NUCLEAR STATION ELECTRICAL DISTRIBUTION SYSTEMS AND HIGH-ENERGY ARCING FAULT EVENTS

July 2019

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Abstract

High-energy arcing faults (HEAFs) are electrical faults characterized by a rapid release of energy in the form of heat and mechanical force, which can result in fire. Recent events have led the Electric Power Research Institute (EPRI) to investigate HEAF events, with a focus on electrical distribution systems. This report provides an overview of nuclear power station electrical distribution systems and covers fault protection system concepts, fault isolation times, the potential impact of HEAFs on Class 1E electrical distribution systems, and typical industry practices and programs that help ensure proper operation.

Executive Summary

This report provides an overview of nuclear power plant electrical distribution systems, including a description of the system, types of components, protective devices, the role of selective coordination, and overcurrent protection. *High-energy arcing fault (HEAF)* and *unit-connected design* are defined. Fault interrupting (or isolation) times are examined, and expected fault durations are identified. Examples of non-arcing short circuit fault and a HEAF isolation times are provided. Situations where an arcing fault is not isolated by the first, or primary, circuit breaker are covered, including the situation where the fault current magnitude is below that of the instantaneous overcurrent setting. The report includes observations from HEAF operating experience that pertain to electrical distribution systems. Electrical distribution system designs used by nuclear power plants are identified and grouped. How these designs might be impacted by various HEAF scenarios is explained, and common electrical distribution system maintenance and testing practices are identified.

Operating experience has revealed that a main generator can feed a HEAF for several seconds following a unit trip if a fault originates in the unit-connected design. This is a design in many fossil and nuclear plants that do not use a generator breaker that can isolate the energy source (main generator) from the fault during generator coast-down before the voltage collapses. Appendix A summarizes an actual generator-fed fault event that lasted for approximately 6 seconds. The appendix provides graphical representation from the digital fault recorder of the main generator voltage decay and response to changes in the arcing current (load) as the generator voltage decays during coast-down.

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We also know from operating experience that arc faults can arise, and, when combined with any latent issue with the nearby protective device or switchgear (such as a breaker malfunction), they can escalate an event to the point where significant high-energy damage can occur. A strong preventive maintenance (PM) and test program is an important element in preventing HEAF events.

A selectively coordinated protection system ensures that the nearest circuit protective device to a fault (for example, a breaker or fuse) completely isolates the fault without relying on any other upstream protective device, and that it does not unnecessarily remove power to non-faulted parts of the system.

According to data from the Organization for Economic Cooperation and Development, 46 of 48 HEAF events were associated with equipment maintenance. In addition, a review of the Electric Power Research Institute (EPRI) Fire Events Database shows that the most prevalent cause of failure is inadequate maintenance. A strong electrical distribution system maintenance and testing program is an effective way to help prevent and/or mitigate the impact of a HEAF. These practices include circuit breaker maintenance, bus transfer testing, relay testing, inspection and testing of bolted bus bar and other electrical connections, and cable monitoring. Based on operating experience, properly maintained and functional fast bus transfer schemes are particularly important. HEAFs can be prevented by ensuring that both current-carrying and protective equipment is fully functional by performing appropriate PM according to established schedules.

The EPRI report *Characterization of Testing and Event Experience for High-Energy Arcing Fault Events* (3002011922), a companion white paper, reviews industry events and recent testing.

An additional EPRI report issued in 2019 *Critical Maintenance Insights on Preventing High-Energy Arcing Faults* (3002015459) communicates the critical insights for HEAF prevention.

Introduction

The objectives of this report are as follows:

- To provide an overview of typical nuclear power station electrical distribution systems (EDS), with the focus on components and topics pertinent to high-energy arcing faults (HEAFs)
- To present EDS fault protection concepts and fault isolation times, including examples
- To characterize potential HEAF events that are of the greatest concern with respect to EDS and the propensity to cause major damage
- To review industry operating experience to identify lessons learned from the perspective of the EDS
- To explore the potential impact of HEAFs on Class 1E EDS. For specific designs, the report addresses the potential consequences of a HEAF event, as well as the susceptibility of the design to a HEAF
- To describe typical industry system practices and programs that help ensure that EDS operate properly to prevent or mitigate the impact of HEAFs

The scope of this report is HEAFs within medium-voltage (1,000-V to 35,000-V) EDS in nuclear power plants. The report concerns itself more with direct damage from the HEAF than the byproduct (such as fire), which is the subject of the Electric Power Research Institute (EPRI) white paper, *Characterization of Testing and Event Experience for High-Energy Arcing Fault Events* (3002011922). Low-voltage systems are not covered because most operating history of interest involve a high or a medium voltage.

Glossary

arcing fault current. A fault current flowing through an electrical arc plasma, also called *arc fault current* and *arc current* [1].

arc flash. The light and heat produced from an electrical arc supplied with sufficient electrical energy to cause substantial damage, harm, fire, or injury. An arcing fault results when current flows through air between ungrounded conductors (phase-to-phase fault) or between ungrounded conductors and grounded conductors (phase-to-ground fault). An arcing fault can release, in a small fraction of a second, tremendous amounts of concentrated radiant energy at the point of the arcing, resulting in temperatures that can reach 19,427°C (35,000°F).

auxiliary transformer (AT). The transformer that steps down voltage from the main generator to the plant auxiliary power EDS during power operation. Unless a generator breaker is installed, it is typically de-energized during shutdown (but may be used in maintenance backfeed operation in limited cases). A unit might use one or two ATs per generator. The AT is part of the unit-connected design, with the primary side integrated with the iso-phase bus duct system. The AT can be a two-winding or three-winding

transformer (with secondary and tertiary windings). Some nuclear power plants will power Class 1E buses from the AT during power operation. It is also referred to as *unit auxiliary transformer (UAT)*.

available fault current. The electrical current that can be provided by the serving utility and facility-owned electrical generating devices and large electric motors, considering the amount of impedance in the current path [1].

barrier. According to IEEE 384-1974 [2], a device or structure interposed between Class 1E equipment or circuits and a potential source of damage to limit damage to Class 1E systems to an acceptable level. An enclosed raceway is considered a barrier according to Section 5.1 of IEEE 384-1974.

bolted fault current. A short circuit or electrical contact between two conductors at different potentials in which the impedance or resistance between the conductors is essentially zero [1].

Class 1E. A term used by the U.S. nuclear industry to specify safety-related equipment according to IEEE Std 308, *IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations*, and the safety classification of the electric equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal or are otherwise essential in preventing significant release of radioactive material to the environment [2].

fault current. A current that flows from one conductor to ground or to another conductor due to an abnormal connection (including an arc) between the two conductors [1].

generator step-up (GSU) transformer. The transformer that steps up the voltage from the main generator to switchyard voltage to transport the generator power to the grid. A unit can use one, two, or three (single-phase) GSU transformers per generator. The GSU is part of the unit-connected design, with the low-voltage side integrated with the iso-phase bus duct system. It is also referred to as the *main power transformer*.

high-energy arcing fault (HEAF). A term characterized by an electrical fault with a rapid release of energy in the form of heat and mechanical force, which could result in a fire. HEAF events are generally characterized by two distinct hazards, as described in the following by electrical codes, standards, and literature (National Fire Protection Association [NFPA] 70E [3] and IEEE 1584 [1]).

radial electrical distribution system. Auxiliary power EDS are primarily radial. Power flows from an incoming high- or medium-voltage source to a load center (or multiple load centers) with parallel branch circuits that ultimately power a single load, either directly or after cascading down through additional switchgear, motor control centers (MCC), and/or panels. Radial systems also use transformers to transform higher-voltage systems to low voltage for smaller loads. IEEE standards 141, 242, and 241 provide additional detail on industrial radial power systems.

ring bus electrical distribution system. A ring bus is typically used for intermediate distribution from a transmission switchyard to the plant radial auxiliary EDS. It is a full-loop system and typically has multiple sources (transmission lines and/or a generator). A fault anywhere in the ring bus results in two devices opening to isolate the fault so that the remaining sources and loads remain in service. Manual isolating switches are installed on each side of the automatic device to allow maintenance to be performed safely and without interruption of service.

station transformer (ST). This transformer steps down switchyard offsite power to the voltage levels used by the plant EDS. It may feed an intermediate medium-voltage ring bus with an additional transformer. The ST is not permanently part of the unit-connected design, but typically part of the bus transfer scheme associated with the AT. The ST might be a two-winding or three-winding transformer (with secondary and tertiary windings). Some nuclear power plants permanently power Class 1E buses from a pair of STs with no connection to the unit ATs. It is also referred to as a *station auxiliary transformer*, *station service transformer*, *startup transformer*, or *reserve auxiliary transformer*.

unit-connected design. A term referring to the operational configuration of the (1) main generator, (2) GSU transformer, (3) generator output switchyard breakers, (4) AT, and (5) associated buses and connections, with no generator circuit breaker and therefore no backup circuit breaker(s) to isolate a generator-fed fault if (i) an AT secondary side bus breaker failed to open (that is, stuck) or is slow to open or (ii) a fault exists between the generator and GSU transformer, or anywhere in the AT to the first secondary or tertiary bus supply circuit breakers. The associated bus and connections include the following:

- An iso-phase bus that connects the main generator to the low side of the GSU transformer and high side of the AT

- A non-segregated bus that typically connects the AT secondary and tertiary windings to the bus supply breakers
- High-voltage connections between the high side of the GSU transformer to the generator output switchyard breakers

Note: In addition to individual component protection (such as generator, GSU transformer), the unit-connected design typically has its own unit-differential protection (main generator, GSU transformer, iso-phase bus duct, yard breakers, and associated aerial wires). This unit-differential protection scheme ensures that all unit-connected components (except the AT) are tripped and locked out (protective device 86) for a fault anywhere in the unit-connected design up to the primary side of the AT.

Electrical Distribution Systems

This section contains a brief overview of plant electrical distribution systems, with a focus on components and topics pertinent to HEAFs.

Description

A nuclear electric power generating station's (plant's) EDS is designed with the necessary alternating current (ac) power to operate safety systems in the event of an accident, to maintain core cooling, and to safely shut down the plant. Consequently, EDS and their protection are essential to the safe and reliable operation of nuclear plants.

Nuclear station EDS consist primarily of electrical buses, transformers, switchgear, circuit breakers, switches, and cables designed to distribute ac power throughout the plant. Electrical switchgear is an assembly of devices that include the internal bus-work, circuit breakers, instrument transformers, protective relays, meters, and auxiliary control.

Figures 1 and 2 show a protective relay and medium-voltage switchgear, respectively, which are a part of the EDS.

Nuclear station EDS and their associated protection systems are similar to non-nuclear or industrial distribution systems. The systems and components are designed and constructed using many of the same industry standards (for example, American National Standards Institute [ANSI] and IEEE standards). A primary difference is that nuclear stations include a secondary level of undervoltage protection to address sustained degraded voltage from offsite utility power (referred to as the *preferred power supply*). This undervoltage protection will not be addressed in this report.

A typical and greatly simplified example diagram of a nuclear power station's EDS is provided in Figure 3.

Voltage Ratings

IEEE 1584 [1] defines *low voltage* as 0–1,000 volts alternating current (Vac) and *medium voltage* as 1,000–35,000 Vac (see Table 1). Nuclear station distribution systems take power from the auxiliary transformer (AT) or station transformers (STs) and convert the voltage to nominal medium voltages typically used at the station.

Large Power Transformers

Nuclear power plants have one or more ATs, STs, and main GSU transformers. Typically, these large power transformers are located outside and include design features such as firewalls to isolate them

Figure 1 – Protective relay

Figure 2 – Medium-voltage switchgear

from each other and plant structures (typically, the plant turbine building). Most ATs and STs (also referred to as the *startup transformer, reserve auxiliary transformer,* or *station auxiliary transformer*) are three-winding transformers. Common electrical distribution arrangements fed from three-winding transformers include the following scenarios.

Scenario 1: Each winding (secondary and tertiary) typically serves one of the following types of configuration:

- Both Class 1E divisions are fed from one winding and the balance-of-plant (BOP) bus(es) from the other winding.
- Each winding serves a non-Class 1E bus that, in turn, feeds a Class 1E bus.
- Each winding serves a parallel Class 1E bus and non-Class 1E bus (with their own dedicated source feeder breakers).
- Each winding serves a dedicated Class 1E bus that contains both Class 1E and non-Class 1E loads. The non-Class 1E loads are connected with a Class 1E breaker that opens upon a safety-injection signal.

Table 1 – Voltage ratings

Term	Voltage (Vac)
High voltage	Greater than 35,000
Medium voltage	>1,000–35,000
Low voltage	0–1000

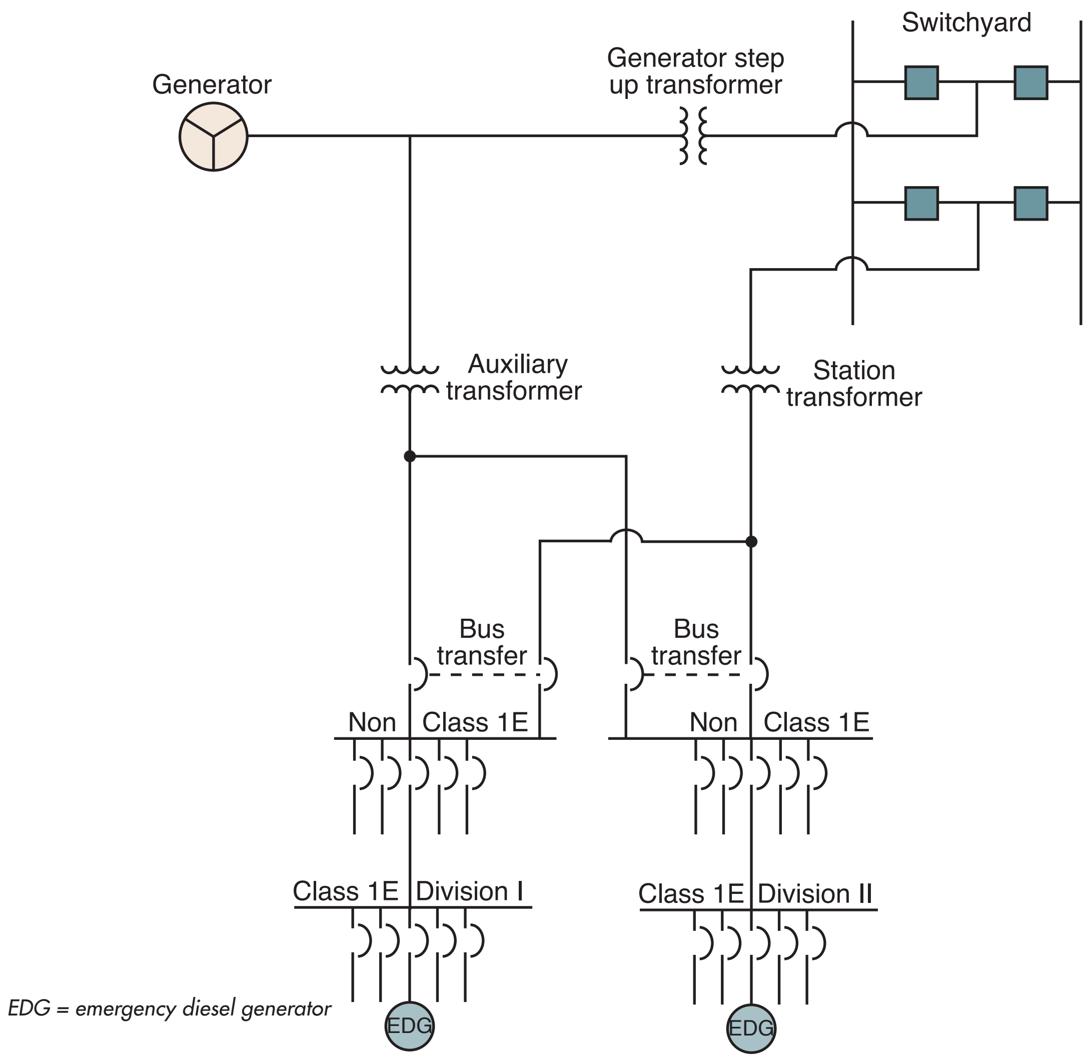

Figure 3 – A simplified example of a one-line diagram for an electrical distribution system

Scenario 2: If multiple transformers exist, the secondary and tertiary windings can be of the same voltage level or different voltage levels and serve one BOP bus and one division of a safety-related (Class 1E) bus.

When the station is not producing power, offsite power is provided to the plant through the ST.

A few designs have generator breakers that are located between the main generator and the AT and GSU transformers. One key design feature to note is that if there is no generator breaker, there is typically only one circuit breaker between the AT and the medium-voltage distribution buses located in the turbine building. This design configuration is called a *unit-connected design*, which is defined in the glossary of this report.

Switchgear

Medium-voltage electrical switchgear is used to distribute ac power throughout the plant. Switchgear is typically a metal-clad assembly of components that include an electrical bus, circuit breakers, protective equipment, metering (potential and current transformers), instrumentation, auxiliary control, barriers, and associated equipment. The primary switchgear subcomponents, such as the circuit breaker, buses, and current transformers, are enclosed in grounded metal compartments, as shown in Figure 4.

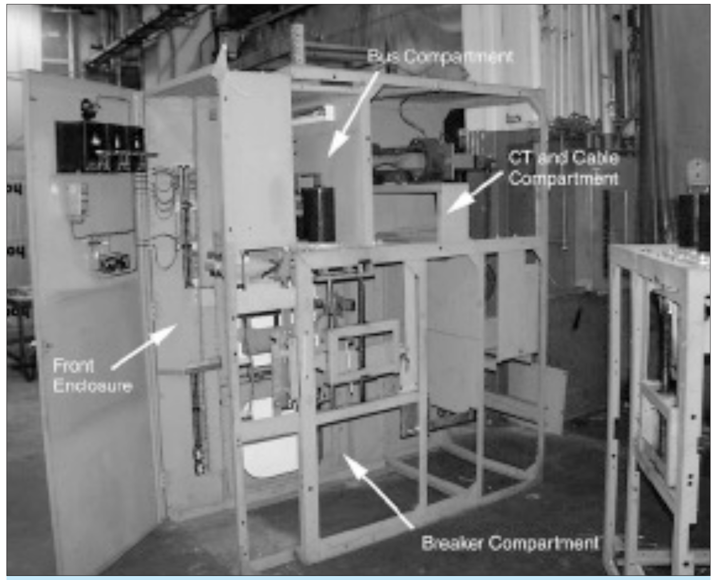

Figure 4 – 4160-Vac switchgear cubicle with the metal cladding (exterior covers) removed

Overcurrent Protection

Critical plant EDS elements require protection from two major types of overcurrent conditions: short circuits and overloads. Short circuits (including shorts to ground, shorts between phases, or a combination thereof) result in abnormal current several orders of magnitude above the normal current (200%–1000% higher than the normal current). Overloads (abnormal condition with end-device, such as mechanical binding or bearing failure or improper system lineup) result in current above normal levels (115%–200% higher than the normal current) but well below typical fault current levels.

Protective relays are used to protect against the previously described overcurrent conditions, including the following:

- Instantaneous overcurrent (protective device, type 50): a device used to clear high-level faults with no intentional time delay; these devices are set to isolate the minimum levels of short circuit current while avoiding severe damage.
- Time-overcurrent (protective device, type 51): a device with inverse time-current characteristics used to clear faults below the instantaneous trip region; these devices insert an intentional time delay in proportion to the fault current level to give other downstream protective devices an opportunity to clear the fault first, that is, selective electrical coordination.
- Differential (protective device, type 87): a device that is designed to monitor a defined zone of the EDS and immediately actuate if it senses a mismatch between current flowing into the zone and flowing out of the zone.
- Thermal overload (protective device, type 49): a device with inverse time-current characteristics used to detect overload conditions (low-level abnormal current) and initiate an alarm or trip of the affected equipment. Type 51 devices can also perform this function.

Short circuits are the failure mode of concern that can lead to HEAFs. Overloads do not immediately manifest themselves as HEAFs; rather, they typically result in localized equipment damage (such as motor damage and premature cable aging). It is noted, however, that an overload condition can ultimately lead to a short circuit if it is allowed to persist long enough that equipment failure occurs.

Distribution system elements that require overcurrent protection typically include transformers, cables, bus ducts, switchgear (bus), MCC, and loads (such as motors).

Current transformers sense the amount of current and transmit this information to protective devices (relays). When the setting on the protective device (relay) has been exceeded, the device sends a signal to protect the system, which typically opens one or more circuit breakers to isolate the faulted equipment.

