as unit availability and transmission line capacity affect the adequacy of reserve margin that is actually available for use. Improving unit availability and transmission line reliability are principal methods specified by Councils for maintaining adequate reserve margin. In addition, bringing units under construction on line and purchasing power are viable means of improving reserve margin.

An evaluation of reserve margins around the United States was performed and published in an AEOD draft report entitled "Grid Performance Factors" [AEOD S96-XX, September 1996]. The report showed that different councils use different methods and have dissimilar acceptability levels for reserve margin. Utilities do not all measure adequacy of reserves by the numbers. Evaluations of reserve margin in an AEOD document (Grid Performance Factors) show that one council is not satisfied with its projected 15 to 20 percent reserve margin, another is satisfied with 20 to 25 percent, while another council measures its reserve margin in percentage of peak demand and percentage of the size of the largest unit in its system. From these varying evaluations of adequacy of reserve margin, the following generalizations can be made: the minimum adequate percentage is 15 percent, reserves below 10 percent of total capacity are unacceptably low, and reserves above 25 percent should be more than adequate for any abnormal situation. Low reserves indicate a potential for problems.

Plant Age

With approximately 38 percent of the United States electricity generated by plants 26 years or older, age has the potential to become a factor in grid stability. Many newer plants are large, producing more megawatts from fewer plants. This concentration of generation can lead to stability problems. When the large plant trips, the nearby plants must pick up the load. In addition, the protective schemes at smaller older plants may not be effective in preventing damage to aging plants and thus further affect grid operation. Most of today's distribution system controller equipment, such as mechanical reclosures, require six cycles to react to a line fault which is not fast enough to provide the virtually instantaneous switching needed to keep sensitive equipment operating properly.

Constraints on Transmission Lines

The amount of power on a transmission line is the product of the voltage and the current and a hard to control factor called the "power factor", which is related to the type of loads on the grid. Additional power can be transmitted reliably if there is sufficient available transfer capability on all lines in the system over which the power would flow to accommodate the increase. There are three types of constraints that limit the power transfer capability of the transmission system:

- thermal/current constraints,
- voltage constraints, and
- system operating constraints.

Thermal/Current Constraints

Thermal limitations are the most common constraints that limit the capability of a transmission line, cable, or transformer to carry power. The resistance of transmission lines causes heat to be produced. The actual temperatures occurring in the transmission line equipment depend on the current and ambient weather conditions (temperature, wind speed, and wind direction) because the weather effects the dissipation of the heat into the air. The thermal ratings for transmission lines, however, are usually expressed in terms of current flows, rather than actual temperatures for ease of measurement. Thermal limits are imposed because overheating leads to two possible problems:

- the transmission line loses strength because of overheating which can reduce the expected life of the line, and
- the transmission line expands and sags in the center of each span between the supporting towers. If the temperature is repeatedly too high, an overheated line will permanently stretch and may cause clearance from the ground to be less than required for safety reasons.

High voltage lines can sag 6 to 8 feet between support towers as they are heated by high current flow and hot weather, and allow flashover between the high voltage line and trees.

Following the August 10, 1996 power outage that affected the western United States, a press release was issued by the Western Systems Coordinating Council on September 25, 1996. The investigation suggests that in all likelihood, the disturbance could have been avoided if contingency plans had been adopted to minimize the effects of an outage of the Keeler-Allston 500 Kv line in the Pacific Northwest. In addition, the task force determined that the loss of the McNary generating units and inadequate tree trimming practices, operating studies, and instructions to dispatchers played a significant role in the severity of the event.

Prior to the flash over from the high voltage line to a tree, the interconnected transmission system was knowingly being operated in a manner that was not in compliance with the WSCC reliability criteria. In addition, the loss of the 13 McNary hydroelectric generating units in the northwest was a major factor leading to the outage of the transmission lines (Pacific Intertie) between the Pacific Northwest and California.

Voltage Constraints

Voltage, a pressure like quantity, is a measure of electromotive force necessary to maintain a flow of electricity on a transmission line. Voltage fluctuations can occur due to variations in electricity demand and to failures on transmission or distribution lines. If the maximum is exceeded, short circuits, radio interference, and noise may occur. Also, transformers and other equipment at the substations and/or customer facilities may be damaged or destroyed. Minimum voltage constraints also exist to prevent inadequate operation of equipment. Voltage on a transmission line tends to "drop" from the sending point to the receiving end. The voltage drop along the ac line is almost directly proportional to the reactive power flows and line reactance. The line reactance increases with the length of the line. Capacitors and inductive reactors are installed, as needed, on lines to control the amount of voltage drop. This is important because voltage levels and current levels determine the power that can be delivered to the customers.

Operating Constraints

The operating constraints of bulk power systems stem primarily from concerns with security and reliability. These concerns are related to maintaining the power flows in the transmission and distribution lines of a network. Power flow patterns redistribute when demands change, when generation patterns change, or when the transmission or distribution system is altered due to a circuit being switched out of service.

When specific facilities frequently experience disturbances which unduly burden other systems, the owners of the facility are required by their Council to take measures to reduce the frequency of the disturbances, and cooperate with other utilities in taking measures to reduce the effects of such disturbances. The Councils have the right to enforce the agreement made within the Council framework.

On August 13, 1996, the amount of electricity transmitted from the Northwest to power hungry California was cut 25 percent to reduce the chances of another blackout similar to the August 10, 1996 event. The reduction amounted to approximately 1,200 megawatts.

4.5.4 Station Blackout

A station blackout is defined as "the complete loss of alternating current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e. loss of the offsite electric power system concurrent with turbine trip and unavailability of the onsite emergency ac power system)." Because many of the safety systems required for reactor core cooling, decay heat removal, and containment heat removal depend on ac power, the consequences of station blackout could be severe. In 1975, the Reactor Safety Study (WASH-1400) demonstrated that station blackout could be an important contributor to the total risk from nuclear power plant accidents.

