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Operating Experience Assessment
Energetic Faults in 4.16 kV to 13.8 kV Switchgear and Bus Ducts That Caused Fires in Nuclear Power Plants 1986–2001

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ABSTRACT

On March 18, 2001, Maanshan Unit 1, a nuclear plant in Taiwan, experienced a fire and a station blackout due to an electrical fault in a safety-related 4.16 kV switchgear. This report assesses the Maanshan event and five U.S events involving similar energetic electrical fires from a technical and regulatory perspective. Assessment of the operating experience found lessons in the areas of fire risk modeling, equipment maintenance, electrical system design, and plant operations.

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ABBREVIATIONS

AAC	alternate ac
AO	auxiliary operator
ASP	Accident Sequence Program
AT	auxiliary transformer
CCDP	conditional core damage probability
CDF	core damage frequency
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
FMEA	failure modes and effects analysis
FSAR	Final Safety Analysis Report
FTC	failure to close
FTO	failure to open
HRR	heat release rate
ICS	integrated control system
IN	information notice
IPE	individual plant examination
IPEEE	individual plant examination of external events
LER	licensee event report
LOOP	loss of offsite power
NCW	nuclear cooling water
NRC	Nuclear Regulatory Commission, U.S.
PRA	probabilistic risk assessment
RCP	reactor coolant pump
RES	Office of Nuclear Regulatory Research
RY	reactor-year
SBO	station blackout
SG	steam generator
SONGS	San Onofre Nuclear Generating Station
ST	start-up transformer

EXECUTIVE SUMMARY

On March 18, 2001, Maanshan Unit 1, a nuclear plant in Taiwan that was designed to U.S. regulations and standards, experienced a fire and station blackout (SBO) due to an energetic electrical fault. The initial fault caused explosions, arcing, smoke, and ionized gases which propagated damage to adjacent safety-related 4.16 kV switchgear. The damage resulted in complete loss of one safety bus and loss of the capability to feed offsite power to the other undamaged safety bus. An independent failure of the redundant emergency diesel generator (EDG) resulted in loss of all AC power. Smoke prevented access to repair the failure. The SBO was terminated after about 2 hours when an alternate AC EDG was started and connected to the undamaged safety bus.

The Office of Nuclear Regulatory Research (RES) assessed the Maanshan event and U.S. events involving similar fire scenarios in the last 15 years from a technical and regulatory perspective. The assessment found five energetic fire events resulting from electrical faults in medium voltage (4.16 to 13.8 kV) switchgear or bus ducts connected to the switchgear. All U.S. events occurred in non-safety related portions of the electrical system. In all of the U.S. events, an energetic electrical fault caused explosions or vaporized metal. In most of the U.S. events, the fault was in the first breaker downstream of the auxiliary transformer and the fault was fed from the generator as the generator field collapsed following generator trip. Four of the six events took place following a bus transfer and involved stuck or slow operation of the bus supply circuit breaker. One event was attributed to degraded insulation in the presence of dirt or moisture and another to thermal failure of a loose bus bar connection. Circuit breakers from several different manufacturers were involved.

The estimated conditional core damage probability (CCDP) for the Maanshan SBO was 2.2E-03. The CCDP for two of the U.S. events was approximately 9E-05. The Nuclear Regulatory Commission Accident Sequence Program (ASP), which provides a safety significance perspective for nuclear plant operating events, considers events with a CCDP greater than or equal to E-04 to be important accident precursors and those greater than or equal to E-05 to be events of interest. One U.S. event, although not risk significant, was a precursor to the Maanshan event since it was caused by the same failure mechanism.

Probabilistic risk assessments continue to show SBO to be a significant contributor to core damage frequency (CDF). Individual plant examinations of external events (IPEEE) results show that fires can be a significant contributor to nuclear power plant risk and that fire CDFs exceeded SBO CDFs at 25 percent of the nuclear plants. Previous RES reviews of IPEEEs found electrical panel fires to be one of the most significant potential contributors to fire risk. Those reviews also found that the methods of analysis applied to panel fires remain an area of quantification uncertainty and debate.

The assessment of these events found fire risk model implications and potential lessons learned in the areas of plant design, maintenance, and operations.

Fire Risk Modeling Implications

The events described in this report add further evidence to the finding in NUREG/CR-6738 that current fire risk modeling of energetic electrical faults in 4.16 kV to 13.8 kV switchgear does not address the following characteristics of energetic fires: (1) the fire bypasses the typical fire initiation and growth stages; (2) a fire inside an electrical panel can propagate outside the panel; (3) the fire may result in failed initial fire suppression attempts; (4) smoke propagation outside the fire area affects operator response; (5) the fire may be longer than the 10 to 30 minutes typically analyzed; and (6) the plant material condition and independent failures may influence the chain of events.

These events demonstrate that fires from energetic electrical faults contain more energy than assumed in fire risk models as evidenced by explosions, arcing, smoke, ionized gases, and melting and vaporizing of equipment. The energy release exceeds heat release rates (HRRs) assumed in fire risk models, possibly by a factor of 1000. Lower HHR values currently used may explain why current fire risk models have not identified the potential larger effects of fires from energetic electrical faults which may include the following: bypass of the fire initiation and growth stages, propagation of the fire to other equipment and across vertical fire barriers, ac power system designs that may be vulnerable to an SBO, failed fire suppression attempts with dry chemicals and the need to use water, longer restoration time to recover, and unexpected challenges and distractions to the operator from fire-induced failures.

Fire risk models may underestimate the risks from fires due to energetic faults in 4.16 kV to 13.8 kV switchgear and bus ducts by not considering: (1) development of HRR values corresponding to energetic electrical energy levels; (2) the effects of propagation from the fault location to other switchgear compartments, bus ducts, or overhead cables; (3) plant ac safety bus and circuit breaker configuration; (4) failed fire suppression attempts; (5) additional recovery actions; and (6) multiple accident sequences from fire induced equipment failures or operator error.

It appears that plant designs with two safety buses connected in parallel (similar to Maanshan) and connected to the auxiliary transformer through a single circuit breaker may be the most likely to experience an SBO from a fire due to an energetic fault.

Maintenance Considerations

The circuit breaker failures of the type which caused these events are maintenance preventable by periodic inspection and tests for degraded electrical insulation, dirt, moisture, and sluggish circuit breakers. Correctly timed operation of start-up transformer (ST) and AT supply circuit breaker mechanisms is critical to preventing fires in switchgear following bus transfers.

Design and Operating Considerations

Plant electrical fires have resulted in unrecoverable damage to portions of the circuits that route offsite power through the plant. Offsite power was available in the switchyard but could not be connected to the undamaged safety bus because the damage could not be isolated.