Protective device types 50 and 51 are the most common. However, differential protection (protective device, type 87) is often used for major equipment, for example, generators, large transformers, major buses, and unit protection. This type of protection generally reaches out to the switchyard. IEEE and ANSI standards provide the criteria on how to establish overcurrent protective schemes, including selection and setting of overcurrent devices to balance reliable protection against nuisance tripping.

A more complete list of different types of protection is provided in the next paragraph. Items in the list are typical for nuclear power EDS, but the list is not all-inclusive. It is noted that not all schemes are used; rather, a combination can be used, depending on the EDS design layout, up to and including the transmission switchyard connection.

The types of protection include the following:

- Phase overcurrent (instantaneous and time overcurrent) relays (device 50/51)
- Differential overcurrent relays (device 87)
- Ground overvoltage relays (device 59G)
- Voltage or current balance relays (device 60)
- Unit differential
- Ground or zero-sequence relays (device 50G or 51G); may include various schemes (ground-differential relaying, ground overcurrent)
- Breaker failure scheme (stuck breaker after 10–12 cycles); not typically used in medium-voltage systems but does exist in nuclear power plant transmission protection systems that tie in offsite power startup or reserve transformer high-side breakers
- For wye transformer fed switchgear: (1) ground overcurrent (solid, low impedance, high impedance) where a resistance or impedance grounding scheme can be used to limit phase-to-ground faults to nondestructive levels or (2) ground-fault protection

Short-Circuit Current Ratings, Interrupting Ratings

As described in IEEE standards and references, the progression of a short-circuit event can be best broken down into the following three distinct regions (see Figure 5):

- Instantaneous region (typically referred to as *momentary, close and latch,* or *half-cycle*)
- Interrupting region (typically referred to as *three-to-eight cycle*)
- Steady-state region (typically, 30 cycles)

HEAFs can be associated with the first two regions of short-circuit fault events, as described in the next section. However, the longer-duration destructive HEAFs also involve the third short-circuit region.

Instantaneous

This is the first half-cycle of short-circuit current. It is the highest instantaneous "peak" current due to the inherent inductance of the distribution system, characterized as a direct current (dc) offset, typically as much as 1.6 times the peak ac. The ac component is also the highest due to generator and/or motor contribution. This is typically referred to as the *asymmetrical fault current*.

Power circuit breakers are not fast enough to interrupt at the first half-cycle; however, they must be able to mechanically withstand the resultant magnetic forces to the breaker to prevent damage. This has been referred to by some standards as the *momentary* or *close and latch rating*. *Close and latch* refers to a breaker's ability to withstand closing into a three-phase bolted fault, to fully latch in the closed position, and subsequently to open without being damaged.

The electrical bus within the switchgear and bus ducts must also be "braced" for this half-cycle, "momentary" current so that it can mechanically withstand the high magnetic forces. The withstand ability is provided by the switchgear or bus duct manufacturer. A typical rating for medium-voltage switchgear is 350 MVA (symmetrical).

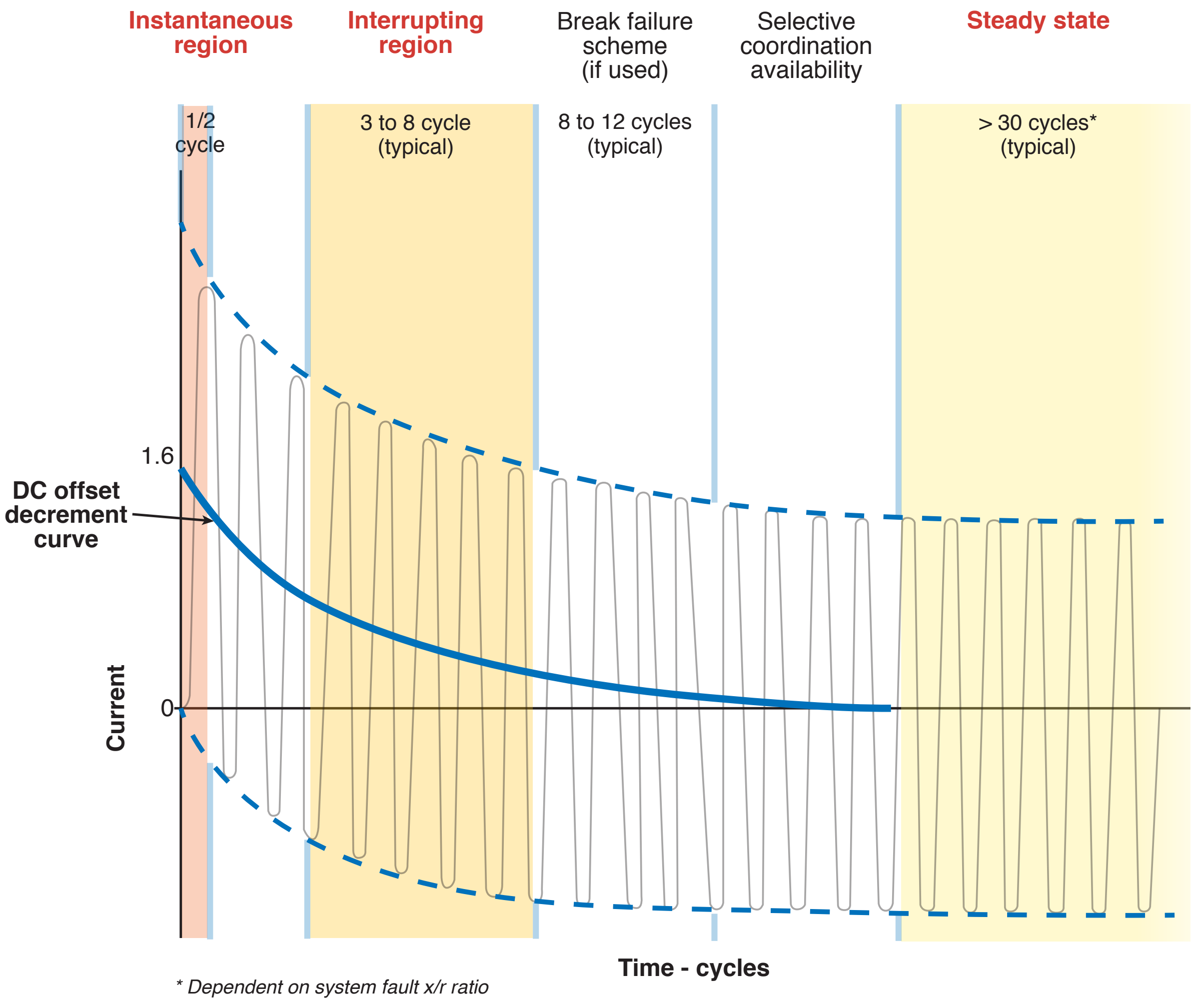

Figure 5 – Three regions of a typical short circuit

Some current-limiting fuses can interrupt this current (within their region of operation) to limit the let-through current; however, they are rarely used in medium-voltage switchgear applications at nuclear plants.

For a bolted fault event, this short-circuit region is associated with the maximum mechanical forces. Equipment must be mechanically braced to withstand these forces until fault current decays to the second short-circuit region, where fault interrupt occurs. If equipment is inadequately braced, a HEAF can rapidly escalate due to the equipment arrangement, resulting in significant physical damage to the equipment itself and surrounding equipment (including damaging the breaker intended to interrupt the fault).

Interrupting

After the half-cycle period, short-circuit current begins to decay as dc offset current starts decreasing. In the interrupting region, dc offset current has decreased from its initial half-cycle value; however, some asymmetrical current remains. From approximately three to eight cycles, the circuit breaker will interrupt the fault current (given no intentional relay time delay). The interrupting rating of a circuit breaker is less than the momentary withstand rating because of the short-circuit decay previously explained. This rating, however, is aimed at a different capability. When a breaker opens, it draws an arc as the contacts part. This arc is directed into arc chutes that extinguish the arc. This rating establishes the maximum voltage and current that the breaker is designed to interrupt.

In a HEAF event, this short-circuit region is the thermal high-energy release phase. The circuit breaker must be adequately rated to interrupt the fault, as previously described. If the contact parting time is too slow, or the contact parting distance is not sufficient to extinguish the arc, high energy from the HEAF can persist, causing surrounding equipment to vaporize and melt. This condition can lead to extensive damage and electrical fires.

Steady State

This is the theoretical value after the dc offset current and asymmetrical current have effectively completely decayed; the steady-state current is less than the momentary and interrupting values. This current is also referred to as the *symmetrical fault current* because, in this region, it remains the only significant component of fault current.

This is also a thermal phase—where cables, transformers, and bus bars are thermally limited; if the HEAF persists (for example, the primary circuit breaker has failed), melting, arcing, splattering, and so on continue and significantly increase the likelihood of causing damage beyond the originating switchgear cubicle into other cubicles, overhead cable trays, adjacent equipment, and so forth.

Further information regarding short-circuit calculations, protection, and coordination can be found in IEEE Std. 242-1986, IEEE C37.010-1999, and other related IEEE standards.

Barriers

IEEE 384-1974 [2] defines a *barrier* as a device or structure interposed between Class 1E equipment or circuits and a potential source of damage, with the interposed device or structure designed to limit damage to Class 1E systems to an acceptable level. An enclosed raceway is considered a barrier, according to Section 5.1 of IEEE 384. If a HEAF originates in a Class 1E circuit, the barrier is intended to limit surrounding damage to equipment of the same train or non-safety equipment and prevent the damage from propagating to the redundant Class 1E electrical train.

IEEE C37.20.2 requires that metal-clad switchgear be provided with metal barriers between primary sections of adjacent vertical sections and between major primary sections of each circuit. Primary sections include the bus compartment, the primary entrance compartment, the removable element compartment, the voltage transformer(s) compartment, and the control power transformer(s) compartment. To minimize the possibility of communicating faults between primary sections, the barriers between primary sections are to have no intentional openings.

Selective Coordination

In a radial EDS, a selectively coordinated protection system ensures that (1) the nearest circuit protective device to a fault (such as a breaker or fuse) completely isolates the fault without relying on any other upstream protective device and (2) it does not unnecessarily remove power to non-faulted parts of the system. Figure 6 is a one-line diagram of a system that is selectively coordinated (see Figure 6a) and one that is not selectively coordinated (see Figure 6b).

The protective device immediately between the fault and the power source (Breaker A in Figure 6) is designed to isolate the fault before the next upstream protective device (Breaker B in Figure 6) operates. If, for any reason, the primary protective device (Breaker A in Figure 6) fails to isolate the fault as designed (for example, because of a stuck breaker, slow breaker, relay race, or incorrect setting), the next upstream protective device (Breaker B in Figure 6) is designed to operate. Anytime that the next upstream protective device isolates the fault over that of the primary protective device, the consequences are that the faulted section is exposed to a longer duration of the fault, resulting in potentially increased damage, and an undesired portion of the unfaulted system is isolated (such as isolation of an entire bus or MCC).

Some systems at the medium- and high-voltage levels may use breaker failure schemes solely for backup protection due to a stuck breaker. Typically, these breaker failure schemes operate in approximately 8–12 cycles to give time for the 3- to 8-cycle primary breaker (typical) to clear the fault.

Protective devices can operate as fast as half-cycle (such as current, limiting fuses operating within their region of the current limit); however, most medium-voltage protective devices are circuit breakers using instantaneous elements operating within three to eight cycles (typical). Coordinated protective devices without instantaneous settings use an inverse or extreme inverse time delay, typically set no more than 45 cycles (0.75 seconds) at the full available fault current. Therefore, aggregate system protection (including selective coordination) is typically accomplished in 45 cycles or fewer.

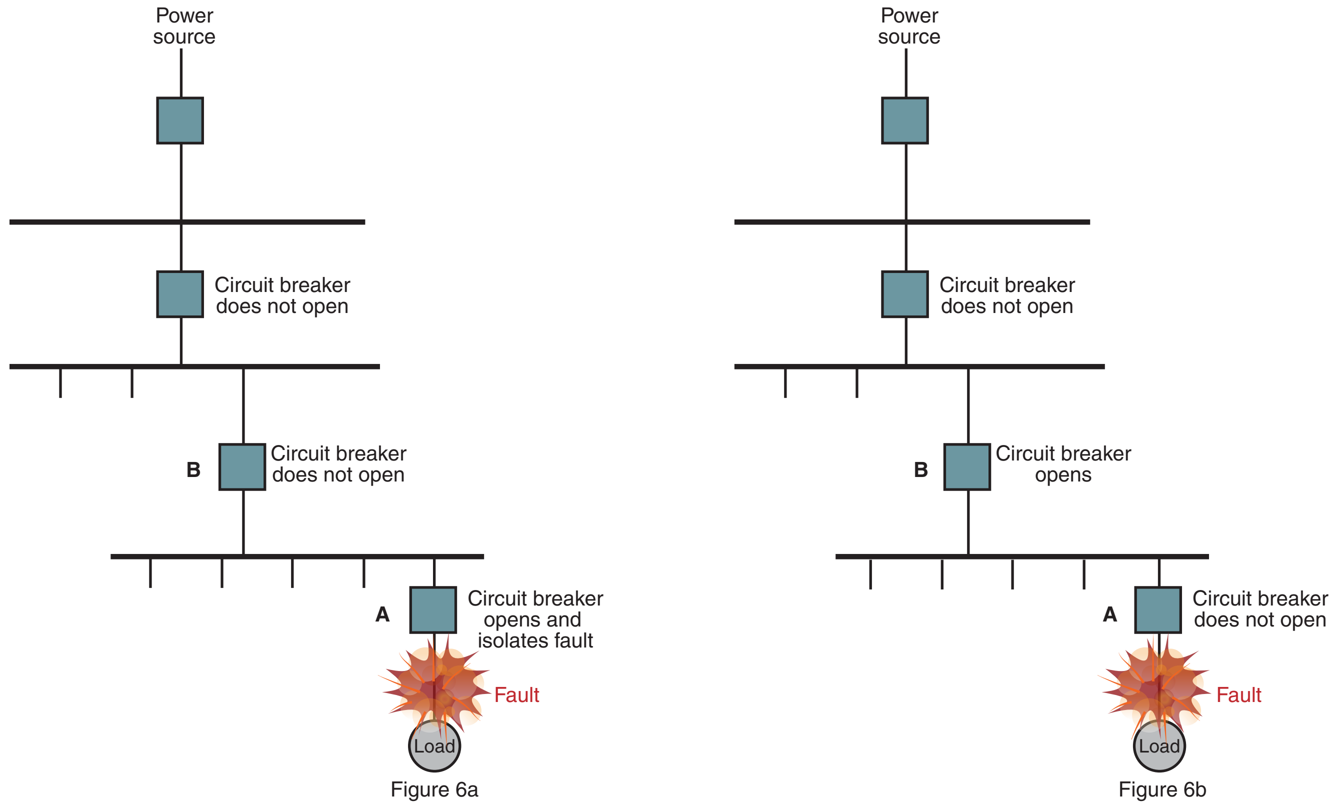

Figure 6 – A selectively coordinated system (6a; left) and a system that is not properly coordinated (6b; right)

Protection and Coordination Objectives

Many of the protective devices used can adjust to operate on the minimum current that will permit them to (1) protect the equipment served and (2) be selective with other series devices. When these two requirements are met, a balance is achieved that supports both rapid fault isolation and minimal disruption to unfaulted portions of the circuit when a short circuit occurs.

Engineering design of selectively coordinated EDS is achieved using graphical analysis of a protective device time-current characteristic curve. The Y-axis is time (log), and the X-axis is current (log). Figure 7 shows an example of a protection and coordination curve. Because protection and coordination are mutual objectives, there are times when one objective cannot be fully met without some sacrifice to the other. When selectivity must be compromised, the sacrifice can be made at the location in the system with the smallest economic and safety consequences. This location varies from system to system.

As an example of compromise, it is desirable for protection of the transformer for both internal and external faults to be as rapid as possible to minimize the damage to large, expensive power transformers. Conversely, this protection might be reduced if selective coordination system design is the overriding objective, which is often the case for smaller, less consequential transformers. In other cases, sacrificing coordination between a transformer primary protection and its secondary main circuit breakers might not be detrimental to system security.

Separation Criteria

Separation criteria applies only to nuclear safety-related, Class 1E systems. Non-Class 1E buses/trains are not required to meet the applicable IEEE standards. For nuclear stations that do not have an intermediate non-Class 1E bus and have only one breaker separating each Class 1E bus from the AT or ST, separation is more critical in containing the electrical fault damage to one Class 1E train.

IEEE Std 384-1974, *IEEE Trial-Use Standard Criteria for Separation of Class 1E Equipment and Circuits* [2], defined the separation requirements for most of the earlier U.S. nuclear power plant safety-related (Class 1E) buses. The IEEE design criterion is that there be physical separation and independence of the circuits and

equipment making up or associated with the Class 1E power systems, Class 1E protection systems, and Class 1E equipment. It sets forth the criteria for the separation of circuits and equipment that are redundant.

Specifically, as related to HEAF events, separation criteria considerations according to IEEE 384-1974 [2] include the following:

- The degree of separation required varies with the potential hazards in a particular area.
- The separation of circuits and equipment should be achieved by the following:
  - Safety class structures
  - Distance
  - Barriers
  - Any combination thereof
- Cable and raceway separation requirements

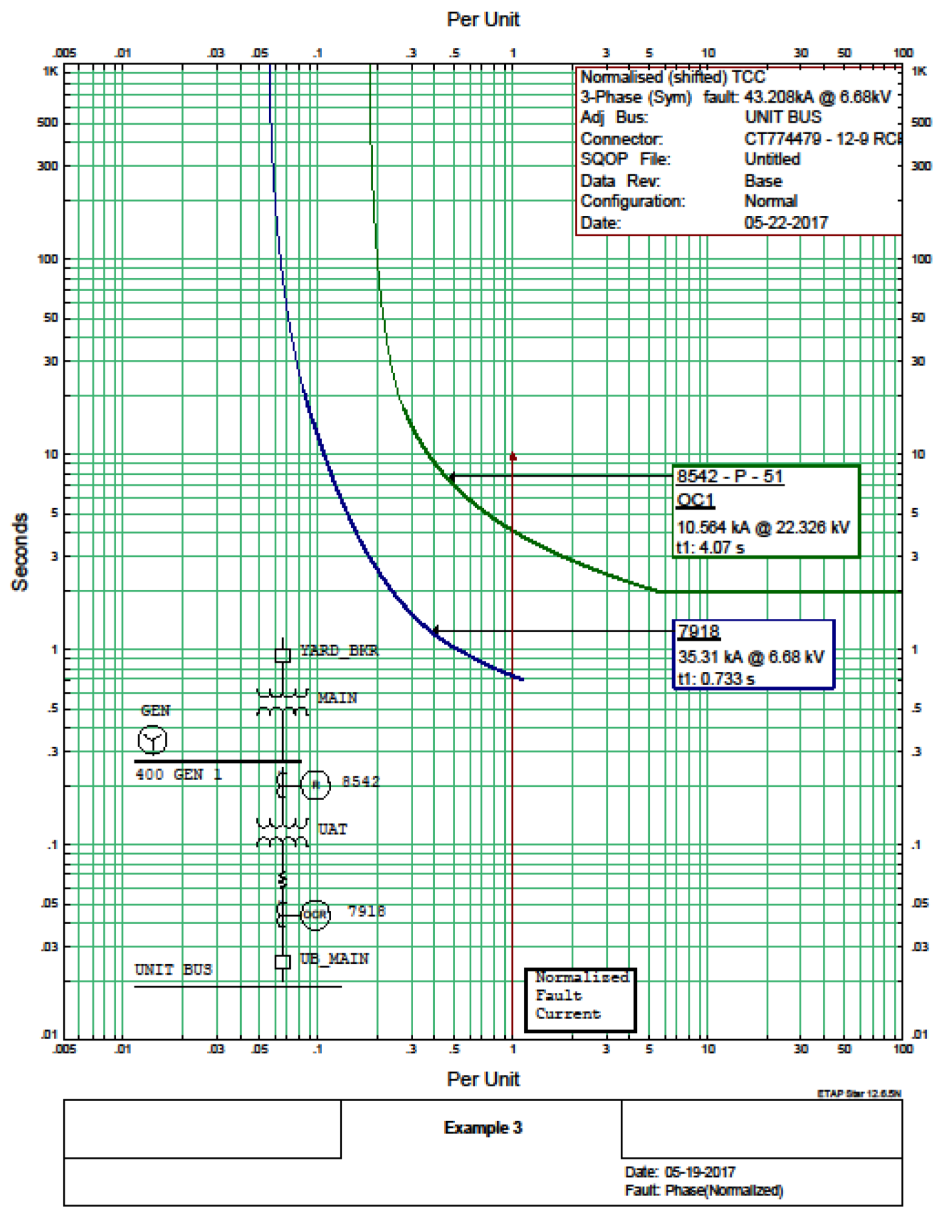

Figure 7 – Example of protection and coordination time-current characteristic curve

- Switchgear: redundant Class 1E distribution switchgear groups should be physically separated in accordance with the requirements of Clause 4 of IEEE Std 384-1974

Additionally, U.S. Nuclear Regulatory Commission (NRC) Regulatory Guide 1.75, Revision 1, *Physical Independence of Electric Systems*, was issued in January 1975 and endorsed IEEE Std 384-1974 with certain exceptions that are listed in Section C, *Regulatory Position*.

