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Original Article

Mitigation of high energy arcing faults in nuclear power plant medium voltage switchgear

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A B S T R A C T

A high energy arcing fault event occurred in the medium-voltage (13.8 kV and 4.16 kV) metalclad switchgears in a nuclear power plant not only affecting switchgear but also connected equipment due to the arc energy. The high energy arcing fault also causes a fire that influences the safety function of the unit. Therefore, from the safety point of view, it is necessary to evaluate the influences of high energy arcing fault events on the safety functions of nuclear power plants. The purpose of this paper is to elaborate the characteristics of high energy arcing faults and propose a high energy arcing fault mitigation scheme for medium voltage networks in nuclear power plants.

1. Introduction

An arc flash hazard is defined as “A dangerous condition associated with the possible release of energy caused by an electric arc”. The arc fault occurs when short-circuit current flows through the air rather than through solid connection between phases or phase and ground. In electric power distribution systems, due to the very high fault currents and relatively high voltages typically, these arcing faults carry high levels of energy, releasing a great deal of heat and pressure into the environment. The arc flash event may be considered an electrical explosion of varying magnitude which in some cases is very dangerous and damaging like any explosion would be.

Arc flash events can result from inadvertent contact between energized parts by a loose conductor or dropped tool, contamination, equipment failure, animal intrusions, lacking of maintenance or improper maintenance, and many other causes. The resulting heat and pressure wave can cause significant injury to workers, including severe burn injuries. Electrical burn injuries in the workplace have a high incidence of mortality relative to other workplace injuries. The heat and pressure can also cause significant damage to the equipment within which arcing faults occur [1,2]. Especially the high energy arcing faults (HEAFs) have the potential to cause extensive damage to the failed electrical components and distribution systems along with adjacent equipment and cables within the zone of influence. Furthermore, the significant energy released during a HEAF event can act as an ignition source to other combustible materials resulting in fires. It has been reported that HEAF events in NPP’s throughout the world have demonstrated the potential to damage safety related systems, structures and components (SSC’s) [3].

The devices breaking the circuit can extinguish an arc quickly with minimal damage. Insulating materials located around the bus bars or along the interior walls of the compartment also help quenching the arcing fault. However, when overcurrent devices do not detect, or do not respond quickly enough, these insulating materials, which are commonly a type of plastic composite, can ignite and lead to a fire event. Through the extensive assessment of the literature about arc faults and the characteristics of HEAF at a medium voltage distribution network, an appropriate detection scheme was proposed in this study. Section 2 introduces HEAF cases in the nuclear power plants throughout the world with

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analysis on the causes. Then HEAF types were classified into several categories to select the optimum mitigation method. Arc fault current in the medium voltage switchgear bus in a nuclear power plant was calculated in section 3. Arc flash mitigation techniques were introduced and the 'incident energy reduction by reducing arcing time' was proposed as a solution to mitigate HEAF in section 4. Finally, the effects of the proposed mitigation method were discussed in section 5.

2. HEAF experienced in nuclear power plants

2.1. Major places HEAF are occurring

The OECD FIRE Database Project [4] has indicated that 48 of the total 415 fire events reported from member countries between 1979 and mid-2012 in the Database are HEAF induced fire events. Details can be found in summary in the HEAF events. Twenty-three HEAF events occurred inside plant buildings and fifteen outside (typically in the switchyard/transformer yard or outside building on the plant side), the latter mainly at transformers. Twenty-one events were classified as safety significant or had the potential to impair nuclear safety under different configurations or conditions, due to one or more redundant safety trains being lost or adjacent compartments being affected by direct or consequential fire effects.

Consequential impact to adjacent compartments is to a large part due to cable damaged by fire. The most likely place where HEAF can occur is in the electrical cabinets. Among the above twenty-one events, nine events occurred in the electrical cabinets, five events occurred in the cableways (bus duct, bus bar, and cable runs), four events occurred in the transformers, and remaining three events occurred in the circuit breakers.

2.2. Causes of HEAF in equipment and devices

A recent technical report on the HEAF events showed that HEAF typically occurs in a few specific components such as switchgears and transformers, electric cabinets, cables, connecting boxes and circuit breakers on voltage levels between 0.4 kV and 400 kV. Among the 31 HEAF events in German NPPs 60% (18) is caused by switchgears, and circuit breakers and the contribution by transformer based HEAF events is 10% (3). Technical causes as well as human factor (HF), mistakes in procedures and ageing represent the root causes of the HEAF events observed in German nuclear power plants. Technical root causes are the predominant failure mode (67%). Erroneous human actions played a significant role for five events (16%), ageing effects affected or caused the component failure in case of three events (10%), and faulty procedures and/or administrative reasons were involved in two events (nearly 7%) together with other root causes [5].