This potential increase of risk, combined with increasing indications that onsite emergency power sources (diesel generators in most cases) were experiencing higher than expected failure rates, led the NRC to designate "Station Blackout" as an unresolved safety issue (USI). USI A-44 was established in 1979 and the task action plan that followed concentrated on the analysis of the frequency and duration of loss of offsite power events, and the probability of failure of onsite emergency ac power sources. Other areas of interest included the availability and reliability of decay heat removal systems which are independent of ac power, and the ability to restore offsite power before normal decay heat removal equipment (equipment that relies on ac power) failed due to harsh environment. If the results of the study and analyses demonstrated that the likelihood of a station blackout was significant, then the conclusions would be used as a basis for additional rule making and required design changes as necessary to protect the public health and safety. If safety improvements were indeed necessary, it would be more feasible to identify and initiate improvements with onsite power sources than with either offsite power sources or onsite equipment that required ac power to function. Offsite power source reliability is dependent on several factors such as regional grid stability, potential for severe weather conditions and utility capabilities to restore lost power, all of which are difficult to control. Ultimately, the ability of a plant to withstand a station blackout depends upon the decay heat removal systems, components, instruments, and controls that are independent of ac power. The results of the "Station Blackout" study were published in NUREG-1032.

NUREG-1032 divides loss of offsite power operational experiences into three types:

- plant centered events which had an impact on the availability of offsite power,
- grid blackouts or perturbations which had an impact on the availability of offsite power, and
- weather related and other events which had an impact on the availability of offsite power.

4.5.5 Plant Response

The immediate consequences of a station blackout are not severe unless they are accompanied by an accident such as a loss of coolant accident. If the condition continues for a prolonged period, the potential consequences to the plant and public health and safety can be serious. The combination of core damage and containment overpressurization could lead to significant offsite releases of fission products. Any design basis accident in conjunction with a station blackout reduces the time until core damage and release will occur.

Without systems designed to operate independently of ac power, the only way to mitigate the consequences of a station blackout is to take steps to minimize the loss of reactor vessel inventory and quickly restore electrical power to replenish the lost inventory. This will ensure the ability to remove decay heat from the core and prevent fuel damage. The primary method available to mitigate a station blackout with current plant design features is to initiate a controlled cooldown of the reactor. This evolution is covered in the existing Emergency Procedure Guidelines.

4.5.6 Interim Response by NRC

Interest over loss of all ac power (station blackout) intensified in mid-1980 following license hearings for the operation of the St. Lucie Unit 2 plant in southern Florida. The concern was that with the plant being located in an area subject to periodic severe weather conditions (hurricanes) and questionable grid stability, the probability of a loss of offsite power would be much higher than normal. The Atomic Safety and Licensing Appeal Board (ASLAB) concluded that station blackout should be considered a design basis event for St. Lucie Unit 2. Since the task action plan for USI A-44 was expected to take a considerable amount of time to study the station blackout question, the ASLAB recommended that plants having a station blackout likelihood comparable to that of St. Lucie be required to ensure that they are equipped and their operators are properly trained to cope with the event. NRR changed the construction permit of St. Lucie Unit 2 to include station blackout in the design basis and required Unit 1 to modify its design even though preliminary studies showed that the probability of a station blackout at St. Lucie was not significantly different than for any other plant. Interim steps were taken by NRR to ensure other operating plants were equipped to cope with a station blackout until final recommendations were formulated regarding USI A-44.

Recommendations for improvements to the emergency diesel generators had already been established based on studies of DG reliability (NUREG/CR-0660) and were being implemented for plants currently being licensed. A program for implementing those recommendations at operating reactors was developed, including Technical Specifications improvements. It was recognized that improvements to DG reliability was the most controllable factor affecting the likelihood of a station blackout and could only serve to reduce the probability of occurrence. Generic Letter 81-04 was issued to all operating reactors which required licensees to verify the adequacy of or develop emergency procedures and operator training to better enable plants to cope with a station blackout. Included would be utilization of existing equipment and guidance to expedite restoration of power from either onsite or offsite.

4.5.7 Regulation Changes

Based on information developed following the issuance of USI A-44, a proposed change to NRC regulations and regulatory guidance was published in March 1986 for comment. The rule change consisted of a definition of "station blackout” and changes to 10CFR50.63 which would require that all nuclear power plants be capable of coping with a station blackout for some specified period of time. The time period would be plant specific and would depend on the existing capabilities of the plant as well as a comparison of the individual plant design with factors that have been identified as the main contributors to the risk of core melt resulting from a loss of all ac power. These factors include the redundancy and reliability of onsite emergency ac power sources, frequency of loss of offsite power and the probable time needed to restore offsite power.

With the adoption of 10CFR 50.63, all licensees and applicants are required to assess the capability of their plants to cope with a station blackout and have procedures and training in place to mitigate such an event. Plants are also required to cope with a specified minimum duration station blackout selected on a plant specific basis. In addition, Regulatory Guide 1.155 provides guidance on maintaining a high level of reliability for emergency diesel generators, developing procedures and training to restore offsite and onsite emergency ac power and selecting a plant specific minimum duration for station blackout capability to comply with the proposed amendment. A time duration of either 4 or 8 hours would be designated depending on the specific plant design and site related characteristics.

4.5.8 BWR Application

To assess station blackout, BWRs have been divided into two functionally different classes: (1) those that use isolation condensers for decay heat removal but do not have makeup capability independent of ac power (BWR-2 and 3 designs), and (2) those with a reactor core isolation cooling (RCIC) system and either a high pressure coolant injection (HPCI) system or high pressure core spray (HPCS) system with a dedicated diesel, either of which is adequate to remove decay heat from the core and control water inventory in the reactor vessel, independent of ac power (BWR-4, 5, and 6 designs).

The isolation condenser BWR has functional characteristics somewhat like that of a PWR during a station blackout in that normal make up to the reactor is lost along with the residual heat removal (RHR) system. The isolation condenser is essentially a passive system that is actuated by opening a condensate return valve. The isolation condenser transfers decay heat by natural circulation.