After extinguishing a fire with dry chemical, experience shows that water may be needed to reduce the likelihood of reflash. Prior to using water, it is common practice to de-energize the affected and nearby equipment to eliminate the potential personnel shock hazard. All these activities contribute to the duration of and recovery from the event.

U.S. switchgear fires also involved additional unexpected challenges to the control room and auxiliary operators. Typically, some control room and auxiliary operators participate as members of the fire brigade. Also, pre-existing latent failures (i.e., valve failure not related to the fire) that manifest during a fire have contributed to operator burden. Rapid response to augment the staff following an energetic fire could compensate for many of these concerns.

1 INTRODUCTION

On March 18, 2001, Maanshan Unit 1, a nuclear plant in Taiwan that was designed to U.S. regulations and standards, experienced a fire and station blackout (SBO) due to an energetic electrical fault. The fire started as the result of a fault in the safety-related 4.16 kV switchgear supply circuit breaker. The initial fault caused explosions, arcing, smoke, and ionized gases which propagated to adjacent safety-related 4.16 kV switchgear and damaged six switchgear compartments. The damage resulted in complete loss of the faulted safety bus and its emergency diesel generator (EDG) and loss of offsite power (LOOP) to the undamaged safety bus due to faulting of its offsite electrical feeder circuit. An independent failure of the redundant EDG resulted in loss of all AC power. Smoke hindered access to equipment, delaying the investigation and repair of the failures. The SBO was terminated after about 2 hours when an alternate ac (AAC) EDG was started and connected to the undamaged safety bus.

Maanshan estimated that the conditional core damage probability (CCDP) was 2.2E-03. The Nuclear Regulatory Commission's (NRC) ASP program, which provides a safety significance perspective of nuclear plant operating events, considers events with a CCDP greater than or equal to E-04 to be important accident precursors. The Maanshan AAC EDG was installed based on individual plant examination (IPE) calculations which indicated another onsite power supply would reduce the core damage frequency (CDF) due to an SBO.

SBOs and fires are significant contributors to risk at nuclear power plants. The Office of Nuclear Regulatory Research (RES) review of nuclear plant risks previously found that (1) SBO remains a dominant contributor to the risk of core melt even after implementation of the SBO rule; (2) electrical panel fires are one of the most significant potential contributors to fire risk; and the methods of analysis applied to panel fires remain an area of quantification uncertainty and debate; and (3) while the overall structure of probabilistic risk assessment (PRA) can capture dominant factors involved in fire incidents, methodological improvements were identified to include factors outside of the scope of current PRA.

RES was asked to assess the Maanshan and similar U.S. fires in the last 15 years to capture the important factors and characteristics involved in these events that could be used by NRC and licensee staffs to improve the effectiveness and efficiency of activities and decisions. The scope of the assessment was limited to reactor trips involving fires due to energetic electrical faults in the same general type of equipment involved at Maanshan (i.e., 4.16 kV to 13.8 kV switchgear and bus duct or cable connected to the switchgear). Specific objectives were to identify and assess U.S. fire incidents similar to Maanshan to: (1) better understand and characterize fire effects in fire risk modeling for evaluation under the RES Fire Risk Research Program, (2) identify potential lessons learned in the areas of inspection, plant design, maintenance, and operations, and (3) identify U.S. plants that may be vulnerable to a Maanshan-type event for evaluation under the RES Fire Risk Research Program. These objectives are consistent with the NRC Strategic Performance Plan that states the NRC will review operating experience of foreign plants for safety insights; and to make NRC activities and decisions more effective, efficient, and realistic though review of domestic and international operating experience.

2 BACKGROUND

Energetic electrical faults can result in explosions, arcing, fire, ionized gases, smoke, spurious actuation of circuit breakers, other circuit failures, collateral damage to adjacent equipment, and latent equipment failures independent of the fire. The NRC fire protection requirements in Title 10 of the *Code of Federal Regulations* (CFR) Part 50 and the supporting guidance address fires due to energetic faults. For example, General Design Criterion 3, "Fire Protection," of Appendix A to 10 CFR Part 50 requires that structures, systems, and components important to safety be designed and located to minimize, consistent with other safety requirements, the probability and effects of fires and explosions. Section 50.48, "Fire Protection," of 10 CFR Part 50 requires that each operating nuclear power plant have a fire protection plan that satisfies General Design Criterion 3 of Appendix A to 10 CFR Part 50.

NRC guidance in Regulatory Guide 1.189, "Fire Protection for Operating Nuclear Power Plants," April 2001, Section 4.1.3.6, "Electrical Cabinets," states that electrical cabinets (for example 4.16 kV to 13.8 kV switchgear) present an ignition source for fires and a potential for explosive electrical faults that can result in damage not only to the cabinet of origin but also to equipment, cables, and other electrical cabinets in the vicinity of the cabinet of origin. Regulatory Guide1.189 also states that fire protection systems and features provided for the general area containing the cabinet may not be adequate to prevent damage to adjacent equipment, cables and cabinets following an energetic electrical fault; therefore high voltage cabinets should be provided with adequate spatial separation or adequate physical barriers to minimize the potential for an energetic electrical fault to damage adjacent equipment, cables, or cabinets important to safety.

NUREG/CR-6738, "Risk Methods insights Gained From Fire Incidents," issued August 2001, presented new fire PRA methodology insights based on analyses of 25 fire incidents at U.S. and foreign reactors from 1968 to early 1996. The study compared the chain of events of each incident to how it is modeled in a typical PRA. NUREG/CR-6738 found that the overall structure of PRA can capture dominant factors involved in a fire incident. However, several areas of methodological improvement were identified as general insights that fall outside of the scope of the PRA including: (1) smoke propagation and operator error during plant shutdown may lead into other accident sequences that are otherwise considered unlikely; and (2) multiple initiating fires and secondary fires may occur.

NUREG/CR-6738 analysis of two U.S. fire events involving energetic electrical faults in 4.16 kV and 12 kV switchgear describes characteristics of energetic fires which are not considered in current fire risk modeling as follows: (1) the fire bypasses the typical fire initiation and growth stages; (2) a fire inside an electrical panel can propagate outside the panel; (3) the fire may result in failed initial fire suppression attempts; (4) smoke propagation outside the fire area affects operator response; (5) the fire may last longer than the 10 to 30 minutes typically analyzed; and (6) the plant material condition and independent failures may influence the chain of events.