2.3. Classification of causes and types of HEAF events in 4.16 kV–13.8 KV switchgear and bus ducts

The HEAF occurred in the medium voltage switchgears in nuclear power plants have been reported by many research institutes [3,6]. The causes and types of arc fault may be classified as below;

2.3.1. Insulation or contact failure

At Maanshan, while the operators were transferring Unit 1 back to the preferred 345 kV source, an high energy electrical fault occurred in normal incoming feeder breaker to 4160 V essential bus. Normal incoming circuit breaker indicated open prior to the fault; but when the 345 kV startup transformer was energized, providing voltage to the input side of the circuit breaker, an high energy electrical fault occurred as evidenced by an explosion, arcing, smoke, ionized gases, and fire. This resulted in a loss of offsite power (LOOP) to both the safety and non-safety electrical buses. Maanshan believed the root cause to be insulation failure in circuit breaker. Maanshan identified several possible causes of the insulation failure: overvoltage due to switching or ferromagnetic resonance, overvoltage from residual rotational momentum of reactor coolant pumps (RCP's), or faulty protective relay coordination. Taiwan Power finally concluded that ferromagnetic resonance was the cause of the event [7].

On May 15, 2000, Diablo Canyon Unit 1 was at 100 percent power with the station loads powered from the auxiliary transformer (AT). At AM 00:25, a fault occurred on the 12 kV bus duct between the AT and two 12 kV buses. Protective relays immediately sensed the fault and opened the appropriate switchyard circuit breakers, the generator field circuit breaker, and the 12 kV AT supply circuit breaker. Since there are no circuit breakers between the main generator and the AT, the main generator continued to feed the fault for 4–8 s until the main generator field collapsed. The sustained fault resulted in arcing in the 12 kV bus duct that jumped to and damaged the 4.16 kV bus duct from 12 to 4.16 kV step down transformer. The 4.16 kV bus duct was approximately 4 inches above the 12 kV duct. The Step down transformer tripped, causing the loss of 4.16 kV to the three vital buses, and the start and loading of all three emergency diesel generators (EDG's). Startup transformer (ST) remained energized, supplying power to some 12 kV and 4.16 kV non-vital loads. The licensee concluded that the cause of the fault was the thermal failure of the bolted connection of the center conductor of the 12 kV bus. A polyvinyl chloride boot over the connection overheated and created smoke. The smoke and the radiant heat from the center conductor provided a conductive environment for a phase to phase arc.

During normal operation of the reactor with power at 100% and the turbine generator (T/G) power at 990 MWe a HEAF event occurred on the phase 'B' of the main transformer in the Uljin Unit 1 on 30 January 2001. The root cause of the HEAF event was a contact failure between the tulip contactor of the upper part of the bushing and moving contactor of gas insulated bus (GIB). The arcing induced melting of the tulip contactor of the bushing.

On the other hand, during normal operation of the reactor with power at 100% and T/G power at 602 MWe, a HEAF event with explosion and consequential fire occurred on the phase 'B' of the main transformer in the Kori Unit 1 on April 22, 2002 which caused a turbine/generator trip due to the ground failure between outlet lead wire and outer casing of the main transformer phase 'B'. The root cause of the HEAF event was assumed to be a manufacture flaw. It is assumed that the connection had been damaged slowly but continuously for about 28 years since its installation in 1974 because the connection was lead-welded [8].

2.3.2. Improper bus transfer

0n June 10, 1995, Waterford 3 was operating at 100 percent power with the plant loads fed from ATs at AM 08:58, a remote substation transformer lightning arrester failed. This resulted in a transient current that caused inadvertent operation of the Waterford main transformer sudden pressure relay, tripping the main generator and turbine, and initiating a fast bus transfer of the station loads from the ATs to STs. The buses transferred as designed with the exception of 4.16 kV non-safety bus A (one between A and B). The AT supply circuit breaker to bus A failed to open in 5 cycles while the ST supply circuit breaker to bus A closed within 7 cycles. Since there are no circuit breakers between the AT and the main generator at Waterford 3, the electrical current from the generator continued to supply power to the grid through the AT, the 4.16 kV non-safety bus A, and the ST. The excess current caused an energetic electrical fault with an explosion and fire in the 4.16 kV AT supply circuit breaker to bus A. The root cause of the explosion in the 4.16 kV non-safety bus A was the improper automatic bus transfer, and the improper bus transfer caused the failure of both sources of offsite power. The 3000 amp cable bus between the AT and 4.16 kV non safety bus A was damaged beyond repair. The fire incident severely damaged the contents of the AT circuit breaker compartment and the adjacent metering compartment switchgear. With the assistance of the manufacturer, the licensee determined that failure of the AT circuit breaker to open involved restricted movement of the trip mechanism due to hardened grease.