The shell side of the condenser is supplied with water from a diesel driven pump. However, replenishment of the existing reservoir of water in the isolation condenser is not required until 1 or 2 hours after actuation. It is also possible to remove decay heat from this type of BWR by depressurizing the primary system and using a special connection from a fire water pump to provide reactor coolant makeup. This alternative would require greater operator involvement. Some BWR-3 designs may have installed a RCIC system, thus providing reactor makeup to the already ac power independent decay heat removal function of the isolation condenser cooling system.

A large source of uncontrolled primary coolant leakage will limit the time the isolation condenser cooling system can be effective. If no source of makeup is provided, the core will eventually become uncovered. A stuck open relief valve or reactor coolant recirculation pump seal leak are potential sources for such leakage. When isolation condenser cooling has been established, the need to maintain the operability of such support systems as compressed air and dc power is less for this type of BWR than it is for a PWR. However, these systems would eventually be needed to recover from the transient.

BWRs can establish decay heat removal by discharging steam to the suppression pool through relief valves and by making up lost coolant to the reactor vessel with RCIC and HPCI or HPCS. In these BWR designs, decay heat is not discharged to the environment, but is stored in the suppression pool. Long term heat removal is by the suppression pool cooling mode of the residual heat removal system. The duration of time that the core can be adequately cooled and covered is determined, in part, by the maximum suppression pool temperature for which successful operation of decay heat removal systems can be ensured during a station blackout event and when ac power is recovered.

At high suppression pool temperatures (around 200 degrees 0F) unstable condensation loads may cause loss of suppression pool integrity. Another suppression pool limitation to be considered is the qualification temperature of the RCIC and HPCI pumps which are used during recirculation. Suppression pool temperatures may also be limited by net positive suction head (NPSH) requirements of the pumps in the systems required to effect recovery once ac power is restored.

All light water reactor designs have the ability to remove decay heat for some period of time. The time depends on the capabilities and availability of support systems such as sources of makeup water, compressed air, and dc power supplies. Also considered is degradation of components as a result of environmental conditions that arise when heating, ventilation and air conditioning (HVAC) systems are not operating. System capabilities and capacities are normally set so the system can provide its safety function during the spectrum of design basis accidents and anticipated operational transients, which does not include station blackout.

Perhaps the most important support system for the plant is the dc power system. During a station blackout, unless special emergency systems are provided, the battery charging capability is lost. Therefore, the capability of the dc system to provide instrumentation and control power can significantly restrict the time that the plant is able to cope with a station blackout. Dc power systems are generally designed to provide specific load carrying capacity in the event of a design basis accident with battery charging unavailable. However, dc system loads required for decay heat removal during a total loss of ac power are somewhat less than the expected design basis accident loads. Therefore, most dc power systems in operation today have the capacity to last longer during a station blackout than during a design basis accident.

Actions necessary to operate systems during a station blackout would not be routine. The operator would have less information and operational flexibility than is normally available during most other transients requiring a reactor cooldown.

In BWRs, the isolation condenser appears to need less operator attention than RCIC and HPCI systems. However, operators would have to insure that automatic depressurization does not occur and that makeup to the isolation condenser is available within approximately 2 hours after the loss of ac power. In BWRs with HPCI or HPCS and RCIC, the operator must control both reactor pressure and level. This may require simultaneous actuation of relief and makeup systems.

4.5.9 Accident Sequence

Figure 4.5-4, taken from NUREG-1032, shows a BWR Mark I containment station blackout accident sequence progression. In this scenario, station blackout occurs at time zero (to). The reactor coolant system pressure and level are initially maintained within limits by RCIC and/or HPCI and relief valve actuation. The suppression pool and drywell temperatures begin to rise slowly; the latter is more affected by natural convection heat transport from hot metal (vessel and piping) of the primary system. After 1 hour, because ac power restoration is not expected, the operator begins a controlled depressurization of the primary system to about 100 psi. This causes a reduction in reactor coolant temperature from about 550°F to 350°F, which will reduce the heat load to the drywell as primary system metal components are also cooled. The suppression pool temperature increase is slightly faster than it would have been without depressurization. Drywell pressure is also slowly increasing. At about 6 hours (t1), dc power supplies are depleted and HPCI and RCIC are no longer operable. Primary coolant heatup follows, which increases pressure and level to the SRV setpoint. Continued core heatup causes release of steam. This eventually depletes primary coolant inventory to the point that the core is uncovered approximately 2 hours after loss of makeup (t2). Core temperature then begins to rise rapidly, resulting in core melt and vessel penetration within another 2 or 3 hours (t3). During the core melt phase, containment pressure and temperature rise considerably so that containment failure occurs nearly coincident with vessel penetration, either by loss of electrical penetration integrity (shown at t4) or by containment overpressure after high pressure core melt ejection, around 11 hours into the accident.

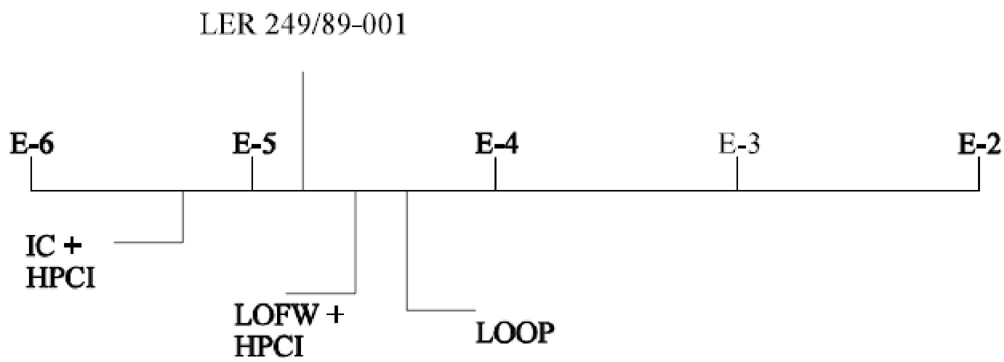
4.5.10 General Containment Information

The BWR Mark I and Mark II containments offer some pressure suppression capability during a station blackout accident, but after a core melt, they may fail by one of two modes. Either mechanical or electrical fixtures in the penetrations will fail because they are not designed for the pressure and temperature that will follow or ultimately, overpressure and subsequent rupture of the containment will occur. Because these containments are generally inerted, hydrogen burn is not considered a likely failure mode. Mark III containments are low pressure, large volume containments, and failure is estimated to result primarily due to over pressurization.