2.1 Risk Perspectives

SBO can be a significant contributor to CDF. NUREG-1560, "Individual Plant Examination (IPE) Program: Perspectives on Reactor Safety and Plant Performance," December 1997, reviewed each plant's IPE and concluded that SBO remains a dominant contribution to the risk of core melt even after implementation of the SBO rule (10 CFR 50. 63, "Loss of All Alternating Current Power"). IPE model an SBO as a LOOP with subsequent random failures of the emergency power supplies. The IPEs model the LOOP as an event initiator with a frequency. There is generally no representation of the offsite electrical supply which includes specifics of the switchyard or in-plant ac power system configuration.

The SBO rule, 10 CFR 50.63, "Loss of all alternating current power," requires that nuclear power plants be capable of maintaining core cooling during an SBO for a specified duration of four or eight hours. The duration required for each plant depends on the individual plant design and SBO risk factors and is usually referred to as the coping time. The risk factors are identified in the SBO rule as (1) the redundancy of the onsite emergency ac power sources, (2) the reliability of the onsite emergency ac power sources, (3) the frequency of a LOOP, and (4) the probable time needed to restore offsite power. Many licensees made modifications to meet the SBO rule requirements, including the addition of, or access to, AAC power supplies to power the safety buses following an SBO.

GL 88-20, "Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," Supplement 4, June 28, 1991, suggests that licensees assess these plant vulnerabilities due to a fire and report the results to the Commission. All licensees have analyzed the risk of nuclear plant fires using probabilistic methods in one form or another as part of their IPEEEs. The fire IPEEEs (and other fire risk models) address postulated fires that may occur in fire zones and address fire occurrence rates, ignition, propagation, and fire suppression in the different fire zones.

NUREG-1742, "Perspectives Gained From The Individual Plant Examination of External Events Program," summarizes the results of the IPEEEs. The NUREG-1742 comparison of the individual nuclear plant fire CDFs from the IPEEEs to the overall internal event CDFs shows that 25 percent of the nuclear plants' fire CDFs exceeded their internal events CDFs. NUREG-1742 states that switchgear rooms were quantified by 90 percent of the plants as specific contributors to the fire-induced CDF, generally on the order of E-06/reactor-year (RY). Several of the plants with large CDF contributions from switchgear rooms identified scenarios that resulted in a LOOP or the loss of cooling water systems that led to RCP seal failures. Plants with low CDF contributions tended to credit separation between trains of equipment and cables.

NUREG-1742 states that electrical panel fires were found by most licensees to be one of the most significant potential contributors to fire risk and the methods of analysis applied to panel fires remains an area of quantification uncertainty and debate. NUREG-1742 notes that: (1) the most commonly cited fire scenario involved a fire starting in a switchgear panel that damaged overhead cables; (2) most licensees assumed cable damage as a result of heat release rates (HRR) of 100 kW (same as other fire sources); and (3) many assumed cable damage above the panel regardless of the HRR. NUREG-1742 also noted that virtually all of the IPEEE analyses treat switchgear fires in the same manner as other fires – the potential for high energy release rate and rapid propagation of faults is not considered.

The IPEEE takes advantage of the results of analyses completed under 10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." Appendix R provides criteria for protection of equipment and circuits to ensure that a large fire plume does not cause the loss of equipment needed for hot shutdown with a LOOP.

The NRC ASP program provides a safety significance perspective on nuclear plant operating events using the CCDP as a metric to determine the relative significance. The ASP analyses do not currently address the characteristics of a fire (e.g., fire propagation and fire suppression). The ASP program considers events with a CCDP greater than or equal to E-04 to be important accident precursors and those greater than or equal to E-05 to be events of interest. The identification of precursors requires identification of those events in which plant functions that provide protection against core damage have been challenged or compromised.

2.2 General Electrical Design and Operating Considerations

During normal operation of a typical nuclear power plant, the main generator supplies power to the grid through an isolated phase bus duct, main transformer, and generator output circuit breakers in the switchyard. The main generator also supplies power to the plant loads through a portion of the isolated phase bus duct, the auxiliary transformer (AT), and the AT supply circuit breaker. The main generator, AT, main transformer isolated phase bus, and the leads to the circuit breakers are "unit connected" (i.e., connected to each other without a generator circuit breaker), as shown in Figure 1, "Typical Unit Electrical Connection."[1]

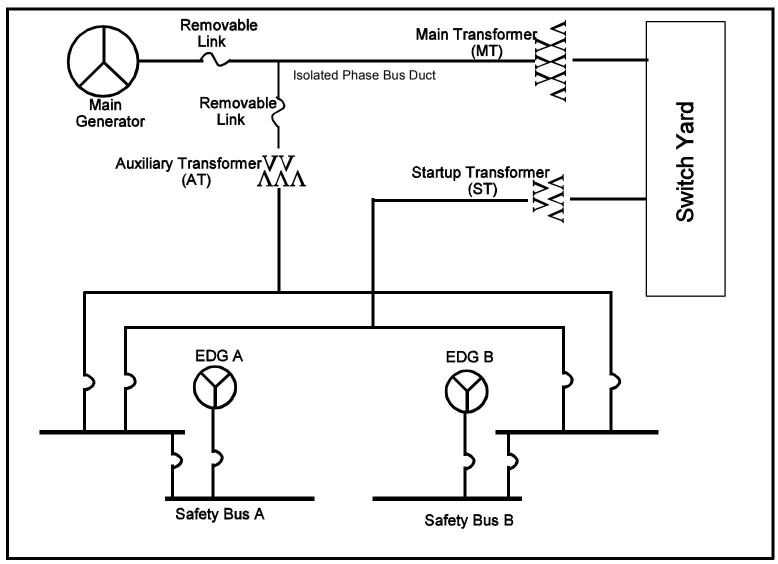

Figure 1 - Typical Unit Electrical Connection

The AT supplies power to station loads when the unit is at power. The startup transformer (ST) supplies power to station loads from an offsite power supply when the unit is starting up, shut down, or just after the generator trips. Power is automatically transferred from the AT to the ST provided voltage and frequency conditions are acceptable. The automatic transfer generally takes place immediately after faults and some turbine trips, but is delayed 30 seconds for all other trips. The operators manually transfer power from the ST to the AT during startup by momentarily paralleling the AT and ST. Thus, the AT and ST circuit breakers are routinely opened and closed once per fuel cycle.

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

[1] Transformer nomenclature varies. For example, the AT is sometimes called the unit AT and the ST is sometimes called the reserve unit transformer or reserve AT. For consistency, the terms AT and ST will be used.

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.