Although revisions to both IEEE Std 384 and NRC Regulatory Guide 1.75 have occurred over the years, most U.S. nuclear power plants' Class 1E separation designs followed the 1974 and 1975 documents, respectively.

Fault Isolation Times

This section covers fault isolation times, examples of typical fault isolation times (or expected fault duration times), and two situations when a fault is not isolated by the first (primary) circuit breaker. Figure 8a shows that the time necessary to isolate an electrical fault consists of relay and circuit breaker operating times.

Cycles and Hertz

Short-circuit fault clearing times are typically expressed in cycles. 60 Hz is defined as 60 cycles/second, so the duration of one cycle, shown in Figure 8b, is 1 second/60 cycles = 0.0167 or 16.7 milliseconds.

Expected Fault Duration

The expected interruption of bolted faults by a medium-voltage primary protective device can range from 1 cycle to 10 cycles (0.0167–0.167 seconds) (see Table 2). Protection systems in nuclear power plants are similar to non-nuclear industrial facilities and use a combination of various protection schemes built around the following EDS configurations:

- Wye (resistance or impedance grounded)
- Delta (ungrounded)
- Wye (ungrounded) (not typically found in nuclear power plants)

Some common protective devices and typical clearing times are shown in Table 2.

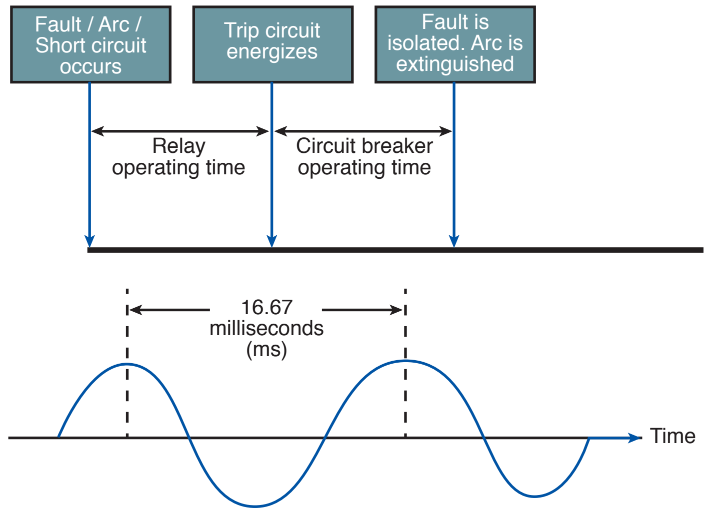

Figure 8 – Time needed to isolate an electrical fault (top; 8a) and a 60-Hz system (bottom; 8b)

Table 2 – Common protective device types and typical clearing times (Reference: Table 41 of IEEE 242-1986, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems" [5].)

Protective Device Type	Constituent Parts and Total	Typical Values (Time in Cycles at 60 Hz)
Induction-style relay-operated breakers (2.4kV–13.8 kV)	Relay time	0.5–2
	Circuit breaker interrupting time	3–8
	Total (relay + breaker)	3.5–10
Medium-voltage and high-voltage fuses	Current limiting range of operation	0.25
	Power fuses	1

Selectively coordinated systems (such as feeder breaker for medium-voltage switchgear that feeds MCCs) typically could take up to 45 cycles to clear if selective coordination is designed into the system (see further discussion on selective coordination).

Fault Isolation Time Examples

Fault isolation times are dependent on where in the system the fault occurs, the maximum available fault current for the location, and whether the fault is isolated by the primary device (that is, the breaker nearest the fault) or a device further upstream in the EDS. Four examples of maximum short-circuit fault isolation times are introduced in the following paragraphs.

Example 1

When a fault is initiated by the failure of an end-device (such as a motor) downstream of a medium-voltage non-Class 1E bus branch circuit breaker, the non-Class 1E branch circuit breaker relay trips with no intentional time delay (3.5–10 cycles). If the non-Class 1E branch circuit breaker fails to open, the non-Class 1E feeder breaker would trip in approximately ¾ of a second (45 cycles), as shown in Figure 9.

Example 2

When a fault is initiated by the failure of the medium-voltage non-Class 1E bus, while the bus is being fed from the ST, the non-Class 1E bus feeder circuit breaker relay trips at ¾ of a second. If the non-Class 1E bus feeder circuit breaker fails to open, the upstream ST secondary circuit breaker would trip in 4½ seconds, as shown in Figure 10.

Example 3

When a fault is initiated by the failure of the medium-voltage non-Class 1E bus, while the bus is being fed from the UAT, the non-Class 1E bus feeder circuit breaker main relay trips in ¾ of a second. If the non-Class 1E bus feeder circuit breaker fails to open, the UAT primary side overcurrent relays would actuate in 4 seconds to trip the upstream switchyard circuit breaker and would attempt to retrip the failed non-Class bus 1E feeder circuit breaker, resulting in a turbine/reactor trip. If the system contains a generator breaker, that breaker would trip as well. See Figure 11.

Example 4

When a fault is initiated by the failure of an end-device (such as a motor) downstream of a medium-voltage Class 1E branch circuit breaker, the Class 1E branch circuit breaker relay trips with no intentional time delay. If the Class 1E branch circuit breaker fails to open, the Class 1E bus feeder circuit breaker would trip in ¼ of a second, as shown in Figure 12.

Fault Isolation If the First Circuit Breaker Does Not Operate

As previously shown in the selective coordination electrical distribution scheme examples, if the primary protective device does not operate, there is a time delay until the next-level, or backup, protective device operates. For faults that persist, this delay results in further damage.

We next consider two situations where an arcing fault is not isolated by the first (primary) circuit breaker—a stuck breaker (breaker does not clear the fault given that the threshold set-point is reached) and an arc fault current magnitude that is below that of the overcurrent setting of the protective device.

Stuck Breaker

A stuck breaker is a latent-passive failure, and a fault is an active failure that reveals the latent stuck breaker failure, which can result in event complications (such as a HEAF). Selective coordination takes a stuck breaker into consideration, as follows.

Given an arcing fault of sufficient magnitude for the protective relay to send a trip signal to its primary breaker (but the breaker failed to operate), the next upstream breaker should clear the fault but with an intentional delay. For a bolted (zero impedance) fault, the delay of the next upstream breaker is typically a few cycles longer than the downstream protective device to allow time for the primary device to clear the fault. If the fault is of an arcing nature, the fault impedance can vary over time and increase as the arc gap widens. In these cases, the delay to clear the arcing fault by the next upstream device can be delayed from several additional cycles to several seconds. In extreme, low-magnitude arcing faults, the delay by the next upstream device could be longer.

The magnitude of the arcing fault will determine how long it takes for the next upstream breaker to clear the fault. If the arc fault magnitude is below the coordinated instantaneous trip setting of the protective device, the time to clear the fault will be extended. This is because the current overload region of the breaker (thermal element) will be required to interrupt the fault. This can extend the fault duration from cycles to several seconds or longer.

Obviously, the longer the duration, the greater the extent of damage due to heat generation (i^2t), given equal fault impedance. Industry operating experience has shown that failed protection and/or damaged breakers can result in electrical faults, which can be accompanied by vaporized and melted buswork.

Arc Fault Magnitude Below Instantaneous Setting

The second situation (arc fault magnitude below setting) is also problematic, and the response of the protection system varies with the type of scheme and arc fault.

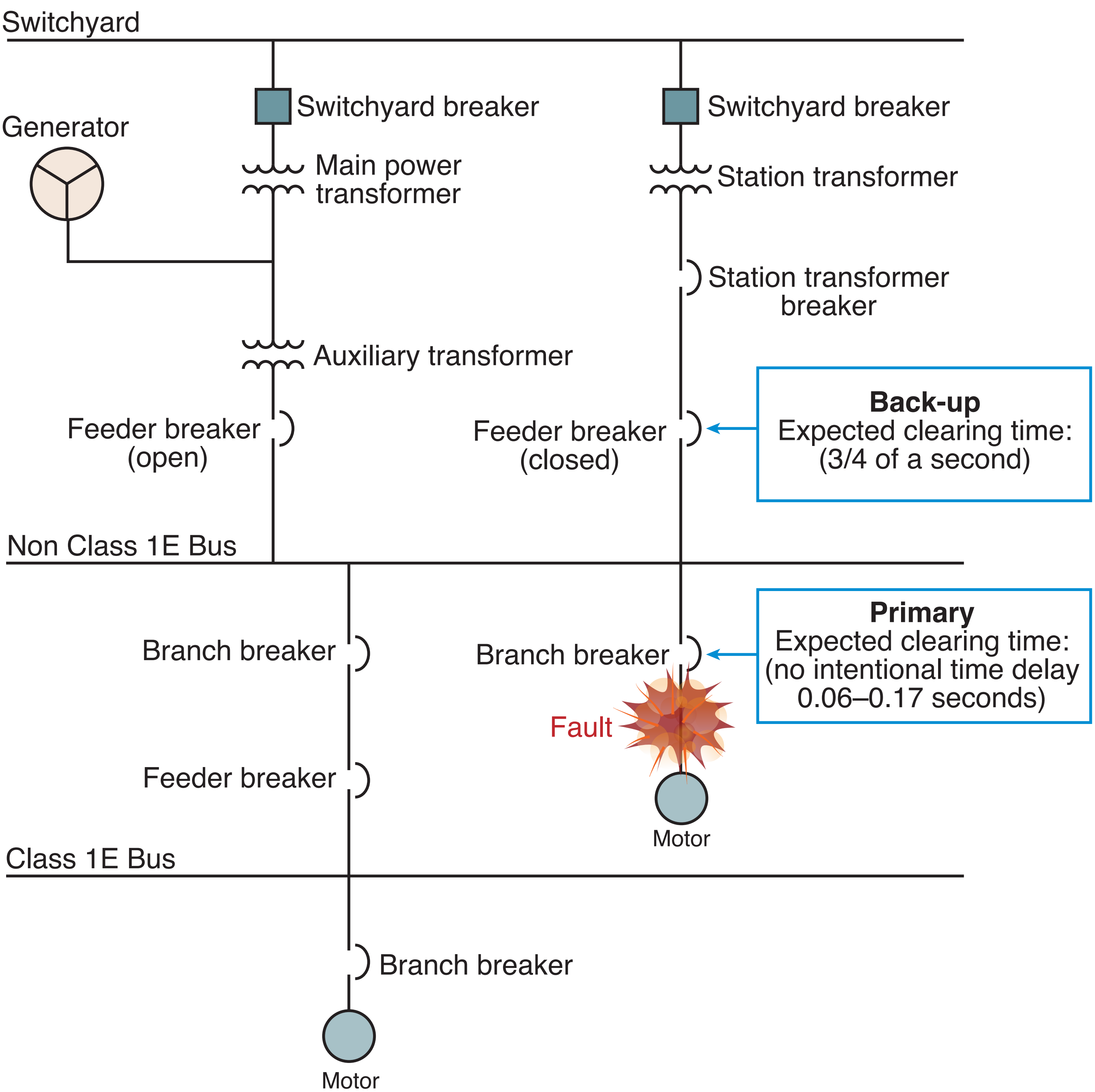

Figure 9 – Example 1: electrical distribution system one-line diagram for fault isolation time

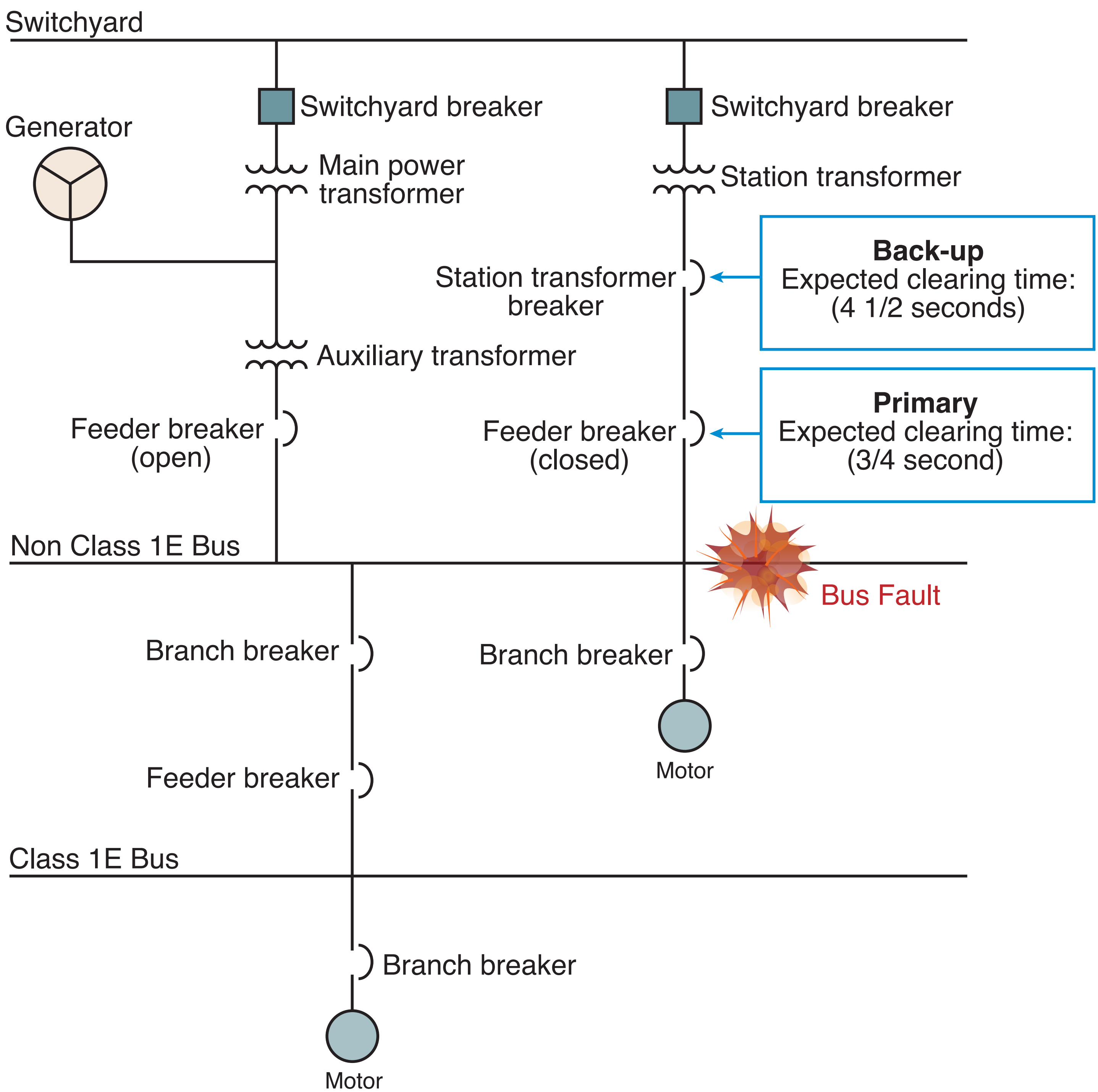

Figure 10 – Example 2: electrical distribution system one-line diagram for fault isolation time

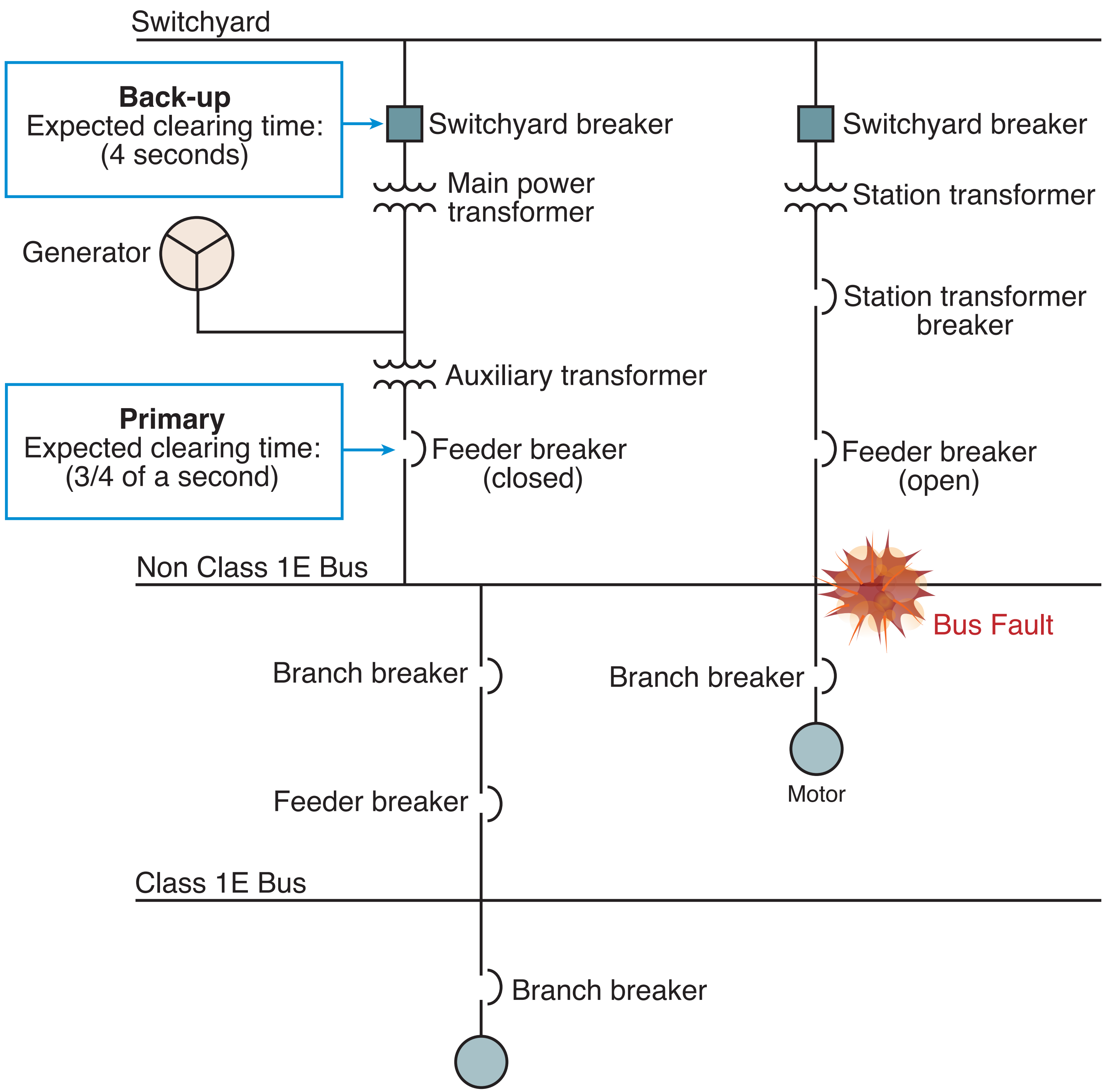

Figure 11 – Example 3: electrical distribution system one-line diagram for fault isolation time