4.5.11 PRA Insights

Plant staffs have typically considered the low probability of numerous failures occurring at the same time as an incredible situation. However, the two examples that follow illustrate that multiple failures have existed simultaneously at licensed facilities.

On March 25, 1989, Dresden Unit 3 experienced a loss of offsite power. The plant also lost both divisions of low pressure coolant injection (LPCI), instrument air (IA), and one division of the containment cooling water system for over one hour. In addition, the high pressure coolant injection (HPCI) system failed to start due to a partially completed manual initiation sequence. The isolation condenser (IC) was used to provide core cooling and decay heat removal. Water makeup to the IC was provided by the condensate system. The relative significance of this event (LER 249/89-001) compared with other postulated events at Dresden is indicated in the diagram below:



Where:

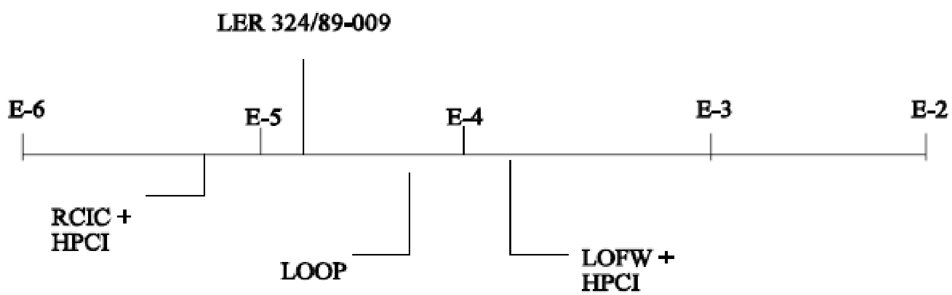
IC	-	isolation condenser
LOFW	-	loss of feedwater
LOOP	-	loss of offsite power

The conditional probability of severe core damage for this event is $1.3X\ 10^{-5}$. The dominant sequence associated with the event (highlighted on figure 4.5-5), involves simultaneous failures of an SRV to close, HPCI to start, and the operators to depressurize using ADS. Note that the shutdown cooling system for Dresden is separate from LPCI and redundant capability exists for decay heat removal.

On June 17, 1989, Brunswick 2 experienced a loss of offsite power. The control room previously received a ground fault annunciator alarm on the Standby Auxiliary Transformer (SAT) and had called the transmission system maintenance team to initiate repairs. The plant recirculation pumps were being powered from the SAT per procedure to minimize pump seal failure caused by frequent tripping of the recirculation pumps.

The operators had started a planned power reduction when a technician shorted out the transformer, which caused a loss of the SAT and eventually a dual recirculation pump trip. The operator manually scrammed the reactor in accordance with procedures. A dual recirculation pump trip requires the plant to be manually scrammed if the trip results in operation in the region of instability outlined in NRCB 88-07. The plant scram caused a loss of the unit auxiliary transformer and the loss of offsite power. While attempting to place the unit in cold shutdown, the outboard RHR injection valve was discovered stuck in the closed position. It was later determined that the valve disk had separated from the stem.

The conditional probability of severe core damage for this event is $3.6X10^{-5}$. The dominant accident sequence (figure 4.5-6) involves failure to recover offsite power in the short term, coupled with loss of emergency power and battery depletion. It should be noted that if PRA had been considered prior to working on the SAT, the plant staff could have identified that transferring pump power to the unit auxiliary transformer would have been highly beneficial. The relative significance of this event (LER 324/89-009) compared with other postulated events at Brunswick is indicated in the diagram below:



4.5.12 Risk Reduction

The process of developing a probabilistic model of a nuclear power plant involves the combination of many individual events (initiators, hardware failures, operator errors, etc.) into accident sequences and eventually into an estimate of the total frequency of core damage. After development, such models can also be used to assess the importance of individual events. Detailed studies have been analyzed using several event importance measures.

One such measure is the risk reduction importance measure. The risk reduction importance measure is used to assess the change in core damage frequency as a result of setting the probability of an event to zero. Using this measurement, the following individual events at Grand Gulf were found to cause the greatest reduction in core damage frequency if their probabilities were set to zero:

- Loss of offsite initiating event. The core damage frequency would be reduced by 95 percent.

- Failure to restore offsite power in one hour. The core damage frequency would be reduced by approximately 70 percent.
- Failure to repair hardware faults of diesel generator in one hour. The core damage frequency would be reduced by approximately 46 percent.
- Failure of the diesel generator to start. The core damage frequency would be reduced by approximately 23 to 32 percent.
- Common cause failures to the vital batteries. The core damage frequency would be reduced by approximately 20 percent.

4.5.13 Summary

Station Blackout is one of the largest contributors to core damage frequency at BWRs. At all light water reactors, operators have to be prepared to deal with the effects of a loss of and restoration of ac power to plant controls, instrumentation, and equipment. Although loss of all ac power is a remote possibility, it is necessary to address the problem both in training of personnel and equipment design. Extensive studies are being conducted to find ways of better understanding and coping with the effects of a total loss of ac power.

BWRs have such a large number of motor driven injection systems that a loss of electrical power implies loss of injection capability. This is why station blackout is consistently identified by PRAs to be the dominant core melt precursor for BWRs.