The offsite power supply cables or bus duct from the AT and ST that are routed through the plant terminate in non safety or safety-related medium-voltage (4.16 kV to 13.8 kV) metal-clad switchgear "supply" circuit breakers that connect to a bus that feeds multiple station loads though other circuit breakers. The load, AT supply, and ST supply circuit breakers are located in the same switchgear in individual, adjacent steel cubicles. In some plants, the AT and ST supply circuit breakers are near one another to facilitate local operation. In other plants, they are located on the ends of the switchgear to maximize separation. The arrangement of the supply circuit breakers is unique to each plant. The bus and a dc control bus run through the cubicles in separate passageways. Control cabling also runs between the cubicles through small openings. The metal-clad switchgear used in nuclear power plants has been used widely in general power plant and industrial applications for years and is designed to withstand voltage and current abnormalities.

Table 1, "Typical Switchgear Voltage and Current Interrupting Ratings," shows the nominal rated voltage, the maximum rated (continuous) voltage, the low frequency voltage withstand (one minute at ±20 percent frequency), the impulse voltage withstand (voltage spike), and the current- interrupting ratings for typical nuclear plant medium-voltage metal-clad switchgear. The voltage data were obtained from American National Standards Institute/Institute of Electrical and Electronic Engineers C37.20.2-1987, "Metal-Clad and Station-Type Cubicle Switchgear," and the current-interrupting ratings (and capability) from licensee final safety analysis reports (FSAR). C37.20.2-1987 and earlier versions reflect the status of the standard at the time U.S. plants were designed and constructed and is representative of nuclear plant switchgear ratings.

Table 1 Typical Switchgear Voltage and Current Interrupting Ratings

Nominal rated (kV) (line/line)	Maximum rated (kV) (line/line)	Low-Frequency withstand (kV) (line/ground)	Impulse withstand (kV) (line/ground)	Current-interrupting rating (capability) at rated voltage and 5 cycles interrupting time (kA)
4.16	4.76	19	60	47 kA (350MVA),
7.2	8.25	36	95	39.5 kA (750MVA),
13.8	15	36	95	42 kA (1000 MVA)

Overvoltages up to approximately 2 times rated voltage may follow imperfect bus transfers, generator load rejection, faults, and incorrect switching operation. Over voltages of 10 times rated can occur following phenomenon such as ferroresonance. Ferro resonance is the result of the interaction of the reactance of a saturable magnetic device, such as a power system transformer, and the system's capacitance, such as a transmission line, to cause a sustained over voltage. Table 1 shows that switchgear can withstand 3–4 times rated voltage for 1 minute and 6–10 times rated voltage for a voltage spike. Large fault currents, up to 20 times rated current, can result when current conductors short to ground or each other. The switchgear is selected with current interrupting ratings in Table 1 that exceed the large fault currents calculated in the design. 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.

A circuit breaker can have a failure to close (FTC) or a failure to open (FTO). A circuit breaker FTC results in detectable power interruption. A circuit breaker FTO, or opens slowly, is usually detected and an upstream circuit breaker is opened automatically. For example, if the ST supply circuit breaker fails to open to disconnect a faulted circuit, an upstream switchyard circuit breaker will generally open in time to prevent equipment damage. However, in the unit connection there is typically no circuit breaker upstream of the AT supply circuit breaker, and following the FTO, the main generator continues to energize the AT, the AT leads, the AT supply circuit breaker, and the switchgear. Under faulted conditions, the main generator current feeds the fault until the voltage collapses. The AT leads or switchgear, although generally designed to withstand short circuit currents for a short time, will most likely fail if the short circuit or fault is not cleared quickly. The energetic discharge may result in collateral damage to nearby equipment.

An open circuit due to FTO or FTC of one or two of the three supply circuit breaker poles results a faulted condition: unbalanced overvoltages, ground currents, and excess current that are reversed in phase – negative phase sequence currents. For some power systems, the open circuit fault may not be easily detected by protective relaying. Some licensees time the supply circuit breakers as part of switchgear preventive maintenance to assure coordinated operation.

The independence of the offsite power system, the emergency power system, and the redundant portions of the emergency power system is an important design consideration in nuclear power plants because of the possibility of a fire. General Design Criterion 17 of 10 CFR Part 50, Appendix A states that "....The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure...." As a result of these requirements, emergency power should remain available following a LOOP.

Independence between redundant safety equipment is achieved through physical separation, for example by locating redundant equipment such as the EDGs in separate rooms whose walls are fire barriers. To assure that the emergency power supply is available following a LOOP, the safety-related power system is electrically isolated from the non safety offsite power system by a safety-related bus supply circuit breaker based on the assumption that fault voltage and currents applied to the non safety side of the supply circuit breaker will not degrade the safety system. In addition, licensees FSARs summarize the results of failure modes and effects analyses (FMEA) of the emergency power system to show that no single failure will cause loss of all emergency power due to a LOOP. The FMEAs also show that the failure of a safety bus, or either of the safety bus supply circuit breakers does not cause a loss of the redundant safety buses or safety bus supply circuit breakers.

As mentioned earlier, some licensees added AAC power supplies to power the safety buses following an SBO. To assure separation between the AAC power supply and other power supplies RG 1.155, "Station Blackout," Section 3.3.5.2 states that no single-point vulnerability should exist whereby a weather-related event or single active failure could disable any portion of the blacked-out units onsite emergency ac power sources or the preferred power sources and simultaneously fail the AAC power source.

3 DISCUSSION OF FIRE EVENTS

RES completed a search of licensee event reports (LERs) in the Sequence Coding and Search System (SCSS) for incidents since 1986 that were similar to the Maanshan event. Specifically, reactor trips were found involving fires due to energetic electrical faults in 4.16 kV to 13.8 kV switchgear and power supply bus duct or cable connected to the switchgear. The SCSS search was not restricted by equipment safety classification or location.

Preliminary SCSS searches looked for fires due to energetic electrical faults in 600v and smaller switchgear and electrical cabinets. RES/Division of Risk Analysis and Applications/Operating Experience Risk Analysis Branch (RES/DRAA/OERAB) identified 14 U.S. switchgear room fire events from 1986 to 1999 involving small, non-energetic fire incidents from preliminary searches of databases. The operational experience shows that the 600v and smaller switchgear and electrical cabinets fires were generally instantaneous and damaged the faulted cabinet; they did not release large amounts of energy and cause widespread damage or multiple fires. Electrical fires in 600v and smaller switchgear and electrical cabinets were not due to energetic faults. The voltage threshold for energetic switchgear and bus duct faults appears to be 4.16kV and above. Thus, these events were not important for the purposes of this report and are not discussed further.

The five energetic faults which are the basis of this analysis are listed in Table 2, "Summary of Event, Fire, and Risk Insights." The first column in Table 2 identifies the nuclear plant where the event took place. The second and third columns characterizes the event and the fire. The remaining columns summarize estimated risk results. Two of these events were also included in NUREG/CR-6738.