January 3, 1989, Oconee 1 was at 26 percent power and in the process of manually transferring non-safety 6.9 kV bus from the ST to the AT. Immediately after the transfer, an energetic electrical fault occurred resulting in a fire and explosion in the AT supply circuit breaker that feeds the non-safety bus. The AT protective relays detected an electrical fault and tripped the turbine generator, the switchgear 6.9 kV supply circuit breaker for the AT (which failed to completely open), and the two RCPs fed from the switchgear. The main generator continued to supply energy to the fault through the stuck 6.9 kV supply circuit breaker from the AT until the generator field decayed. Later inspections could not determine the cause with any certainty. Inspection found that the 6.9 kV supply circuit breaker for the AT failed to open and was heavily damaged by fire and heat and that an explosion blew the AT supply circuit breaker compartment door off its hinges.

On February 3, 2001, SONGS Unit 3 was at 39 percent power and in the process of power ascension following a refueling outage. The operators were in the process of transferring non-safety buses from the ST to the AT. Each SONGS Unit has one AT and three STs. At PM 03:13 the operator closed 4.16 kV AT supply circuit breaker (normal) onto the non-safety bus, and the ST supply circuit breaker (alternative) that was feeding the non-safety bus opened as designed. Just after this transfer, the AT protective relays detected a fault and tripped the main generator, the generator output circuit breakers in the switchyard, and AT supply circuit breaker (normal). Even though AT supply circuit breaker (normal) tripped, the fault was not isolated, and the main generator continued to supply energy to the fault. The fault was energetic and resulted in the burning and failure of the AT current limiting grounding resistor and started the fire in circuit breaker (normal). The damage was so extensive that the exact cause of the fault could not be determined. The licensee found the circuit breaker (normal) phase C arcing contact completely melted and concluded that circuit breaker (normal) phase C failed to open completely during the bus transfer. The licensee also indicated that arcing, fire, smoke, and ionized gases in circuit breaker (normal) caused multiple faults on the bus, and collateral damage to 4 other switchgear compartments and the offsite power circuit connection at circuit breaker (alternative).

2.3.3. Improper relay setting

On July 6, 1988, Palo Verde Unit 1 was at 100 percent power with the plant's loads powered from the AT. A three-phase-to ground fault occurred in non-safety 13.8 kV bus. The generator continued to feed the bus fault since the 13.8 kV circuit breakers that connect the AT to the bus did not open immediately due to the design of the bus relay protection. The bus overcurrent protection was designed to operate and isolate the bus fault in 42 cycles for a 24000 amp fault; however, the fault was energetic enough to fail the AT electrically, rupture its tank, and start it on fire within 20 cycles. The switchgear failure was attributed to cracked and brittle bus insulation, and dirt that had accumulated in the switchgear. Inadequate preventive maintenance and housekeeping controls were identified as causal factors.

3. Arc flash analysis for MV switchgear of a nuclear power plant

It is quite obvious that the most effective and practical method to reduce the arcing fault energy level is to reduce the arcing time. In practice, this means minimizing the operation time of the protection [9,10]. The arcing fault arc energy estimation is possible by the calculation of the short circuit current in a circuit. Then estimated arcing fault energy is used for the design of personal protection equipment and arc flash protection system to determine the level of hazard to personal and as a proximity for potential equipment damage as well. .

The following is the evaluation result of arc flash hazard in the 13.8 kV Switchgear of a 1000 MW PWR NPP. The IEEE Standard 1584–2002 [11] recommended procedure was used in the evaluation. The empirically derived equations were developed by IEEE working group on arc flash. To evaluate the specific equipment or arc flash scenario a more refined arc flash analysis approach is required [12,13]. These equations are based on test results and are applicable for the conditions specified in Table 1 [14,15].

3.1. Determine arc fault currents

For medium voltage systems (>1 kV), the arc current is given by equation;

$$Ia = 10^{\{0.00402+\ 0.983\ \log\ (I_{bf}\ )\}} \tag{1}$$

where log is the log10

Ia = arcing current (kA)
I_{bf} = bolted fault current for three-phase faults (symmetrical RMS) (kA),

In the 13.8 kV switchgear bus of the reference plant, symmetrical short circuit current is 29.3 kA [16].

Then Ia $= 10^{\{0.00402+\ 0.983\ \log 29.3\}} = 27.92$ kA

3.2. Estimate of normalized incident energy

The normalized incident energy, based on 0.2 s arc duration and 610 mm distance from the arc, is given by equation;

$$E = 10^{\{K1+K2+1.081^{*}\ \log\ (I_a)+0.0011G\}} \tag{2}$$

where

E_n = incident energy normalized for time and distance (J/cm^2)
$K_1 = -0.792$; open configuration $= -0.555$; box configuration
$K_2 = 0$; ungrounded and high resistance grounded systems $= -0.113$; grounded systems

Table 1
Conditions for which the IEEE Std 1584-2002[1] equations are applicable.