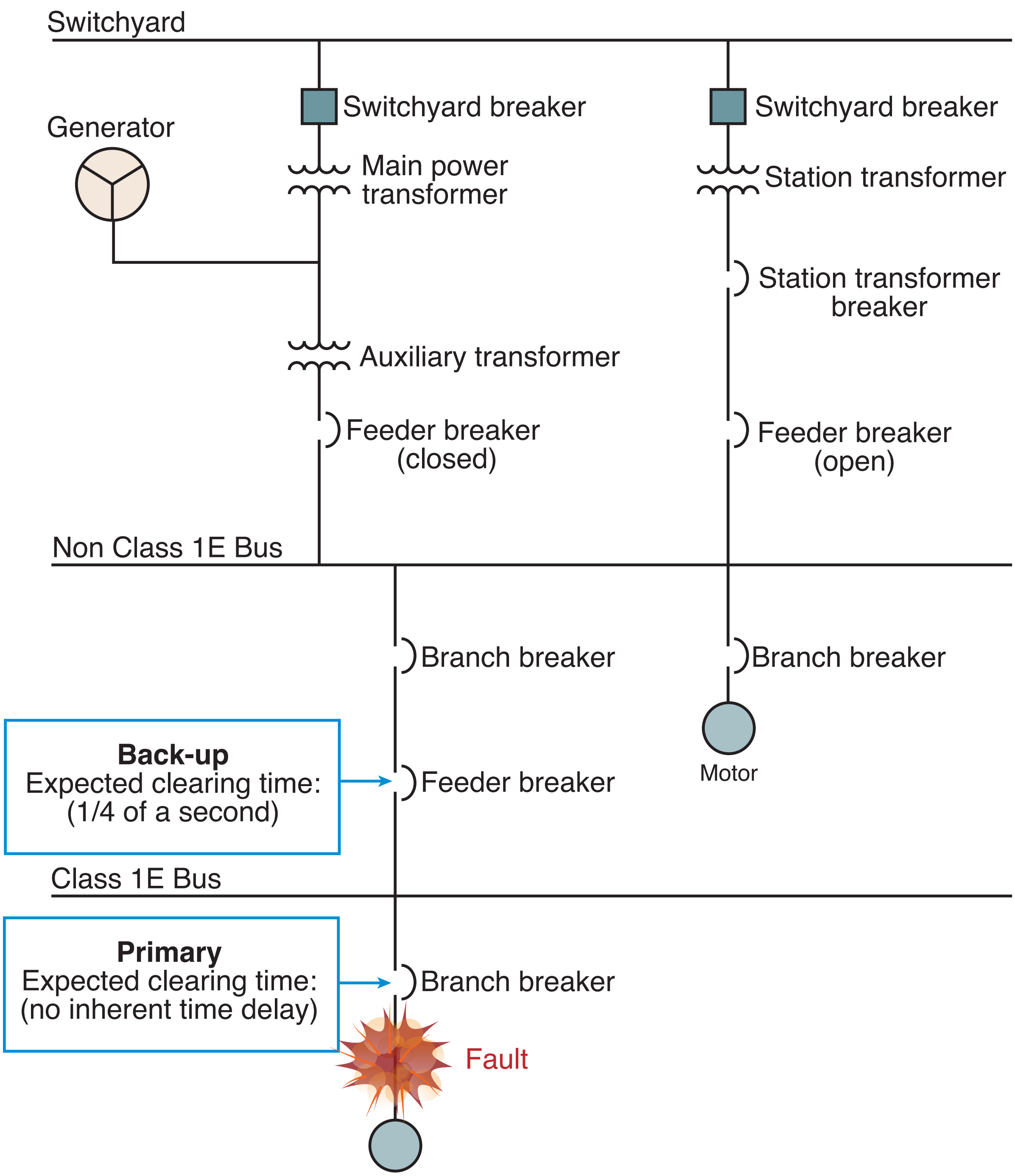

Figure 12 – Example 4: electrical distribution system one-line diagram for fault isolation time

Phase-to-phase arc faults should be rapidly detected and isolated by differential protection schemes. However, differential protection schemes typically are on large transformers, generators, and unit protection schemes. Some medium-voltage buses have bus differential protection schemes, but this is not always the case. An arcing phase-to-phase fault below the instantaneous setting can be expected to last for several seconds before being detected by timed overcurrent element, propagating to ground, isolated by an upstream scheme (taking out more equipment than desired), or self-extinguishing on its own. Depending on the amplitude and duration of the arc, collateral damage might impact several non-Class 1E switchgear and overhead cable trays and potentially one train of Class 1E if downstream of the non-Class 1E system.

Phase-to-ground arc faults should be isolated by differential protection schemes or ground fault schemes. In high-resistance ground schemes, the fault current is typically limited to a few amps and might even be designed to trigger an alarm in lieu of a trip function. Even at lower levels, arcing faults can still inflict damage (such as overheated grounding resistors and a resulting fire). Ideally, all arcing faults should be detected and isolated as soon as practical.

Characteristics of HEAF Events

HEAF event characteristics are discussed in the NRC report, *Operating Experience Assessment Energetic Faults in 4.16 kV to 13.8 kV Switchgear and Bus Ducts That Caused Fires in Nuclear Power Plants* [5] and Nuclear Energy Agency (NEA) NEA/CSNI/R(2013)6, *Organization for Economic Cooperation and Development (OECD) Fire Project—Topical Report No. 1, Analysis of High Energy Arcing Fault (HEAF) Fire Events*, June 2013 [6]. The NRC report covers one HEAF event outside of the United States and five HEAF events within the United States. The NEA report analyzed 48 events from their OECD fire database. HEAF event characteristics identified by these reports include the following:

- Circuit breaker and bus transfer failures, as follows:
  - In most of the U.S. events, the fault was in the first breaker downstream of the AT or ST (auxiliary transformer or start-up transformer)" [5].
  - "Four of the six events took place following a bus transfer and involved a stuck or slow bus supply circuit breaker" [5].
  - "In four of the five U.S. events, the single circuit breaker failed to operate correctly after bus transfer, creating, and in some cases exacerbating, a faulted condition" [5].
- Unit-connected design and faults fed by the generator, as follows:
  - "In 3 of the events, the fault was fed from the generator as the generator field collapsed following generator trip. Following a generator trip, the generator residual voltage continues to energize equipment in the unit connection for several seconds until the generator magnetic flux decays to a small value; and under faulted conditions, the generator current continues to feed the fault until the voltage decays. For large generators like those used at nuclear generating plants, the required interrupting fault capacity of a generator circuit breaker usually makes the application cost prohibitive and the risks associated with unit-connected design are implicitly accepted" [5].
  - "The main generator, AT, main transformer isolated phase bus, and the leads to the circuit breakers are 'unit-connected' (that is, connected to each other without a generator circuit breaker…" [5]. (See the glossary for a definition of unit-connected design.)
  - "The review found plants that are the most vulnerable have two safety buses connected in parallel (similar to Maanshan) to the AT through a single circuit breaker…" [5].

The NRC Operating Experience Assessment report, Appendix A, Table A-1 [5], provides a list of U.S. nuclear plants that have a safety bus configuration similar to Maanshan's (two or more redundant load groups connected in parallel to one source of power) or plants whose safety buses are powered by the AT through a single feeder circuit breaker. Various electrical system designs and their safety bus configurations are discussed further in this report under "System Designs and HEAF Impact."

Although specific ranges for the duration of HEAF events are not provided, it was noted that events that were fed by the main generator lasted for "several seconds." In one instance, the event reportedly lasted for 8 seconds.

Review of Industry Events

This section reviews available industry operating experience and attempts to identify lessons learned from the perspective of the EDS. The review encompassed two sources of data— NEA/CSNI/R(2013)6, *OECD Fire Project—Topical Report No. 1, Analysis of High Energy Arcing Fault (HEAF) Fire Events* [6] and the EPRI Fire Events Database [7, 8] augmented with recent U.S. event experience.

The evaluation showed that according to the OECD data, 46 of 48 HEAF events were associated with equipment failure [6]. A review of the EPRI Fire Events Database shows that the most prevalent

cause of failure is inadequate maintenance [9]. Considering these findings, it is reasonable to conclude that many HEAFs could have been prevented through better equipment maintenance.

A review of OECD data determined that 19 events were located in the switchyard or outside of the plant buildings (outside of the power block), 11 were on low-voltage systems, and 18 were on medium-voltage systems. Of the medium-voltage equipment within the plant (power block), the failures were attributed as follows:

- Switchgear/circuit breakers: 7
- Electrical cabinets or equipment: 6
- Electrical bus: 3
- Cables: 2

EPRI Fire Event Database

EPRI catalogs and classifies U.S. fire event experience to support fire probabilistic risk assessments. These operational data are used to develop fire ignition frequency estimates of nuclear power plant components, including fires in electrical equipment resulting in HEAFs. The review of U.S. HEAF events spanned 37 years of operation and 32 events as analyzed in the EPRI report Characterization of Testing and Event Experience for High-Energy Arcing Fault Events (3002011922) [9].

A review of the data revealed the following noteworthy observations with respect to EDS:

- Ninety-one percent of the HEAF events occurred in non-Class 1E equipment. This is a significant statistic because it indicates that HEAFs primarily involve non-Class 1E equipment located in non-safety-related structures.
- A significant number of events (9 of 32) involved actuation of the main generator protection scheme to mitigate the fault. In these events, the fault persisted for several seconds while the generator coasted down and the voltage decayed. These events impacted only non-Class 1E equipment in non-Class 1E locations of the plant operating within the medium-voltage range. A post-event fire was observed in all events. In eight of the events, damage was observed beyond the event origin. Although the events did not involve safety-related equipment or locations, they caused significant damage and were challenging.
- Only four HEAF events occurred in the low-voltage range (480–1000 V). There is evidence that most HEAF events occur at the medium-voltage level (84%).
- Ninety-four percent of events occurred on switchgear, circuit breakers, or electrical buses.

System Designs and HEAF Impact

This section explores the potential impact of HEAFs on various configurations of Class 1E EDS. For specific designs, the potential consequences of a HEAF event as well as the susceptibility of the design to a HEAF are addressed. The consequences considered are damage that results in partial loss of offsite power (LOOP), loss of all ac power to one Class 1E bus, full LOOP, or a station blackout (SBO).

Research of 105 nuclear unit station one-line diagrams confirms that there are several electrical distribution schemes for powering Class 1E buses. The various Class 1E electrical alignments are grouped, as follows:

- Unit-connected design (generator, AT [including secondary/tertiary bus supply breakers], GSU transformer [including switchyard breakers])
  - Class 1E bus directly connected to the AT through a single bus supply breaker
  - Class 1E bus connected downstream of an intermediate non-Class 1E bus and/or transformer connected to the AT
- Generator breaker separating the generator from AT and main GSU transformers
- Class 1E buses fed from offsite power at all times (such as an ST or startup transformer)
- Transformer winding connection configuration, as follows:
  - Single-winding feeding both downstream divisions of Class 1E buses
  - Separate windings feeding each downstream division of Class 1E

It should be noted that most nuclear power plant electrical distribution designs include an intermediate non-safety-related bus (and sometimes a transformer) between the AT or ST secondary/tertiary breaker and the Class 1E bus supply breaker. In these cases, if a fault occurs with the Class 1E bus supply breaker, backup protection is provided by the upstream bus supply breaker from the AT feeding the intermediate non-Class 1E bus, given that selective coordination was designed into the two series breakers.

For the most part, no U.S. nuclear plant EDS designs are exactly the same. However, the U.S. nuclear fleet EDS designs were able to be simplified and grouped into one of eight general arrangements to evaluate HEAF impacts.

The remainder of this section presents eight specific EDS designs showing some common general arrangements of the Class 1E bus alignment. For each design, the potential consequences (impact) of a HEAF event within the unit-connected design and offsite power configuration are covered.

Each EDS design considers three HEAF event scenarios. Each of the following eight figures includes two fault zones where a HEAF is postulated to occur.

Fault zone 1 is the area between the AT secondary/tertiary winding(s) and the high side of the associated downstream bus supply breakers fed from the AT. This is typically either a non-segregated bus duct or power cables. In these fault zone scenarios, 1) all equipment and protection are expected to work as designed, and 2) the bus supply breaker from the AT supply breaker to a Class 1E bus fails to open (that is, stuck)

Fault zone 2 is the main switchgear bus fed by the AT (including the bus supply breakers from the AT) and switchgear load breakers. A HEAF in fault zone 2 is an internal switchgear fault. Assuming that the protection system operates as designed (that is, bus lockout and the supply breaker opens), the HEAF would be isolated from all sources of energy (including the generator collapsing voltage during coast-down for system designs 1–6). If the bus supply breaker downstream of the AT fails to open (stuck breaker), HEAF damage at the switchgear will be significantly more severe due to the generator feeding the HEAF during coast-down (several seconds).

The purpose of evaluating electrical system distribution designs 1 through 8 is to standardize the potential consequences to the Class 1E electrical buses following a HEAF event in the auxiliary power distribution system. It is not intended that given the initiating event, the outcome described in the following listing would be the only expected outcome. Other outcomes (less or more severe) are possible given additional complications or physical plant arrangements as evidenced in actual HEAF operating experience. It is intended to rank EDS design vulnerability to long duration HEAF events (highest to lowest) for unit-connected designs (primary) and offsite designs (secondary) assuming similar consequences. See Table 3. Five assumptions are made given common EDS and their protection systems (and may not be true in every nuclear unit), as follows:

1. Buses are assumed to have a bus lockout feature as part of the protection scheme.
2. For simplicity, it is assumed that the bus transfer scheme is that of a fast dead bus transfer with no supervisory feature.
3. Large transformer selective coordination of the primary and secondary/tertiary breakers may not exist in all time-current regions (IEEE Std 242-1986, Section 14.5.2(10)).
4. Two redundant divisions of safety-related Class 1E buses.
5. Automatic bus transfers only occur from AT to ST or ST to ST. No automatic bus transfers occur from an ST to the AT.

The following is a detailed HEAF impact assessment for each of the eight EDS designs:

System Design 1

Nuclear power plants with two Class 1E buses connected in parallel downstream of the AT secondary winding (unit-connected) through a single bus supply circuit breaker (for each Class 1E bus) are the most vulnerable to the impact and consequence of a long-duration, generator-fed HEAF (see Figure 13).

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), and initiate a bus transfer to the ST for both Class 1E divisions.

There is the potential for the main generator to feed the HEAF through the AT during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated. The result is that the Class 1E buses will be transferred to the ST and fed from offsite power.

Table 3 – Common electrical distribution system designs and relative generator-fed HEAF risk

Electrical Distribution System (EDS) Configuration	Generator-Fed HEAF Susceptibility	Class 1E Bus HEAF Vulnerability	Expected HEAF Outcome by Fault Zone	Number of U.S. Nuclear EDS Designs Out of 105 Units[1]
Design 1 Unit-Connected Design: Two Class 1E buses connected in parallel downstream of the AT secondary winding through a single bus supply circuit breaker (for each Class 1E bus). Figure 13.	Yes	Highest [Potential for extensive Gen-Fed HEAF damage to one Class 1E bus division]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): LOOP and loss of power to one Class 1E division. Precursor to SBO 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP and loss of power to one Class 1E division. a. One failure away from LOOP b. Two failures away from SBO	6
Design 2 Unit-Connected Design: Two Class 1E buses, each powered by a separate AT winding, through a single bus supply circuit breaker for each Class 1E bus. Figure 14.	Yes	Highest [Potential for extensive Gen-Fed HEAF damage to one Class 1E bus division]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): LOOP and loss of power to one Class 1E division. Precursor to SBO 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP and loss of power to one Class 1E division. a. One failure away from LOOP b. Two failures away from SBO	2
Design 3 Class 1E buses at least one breaker downstream of the unit-connected design through intermediate non-Class 1E buses fed from one AT winding. Figure 15.	Yes	High [No expected extensive Gen-Fed damage to Class 1E bus, only non-Class 1E bus]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): LOOP with both Class 1E divisions powered by the EDGs a. Two failures away from SBO\ 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO	7
Design 4 Class 1E buses at least one breaker downstream of the unit-connected design through intermediate non-Class 1E buses fed from separate AT windings. Figure 16.	Yes	High [No expected extensive Gen-Fed damage to Class 1E bus, only non-Class 1E bus]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): LOOP with both Class 1E divisions powered by the EDGs a. Two failures away from SBO 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO	3

[1] *Note: Sum of nuclear EDS designs exceed 105 in the above table because some nuclear units employ multiple system design types within one nuclear unit.*

Table 3 – Common electrical distribution system designs and relative generator-fed HEAF risk (continued)

Electrical Distribution System (EDS) Configuration	Generator-Fed HEAF Susceptibility	Class 1E Bus HEAF Vulnerability	Expected HEAF Outcome by Fault Zone	Number of U.S. Nuclear EDS Designs Out of 105 Units[1]
Design 5 Hybrid Design: 1. One Class 1E bus powered by generator/AT through an intermediate non-Class 1E bus (for example, Design 3). 2. One Class 1E bus powered by offsite power through ST (that is, Design 8). Figure 17.	Yes [Only one non-Class 1E/Class 1E lineup (division) vulnerable to Gen-Fed HEAF]	Moderate [For some events, only one bus transfer is required]	1. Zone 1A HEAF: Class 1E Bus transferred to offsite power (ST) 2. Zone 1B HEAF: LOOP (due to expected unit trip) 3. Zone 1A HEAF (Stuck Breaker): LOOP a. Two failures away from SBO 4. Zone 1B HEAF (Stuck Breaker): LOOP (due to expected unit trip) a. Two failures away from SBO 5. Zone 2A HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO 6. Zone 2B HEAF (Stuck Breaker): LOOP (due to expected unit trip) a. Two failures away from SBO	8* *Note: Two of these units also have a generator circuit breaker (GCB) for the buses fed from the AT
Design 6 Class 1E buses at least one breaker downstream of the unit-connected design through intermediate non-Class 1E buses fed from two separate/dedicated ATs. Figure 18.	Yes	Moderate-Low [Design 6 improves outcome of Zone 1 HEAF (stuck breaker)]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO	12* *Note: • Four of these units also have a dedicated generator circuit breaker (GCB) for each AT in their EDS system design (that is, 2 GCBs per unit). • One unit has one GCB serving both ATs
Design 7 Generator circuit breaker (GCB) between generator and the AT/GSU transformers. Class 1E buses fed from intermediate non-Class 1E buses. This design isolates the main generator from rest of the unit-connected system within a few cycles. (that is, generator breaker can be credited as a backup to the AT bus supply breakers). Figure 19.	No [At least two independent failures needed for Gen Fed HEAF potential (that is, 2 stuck breakers)]	Low [Buses must transfer due to unit trip]	1. Zone 1 HEAF: Class 1E Buses transferred to offsite power (ST) 2. Zone 1 HEAF (Stuck Breaker): LOOP. a. Two failures away from SBO 3. Zone 2 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO	15* *Note: All EDS design types that have GCB are accounted for here; however, the GCB is applied across may EDS design types as follows: • Design Type 3: 2 units • Design Type 4: 2 units • Design Type 5: 2 units • Design Type 6: 5 units** • Design Type 8: 4 units ** Four of these five units have 2 GCBs, one dedicated to each AT

Table 3 – Common electrical distribution system designs and relative generator-fed HEAF risk (continued)

Electrical Distribution System (EDS) Configuration	Generator-Fed HEAF Susceptibility	Class 1E Bus HEAF Vulnerability	Expected HEAF Outcome by Fault Zone	Number of U.S. Nuclear EDS Designs Out of 105 Units[1]
Design 8 Class 1E buses permanently fed from offsite power through ST for all modes of operation.	No	Lowest	This configuration eliminates a main generator-fed HEAF to the Class 1E buses because the Class 1E buses are fed from the STs (offsite power) where the main generator would be isolated by the generator output switchyard breakers. Additionally, for a fault on the unit-connected design, no bus transfer is required for the Class 1E buses (or their upstream intermediate buses). For faults on the ST: 1. ST Zone 1 HEAF: Class 1E Buses transferred to the alternate offsite power source (ST#2) 2. ST Zone 1 HEAF (Stuck Breaker): LOOP. a. Two failures away from SBO 3. ST Zone 2 HEAF (Stuck Breaker): Partial LOOP. a. One failure away from LOOP b. Three failures away from SBO	63* *Note: With some units, the Class 1E buses are fed directly from the ST and may have a different outcome than described (for example, loss of one Class 1E division if the HEAF originates in the switchgear). Nonetheless, the impacted Class 1E bus would still avoid an extended duration, generator fed HEAF. • Four units also have GCB for the BOP buses fed by AT

HEAF in Fault Zone 1 with Stuck Supply Breaker

If the bus supply breaker from the AT in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer attempt to isolate the Class 1E buses from the HEAF, the ST could momentarily contribute to the HEAF upon closure of the ST supply breakers. Upon detection of the fault by the ST protection system, the ST is expected to lock out and open its associated switchyard breakers.

The resulting actuation of the bus undervoltage relays will start the associated bus emergency diesel generators (EDGs), and the EDG output breakers will close in on their associated Class 1E bus. For the Class 1E bus division involved with the HEAF (stuck breaker), the EDG protection system is expected to trip open the EDG output breaker on overcurrent and the Class 1E bus will be de-energized. The other Class 1E division will be powered from its EDG.