The fourth column provides the event CCDP. The CCDPs for these events are mixed, varying four orders of magnitude between the largest and smallest values. The NRC ASP Program considers events that have a CCDP greater than or equal to E-04 to be important precursors, those greater than E-05 to be of interest, and those smaller are screened from further ASP consideration. To date, the NRC has identified about 210 ASP events; of these, 60 are important precursors. Based on the ASP program criteria the Maanshan SBO is an important accident precursor; and the Diablo Canyon 33 hour LOOP and the Waterford partial LOOP were events of interest. The Diablo Canyon CCDP analysis assumed that power could have been recovered much sooner than the actual 33 hours, if necessary to response to a SBO. The NRC staff determined that the CCDP would be on the order of 5E-05, 3E-04, and 1E-03 for power recovery times of 2.5, 14, and 24 hours, respectively, showing that the risk significance of the Diablo Canyon event is impacted greatly by the assumed recovery time. The San Onfre, Oconee, and Palo Verde events were not events of interest from an ASP perspective.

The fifth column provides fire risk insights as reported in licensee IPEEEs and summarized in NUREG-1742. Comparison of the individual plant total fire CDFs to the internal events CDF shows that the total fire CDF is generally on the same order of magnitude as the internal events CDF – fire is considered a major risk contributor. Typically the IPEEE analyzed a fire of the conventional type with limited energy and propagation rate – the results are shown in the last column of Table 2. The Palo Verde safety related bus configuration is similar to Maanshan; and both Palo Verde and Maanshan have AAC power to the safety buses. Although no values are available for column 5 for Maashan, because of similarities of the bus arrangement to Palo Verde, the Maashan values would probably be similar to Palo Verde.

Other risk insights provided by IPEEEs that are not shown in Table 2 which confirm the potential risk significance of energetic fires include calculations by Palo Verde and San Onofre Nuclear Generating Station (SONGS). The Palo Verde IPEEE internal fire analysis estimated CDF of 3E-04/RY from a fire in the safety related switchgear room that destroys everything in the room and causes a LOOP to both safety buses. However, that sequence was not included in the final IPEEE results because it was determined at the time that it was extremely unlikely to happen. SONGS used their current IPE model to calculate that the increase in the CDF due to a fire of the type experienced (non-safety bus) at SONGS was 3E-06/RY.

Table 2 Summary of Event, Fire, Risk Insights

Plant	Event Summary	Event Fire Characteristics	Event CCDP	Licensee IPEEE Insights from NUREG-1742	
				Total Fire CDF (per RY)	Internal Events CDF (per RY)
Maanshan	2 hour SBO, no RCP seal damage	explosion, arcing, ionized gases, collateral damage, smoke affected access to failed EDG, out in 4 minutes with carbon dioxide system	2.2E-03		
SONGS	reactor trip	arcing, smoke, ionized gases, collateral damage, failed suppression attempt , fire-induced and independent failures, out in 147 min with water	< E-06	1.6E-05	3.00E-05
Diablo Canyon	reactor trip and 33 hour LOOP	arcing, smoke, collateral damage, out in 78 minutes	9.8E-05	2.73E-05	8.8E-05
Waterford	reactor trip, partial LOOP, loss of one RCP seal	explosion and smoke, collateral damage, out in 84 minutes with water	9.1E-05	7E-06	1.8E-05
Oconee	reactor trip, overcooling event	explosion, smoke in control room, out in 59 min	< E-06	5.8E-06	2.3E-05
Palo Verde	led to reactor trip; initiated 7 hour LOOP	two fires 60 minutes apart due to same bus fault	< E-06	8.67E-05	9.0E-05

3.1 Maanshan Unit 1 Station Blackout

Attempts to contrast Maanshan and the US plants in the areas of plant design, operations, and maintenance were limited to information in Maanshan event reports, a 1985 copy of the Maanshan FSAR, and brief discussions with Taiwan Power. Maanshan is a dual unit Westinghouse three-loop pressurized-water reactor reactor site in Taiwan that began commercial operation in 1984 and 1985, respectively. The Maanshan FSAR indicates that Maanshan was designed and built by a U.S. architect-engineer-constructor to U.S. industry standards and Nuclear Regulatory Commission regulations and guidelines in effect up to the mid 1980's, (i.e. it is designed to regulatory requirements similar to most U.S. nuclear plants). Taiwan Power said that the swing EDG was installed after an IPE indicated it would reduce the CDF due to an SBO. Similar to U.S. maintenance practices, Taiwan Power claimed to routinely performed safety equipment maintenance as recommended by the equipment manufacturer.

At Maanshan, seasonal weather conditions after midnight on March 18, 2001, caused salt deposits on insulators resulting in intermittent malfunctions of all four 345 KV transmission lines. Because of the continuing problems with the transmission lines, both nuclear units had been shut down more than 20 hours earlier. Electrical power to the plant was being supplied from the startup transformers.

Refer to Figure 2, “Maanshan Simplified Electrical Switchgear Diagram.” Maanshan has two STs per unit. The preferred source of offsite power is the 345 kV ST and the alternate source is the 161 kV ST. At the time of the event, the plant was being powered from the 161 kV source, which was not affected by salt deposits.

At 0046, while the operators were transferring Unit 1 back to the preferred 345 kV source, an energetic electrical fault occurred in feeder breaker 17 to 4160 V essential bus A. Breaker 17 indicated open prior to the fault; but when the 345 kV startup transformer was energized, providing voltage to the input side of breaker 17, an energetic electrical fault occurred as evidenced by an explosion, arcing, smoke, ionized gases, and fire. Taiwan Power indicated that breaker 17 may have been momentarily closed while breaker 15 was closed. The arcing, smoke, ionized gases, and fire released by the energetic electrical fault inside breaker compartment 17 propagated and caused collateral damage to other switchgear compartments, including a fault on essential bus A, and a fault on the input side of feeder breaker 15, which was separated from breaker 17 by one cubicle. Breakers upstream of both 345 kV and 161 kV STs opened to isolate the faults. The fault locations on breakers 17 and 15 are marked by “X.” This resulted in a LOOP to both the safety and non safety electrical buses. Maanshan Unit 2 has separate STs and was unaffected by the problems on Unit 1.