Parameter	Applicable Range
System voltage (kV)	0.208–15 kV
Frequencies (Hz)	50 or 60 Hz
Bolted fault current (kA)	0.7–106 kA
Gap between electrodes (mm)	13–152 mm
Equipment enclosure type	Open air, box, MCC, panel, switchgear, cables
Grounding type	Unground, grounded, high resistance ground
Phases	3 Phase faults

[Note] IEEE 1584 Guide is in the process of being republished and different equations will be provided. Arcing fault analysis should be performed using the latest version of IEEE 1584 available.

Table 2
Distance factor(x) for various voltages and enclosure types.

Enclosure Type	208V to 1 kV	>1–15 kV
Open air	2	2
Switchgear	1.437	0.973
MCC and Panels	1.641	
Cable	2	2

[Source] Table 4 of IEEE Std 1584-2002.

G = gap between conductors (mm), Gap of the 13.8 kV switchgear is 93 mm (estimated).
Then $E_n = 10^{\{-0.555-0.113+1.081^{*}\log 27.92+0.0011*93\}} = 9.94\ \mathrm{J/cm^2}$

3.3. Estimate of incident energy

The normalized incident energy is used to obtain the incident energy at a normal surface at a given distance and arcing time with equation;

$$E = 4.184\, C_f E_n \left(\frac{t}{0.2}\right)\left(\frac{610}{D}\right)^x \tag{3}$$

where

E = incident energy ($\mathrm{J/cm^2}$)
Cf = Calculation factor = 1.0; voltage > 1 kV = 1.5; voltage ≤ 1 kV
t = arcing time (seconds)
t is coordination time plus circuit breaker trip time; Maximum pickup time of the incoming feeder is 1 s (Fig. 2) and circuit breaker trip time is 5 cycles. therefore
1.0 + 5/60 = 1.08 s
D = working distance from the possible arc point (mm) to the person; 1200 mm (1200 mm is estimated working distance for 13.8 kV SWGR)
x = distance exponent as shown in Table 2.
Then
$E = 4.184*1.0*9.94\left(\frac{1.08}{0.2}\right)\left(\frac{610}{D}\right)^{0.973} = 116.26\ \mathrm{J/cm^2}$

3.4. Flash protection boundary

The flash protection boundary is the distance at which a person without personal protective equipment (PPE) may get a second-degree burn that is curable;

$$DB = 610^{*}\left[4.184\, C_f E_n \left(\frac{t}{0.2}\right)\left(\frac{1}{E_B}\right)\right]^{1/x} \tag{4}$$

where.

D_B = distance of the boundary from the arcing point (mm)
Cf = calculation factor = 1.0; voltage > 1 kV = 1.5; voltage ≤ 1 kV
E_n = incident energy normalized
E_B = incident energy at the boundary distance ($\mathrm{J/cm^2}$); E_B can be set at 5.0 $\mathrm{J/cm^2}$ (1.2 $\mathrm{Cal/cm^2}$) for bare skin.
t = arcing time (seconds) = 1.08 s
x = the distance exponent from Table 2.
Then $\left[DB = 610*4.184*1.0*9.94\left(\frac{1.08}{0.2}\right)\left(\frac{1}{5}\right)\right]^{1/0.973} = 30,450$ mm

This indicates that within 30 m of the arc flash, any unprotected person could sustain second-degree burns from the fault incident energy.

4. Arc flash mitigation methods

4.1. General

The Risk Control Hierarchy (RCH) in the ANSI/AIHA-Z10 standard is designed to provide electrical safety professionals with a roadmap for setting the right safety objectives that result in the reduction of electrical risks. Different methods to mitigate arc flash events have been introduced and can be divided into two general categories: active and passive.

Passive mitigation is defined to be an equipment option or type that either contains and redirects the arc blast or helps to eliminate the potential of a flash event (i.e., insulated main bus). This type of

Table 3
.Arc flash mitigation techniques.

Passive	Active
Reduce exposure with equipment options	**Technology to reduce arcing time & incident energy**
• Insulated/isolated bus	• Arc absorber
• IR scanning windows	• Zone selective interlocking (ZSI) instantaneous
• Closed door drawout of breakers	• Crow bar
• Side section barriers	• Bus differential (87B)
• Hinged vs. bolted doors	• Alternate setting groups
• Heaters	• Current limiting devices
Reduce exposure with equipment types	**Design practices to reduce arcing time & incident energy**
• Arc resistant structures	• Consider fault currents
	• Transformer sizes
	• Grounding
	• Reducing bus capacity
Others?	**Reduce exposure via maintenance practices**
	• Follow NFPA 70E
	• No live maintenance
	• Remote switching
	• Remote racking
	• Remote monitoring
	• Remove contaminants
	• Training & labeling
	• Use of proper PPE
	• Maintenance setting