The result is a LOOP and a loss of power to one Class 1E division. If the EDG (associated with the Class 1E bus not involved with the stuck breaker) fails to start or load, the result is an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 (one division of Class 1E switchgear) with a stuck breaker (bus supply breaker from the AT to the faulted bus) has the potential to adversely impact both Class 1E divisions. This is because the same AT winding that feeds the HEAF also feeds the non-faulted Class 1E bus.

Even if the AT locks out, causing a turbine-generator trip (generator output switchyard breakers open), the generator could potentially continue to feed the HEAF through the AT and stuck breaker for several seconds during generator coast-down.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST to the non-faulted Class 1E bus, because it is expected that the faulted bus lockout signal would prevent closing of the bus supply breaker from the ST.

Upon successful closure of the bus supply breaker from the ST to the non-faulted Class 1E bus, the bus transfer is complete and power is restored.

The resulting actuation of the bus undervoltage relays of the faulted Class 1E bus will start the associated EDG. Due to the bus lockout resulting from the HEAF, the EDG will not close the output breaker onto the faulted Class 1E bus and that Class 1E bus will be de-energized after the event.

The result is a partial LOOP; however, there is also a loss of power to one Class 1E division. The resulting station configuration is one failure away from a LOOP and two failures away from an SBO.

System Design 2

The consequences and impact of a HEAF to nuclear power plants with two Class 1E buses, each powered by a separate AT winding (unit-connected) through a single bus supply circuit breaker for each Class 1E bus, are covered in this section (see Figure 14).

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), and initiate a bus transfer to the ST for both Class 1E divisions.

There is the potential for the main generator to feed the HEAF through the AT during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated.

The result is that the Class 1E buses will be transferred to the ST and fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

If the bus supply breaker from the AT in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer in an attempt to isolate the Class 1E bus from the AT feeding the HEAF, the ST could momentarily contribute to the HEAF upon closure of the ST supply breakers. Upon detection of the fault by the ST protection system, the ST is expected to lock out and open its associated switchyard breakers.

The resulting actuation of the bus undervoltage relays will start the associated bus EDGs, and the EDG output breakers will close in on their associated Class 1E bus. For the Class 1E bus division involved with the HEAF (stuck breaker), the EDG protection system is expected to trip open the EDG output breaker on overcurrent, and that Class 1E bus will be de-energized. The other Class 1E division will be powered from its EDG.

The result is a LOOP and a loss of power to one Class 1E division.

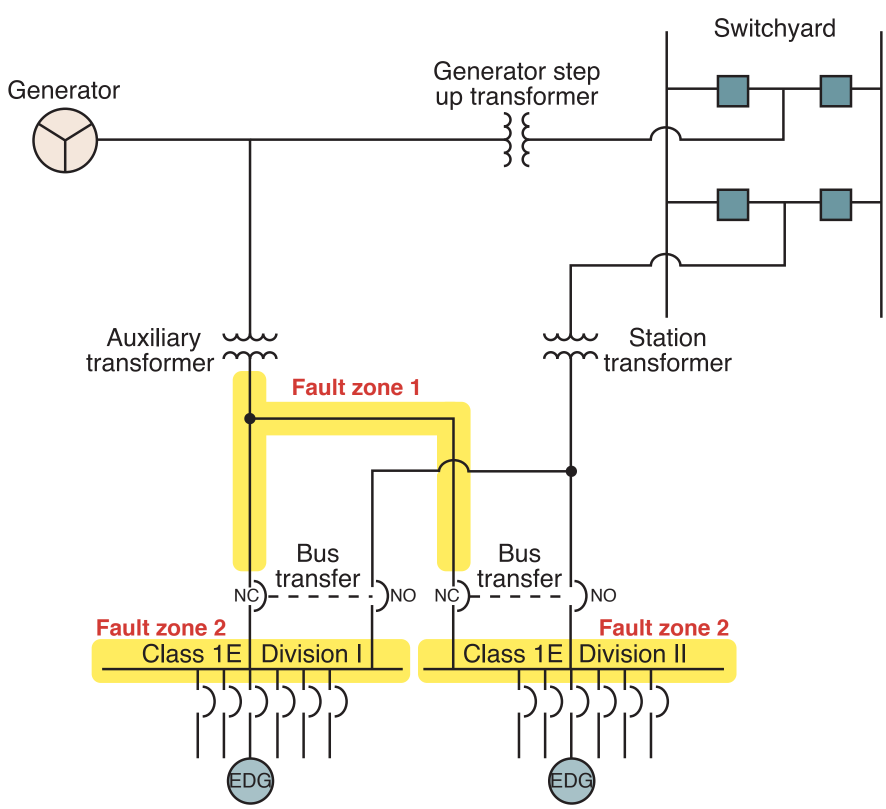

Figure 13 – Electrical distribution system design 1

If the EDG (associated with the Class 1E bus not involved with the stuck breaker) fails to start or load, the result is an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 (one division of Class 1E switchgear) with a stuck breaker (bus supply breaker from the AT to the faulted bus) has the potential to impact both Class 1E divisions. This is because the same AT that feeds the HEAF feeds the non-faulted Class 1E bus.

Even if the AT locks out, causing a turbine-generator trip (generator output switchyard breakers open), the generator could continue to feed the HEAF through the AT and stuck breaker for several seconds during generator coast-down.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST to the non-faulted Class 1E bus, because it is expected that the faulted bus lockout signal would prevent closing the bus supply breaker from the ST to the faulted Class 1E bus.

Upon successful closure of the bus supply breaker from the ST to the non-faulted Class 1E bus, the bus transfer is complete and power is restored.

The resulting actuation of the bus undervoltage relays of the faulted Class 1E bus will start the associated EDG. Due to the bus lockout resulting from the HEAF, the EDG will not close the output breaker onto the faulted Class 1E bus.

The result is a partial LOOP; however, there is also a loss of power to one Class 1E safety division. The resulting station configuration is one failure away from a LOOP and two failures away from an SBO.

System Design 3

This section covers the potential consequences and impact of a HEAF to nuclear power plants where the Class 1E buses are at least one breaker downstream of the unit-connected design through intermediate non-Class 1E buses fed from one AT winding (see Figure 15).

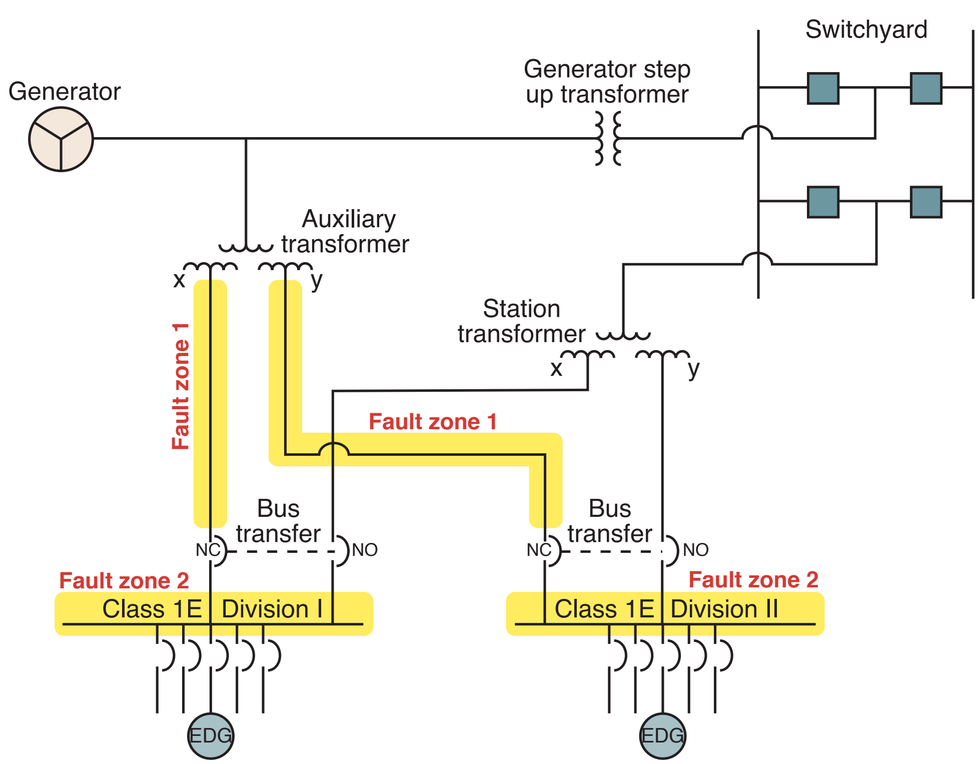

Figure 14 – Electrical distribution system design 2

Although the ATs are typically three-winding, in this system design, the secondary winding is not shown because it is used for non-safety-related BOP loads, and the tertiary winding shown feeds both divisions of non-Class 1E and Class 1E buses.

Note: For a HEAF that originates on the AT secondary winding feeding the BOP buses only, the Class 1E buses would expect to be successfully transferred to the ST.

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), and initiate a bus transfer to the ST for both non-Class 1E buses along with the Class 1E buses that they feed.

There is the potential for the main generator to feed the HEAF through the AT during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the non-Class 1E and Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated. The result is that the non-Class 1E/Class 1E lineups will be transferred to the ST and fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

If the bus supply breaker from the AT in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer attempt to isolate the non-Class 1E/Class 1E lineups from the HEAF, the ST could momentarily contribute to the HEAF upon closure of its tertiary breaker. Upon detection of the fault by the ST protection system, the ST locks out and opens its bus supply breakers and associated switchyard breakers, causing a loss of voltage at both non-Class 1E and Class 1E lineups.

The resulting actuation of the Class 1E bus undervoltage relays will start the associated bus EDG, and the EDG output breakers will close in on their associated Class 1E bus.

The potential result is a LOOP with both Class 1E division buses fed from their associated EDGs. However, the faulted non-segregated bus or cable feed to the non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus feed, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the station is one failure away from an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 with a stuck bus supply breaker from the AT has the potential to impact both Class 1E divisions. This is because the same AT winding that feeds the HEAF feeds the non-faulted non-Class 1E/Class 1E bus lineup.

Even if the AT locks out, causing a turbine-generator trip (generator output switchyard breakers open), the generator could continue to feed the HEAF through the AT and stuck breaker for several seconds during generator coast-down.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST to the non-faulted non-Class 1E/Class 1E bus lineup, because it is expected that the faulted bus lockout signal would prevent closing of the bus supply breaker from the ST.

Upon the successful closure of the bus supply breaker from the ST to the non-faulted non-Class 1E/Class 1E lineup, the bus transfer is complete, and power is restored.

The resulting actuation of the Class 1E bus undervoltage relays will start the EDG associated with the faulted non-Class 1E/Class 1E lineup and EDG output breaker will close to power the respective Class 1E bus.

The potential result is a partial LOOP. However, the faulted non-Class 1E bus with the stuck breaker will be lost. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired and returned to service.

The station result will be one failure away from a LOOP and three failures away from an SBO.

System Design 4

This section covers the potential consequences and impact of a HEAF to nuclear power plants where two Class 1E buses are at least one breaker downstream of the unit-connected design through intermediate non-Class 1E buses fed by one AT with two separate windings (see Figure 16).

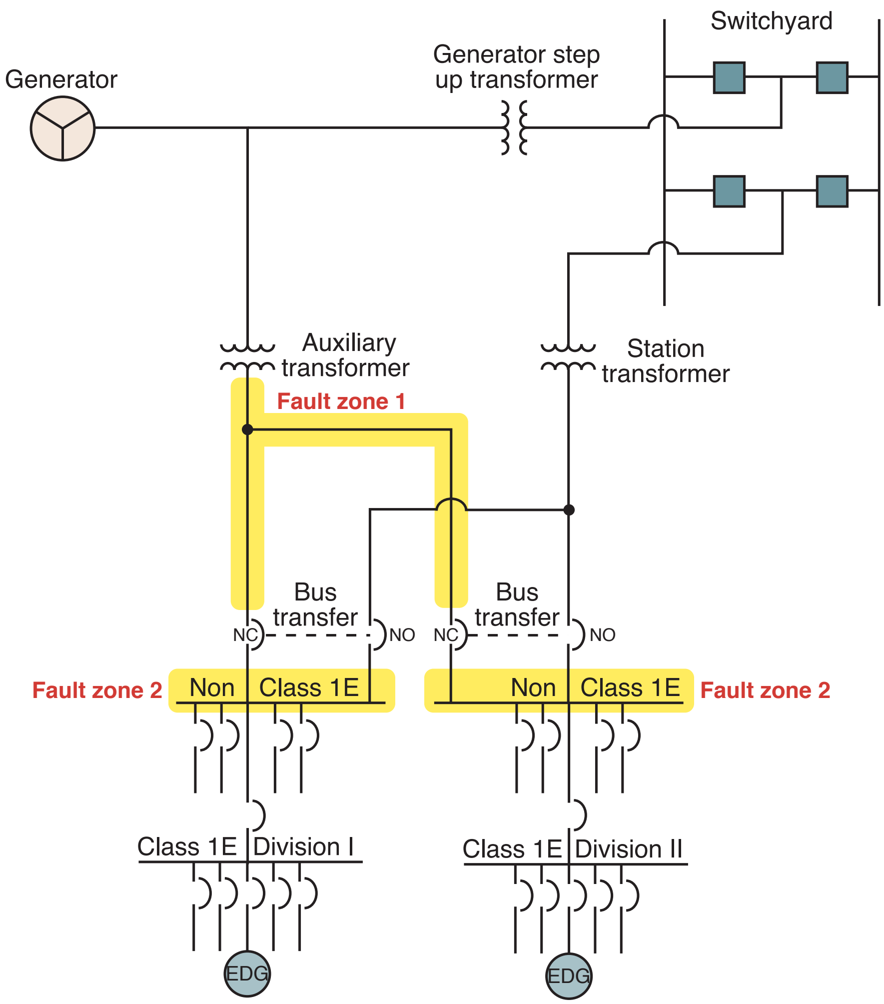

Figure 15 – Electrical distribution system design 3

Similar to system design 3, the outcome of a HEAF is still expected to affect both non-Class 1E/Class 1E lineups. However, the separate AT windings (one dedicated for each non-Class 1E/Class 1E lineup) afford some isolation in that the non-faulted AT winding is not expected to feed the HEAF. Therefore, the voltage is not expected to become significantly depressed on the non-faulted non-Class 1E/Class 1E bus lineup. Nonetheless, an AT lockout is still expected to result in a unit trip and bus transfer of both non-Class 1E and Class 1E lineups to the ST.

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), and initiate a bus transfer to the ST for both non-Class 1E and Class 1E bus lineups. There is the potential for the main generator to feed the HEAF through the AT during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the non-Class 1E and Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated.

The result is that the non-Class 1E/Class 1E lineups will be transferred to the ST and fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

If the bus supply breaker from the AT in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer in an attempt to isolate the non-Class 1E/Class 1E bus lineups from the HEAF, the ST could momentarily contribute to the HEAF upon

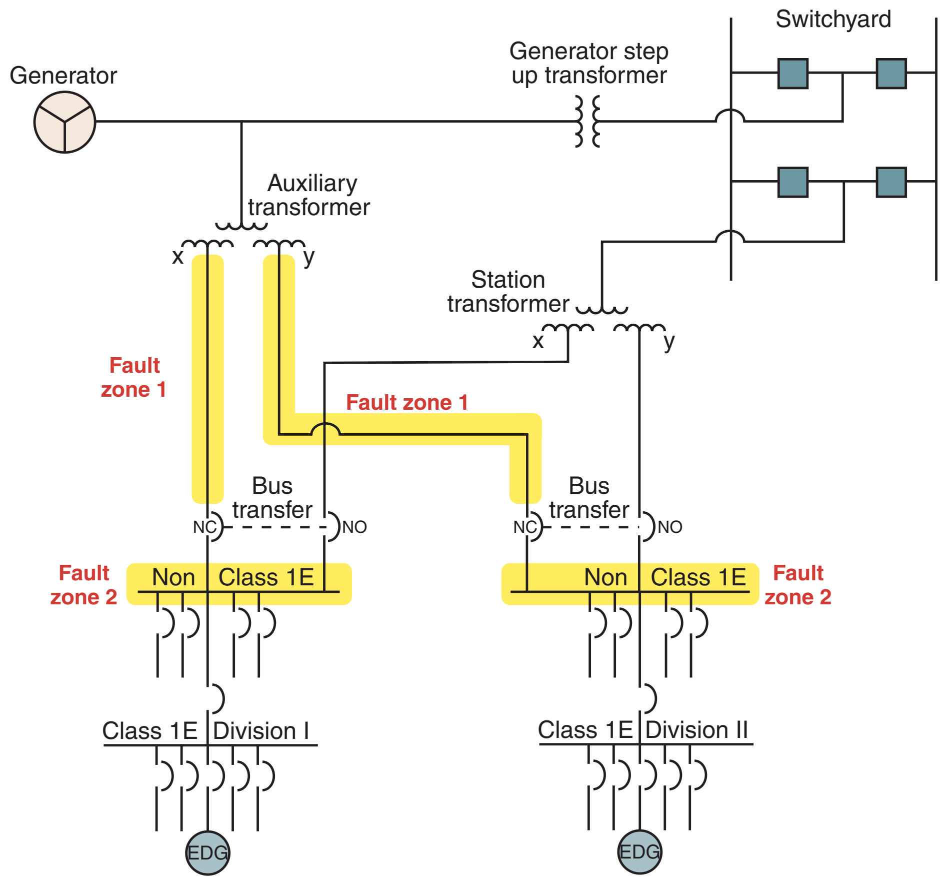

Figure 16 – Electrical distribution system for design 4

closure of its supply breakers. Upon detection of the fault by the ST protection system, the ST is expected to lockout and open its bus supply breakers and associated switchyard breakers, causing a loss of voltage at the non-Class 1E/Class 1E lineups.

The resulting actuation of the Class 1E bus undervoltage relays will start the associated bus EDG, and the EDG output breakers will close to power their associated Class 1E buses.

The potential result is a LOOP with both Class 1E division buses fed from their associated EDGs. However, the faulted non-segregated bus or cable feed to the non-Class 1E buses will be lost. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to the offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

Given the LOOP condition, if one of the EDG fails to start and/or load, the station is one failure away from an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 with a stuck bus supply breaker from the AT has the potential to initially impact only one of the non-Class 1E/Class 1E divisions due to the separate winding feeds. However, if the HEAF persists, it will result in activating the AT protective trip lockout, causing a turbine-generator trip (generator switchyard breakers open), and initiating a bus transfer to the ST.

Even if the AT locks out, causing a turbine-generator trip (generator output switchyard breakers open), the generator could continue to feed the HEAF through the AT and stuck breaker for several seconds during generator coast-down.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST to the non-faulted non-Class 1E/Class 1E bus lineup, , because it is expected that the faulted bus lockout signal would prevent the closing of the bus supply breaker from the ST.

Upon successful closure of the bus supply breaker from the ST to the non-faulted non-Class 1E/Class 1E lineup, the bus transfer is complete and power is restored.

The resulting actuation of the Class 1E bus undervoltage relays will start the EDG associated with the faulted non-Class 1E/Class 1E lineup, and the EDG output breaker will close to power the respective Class 1E bus.

The potential result is a partial LOOP. However, the faulted non-Class 1E bus with the stuck breaker will be lost. With respect to the damaged non-Class 1E bus, the associated downstream Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired.

The station result will be one failure away from a LOOP and three failures away from an SBO.

System Design 5

This section covers the potential consequences and impact of a HEAF to nuclear power plants where the nuclear Class 1E EDS power source is a hybrid of the unit-connected design (for example, System Design 3) and of the offsite power connection (System Design 8). That is, one Class 1E bus is powered by a generator and associated AT through an intermediate non-Class 1E bus, and the other Class 1E bus is powered from offsite power (see Figure 17).

With this hybrid arrangement, the non-Class 1E/Class 1E bus lineup aligned to the AT is vulnerable to a generator-fed fault. The other non-Class 1E/Class 1E bus lineup is aligned to offsite power and not directly vulnerable to a generator-fed HEAF. Additionally, only one bus transfer is required because no bus transfer is required for the division already on the ST with a unit trip.

For the following scenarios, the zones are split into 1A and 2A (generator/AT feed) and 1B and 2B (offsite power feed).

HEAF in Fault Zone 1A

A HEAF in fault zone 1A is expected to result in an AT protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), and initiate a bus transfer to the ST for the affected non-Class 1E/Class 1E bus lineup associated with Division I.

There is the potential for the main generator to feed the HEAF through the AT during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the non-Class 1E and Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated. The result is that the impacted non-Class 1E/Class 1E bus lineup associated with Division I will be transferred to the ST and fed from offsite power.