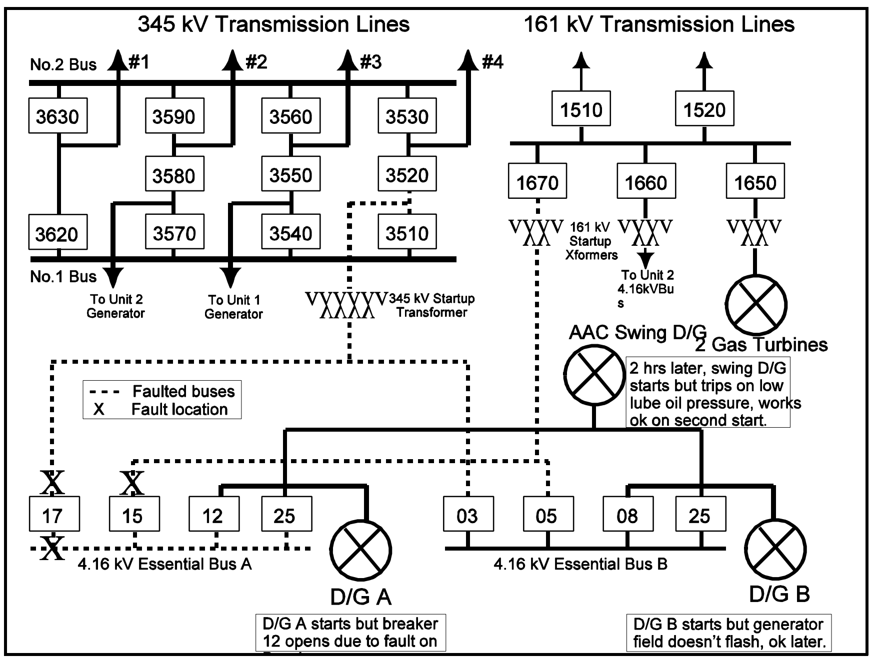

Figure 2 - Maanshan Simplified Electrical Switchgear Diagram

Each Maanshan unit has two dedicated EDGs. EDG A supplies essential bus A and EDG B supplies essential bus B. In addition, an AAC swing EDG can be manually connected to either essential bus. During this event EDG A started but did not connect due to the faulted conditions on essential bus A. EDG B started automatically as designed; essential bus B was not powered due a lack of generator excitation. The steam-driven auxiliary feedwater pump started and ran successfully. The reactor coolant system operated in natural circulation.

Attempts to restore EDG B were deterred due to smoke and lack of lighting. Although EDG A and B are located in separate rooms, carbon dioxide activation in the switchgear room blew the switchgear room door open and filled the passageway from EDG A to B with smoke. At about 0250, the first attempt to start the AAC swing EDG failed due to low oil pressure. A second attempt to start the swing EDG was successful. At 0254, 2 hours after the initial loss of ac power, the swing EDG was successfully connected to essential bus B. The initial failure of the AAC swing EDG to start was due to low lube oil temperature. Its normal lube oil heating was lost with the loss of ac power.

The switchgear fire was extinguished quickly with the automatic carbon dioxide system discharge. The plant staff noted the activation of the fire suppression system and onsite staff reported that heavy smoke propagated to the control building on the floor 46 feet below the control room, where the essential buses are located. The local offsite fire department was called and later provided portable ventilation and lighting to allow access to EDG B and the damaged switchgear.

The operators' efforts focused on two major goals: (1) to restore ac power to at least one emergency bus; and (2) to reduce reactor temperature and pressure to prevent reactor coolant pump (RCP) seal damage. The plant was on natural circulation and the steam-driven emergency feedwater pump and atmospheric steam dump valves were used to remove decay heat. With only minor problems maintaining appropriate cool down rates, reactor temperature and pressure were reduced and no increased RCP seal leakage was noted. Regarding reestablishment of ac power, after the difficulty noted above, the swing EDG was used to power emergency bus B. The Maanshan unit emergency batteries are designed to provide dc power for up to 8 hours during a loss of ac power event. Since essential bus B was powered from the swing EDG within about 2 hours, the battery capacity was not challenged.

The event was a significant challenge to the operators but their responses were sufficient to maintain the plant in a safe condition. Since the plant was starting up from a refueling outage and was shut down almost a day prior to the loss of ac power, the decay heat was relatively low. Had the loss of ac occurred while the plant was operating at 100 percent power, the decay heat would have been significantly more, presenting the operators with a greater challenge to reduce reactor temperature and pressure to reduce the likelihood of RCP seal failure. The 8-hour battery life and the swing EDG provided more time and flexibility to respond to this type of event than would be available at many other nuclear plants. No attempts were made to restore the 161 kV or 345 kV offsite power supplies to essential bus B. The restoration of offsite power was hampered as there were no disconnects or links to isolate essential bus B from the faults on the input side of breakers 15 and 17.

The damage to essential bus A was extensive. Maanshan reported ground faults on the power side of the 4.16 kV bus and circuit breakers 17 and 15. Photographs and drawings were shown at a meeting with Taiwan Power that indicated that breaker 17 and 15 were separated by one switchgear cubicle. Five cubicles adjacent to breaker 17 were damaged; two cubicles were damaged in one direction and three in the other direction.

Maanshan believed the root cause to be insulation failure in breaker 17. Although not certain, Maanshan identified several possible causes of the insulation failure: overvoltage due to switching or ferromagnetic resonance, overvoltage from residual rotational momentum of RCPs, or faulty protective relay coordination. To date, the information reviewed indicates that there was no protective relaying (bus differential relays) that would quickly detect some of the faults and lockout the circuit breakers. A University of Texas consultant working for Taiwan Power noted that extensive damage, including vaporizing of metal indicated a very high electrical current. His review of the Maanshan station logs found that frequent negative phase sequence current alarms (from frequent unbalanced transmission line voltages since 1985) may have resulted in premature aging of the switchgear insulation. Taiwan Power recently concluded that ferromagnetic resonance was the cause of the event. Taiwan Power also concluded there was insufficient electrical separation between safety bus A and B, and subsequently added an interlock between bus A and B. Taiwan Power also added emergency startup of the EDGs to its regular test schedule.

The Maanshan FSAR presents a FMEA which includes analyses of the 4.16 kV safety-related bus and its bus supply circuit breakers 17 and 15. The purpose of a FMEA is to demonstrate that a failure of a single component in the safety related power system does not prevent satisfactory equipment performance needed for safe shutdown. A 4.16 kV bus fault is evaluated to result in the loss of one redundant load group and have no effect on continued operation of the other load group. The failure of circuit breaker 17 and 15 to open are each individually evaluated to result in the loss of power to one redundant bus and have no effect on the continued operation of the other redundant load supply circuit breaker. The FMEA scope, method, and results are consistent with U.S. FMEAs of the safety-related power system found in most U.S. FSARs.

3.2 San Onofre Unit 3 Reactor Trip

On February 3, 2001, SONGS Unit 3 was at 39 percent power and in the process of power ascension following a refueling outage. SONGS Unit 2 was at 100 percent power. 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.