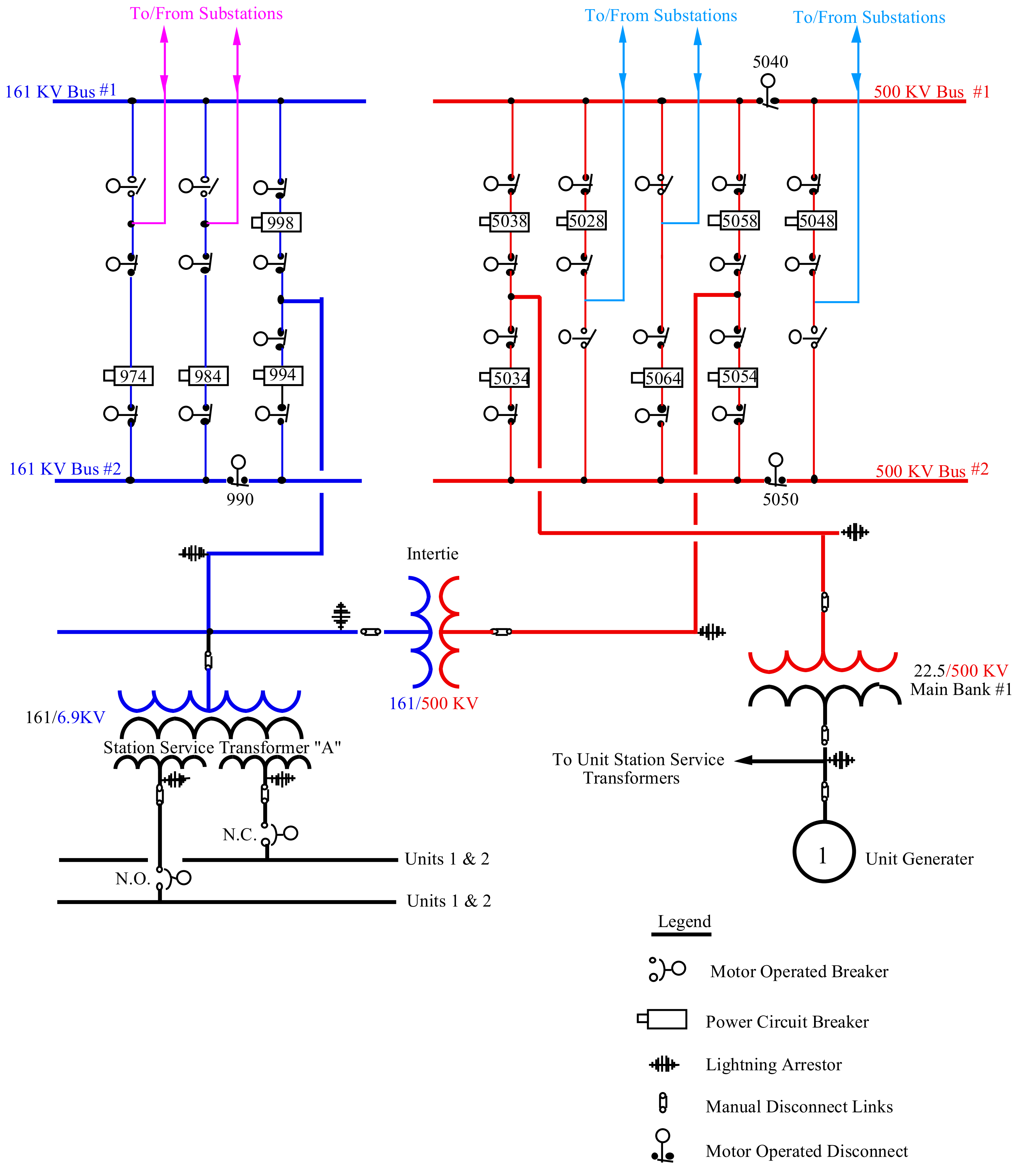


Figure 4.5-1 Offsite Power