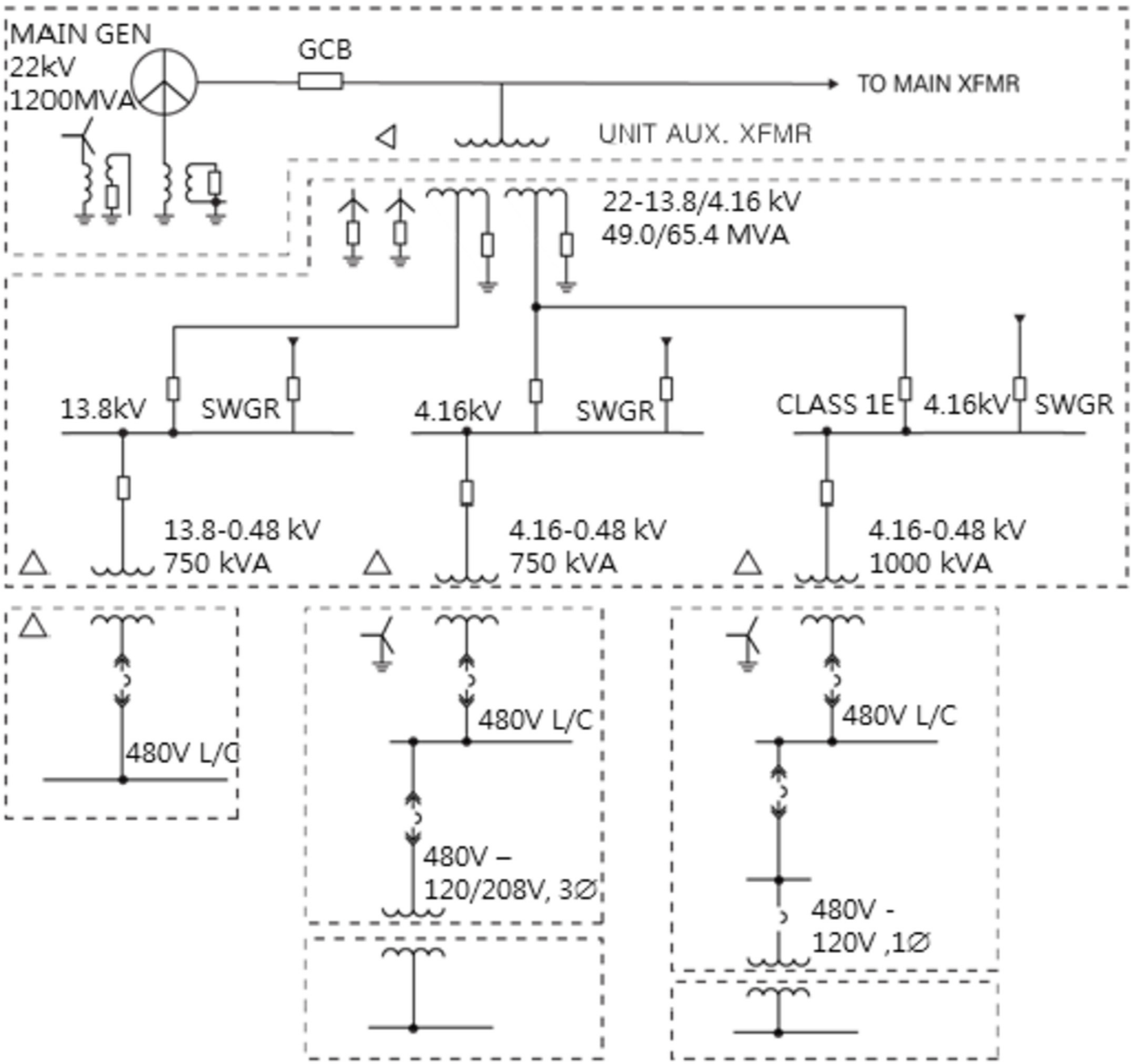

Fig. 1. Simplified single line diagram of the auxiliary power system of a nuclear power plant.

mitigation does not require any actions or settings by an operator to implement. The other method is the active mitigation. Active mitigation takes a proactive approach to reducing both incident energy and the exposure to arcing faults through the active use of technology, design, and maintenance practices. Table 3 contains a list of passive and active items [17,18]. Meanwhile, the necessity of good maintenance practices on all electrical equipment to ensure proper safe operation regardless of safety technology relied upon is inevitable.