HEAF in Fault Zone 1B

A HEAF in fault zone 1B is expected to result in an ST protective trip lockout (opening the associated switchyard breakers) and initiate the start of the impacted Division II EDG, closing the output breaker, and powering the Class 1E Division II loads.

Additionally, it is expected that critical BOP loads will be lost and a unit trip will result. Because the ST is not available, Division I EDG will also start, close its output breaker and power the Class 1E Division I loads.

The expected result is that a LOOP will occur and both Class 1E divisions will be powered by their associated EDGs.

HEAF in Fault Zone 1A with a Stuck Supply Breaker

If the AT supply breaker in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer in an attempt to isolate the non-Class 1E/Class 1E lineup from the HEAF, the ST could momentarily contribute to the HEAF upon closure of its bus supply breaker. Upon detection of the fault by the ST protection system, the ST locks out and opens its supply breakers and associated switchyard breakers, causing a loss of voltage at the non-Class 1E/Class 1E lineups.

The resulting actuation of the Class 1E bus undervoltage relays will start the EDGs, and the EDG output breakers will close in on their associated Class 1E buses.

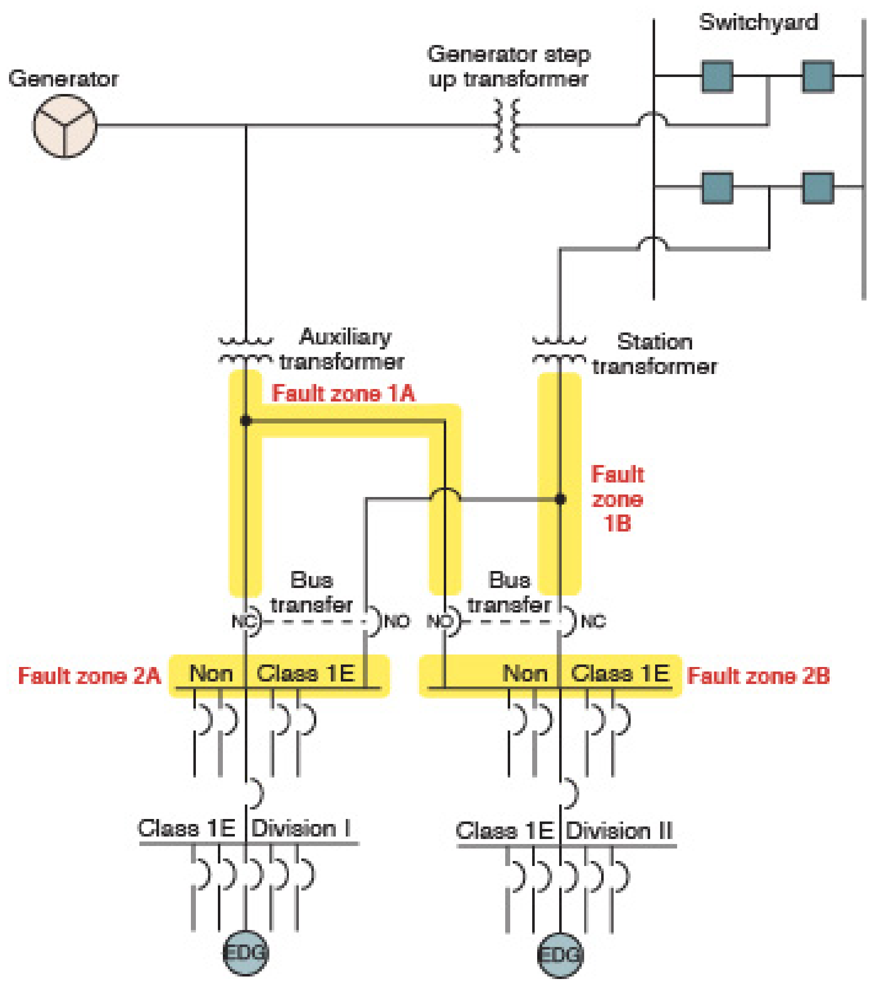

Figure 17 – Electrical distribution system design 5

The potential result is a LOOP with both Class 1E buses fed from their associated EDG. However, the faulted non-segregated bus or cable feed to the non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus feed, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to the offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the station is one failure away from an SBO.

HEAF in Fault Zone 1B with a Stuck Supply Breaker

If the bus supply breaker from the ST in the same circuit as the HEAF does not open (that is, stuck) in an attempt to isolate the non-Class 1E/Class 1E bus lineup from the HEAF, the switchyard supply breakers to the ST will still open in a few cycles to de-energize the ST, isolating power to the HEAF and non-Class 1E/Class 1E bus line up associated with Division II.

The loss of voltage will result in actuation of the Class 1E Division II, bus undervoltage relays will start the associated bus EDG, and the EDG output breaker will close in on the associated Class 1E bus.

It is expected that the loss of power to the intermediate non-Class 1E bus also results in trips of critical BOP operating loads causing a reactor/turbine trip. Because the ST will not be available for a bus transfer, the non-Class 1E/Class 1E bus Division I lineup will also experience a loss of power. Similar to Class 1E Division II, the Class 1E Division I EDGs will start and power the Class 1E Division I loads.

The potential result is a LOOP. However, the faulted non-Class 1E bus that was connected to the ST will be lost. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the consequence is a LOOP, and the station is one failure away from an SBO.

HEAF in Fault Zone 2A with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2A with a stuck bus supply breaker from the AT has the potential to initially impact one Class 1E bus (for example, Division I). The AT would be expected to lockout, causing a turbine-generator trip (generator output switchyard breakers open), and the generator could continue to feed the HEAF through the AT and stuck breaker for several seconds during generator coast-down.

The faulted non-Class 1E bus is also expected to lockout and prevent the bus supply breaker from the ST from closing, resulting in a loss of voltage to that non-Class 1E/Class 1E bus lineup. The resulting actuation of the Class 1E bus undervoltage relays will start the associated Division I Class 1E bus EDG and close the EDG output breaker onto the Class 1E Division I bus.

The result is a partial LOOP. However, the faulted non-Class 1E bus with the stuck breaker will be lost. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired and returned to service.

The resulting station configuration is one failure away from a LOOP and three failures away from an SBO.

HEAF in Fault Zone 2B with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2B with a stuck bus supply breaker from the ST has the potential to initially impact only one of the non-Class 1E/Class 1E lineups. However, if the HEAF persists, it will result in the ST protection system actuating (lockout), opening the associated switchyard breakers in a few cycles, isolating power to the HEAF and non-Class 1E/Class 1E bus lineup Division II.

The resulting actuation of the Class 1E bus undervoltage relays will start the associated Division II Class 1E bus EDG and close the EDG output breaker onto the Class 1E Division II bus.

It is expected that the loss of power to the intermediate non-Class 1E bus also results in trips of critical BOP operating loads causing a reactor/turbine trip. Because the ST will not be available for a bus transfer, the non-Class 1E/Class 1E bus lineup will also experience a loss of power. Similar to Class 1E Division II, the Class 1E Division I EDGs will start and power the Class 1E Division I loads.

The result is a LOOP. However, the faulted non-Class 1E bus with the stuck breaker will be lost. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired and returned to service.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the station is one failure away from an SBO.

System Design 6

This section covers the potential consequences and impact of a HEAF to nuclear power plants where two Class 1E buses are one breaker downstream of the unit-connected design through an intermediate non-Class 1E bus fed by two separate ATs. This design provides an improved degree of electrical and physical separation of the two non-Class 1E/Class 1E lineups within a unit-connected design (see Figure 18).

This electrical system design reduces the direct impact of generator fed HEAF vulnerability to only one non-Class 1E/Class 1E lineup (other non-Class 1E/Class 1E lineup is powered by a separate AT that would not be involved directly with the HEAF).

The three scenarios that follow assume that the HEAF is in the circuit fed by the AT#1 circuit.

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT#1 protective trip lockout, causing a turbine-generator trip (generator output switchyard breakers open), tripping of AT#2, and initiate a bus transfer to the station transformers, ST#1 and ST#2, for both non-Class 1E and Class 1E bus lineups.

There is the potential for the main generator to feed the HEAF through the AT#1 during coast-down. However, the damage is expected to remain in the non-segregated bus section (or cables) and not affect the non-Class 1E and Class 1E buses, which have been electrically isolated by the bus transfer and are physically separated.

The result is that the Class 1E buses will be transferred to the STs and fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

Subsequent to the AT#1 lockout, if the AT#1 supply breaker in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer in an attempt to isolate the non-Class 1E/Class 1E bus lineup from the HEAF, the associated ST#1 could momentarily contribute to the HEAF upon closure of its supply breaker. Upon detection of the fault by the ST#1 protection system, the ST#1 locks out and opens its bus supply breakers and associated switchyard breakers, causing a loss of voltage at the non-Class 1E/Class 1E (Division I) lineup.

The resulting actuation of the Class 1E (Division I) bus undervoltage relays will start the associated impacted Class 1E bus EDG, and the EDG output breaker will close in on the associated Class 1E bus.

The potential result is a partial LOOP. However, the faulted non-segregated bus or cable feed to the non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus feed, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

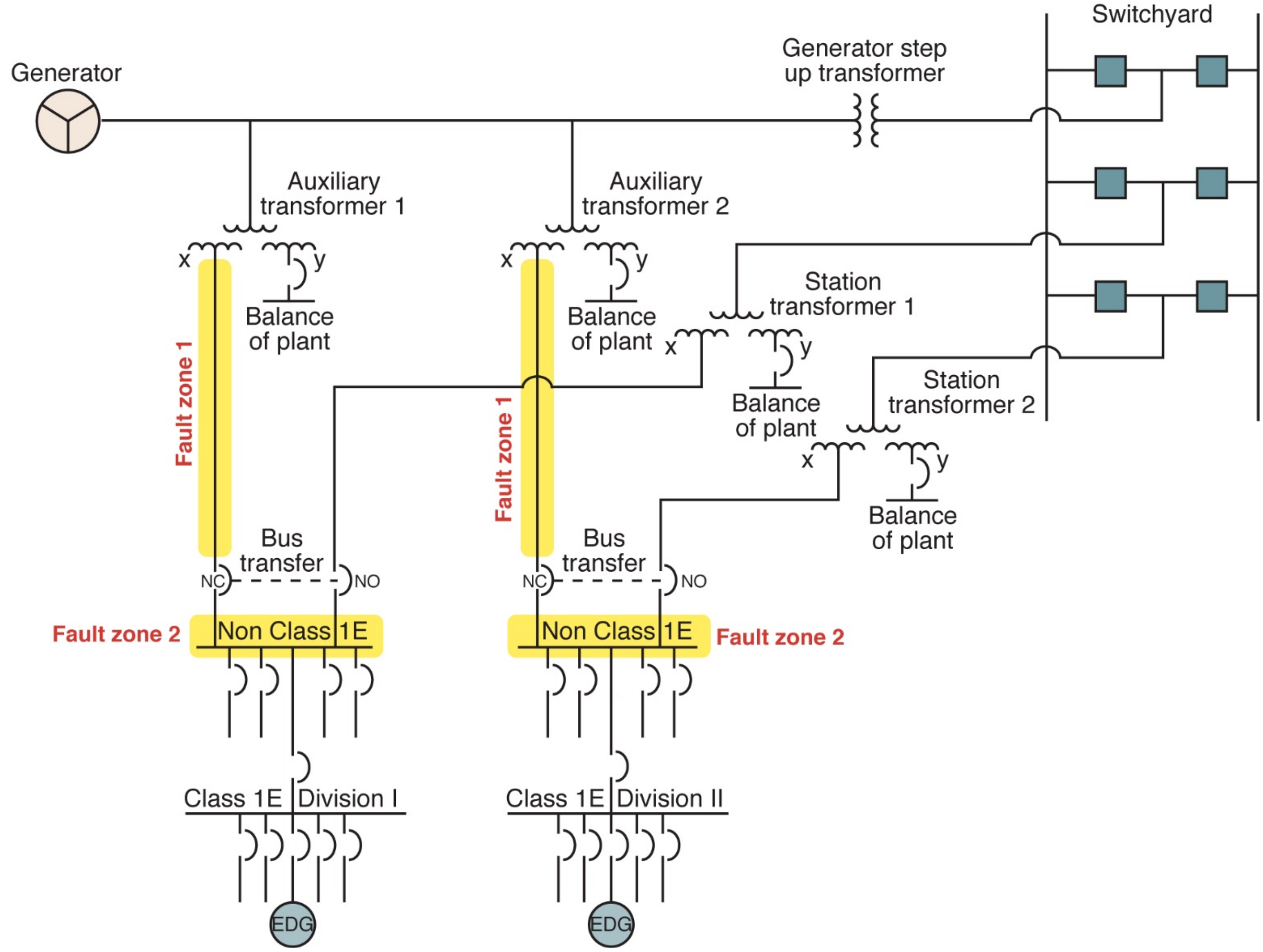

Figure 18 – Electrical distribution system design 6

The result is one failure away from a LOOP and three failures away from an SBO.

Note: Some stations have each of the two ATs protected by a dedicated generator circuit breaker (GCB) for each non-Class 1E/Class 1E lineup, eliminating generator-fed HEAFs altogether.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 with a stuck bus supply breaker from AT #1 has the potential to initially impact only one of the non-Class 1E/Class 1E lineups due to the separate ATs. However, if the HEAF persists, it will result in a protective trip lockout of the associated AT causing a turbine-generator trip (generator output switchyard breakers open), tripping AT#2, and initiating a bus transfer to the STs for both non-Class 1E and Class 1E lineups.

The resulting bus transfer will be expected to only close the ST#2 bus supply breakers to the non-faulted bus because it is expected that the faulted bus lock out signal would prevent the closing of the ST#1 bus supply breaker to the faulted bus.

Upon completion of the bus transfer (except the faulted locked out non-Class 1E bus), the closure of the bus supply breakers from ST#2 provides power to the unimpacted non-Class 1E/Class 1E lineup.

The resulting actuation of the impacted Class 1E Division I bus undervoltage relays will start the associated bus EDG, and the EDG output breaker will close in on its associated Class 1E Division I bus. Class 1E Division II bus will remain fed from offsite power through ST#2.

The potential result is a partial LOOP with Class 1E bus Division II fed from offsite power through the ST#2 and Class 1E bus Division I fed from its associated EDG. However, the non-Class 1E bus involved with the HEAF will be lost, with the Class 1E bus Division I powered by its EDG. With respect to the damaged non-Class 1E bus, the associated Class 1E Division I bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired.

The resulting station configuration is one failure away from a LOOP and three failures away from an SBO.

System Design 7

This section covers the potential consequences and impact of a HEAF to nuclear power plants where a generator breaker exists between the main generator and the AT and GSU transformer. In some cases, the Class 1E bus is one additional breaker downstream of the AT through an intermediate non-Class 1E bus fed by the AT (see Figure 19). This design essentially isolates the main generator from the rest of the unit-connected system within a few cycles after a turbine-generator trip, eliminating the impact and consequence of a long-duration, generator-fed HEAF (that is, the generator breaker credited as a backup to the AT bus supply breakers).

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an AT protective trip lockout tripping the generator breaker, and the turbine-generator (generator output switchyard breakers open) initiating a bus transfer to the ST for both non-Class 1E/Class 1E bus lineups. The potential for a generator-fed HEAF is eliminated by the opening of the generator breaker.

The result is that the non-Class 1E and Class 1E lineups will be transferred to the ST and fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

Although a generator-fed fault is prevented when the generator breaker opens, if the bus supply breaker from the AT in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer attempt to isolate the non-Class 1E/Class 1E bus lineup from the HEAF, the ST could momentarily contribute to the HEAF upon closure of its bus supply breakers because there is no bus lockout. Upon detection of the fault by the ST protection system, the ST locks out and opens its bus supply breakers and associated switchyard breakers, causing a loss of voltage at the non-Class 1E/Class 1E lineups.

The resulting actuation of the Class 1E bus undervoltage relays will start the associated bus EDGs, and the EDG output breakers will close in on their associated Class 1E buses.

The potential result is a LOOP with both Class 1E buses fed from their associated EDGs. However, the faulted non-segregated bus or cable feed to the non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus feed, the associated Class 1E bus must remain powered by its associated EDG because it cannot be

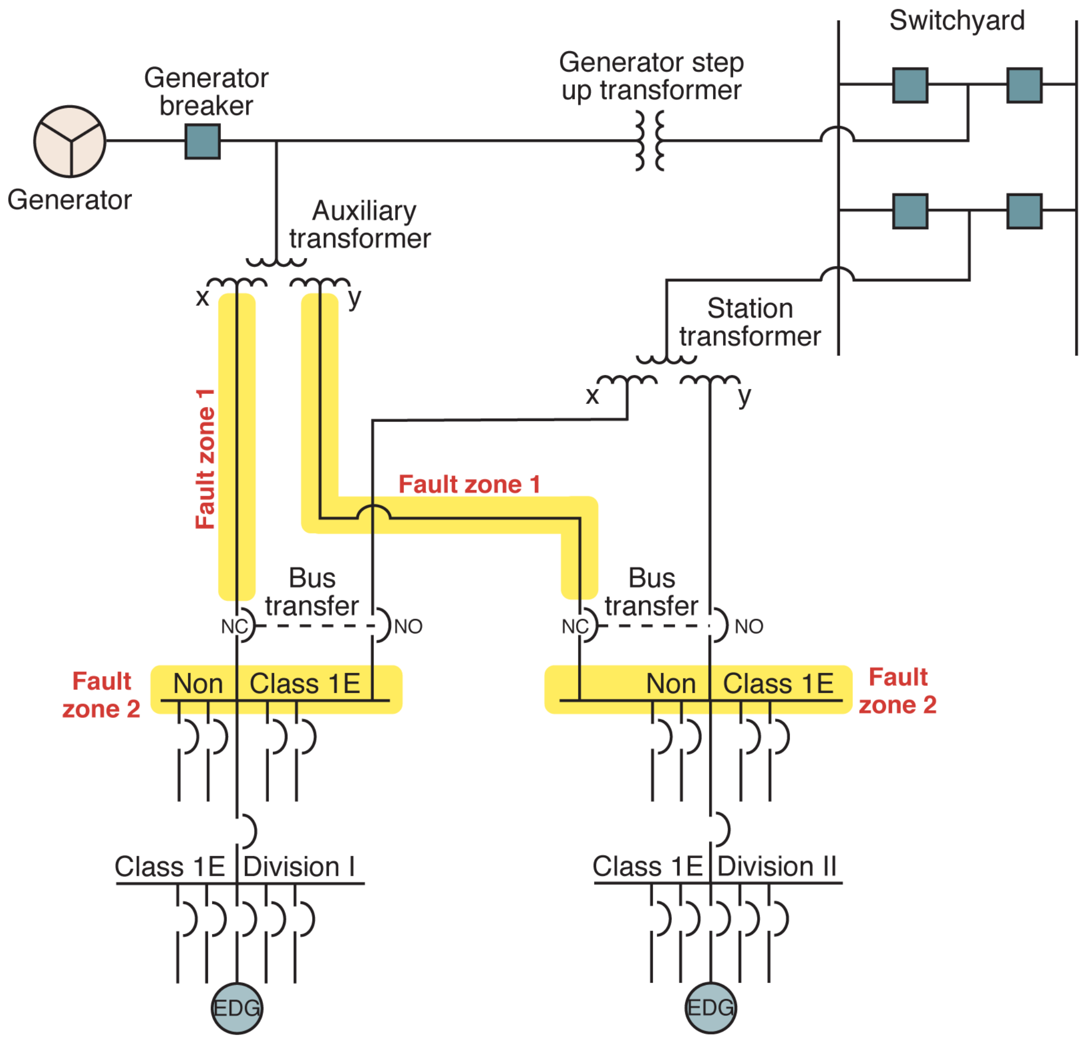

Figure 19 – Electrical distribution system design 7

restored to offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the station is one failure away from an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 with a stuck bus supply breaker from the AT has the potential to initially impact only one of the non-Class 1E/Class 1E divisions due to the separate winding feeds. However, if the HEAF persists, it will result in activating the AT protective trip lockout tripping the generator breaker and turbine-generator (generator output switchyard breakers open), initiating the bus transfer scheme to the ST.

Opening of the generator breaker will eliminate the generator from feeding the HEAF.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST to the non-faulted non-Class 1E/Class 1E bus lineup, because it is expected that the faulted bus lockout signal would prevent the closing of the bus supply breaker from the ST to the faulted bus.