Distribution

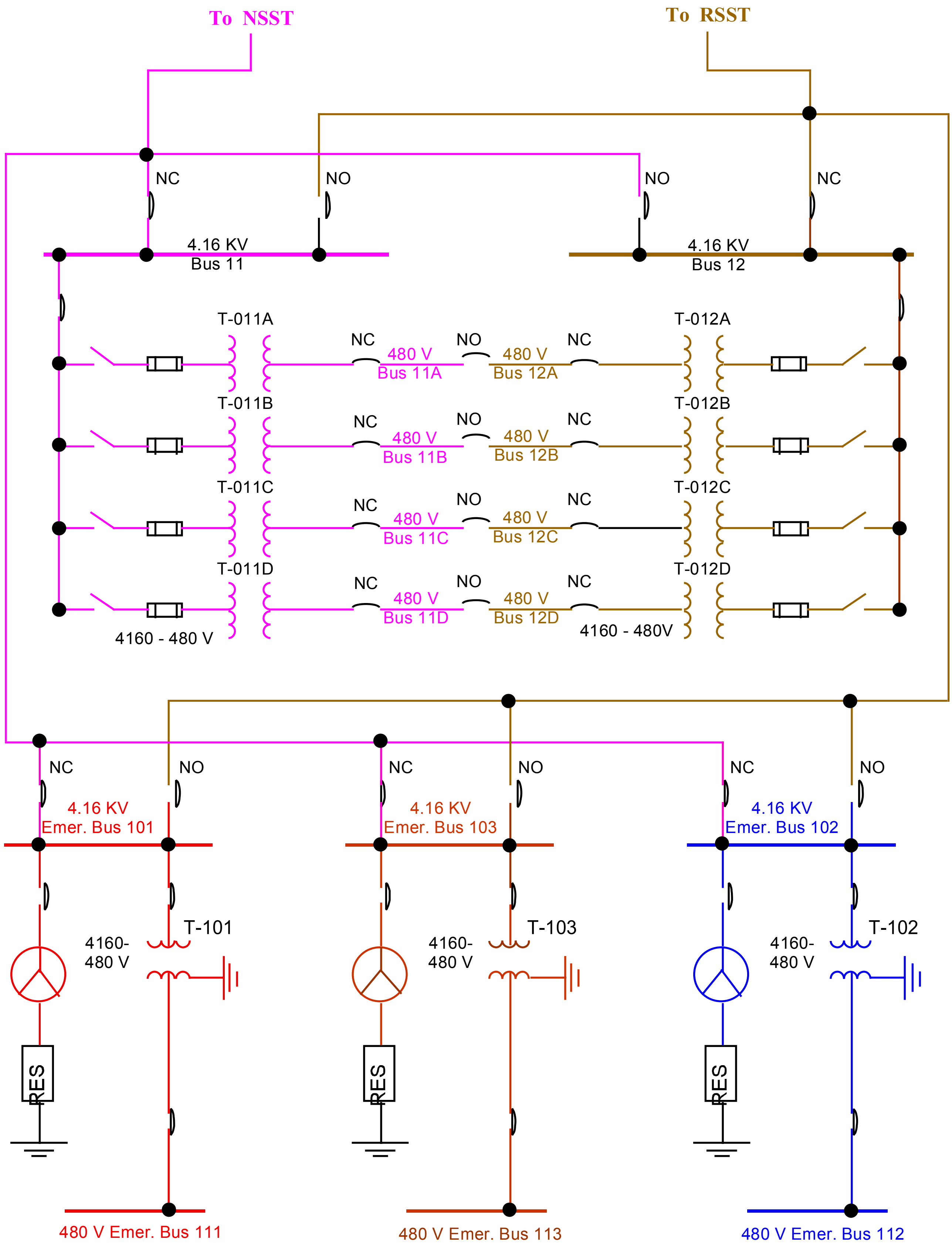