4.2. Incident energy reduction by reducing arcing time

Most of the items in Table 3 should be considered at the electrical distribution system design stage. Switchgear design and planned system operation are important factors. High-speed relaying is often the easiest way to reduce incident energy. However, the reduction of arcing time by adjusting relay coordination time is not satisfactory to reduce the arcing incident energy. Dedicated protection scheme is necessary. There are several techniques that can be utilized to reduce arc flash energy [19].:

(1) Enable sensitive instantaneous overcurrent elements during maintenance
(2) Relays with instantaneous element supervised by arc or noise detection
(3) Fast trip schemes using relays and communications (Zone selective interlocking or blocking)
(4) Current differential relay protection
(5) Reduce coordination intervals of existing time overcurrent relays
(6) Breaker failure protection

In this paper, study is focused on the reduction of arcing fault energy by reducing arcing time in terms of MV switchgear relaying and protection [20]. After reviewing the current overcurrent protection system of the 13.8 kV switchgear in Korean standard nuclear power plants, appropriate arcing time reduction technique is proposed [21].

4.3. Existing overcurrent protection scheme of medium voltage switchgears in nuclear power plants

Fig. 1 is the simplified single line diagram of the auxiliary power system of a pressurized water reactor type nuclear power plant (one division only). Overcurrent protective devices can generally be classified as having either time-overcurrent or instantaneous trip characteristics. It is therefore logical that any primary overcurrent device which fails to complete its mission would be backed up by other devices which also function on over current sensing, but set to operate at higher levels of time and/or current.

In principle, incoming feeders of a switchgear and branch feeders supplying power to sub-distribution panel are provided with time overcurrent relay (ANSI device no. 51) and branch feeders for end loads (motors, transformers, and heaters) are provided with instantaneous time overcurrent relay (50) and time overcurrent relay. The time overcurrent relay of an incoming feeder coordinates with the instantaneous overcurrent relay of it's branch feeder if a short circuit fault is occurred in a branch feeder. The backup protective devices are set to operate at some predetermined time interval after the primary device operation. And a backup device must be able to withstand the fault conditions for a longer period than the primary protective device.

For most applications, the operation of the backup device will isolate other circuits, in addition to the faulted or overloaded circuit in which primary protection was inoperative. Fig. 2 [22] is the relay coordination curve for a feed water booster pump (FWBP) motor