Upon completion of the bus transfer of the non-faulted bus, the closure of the bus supply breaker from the ST provides power to the non-faulted non-Class 1E/Class 1E lineup.

A loss of power condition will exist in the faulted non-Class 1E/Class 1E lineup due to the bus lockout. The resulting actuation of the impacted Class 1E bus undervoltage relays will start the associated bus EDG, and the EDG output breaker will close in to power the associated Class 1E bus.

The potential result is a partial LOOP. However, the faulted non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus, the associated downstream Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired.

The result is one failure away from a LOOP and three failures away from an SBO.

The primary benefit of generator breaker over the previous unit-connected designs 1 through 6 is that the generator breaker is considered a backup to the AT bus supply breaker(s) in the event of a failure to open during an auto bus transfer sequence. A generator fed fault can only be considered if two independent breaker failures are taken into account.

Note 1: Variations on this generator breaker scheme further reducing HEAF vulnerability to the Class 1E bus(es) include the following:

- Two separate ATs (one for each division)
- Two separate ATs with dedicated generator circuit breakers (GCBs)
- Class 1E buses fed from offsite power and not a part of the unit-connected design

Note 2: One unit has 2 ATs, a generator breaker, but no intermediate bus between AT and Class 1E buses. Nonetheless, scenario would require two independent failures (that is, two stuck breakers) for the generator to feed a Class 1E switchgear HEAF.

System Design 8

This section covers the potential consequences and impact of a HEAF to nuclear power plants where the Class 1E or non-Class 1E/Class 1E bus lineups are fed from offsite power through one ST, and has an alternate backup ST. See Figure 20.

EDS designs where the Class 1E buses (or intermediate non-Class 1E buses serving Class 1E buses) are permanently fed from offsite power through the ST for all modes of operation are not subject to the impact and consequence of a generator-fed HEAF from the unit-connected design in any mode (startup, power operation, or shutdown). This is because of the following:

- Class 1E buses are isolated from the unit-connected design.
- Class 1E buses are not vulnerable to potential fault energy being fed from the main generator during coast-down.
- Class 1E buses do not have to undergo a fast bus transfer upon a turbine-generator trip.

Additionally, with this design, the Class 1E buses are fed from off-site power through the STs, where the main generator would also be isolated by the generator output switchyard breakers. Even given a stuck switchyard breaker, the "breaker failure" scheme would isolate the next breaker(s) out from the stuck breaker. Should the breaker failure actuation result in the loss of the ST, all Class 1E bus(es) are expected to transfer to their associated EDGs, given no other failure. Therefore, this section does not evaluate HEAFs on the unit-connected design and instead evaluates potential HEAF effects on the ST circuits feeding the non-Class 1E/Class 1E lineups.

HEAF in Fault Zone 1

A HEAF in fault zone 1 is expected to result in an ST#1 protective trip lockout, and the non-Class 1E/Class 1E lineups will transfer to the ST#2 and be fed from offsite power.

HEAF in Fault Zone 1 with a Stuck Supply Breaker

If the ST#1 bus supply breaker in the same circuit as the HEAF does not open (that is, stuck) during a bus transfer attempt to isolate the non-Class 1E/Class 1E bus lineup from the HEAF, the ST#2 could initially feed the HEAF upon closure of its associated bus supply breaker.

Upon detection of the fault by the ST#2 protection system, the ST locks out and opens its bus supply breakers and associated switchyard breakers, causing a loss of voltage at the non-Class 1E/Class 1E lineups.

The resulting actuation of the Class 1E bus undervoltage relays will start the associated bus EDG, and the EDG output breakers will close in on their associated Class 1E buses.

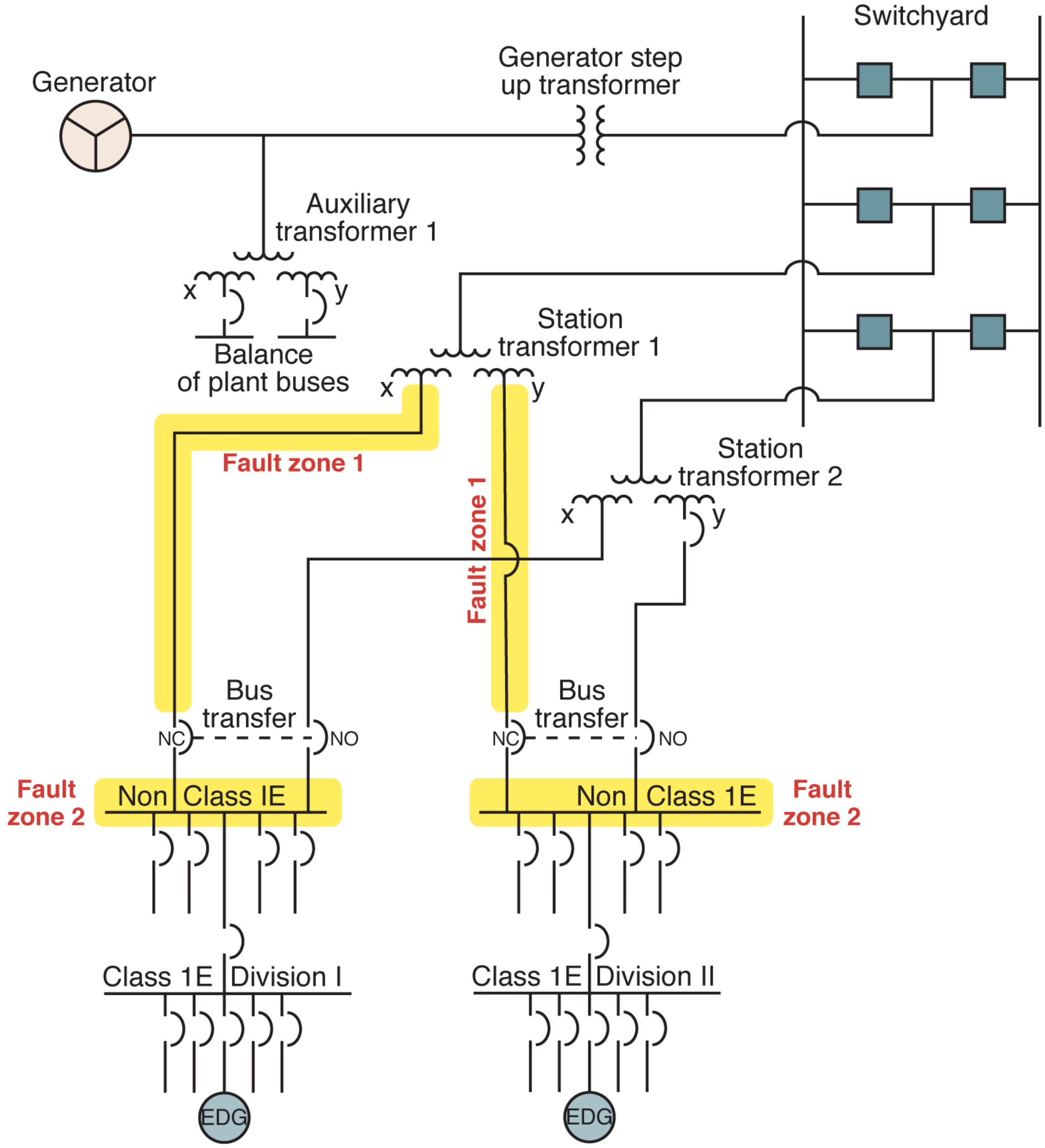

Figure 20 – Electrical distribution system design 8

The potential result is a LOOP with both Class 1E division buses fed from their associated EDGs. However, the faulted non-segregated bus or cable feed to the non-Class 1E bus will be lost. With respect to the damaged non-Class 1E bus feed, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus feed (non-segregated bus or cable) and stuck breaker are repaired and/or replaced.

Given the LOOP condition, if one of the EDGs fails to start and/or load, the station is one failure away from an SBO.

HEAF in Fault Zone 2 with a Stuck Supply Breaker

A HEAF anywhere in fault zone 2 with a stuck ST#1 bus supply breaker has the potential to initially impact only one of the non-Class 1E/Class 1E lineups due to the separate winding feeds.

However, if the HEAF persists, it will result in the ST#1 protection system actuating (lockout), opening the associated switchyard breakers, and initiating a bus transfer to ST#2.

The resulting bus transfer will be expected to only close the bus supply breaker from the ST#2 to the non-faulted bus, because it is expected that the faulted bus lockout signal would prevent the closing of the bus supply breaker from the ST#2 to the faulted bus.

Upon completion of the bus transfer of the non-faulted non-Class 1E bus, the closure of the bus supply breaker from ST#2 provides offsite power to the non-faulted non-Class 1E/Class 1E lineup.

The resulting actuation of the Class 1E bus undervoltage relays on the Class 1E bus impacted by the HEAF will start the associated bus EDG. The EDG output breaker will close and power the associated Class 1E bus.

The potential result is a partial LOOP. With respect to the damaged non-Class 1E bus, the associated Class 1E bus must remain powered by its associated EDG because it cannot be restored to offsite power until the non-Class 1E bus is repaired.

The resulting station configuration is one failure away from a LOOP and three failures away from an SBO.

Class 1E Bus Feed Variations HEAF (Zone 3) Analysis

Although no medium-voltage Class 1E switchgear HEAFs (fed by an intermediate bus) have been reported in the United States, an additional HEAF scenario that was considered for EDS designs 3 through 8 is a HEAF that occurs within the Class 1E switchgear downstream of an intermediate non-Class 1E bus (Zone 3) with a stuck breaker. It is worthy to consider two distinct EDS arrangements in the power feed from the intermediate non-Class 1E bus to the Class 1E bus.

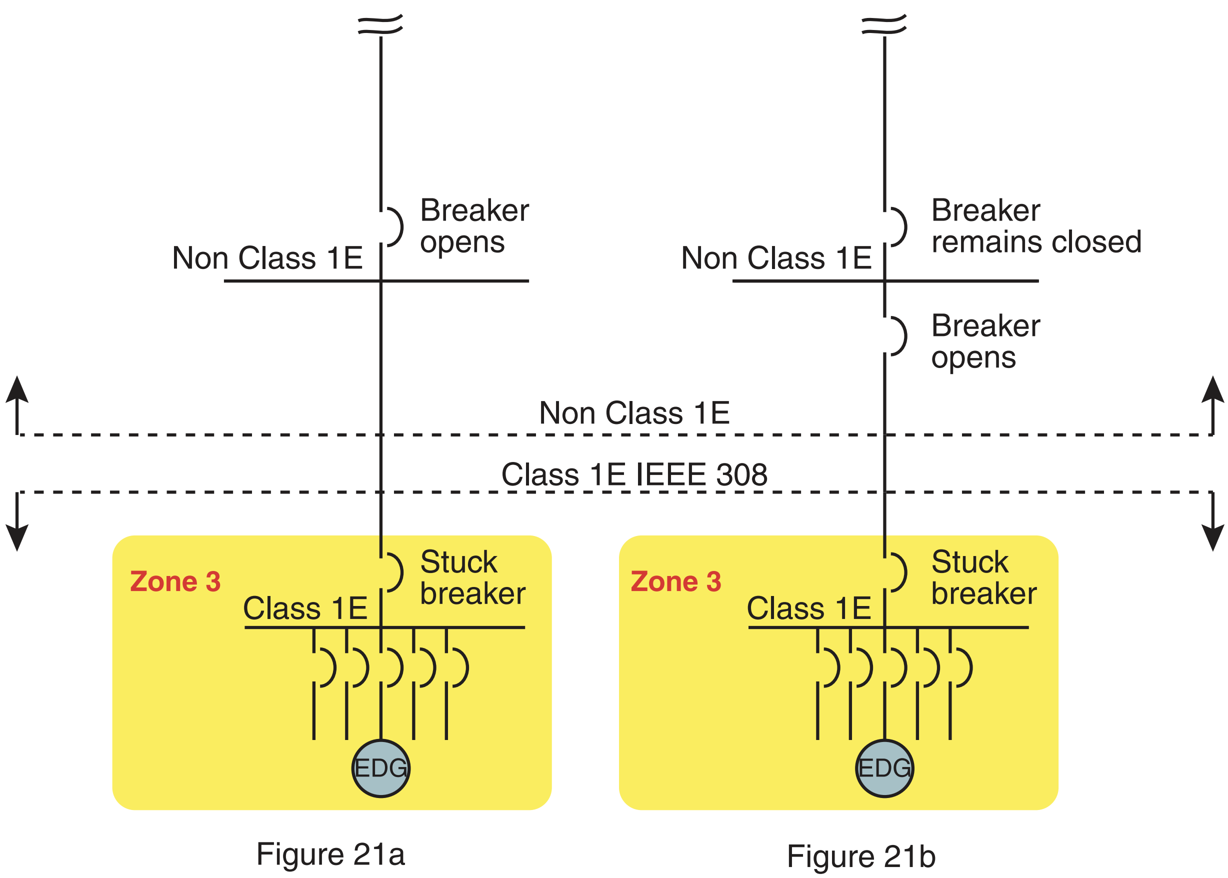

Figure 21 – Single Class 1E bus breaker feed (21a; left) and double Class 1E bus breaker feed (21b; right)

These two arrangements are as follows:

1. One Class 1E bus supply breaker located at the Class 1E switchgear. The feed from the intermediate non-Class 1E bus is a breakerless connection (bus duct or cable). See Figure 21a.
2. Two (or more) breakers between the intermediate non-Class 1E bus and the Class 1E bus. Typical arrangements are one non-Class 1E breaker located in the non-Class 1E intermediate bus feeding a second in series Class 1E bus supply breaker installed in the Class 1E switchgear. This provides double isolation protection between the intermediate bus and the Class 1E bus. See Figure 21b.

For HEAFs that originate in the Class 1E switchgear (Zone 3), with a stuck breaker, the likely outcome for the two aforementioned EDS arrangements would be the following:

1. One breaker between intermediate bus and Class 1E bus, as follows:

   With the Class 1E bus supply breaker stuck, the upstream non-Class 1E bus supply breaker would be required to operate to isolate the HEAF at the Class 1E bus. The non-Class 1E bus would lock out and all associated loads on that bus would be de-energized. Because they are likely critical BOP loads, a unit trip can be expected. Because the intermediate bus is locked out, the auto bus transfer of the non-Class 1E bus to the alternate source (that is, ST) would be blocked. It would be expected that the redundant Class 1E bus would successfully transfer to its offsite circuit (that is, ST). The failure of the Class 1E bus switchgear would also prevent the EDG from repowering the loads and result in a unit trip and a partial LOOP. Given this particular partial LOOP condition, the station is two failures away from an SBO.

2. Two (or more) breakers between intermediate bus and Class 1E bus, as follows:

   The expected outcome would still result in a loss of that Class 1E division. However, it is expected that the other circuit breaker located at the non-Class 1E intermediate bus will successfully operate (open) and the other redundant Class 1E bus successfully transfer to offsite power (ST). There would be two benefits, as follows:

   a. The series breaker would be expected to operate faster than the upstream, coordinated non-Class 1E intermediate bus supply breaker, and potentially limit the HEAF damage.
   b. To prevent a lockout of the non-Class 1E intermediate bus, potentially avoiding a plant trip.

   Nonetheless, just like the previous scenario, the failure of the Class 1E bus switchgear would also prevent the EDG from repowering the loads, resulting in a partial LOOP but with the unit remaining on line. Given this particular partial LOOP condition, the station is two failures away from an SBO.

   In both scenarios, the station would enter the associated plant Technical Specifications for a lost Class 1E division for restoration of the bus. In the case where the unit remains on-line, the limiting condition of operation allowed outage time would be the limiting factor to the time the unit may remain on-line for restoration of the Class 1E bus.

Industry Practices That Help Ensure System Performance

This section identifies and describes some of the more common maintenance and testing practices and programs that help ensure that EDS protection schemes operate properly to prevent or mitigate the impact of a HEAF. Some stations may have adopted other programs or additional practices. An updated summary of critical insights on HEAF prevention through maintenance was issued in 2019 as *Critical Maintenance Insights on Preventing High-Energy Arcing Faults* (3002015459).

Proper Maintenance Is Prevention

HEAF events start with an electrical fault that is caused by a degraded electrical connection or an insulation failure. Proper maintenance, inspection, and the testing of station electrical distribution equipment would have prevented many HEAF events described in the literature. Reducing equipment failures through maintenance will reduce the likelihood of a HEAF event. It is especially important to properly maintain critical equipment that could lead to more significant HEAF events, such as critical feeder circuit breakers (including non-Class 1E), isolated and non-segregated phase buses, and other high- and medium-voltage equipment that may cause a more severe HEAF event.

According to the NRC's *Office of Nuclear Regulatory Research in Operating Experience Assessment Energetic Faults in 4.16 kV to 13.8 kV Switchgear and Bus Ducts That Caused Fires in Nuclear Power Plants:*

> *Preventive maintenance and testing consistent with the manufacturer's recommendations generally provide reasonable assurance that the switchgear ratings are not degraded due to aging, contamination, or other maintenance preventable failure mechanisms. Protective devices are installed to detect abnormal voltages and currents and automatically trip circuit breakers to isolate an abnormality.* [5]

Circuit Breaker Maintenance

Circuit breaker maintenance programs include routine preventive maintenance (PM) and refurbishment programs. Due to the mechanical nature of circuit breakers, maintenance is typically time-based. Maintenance tasks and frequencies are developed using manufacturer guidance and industry operating experience. Maintenance frequencies are often modified by stations based on the circuit breaker criticality, environment, maintenance history, industry operating experience, and other considerations. EPRI's Preventive Maintenance Basis Database (PMBD) [10] is a system that contains maintenance schedules for major components in power generating facilities. The PMBD provides switchgear maintenance tasks and frequencies that serve as a baseline that nuclear stations can modify based on station-specific conditions and experience. The PMBD also provides a list of common maintenance tasks performed on circuit breakers. According to the EPRI PMBD, for critical medium-voltage circuit breakers, routine PM is performed every 4 to 6 years, and refurbishments (overhauls) are performed every 8 to 12 years. Many programs also include requirements for PM checks or complete refurbishment if a circuit breaker has interrupted a heavy fault.

Timing and Travel Analysis

Timing and travel analyses of circuit breakers are typically performed when circuit breakers are refurbished. These tests analyze the duration of the time that it takes for the circuit breaker to operate and confirm the breakers open within their design limits. Operating time duration is critical in ensuring rapid clearing of faults and preventing or minimizing the damage from a HEAF event, if the circuit breaker is part of a bus transfer scheme.

Switchgear Control Power Status Lights

AC medium-voltage circuit breakers require separate dc power to operate. When the current transformer senses abnormal current exceeding the protective relay setting, a dc signal is sent from the protective relay to the circuit breaker to open. If dc power is not available, the breaker "opening coil" in the breaker control circuit will not energize, and the breaker will not open [11]. This failure mode is commonly referred to as a *stuck breaker* and is factored into relay settings when performing selective coordination studies.

Additionally, it should be noted that stuck breaker events (due to the loss of dc control power) can be prevented by using switchgear dc power available status lights or the breaker status lights on the breaker cubicle. These lights can be inspected periodically via operator walkdowns to ensure that the appropriate light is illuminated. Once per shift, operator walkdowns of switchgear circuit breaker status is an important component to a nuclear station PM program.

Reduced Control Voltage Testing

Reduced control voltage testing of the trip and close coils is typically performed during routine PM on all medium- and low-voltage, metal-clad circuit breakers. This test ensures that the circuit breaker will operate under low dc control voltage conditions. Test values are calculated based on station-specific calculations.

Features Designed to Prevent Faults

For most medium-voltage, metal-clad circuit breakers, when the breakers are removed from the switchgear, automatic shutters close off and prevent exposure of the primary conductors.

Industry standards require mechanical safety interlocks to provide for safe removal, test, and insertion of the circuit breaker into the structure by not allowing unsafe conditions, such as racking a closed-circuit breaker onto an electrical bus.

Maintenance of Switchgear Primary Connections

Based on industry experience, which includes HEAF events listed in the literature, proper maintenance includes the connection between the primary connections (stabs) on the circuit breaker and the connections (fingers) where the circuit breaker is inserted into the switchgear bus. Industry operating experience and the EPRI fire events database include events where the lack of proper maintenance of primary connections, including the bus and circuit breaker connections, has resulted in electrical faults or HEAF events. Stations have periodic PM and refurbishment frequencies for medium-voltage circuit breakers, but switchgear maintenance outages do not occur as often. The switchgear contains connections to the circuit breaker, which might not be maintained as often as the connection on the circuit breaker. For critical switchgear, such as feeder circuit breakers that carry higher currents, and switchgear that is part of a bus transfer scheme, proper maintenance of

connections on both the bus side and the circuit breaker side is especially important. Inspections should be performed on proper silver-plating of connections, both on the switchgear bus and the circuit breaker. Maintenance should ensure that the proper spring tension in springs is used in the design of the primary connection. Also, proper alignment of the circuit breaker into the switchgear cubicle should be verified.