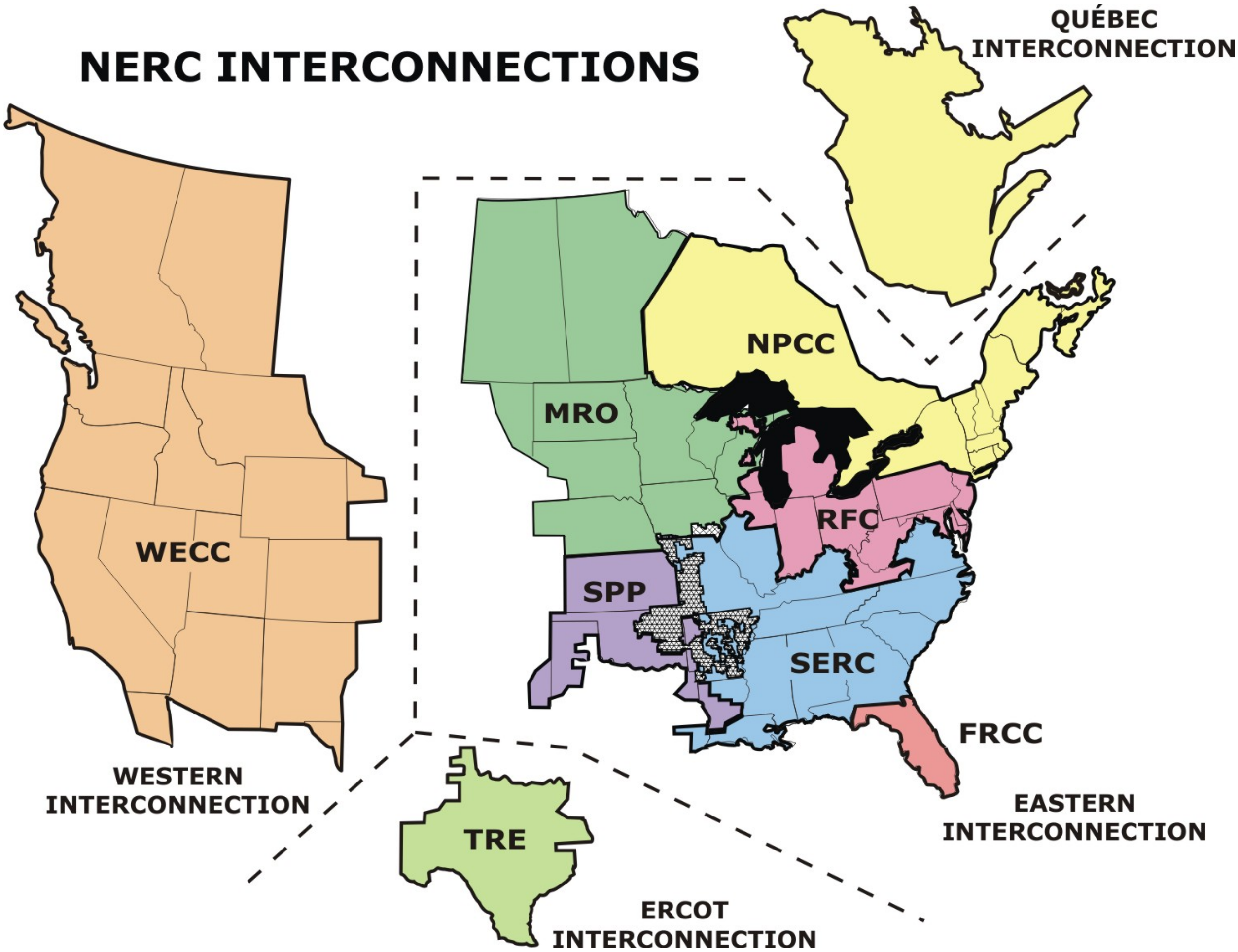
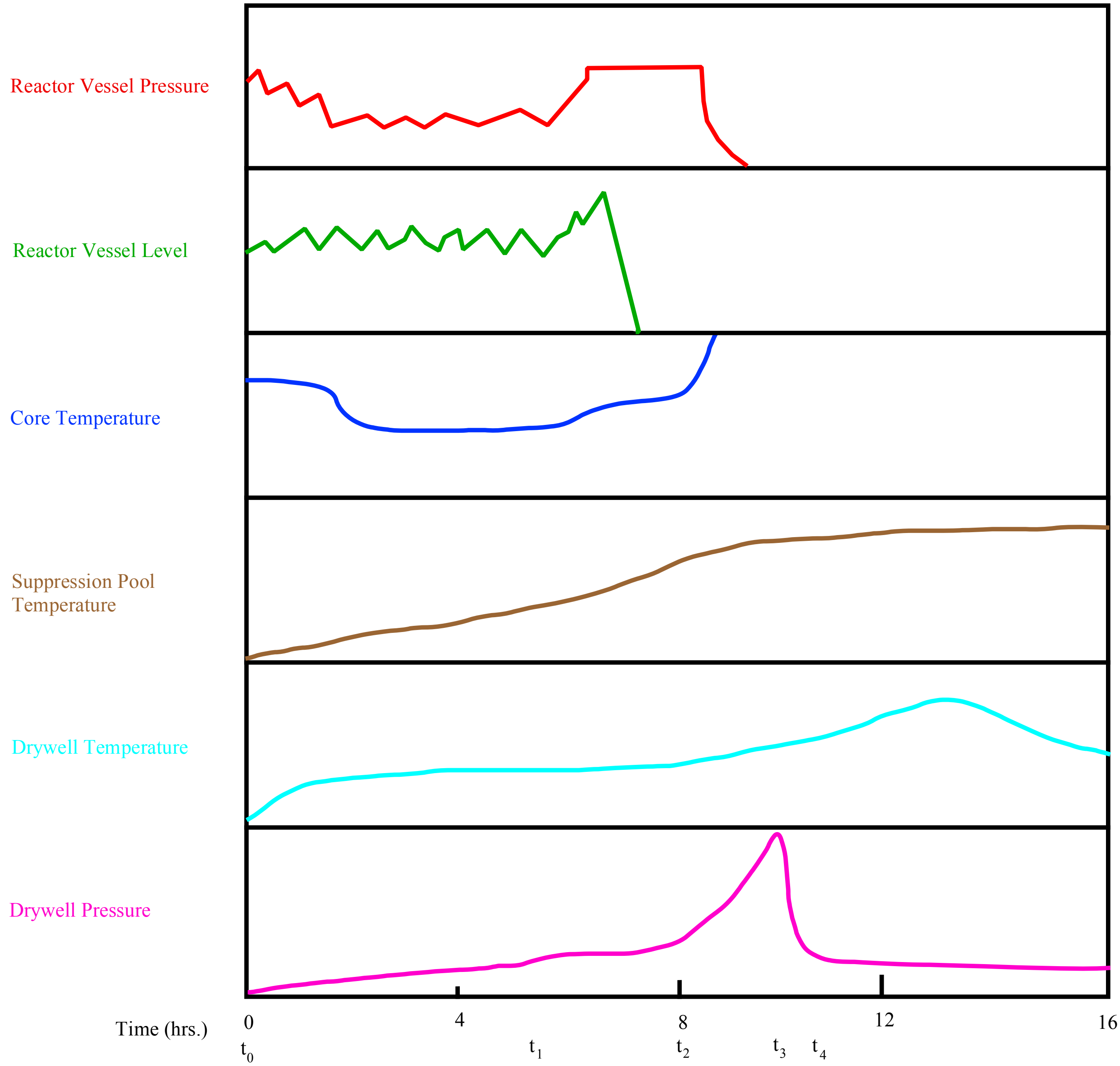