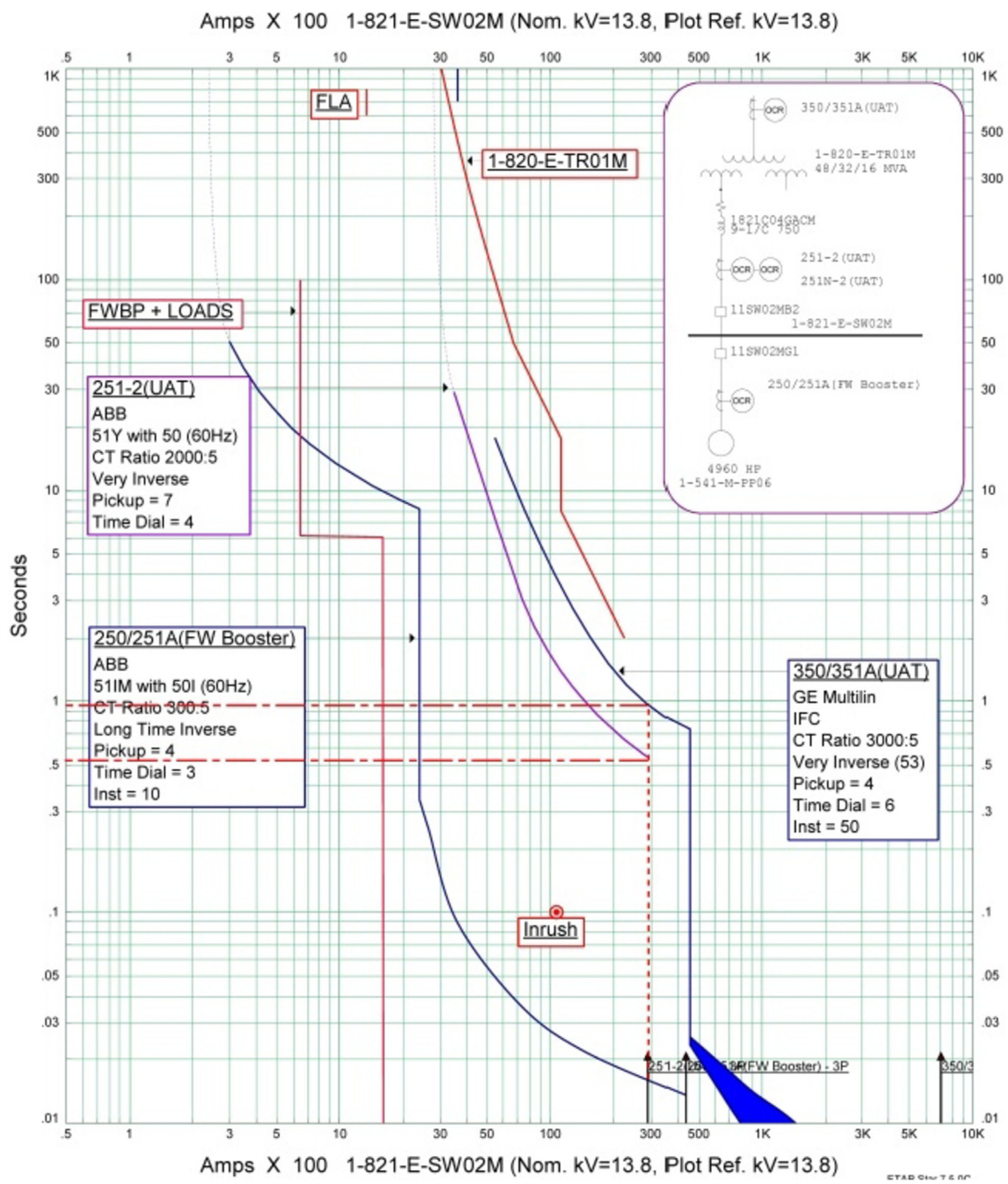

Fig. 2. Typical relay coordination curves of the 13.8 kV.

circuit. If an arcing fault occurs in the 13.8 kV switchgear bus it would take 0.5 s (51 relay of switchgear incoming feeder) to 1.0 s (51 relay of UAT primary side) to pick up the fault and additional 3 to 5 cycles to clear the fault. That means the arc fault occurred in the 13.8 kV switchgear bus continues about 0.5–1 s until overcurrent relay and circuit breaker clears the fault. As a result, the significant energy released during an arc fault event can act as an ignition source to other combustibles resulting in fires. The estimated incident energy released by the arcing fault continued for 1.0 s in the 13.8 kV switchgear bus is 116.26 J/cm^2 (Eq. (3)).

4.4. Zone selective interlocking method

Bus differential protection and zone selective interlocking (ZSI) are typical ways to provide fast tripping of circuit breakers. The bus differential relay (87B) measures 100% of the current into and out of a bus. Simply, if the summation of input current is the same with total output currents, then considered as no fault. If the vectorial summation of input currents and output currents are not the same, somewhere within protection zone fault is occurred and then trip all bus breakers instantaneously.

In the 1980s, ZSI was developed as almost an equivalent and cost-effective bus differential scheme for low-voltage switchgear. In recent years, some MV switchgear relays also became available with ZSI. This now permits almost the equivalent of 87B protection for smaller power systems where bus differential relaying would not be generally applied [10].

ZSI logic adds fault location based logic to the overcurrent protection without the need to add additional current sensors and hence prevents the associated expense and space sacrifices of those sensors. It requires that tiers of circuit breaker trip units or relays communicate with the next tier upstream that is to be coordinated. It may be implemented with "n" levels although 2 levels (main and feeder breakers) application are the most common [23]. Refer to Fig. 3 and assume a high level short circuit occurs on the load side of a feeder circuit breaker. Both the main circuit breaker's and the feeder circuit breaker's digital relays sense the fault. The feeder circuit breaker sends a blocking signal to the main circuit breaker letting it know that the fault is in its zone of protection. The blocking signal tells the main circuit breaker to only trip per its time coordinated delayed standard settings (backup to the feeder breakers) while the feeder breaker is the first to clear the fault.

Traditionally, protection coordination is achieved by using instantaneous overcurrent (IOC) element for feeder breakers and timed overcurrent (TOC) element for a main breaker. The minimum coordination time interval (CTI) has to be followed between the downstream and the upstream protection devices. Per IEEE, for static relays used in both downstream and upstream protection devices, CTI must be at least 200 ms. By using ZSI schemes, the CTI between the downstream and the upstream protection devices could be greatly reduced, that, resulting in tremendously reduces arc flash hazard in industrial applications. In addition, the upstream protection device could also use IOC element, instead of using TOC element that makes the relay coordination job much easier [24].

4.5. Effect of zone selective interlocking method

By applying ZSI, the clearing time of the short circuit at the 13.8 kV bus is reduced from maximum 1.08 s–0.13 s. Instantaneous fault pickup time 40 msec plus ZSI processing time 10 msec plus circuit breaker trip time 80 msec is total fault clearing time [25].