Bus Transfer Testing

Due to the integrated nature of normal source and alternative source circuit breakers, initiating signals, timing, protective and control relays, nuclear power plants perform integrated bus transfer testing every 18–24 months. Some of the more common bus transfer schemes (and critical support equipment) include the following [12]:

- Fast bus transfers, as follows:
  - Parallel fast transfer: In this make-before-break bus transfer scheme, the generator lockout relay closes the alternative source breaker, momentarily paralleling the alternative and normal source. The “a” contact of the alternative source breaker is used to trip the normal source breaker. An advantage is that there is no dead-bus time and no disruption of power to loads. A disadvantage is that fast transfer schemes are based on meticulous timing. If a fault occurs and the transfer scheme does not function correctly, the two sources could simultaneously be exposed to the fault.
  - Three-cycle bus transfer: Includes testing of the simultaneous trip and close signals and timing of the normal and alternative source breakers, respectively. Typically, five-cycle breakers are used to minimize dead bus time to approximately three cycles. This integrated testing also verifies proper operation of schemes that use an optional synch-check relay on the alternative power supply to protect against out-of-synchronism events.
  - Six-cycle bus transfer: Includes testing of the early “b” contact of the opening normal source breaker to close the alternative source breaker. In this break-before-make scheme, the alternative source is not placed in service until opening of the normal breaker is confirmed (that is, “b” contact closure upon the opening of a normal source breaker).
- Residual bus transfer: includes testing of the voltage permissive relay (0.25–0.33 per unit) that ensures that voltage has decayed sufficiently to prevent damage to motor shafts and motor winding due to excessive forces.
- In-phase bus transfers: includes testing the associated phase angle and sync-check relay.

Relay Testing and Calibration

Protective relays sense abnormal current flow and provide a signal to isolate faulted circuits or equipment, or portions of the system to allow the remainder of the system to function, limit the damage to faulted equipment, minimize fire or catastrophic damage to adjacent equipment, and minimize hazards to personnel. Typical relays used within nuclear plants are of an electromechanical, solid state, or a microprocessor-based design.

A strong test, calibration, and maintenance program is crucial to maintaining protective relays in a high state of readiness. The frequency of maintenance is typically time-based, and EPRI’s PM templates recommend relay as-found testing and calibration every 2 to 8 years, depending on the criticality of application and service environment.

Protective relay testing includes in-place functional logic string tests, including signal injection to validate timing, set-points, and proper functioning of the operating mechanism. Functional logic string tests validate that the relay sends a trip signal to the protective device(s), including verification that the device operates.

Visual inspections of protective relays identify tightness of connections, cleanliness, proper mechanical and contact alignment, indications of thermal stress, leaking capacitors, pitted, worn, or corroded contacts, and free movement of the disk or corroded edge connectors for solid-state relays [2].

Microprocessor-based relays are not addressed in the current EPRI PM templates, but tests typically performed on those relays ensure that the relay is measuring ac quantities correctly, the scheme logic and protection elements are functioning correctly, and the auxiliary equipment is functioning correctly.

Cables

Medium-voltage cable PM tasks that are used to assess insulation condition are different based on the cable design type that a plant has installed. Shielded or unshielded (non-shielded) cable

[2] *Neoprene is a registered trademark of DuPont.*

designs are both commonly used for cables rated at 5 kV. Typically, cables rated >5kV are required to be shielded. A shield is a helically wrapped metallic tape, corrugated copper drain wire, or concentric aluminum or copper neutral wires installed over the insulation.

This shield provides a path to ground for current (due to phase imbalance or fault current).

Both shielded and unshielded cable designs can be visually inspected. Visual inspection is a useful tool for both shielded and unshielded cables where it can be applied based on cable accessibility. The surface condition of the cable where it is can identify thermal degradation of a cable (the cable color changes, and it may harden or soften). Polychloroprene (Neoprene[2]) and polyvinyl chloride shrink when thermally aged and eventually crack. Although the cracking of the jacket is a sign of thermal aging, it does not necessarily mean the insulation is degraded, but it would be advised to perform some additional checking to make sure the insulation is not brittle as well.

Water, moisture, dirt, and chemical or oil contamination can also be visually identified. In addition to visual inspection, tactile or touching the cable and checking for hardness or sponginess of the surface provides useful information. However, medium-voltage cables should never be touched unless the cables are known to be de-energized and grounded because unsafe and even lethal voltages can be present, depending on cable types and how they are installed. Cable walkdowns for visual inspection are required prior to entering the period of extended operation from 40 to 60 years. Opportunistic visual inspections should be included during motor refurbishment, electrical testing, bus outages, and panel and breaker cubicle inspections; when valve operator housing is opened; and during other maintenance activities. Minimal training should be required for personnel doing the inspections, and it is recommended to use the computer-based training that is available in study, Plant Engineering: Cable Aging Management Training: Identification of Adverse Environment, and Introduction to Visual/Tactile Assessment of Cable (1022979).

Industry operating experience on degradation of medium-voltage cable in wet or submerged operating environments has made the testing of medium-voltage cables an increasingly common practice in the nuclear power industry in the last 5 to 10 years. Insulation resistance testing has little or no value for dry cables of most any type (because air is a very good insulator, a dry cable would need to be almost directly grounded or shorted to be identified by insulation resistance).

Insulation resistance of wet unshielded cables can provide an indication of cable health but should never be used to evaluate a shielded cable in the place of the testing described in the following. Current manufacturing specifications require a cable to be at least 2 gigaohms when new, and many types of cable insulation greatly exceed this value by a factor of 10 or more. EPRI recommends that any unshielded cable whose insulation resistance is less than 100 megaohms/1000 ft (328 megaohms/km) is an indication that the cable insulation is degraded to the point where it should be replaced. Insulation resistance is difficult to trend over time, but any significant change in test results greater than >10% of the previous reading should be evaluated as to why it changed.

Only cables with shielded designs can be evaluated using the electrical test techniques that are the most effective methods for identifying insulation degradation. The reason for this difference in testability is that a shield provides a uniform ground plane to which a test voltage can be applied across the insulation. This design feature allows the use of many electrical tests, but the primary condition monitoring tests for shielded cables are very-low-frequency (VLF) (for example, 0.1-Hz VLF) tangent delta (tan delta/dissipation factor), and partial discharge testing. Each test is described briefly in the following paragraphs.

Tan delta test results provide a global indication of insulation condition. Test acceptance criteria is supplied for cross-linked polyethylene and the various ethylene propylene rubber cables in EPRI study, *Plant Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants, Revision 1* (3002000557) [13]. The test acceptance criteria can be applied to tan delta or dielectric spectroscopy[3] (using 0.1-Hz data) test results. Tan delta can be used to indicate degraded insulation due to water treeing or thermal aging. Tan delta can indirectly identify cable accessory (splice or termination) degradation because, in many cases, electrical discharges (partial discharge, tracking) result in high instability numbers as indicated by high standard deviation (instability of tan delta values at a test voltage level) and/or high delta tan delta (marked increase between two voltage levels, typically at 0.5 times and 1.5 times the line-to-ground voltage).

[3] Henceforth, any mention of tan delta can be assumed to apply to dielectric spectroscopy, except as noted.

Withstand testing using 0.1-Hz VLF should be performed at the IEEE Std. 400.2 recommended maintenance test voltages for 15–60 minutes (30 minutes is the EPRI recommended test duration). This is a go/no-go test—if the cable does not fail, it is an indication that the cable can be returned to service, but if the tan delta results in the "action required" criteria, there is no assurance how long the cable will be reliable if the cause of the degradation cannot be corrected.

Partial discharge testing is useful for detecting accessory degradation; unlike tan delta testing, which is a global test, under the prober test conditions, the level of degradation and the location can be identified. This test typically requires expertise beyond what a typical nuclear facility might have to perform and analyze the test results. It is a less frequently used test in nuclear facilities because many sites have helically wrapped, taped metal shields that often are oxidized or corroded, making them prone to attenuation of the high-frequency signal caused by partial discharge and arcing. This makes detection and location of accessory degradation more complicated if the attenuation level prevents a reflected signal from the cable end opposite the end where the equipment is hooked up to the cable. The cable in question should be evaluated to determine the feasibility to perform partial discharge testing because if it can be applied, it will provide the best direct indication of a potentially degraded cable accessory.

Operator Walkdowns

Switchgear walkdowns are typically performed once per shift, and operators verify that dc power is available via lights on the switchgear. If "dc power available" lights are not present on the switchgear front panel, breaker status indication lights can be used to verify that dc power is available. In this case, both "closed" and "open" indicating lights are checked. If both are not illuminated, immediate investigation is performed to ascertain whether a defective lightbulb is the cause. If it is not a defective lightbulb, the dc control power is checked because a lack of dc control power will prevent breaker operation.

Bus Inspections and Testing

Bus inspections are commonly performed. This maintenance includes the following:

- A visual inspection for obvious signs of damage, insulator damage, missing hardware (boot), and so on is conducted.
- The bus is checked for evidence of overheating.
- Bus bolting is visually inspected to verify that critical compression washers are in place and not missing.
- The inspector verifies that incorrect hardware has not been used (for example, a flat washer in lieu of a compression washer).
- Critical connections are also torque-verified for tightness.
- Micro-ohm readings are performed to verify low-resistance connections (such as ductor, digital low-resistance ohmmeter).
- A portable vacuum cleaner is used to remove debris and dust because dust can have long-term detrimental effects, such as reduced natural ventilation and can become conductive and lead to tracking.
- Flex links are intact and not damaged (such as broken braid strands, broken laminations).
- Upon completion, an insulation resistance test is performed on the bus ready to be returned to service.

Electrical Bus Monitoring Systems

Although bus monitoring systems are not widely used in nuclear power plants, it should be noted that these systems are commercially available. Bus monitoring systems are based on various technologies and include infrared thermography, optic (light-sensitive) temperature monitoring, optic arc flash (light combined with overcurrent), and partial discharge. One U.S. nuclear plant has installed an optic arc flash system on a non-power block ST and downstream circuit breakers that provide power-to-service buildings. The system uses sensors in each breaker cubicle to trip the incoming bus breaker early if increasing current and arc flash are simultaneously sensed.

The arc flash bus monitoring technology was developed primarily to protect station personnel from an arc flash during routine activities in close proximity to switchgear. Although not initially intended for HEAF mitigation, it has the potential given further design reviews and improvements for security (that is, no increase in false trip actuations during non-arc flash conditions). Because the bus monitoring system consists of digital devices, software quality assurance and cybersecurity reviews would have to be performed prior to use in the power block.

Arc flash bus monitoring is a potentially promising technology given that the majority of U.S. nuclear plants could benefit from using the bus monitoring system on the intermediate non-Class 1E buses fed directly from the AT.

Conclusion

Operating experience has revealed that a main generator can feed a HEAF for several seconds following a unit trip if a fault originates in the unit-connected design. This electrical design, present in both fossil and nuclear power plants, does not use a generator breaker that can isolate the energy source (main generator) from the fault during generator coast-down before the voltage collapses.

Operating experience has suggested that arc faults can arise, and when combined with any latent issue with the nearby protective device or switchgear (such as a breaker malfunction), they can escalate an event so that significant high-energy damage can occur. A strong PM and test program is an important element in preventing HEAF events.

A selectively coordinated protection system ensures that (1) the nearest circuit protective device to a fault (such as a breaker or fuse) completely isolates the fault without relying on any other upstream protective device and (2) it does not unnecessarily remove power to non-faulted parts of the system.

According to the OECD data review, 46 of 48 HEAF events were associated with equipment maintenance. In addition, a review of the EPRI Fire Events Database shows that the most prevalent cause of failure is inadequate maintenance. A strong EDS maintenance and testing program is an effective way to help prevent and/or mitigate the impact of a HEAF. These practices include circuit breaker maintenance, bus transfer testing, relay testing, inspection and testing of bolted bus bar and other electrical connections, and cable monitoring. Based on operating experience, properly maintained and functional fast bus transfer schemes are particularly important.

HEAFs can be prevented by ensuring that both current-carrying and protective equipment is fully functional by performing appropriate PM in accordance with established schedules. PM is a combination of time-based inspection, refurbishment, and testing. For current-carrying equipment, the critical focus is periodically verifying and performing maintenance on primary disconnects and other critical connections (silver plating health, proper fasteners, and tightness) through the entire EDS. For protection equipment, verifying settings and actual performance of the protective devices (such as breaker opening), including periodic refurbishment of circuit breaker critical linkages and re-lubrication activities. Cable insulation periodic health testing is also critical. Additionally, when a HEAF has occurred, properly maintained and functional fast bus transfer schemes are particularly important for protection against transferring the HEAF from one source to another. Bus transfer scheme maintenance includes maintenance and testing of the entire integrated scheme, from sensors and permissives to critical breaker timing verifications.

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Appendix A: Generator Voltage Decay Profile Feeding an Arcing Fault (Post Trip)

Background

Several operating experience events have been identified [5] where a number of HEAFs continued to be fed by the coast-down of a main generator due to a stuck (failed closed) breaker between the secondary or tertiary side of the UAT and the first electrical bus (for example, switchgear) of a unit-connected design. This is because the majority of unit-connected designs (as defined in this report) do not have a generator breaker to isolate a fault that occurs immediately downstream of an AT or first-line switchgear from a generator's decaying energy. This may lead to long duration faults that exceed the design ratings of the switchgear and supply breaker.

With further industry testing planned, it was considered for realism that some tests should attempt to replicate the energy delivery from a generator (without supporting active excitation [exciter field breaker open]) feeding a fault where the bus of interest is one breaker downstream of the UAT and not subject the bus to unrealistic full grid voltage (stiff source). This is because it would be expected that the generator switchyard breakers would disconnect the HEAF from offsite power in a few cycles given generator/differential protection lockout trips.

Detailed Discussion

An actual generator-fed arcing event from a power plant was captured via a generator digital fault recorder (DFR) after the generator tripped off-line (exciter field breaker open). The faulted condition was on the high side of the GSU transformer bushings instead of the auxiliary power system. However, the data still provides an insight into generator voltage decay performance when feeding a fault during the coast-down immediately after a unit trip. The DFR clearly shows two of the three phase generator voltage profiles over an approximate six-second duration (see Figure 22). The figure also shows the three generator currents feeding the fault. What is particularly important is that this dynamic voltage decay profile was under load (that is, varying fault conditions).

It is acknowledged that no two events will be identical; however, having an actual recording of a generator feeding an arcing fault is of benefit when reviewing the limitations of unit-connected designs.

Overview and Identification of Voltage and Timing

The following description aids in some of the critical timing of Figure 22 as follows:

- The plant tripped offline:
  - A phase current: 29 kA
  - B phase current: 0 kA
  - C phase current 45 kA

This event was a direct result of a C phase-to-ground fault beginning on the C phase high-side bushing of the GSU (displayed as generator A phase in Figure 22 due to a GSU wye-delta transformation). The fault was cleared from the system (per the Switchyard DFR) in approximately **2.3 cycles** by the tripping of the two generator switchyard breakers.

Support for the fault came from both the generator and the auxiliary busses after the switchyard 240kV breakers opened. The auxiliary 4kV buses were still tied to the generator through the UAT tie breakers. These breakers opened approximately **3 cycles** after the unit high-side trip.

At approximately **26 cycles** after the unit trip, the fault migrates to all three phases, as follows:

- A phase current: 28 kA
- B phase current: 27 kA
- C phase current 41 kA

At approximately **2.91** seconds after the unit trips, the generator A phase current feeding the fault decreases to zero amps and its contribution to the fault is over.

At approximately **3.28** seconds after the unit trips, the generator B and C phase currents feeding the fault attempt to clear, but the fault restrikes.

At approximately **5.91** seconds after the unit trips, the generator B and C phase currents feeding the fault decrease to zero amps (fault clears), and the generator-fed fault event is terminated.

All faults have cleared and the unit continues to wind down normally. It can be seen that generator voltage still exists after 6 seconds as the generator coasts down.

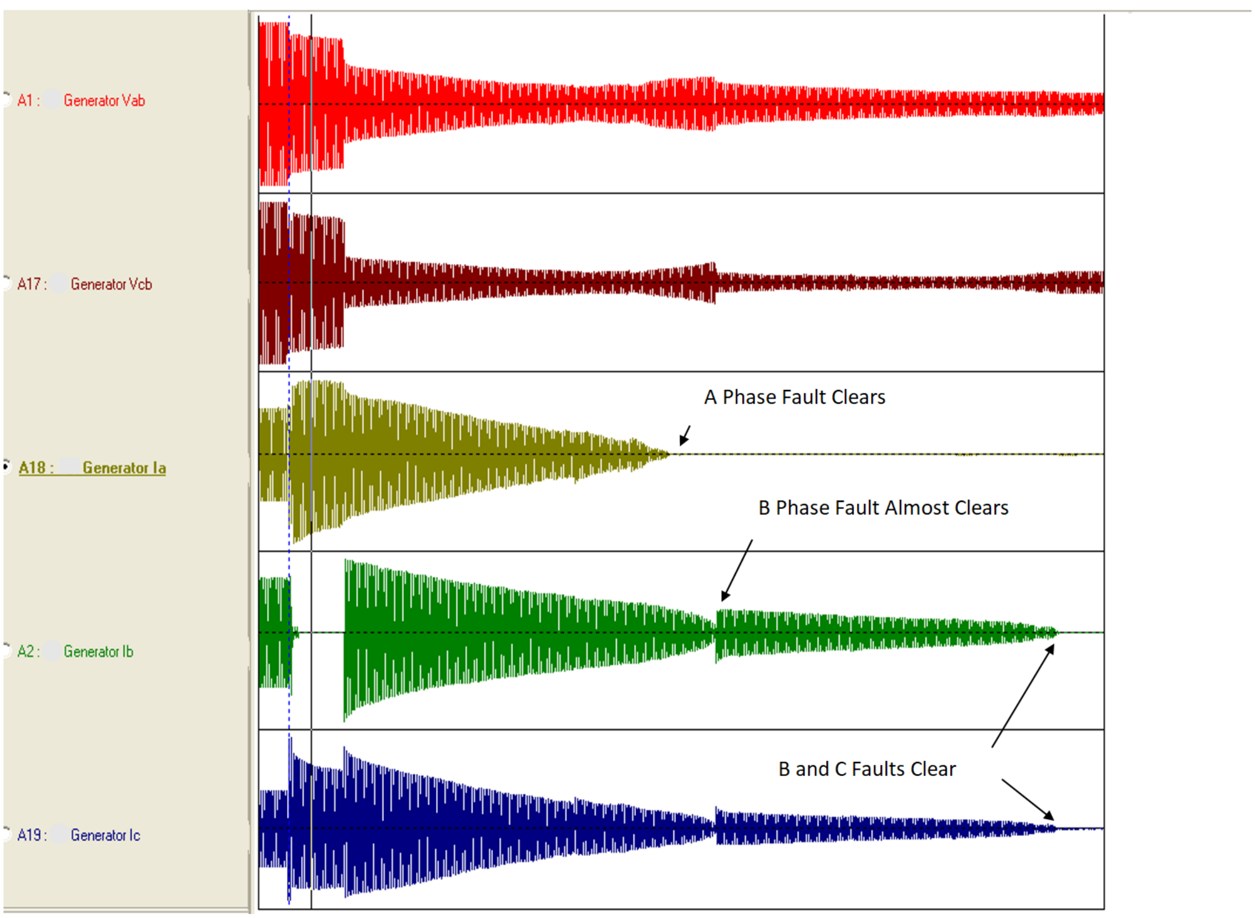

Figure 22: DFR of main generator voltage decay for approximately 6 seconds

Note: Top two traces (red and brown/magenta) are the main generator phase voltages. The bottom three traces are the arcing currents across the high voltage side of the GSU transformer.

It can be seen previously that the fault energy (as a load) has an influence over the generator decaying voltage profile (and vice versa), as follows:

1. When the fault current is at a very low level, approaching extinction, generator voltage begins to rise.
2. A sufficient rise in generator voltage can cause an extinguished arcing fault current to restrike.
3. The relationship is symbiotic, that is, as the arcing fault current restrikes, the generator voltage immediately drops in response to the load (that is, arc restrike).

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Risk and Safety Management

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