Figure 4.5-2 Emergency AC Power System



Council	Generating Capacity (MW) 2010	Nuclear Capacity(MW)	Nuclear % of total.
FRCC – Florida Reliability Coordinating Council	48,122	3,902	8.1
MRO – Midwest Reliability Organization	54,034	4,176	7.7
NPCC – Northeast Power Coordinating Council	76,193	9,867	12.9
RFC – Reliability First Corporation	221,300	32,766	14.8
SERC – SERC Reliability Corporation	252,775	34,964	13.8
SPP – Southwest Power Pool, RE	57,773	1,166	2.0
TRE – Texas Reliability Entity	86,981	5,170	5.9
WECC – Western Electricity Coordinating Council	208,595	9,645	4.6
Total	1,005,773	101,656	10.1

Figure 4.5-3 Member Councils of the North American Electrical Reliability Corporation



Time	Sequence of Events
t_0	Loss of all AC power
t_1	DC power (batteries) depleted
t_2	Core uncovery begins
t_3	Reactor vessel penetration
t_4	Containment failure

Figure 4.5-4 BWR Station Blackout Accident Sequence (Mark I Containment, HPCI, and RCIC)

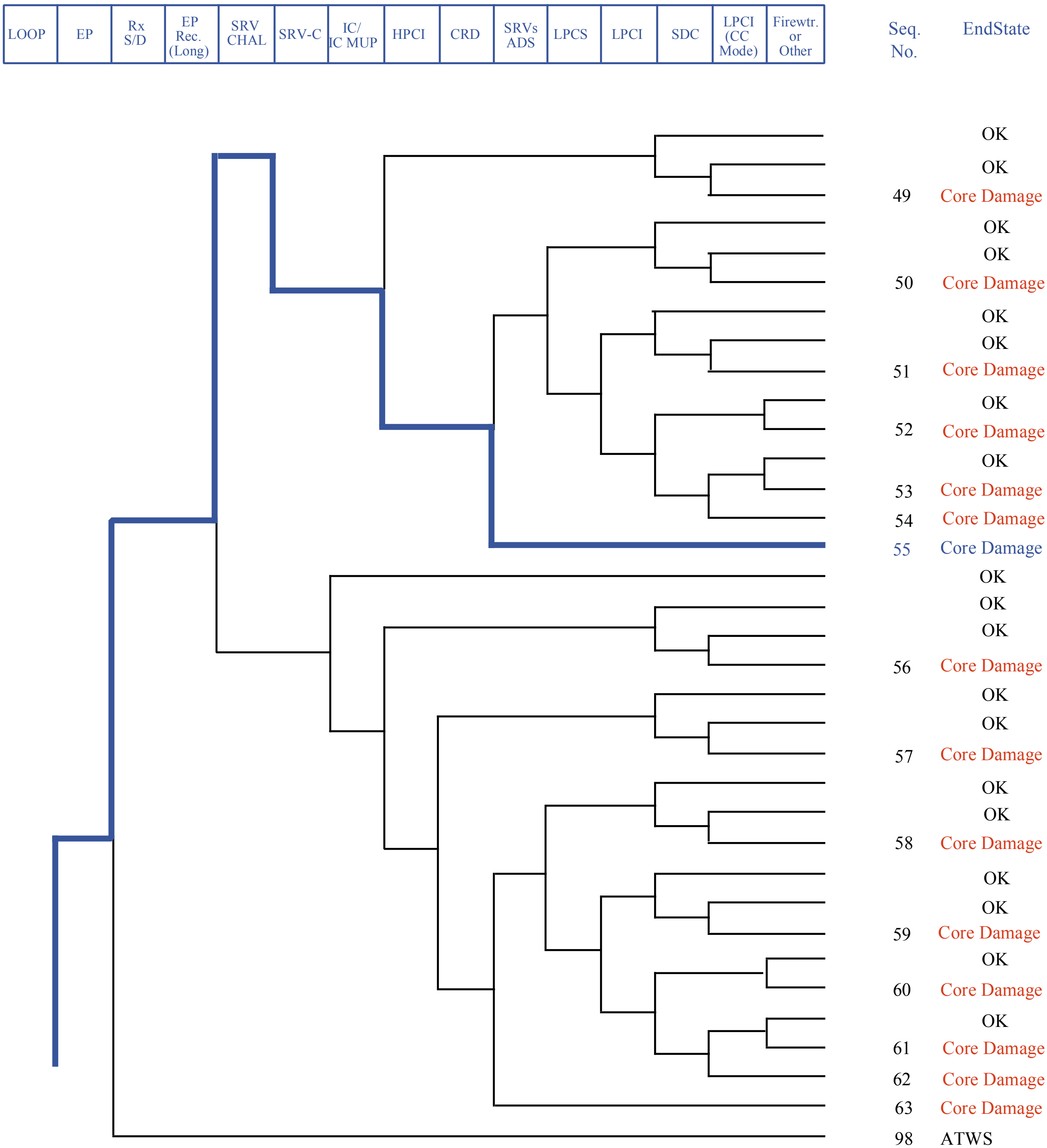


Figure 4.5-5 Dominant core damage sequence for LER 249/89-001 (Dresden 3 with Isolation Condenser)

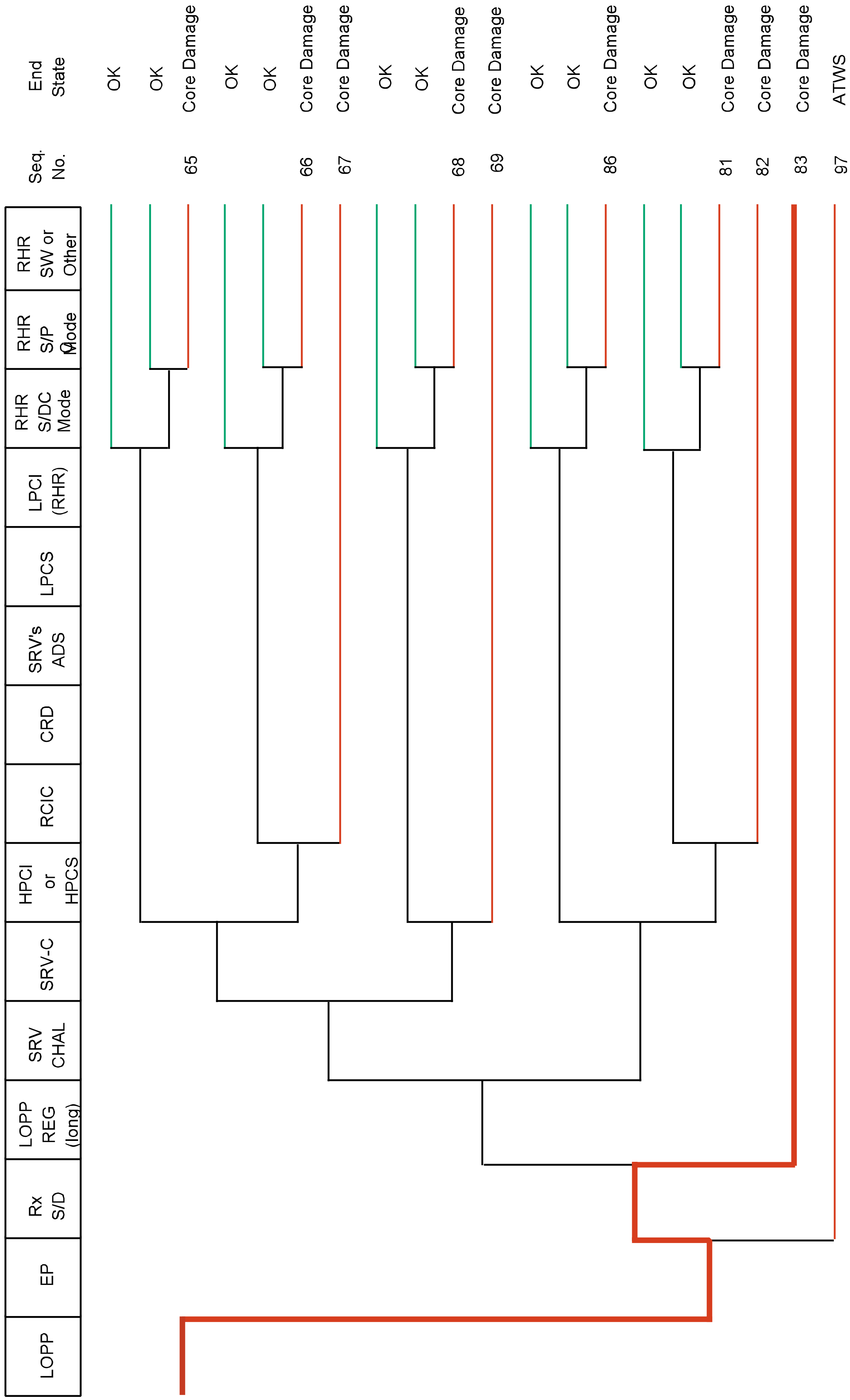


Figure 4.5-6 Dominant Core Damage Sequence for LER 324/89-009