If the arc clearing time is reduced to 130 msec, the calculation results are changed as follows;

The normalized incident energy is calculated by Eq. (2); $E_n = 10^{\{-0.555-0.113+1.081*\log 27.92+0.0011*93\}} = 9.94$ J/cm^2 and incident energy is calculated by Eq. (3);

$$E = 4.184*1.0*9.94\left(\frac{0.13}{0.2}\right)\left(\frac{610}{1200}\right)^{0.973} = 13.99\,\mathrm{J/\,cm^2}$$

Then flash protection boundary is calculated by Eq. (4);

$$DB = 610*\left[4.184*1.0*9.94\left(\frac{0.13}{0.2}\right)\left(\frac{1}{5}\right)\right]^{1/0.973} = 3,456mm$$

As a result, the incident energy is reduced to about 13.99 J/cm^2

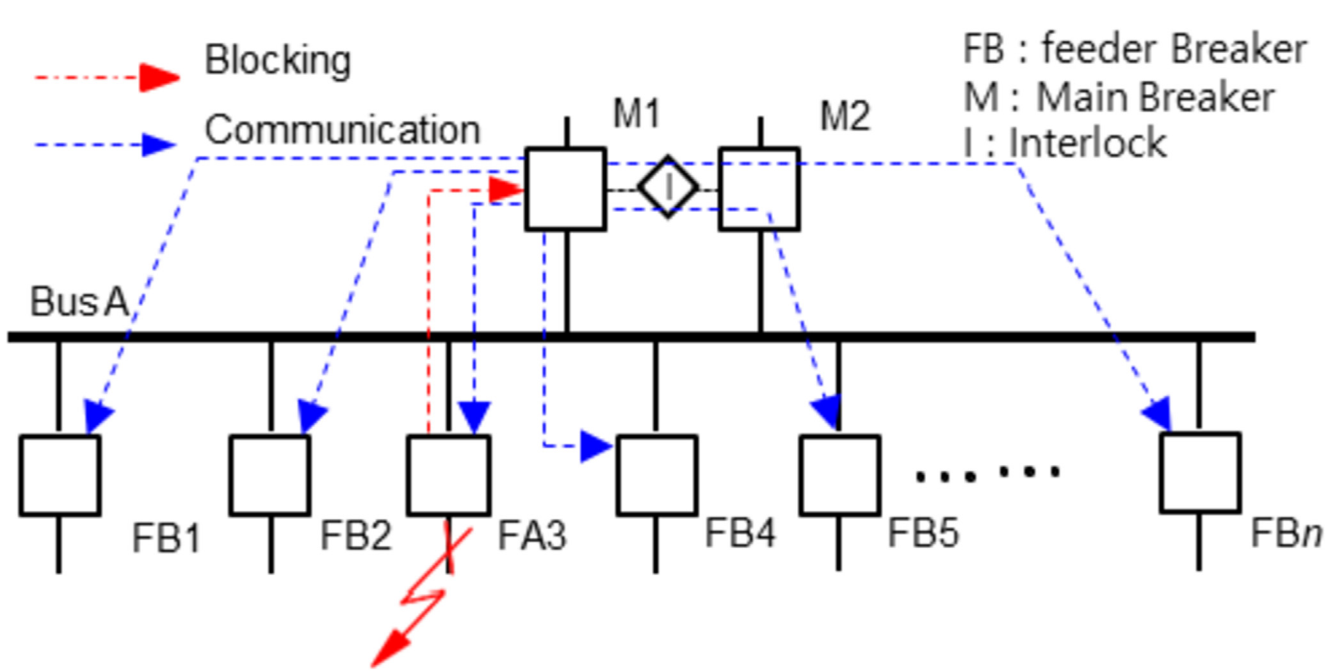

Fig. 3. Zone selective interlocking.

from 116.26 J/cm^2. And arc flash protection boundary is tremendously reduced form 30.5 m–3.5 m.

5. Discussion and conclusions

The organization for economic co-operation and development (OECD) nuclear energy agency (NEA) reported the occurrence of HEAF in the NPPs throughout the world. HEAFs have the potential to cause extensive damage to the failed electrical components and distribution systems along with adjacent equipment and cables within the zone of influence. Furthermore, the significant energy released during a HEAF event can act as an ignition source to other combustibles resulting in fires. In this regard, worldwide research is underway on the arc damage mechanism, the extent of the affected area, the protection method, and the arc flash modeling method.

This paper suggests the ZSI method as a suitable solution to mitigate the HEAF in the medium voltage SWGR of NPPs based on the arc incident energy reduction calculation result. In addition, generator circuit breaker (GCB) is to be installed to quit fault current contribution when the generator is tripped.

Conventional MV switchgear overcurrent protection system provides only time overcurrent relay (TOC) to the incoming feeder circuit breaker of the switchgear. For the selectivity, coordination time delay is provided for the upstream circuit breaker relay. Therefore, short circuit fault on the bus is not detected instantaneously. That is the reason why arcing fault on the medium voltage bus is not effectively detected and cleared. One of the solutions is installing bus differential relay (87B) to prevent or mitigate arcing fault. But it is not common at MV switchgear of nuclear power plants due to increased space requirements for relay and CTs. To provide instantaneous overcurrent protection without sacrificing coordination with branch feeder circuit breaker, the combination of chronometric coordination and logical coordination is required.

Conflicts of interests

The author declares that there is no conflict of interests regarding the publication of this paper.

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