Refer to Figure 3, "San Onofre 3 Electrical Single Line Diagram." At 1513 the operator closed 4.16 kV AT supply circuit breaker 3A0712 onto bus 3A07, and the ST supply circuit breaker 3A0714 that was feeding bus 3A07 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 3A0712. Even though AT supply circuit breaker 3A0712 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 3A0712. The faults are shown in Figure 3 as "X's." In addition, arcing, fire, smoke, and ionized gases diffused from the switchgear compartment housing circuit breaker 3A0712 through the passageways between adjacent cubicles and caused a ground fault on the ST side of circuit breaker 3A0714, which was separated from circuit breaker 3A0712 by one cubicle. The ST protective relays sensed a fault and tripped the 230 kV switchyard circuit breaker that feeds the ST and the Unit 3 STs. This resulted in a loss of power to the Unit 3 safety and non safety buses, the automatic transfer of the Unit 3 safety buses 3A04 and 3A06 to Unit 2, and the automatic start of the Unit 3 EDGs. The Unit 3 reactor tripped after the RCP speed decreased as bus voltage decayed following the slow transfer of the RCP buses to Unit 2.

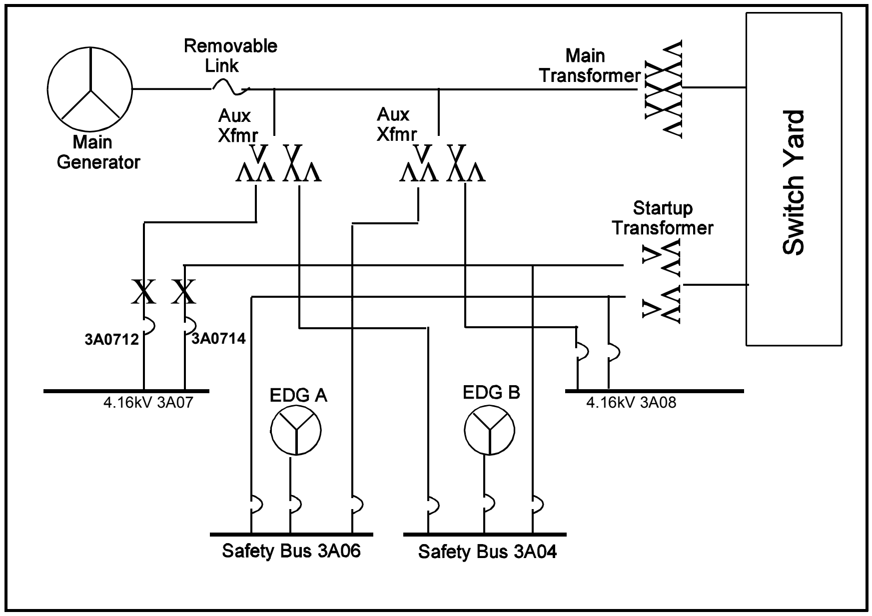

Figure 3 - San Onofre 3 Electrical Single Line Diagram

Heat was removed from the reactor coolant system using auxiliary feedwater, the steam generators (SGs), and the atmospheric dump valves. The were several fire-induced failures. The dc main turbine lube oil pump lost power, damaging the Unit 3 turbine and generator rotors and bearings (the repairs took several months). The fire resulted in the loss of non-safety dc power to the Unit 3 annunciators (restored in 14 minutes). The fire also caused flooding of the condensate storage tank room due to the loss of dc-powered level controls. The event was a significant challenge to the operators; however, their responses were sufficient to maintain the plant in a safe condition.

Station firefighters arrived at the scene at 1522 and reported the fire out 18 minutes later. At 1720, the station firefighters opened the door to circuit breaker cubicle 3A012 and observed flames. The fire was permanently extinguished with water 147 minutes into the event after attempts to extinguish the fire with dry chemicals failed. The delay in using water was caused by the reluctance of the shift manager to grant permission to use water on the electrical fire. After the event the licensee observed that dry chemicals temporarily removed air from the fire but did not reduce the heat, and reflash occurred once the air was reintroduced.

The damage was so extensive that the exact cause of the fault could not be determined. The licensee found the circuit breaker 3A012 phase C arcing contact completely melted and concluded that circuit breaker 3A012 phase C failed to open completely during the bus transfer. The licensee also indicated that arcing, fire, smoke, and ionized gases in circuit breaker 3A0712 caused multiple faults on bus 3A07, and collateral damage to 4 other switchgear compartments and the offsite power circuit connection at circuit breaker 3A0714. However, the condition of other equipment also contributed to the failures during the event. For example, the dc turbine lube oil pump did not start because its circuit breaker tripped prematurely; the as found trip point was 510 amps which is below the motor starting current of 650 amps. The trip device was damaged and would not respond to adjustments. In addition, the annunciator was lost due to the lack of circuit breaker coordination in the dc system.

3.3 Diablo Canyon Unit 1 Reactor Trip and LOOP

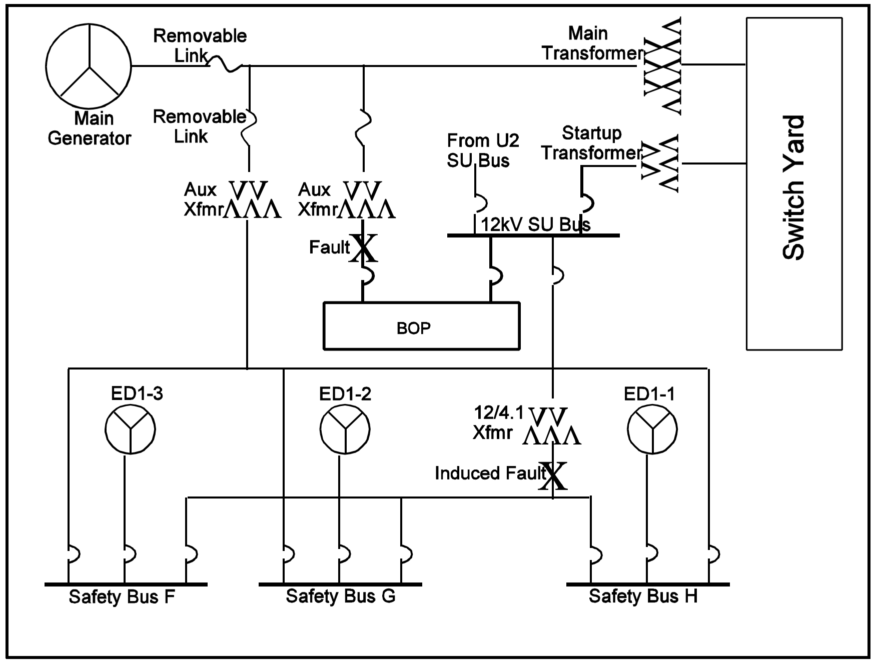

Figure 4 - Diablo Canyon 1 Electrical Single Line Diagram

On May 15, 2000, Diablo Canyon Unit 1 was at 100 percent power with the station loads powered from the AT. At 0025, 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 switchyard circuit breakers, the generator field 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 seconds 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 ST 1-2. The 4.16 kV bus duct was approximately 4 inches above the 12 kV duct. ST 1-2 tripped, causing the loss of 4.16 kV to the three vital buses, and the start and loading of all three EDGs. ST 1-1 remained energized, supplying power to some 12 kV and 4.16 kV non-vital loads. Figure 4, “Diablo Canyon 1 Electrical Single Line Diagram,” shows the 12 kV fault and 4kV induced fault locations.

Security guards and roving fire watch personnel promptly detected the fire. The fire brigade responded in 18 minutes, extinguished the fire with dry chemicals 17 minutes after arriving, and cleared the smoke from the room. The fire was declared out at 0143, 78 minutes after it started. At 0400 teams were assigned to recover offsite power to the safety loads, investigate the cause of the fault, and restore damaged equipment. Offsite power was restored in 33 hours and 34 minutes.

An NRC inspection found that approximately 3 feet of the center 12 kV bus bar and 6–9 inches of the other two 12 kV bus bars had vaporized, several feet of the 12 kV bus duct had melted, and a one-square-foot hole was burned into the 4 kV bus duct. 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 an conductive environment for a phase to phase arc. The connection was believed to have been silvered and the nut torqued to less tight than that recommended by the manufacturer when it was replaced after a 1995 AT transformer fault and fire on the 12 kV bus, as reported in LER 275/95-014, “Diesel Generators Started and Loaded as Designed Upon Failure of Auxiliary Transformer 1-1 Due to Inadequate/Ineffective Procedures Related to the Control of Grounding Devices.” The licensee also believed the aluminum bus duct load-carrying capability was marginal and replaced some sections with higher amperage copper bus. The NRC inspectors found that the licensee included the 12 kV system under the Maintenance Rule; however, the NRC inspectors found that the licensee did not perform preventive maintenance on the bus duct. The licensee responded by saying that the vendor did not recommend any preventive maintenance.

The control room staff maintained safety functions and responded appropriately to the failure of the component cooling water pump 1-2 shaft-driven oil pump. The operating staff placed a portable generator in service, installed temporary jumpers to maintain switchyard battery voltage, and provided temporary power to the auxiliary building sump pumps. The plant computer failed 17 hours into event because of a loss of battery power.

The NRC issued Information Notice (IN) 2000-14, “Non-Vital Bus Fault Leads to Fire and Loss of Offsite Power,” dated September 27, 2000, to inform the industry of equipment and design issues following this event.

3.4 Waterford Unit 3 Reactor Trip and Partial LOOP

0n June 10, 1995, Waterford 3 was operating at 100 percent power with the plant loads fed from ATs 3A and 3B. At 0858, a remote substation transformer lightning arrester failed. This resulted in a transient 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 3A and 3B. Refer to Figure 5 “Waterford 3 Electrical Single Line Diagram.” The buses transferred as designed with the exception of 4.16kV non-safety bus 3A2. The AT supply circuit breaker to bus 3A2 failed to open in 5 cycles while the ST supply circuit breaker to bus 3A2 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 3A2, 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 3A2. A fault recorder in the switchyard indicated that the generator supply was 180 degrees out of phase with the offsite power supply. The RCPs A and C which were fed through the ST and 6.9 kV bus slowed in response to low voltage caused by the fault and out of phase condition. The reactor tripped on low departure from nucleate boiling ratio from channels A and C. Both the AT and ST circuit breakers received overcurrent trip signals.

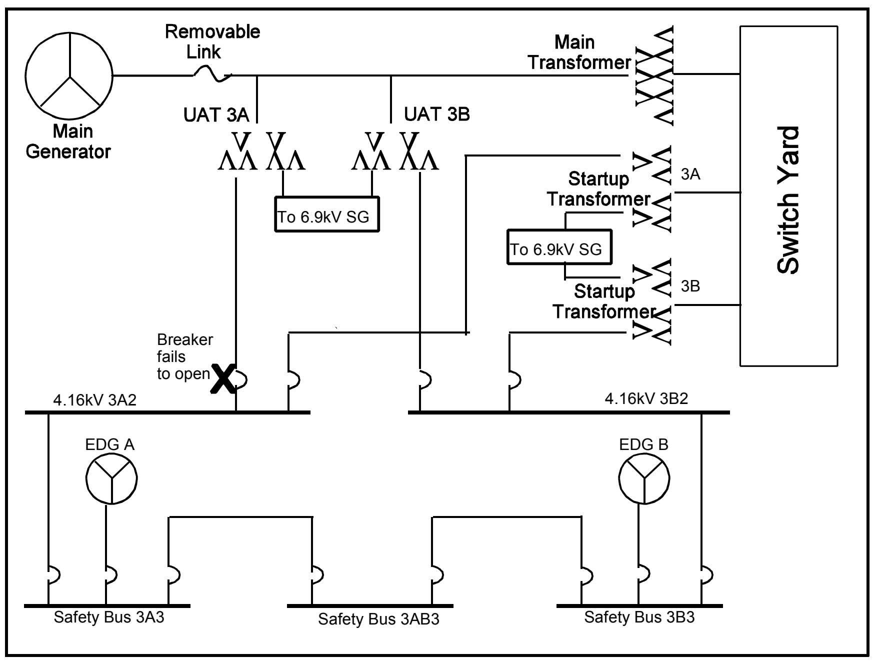

Figure 5 - Waterford 3 Electrical Single Line Diagram

The ST circuit breaker tripped but the AT circuit breaker again failed to open. Therefore, the residual energy of the main generator continued to feed the fault. An undervoltage condition tripped the 4.16 kV 3A2 bus feed to 4.16 kV safety bus 3A3, and EDG A started and loaded. At 0929, ST 3A tripped just after the 4.16 kV ST supply circuit breaker A2 spuriously closed.

The auxiliary component cooling water pump A was manually started 23 minutes into the event (at 0919) as it tripped when voltage was lost to the 4.16 kV safety bus 3A3. RCP 2B indicated high thrust bearing temperature as the result of a rise in the component cooling water temperature that accompanied the loss of auxiliary component cooling water pump A. An NRC inspection report states the shift supervisor made a conservative decision to stop the RCP 2A since it had one failed seal.

Detection of the fire was not prompt. About 8 minutes into the event, the turbine building operator reported heavy smoke, but no fire, coming from the turbine building switchgear room. The shift supervisor directed removal of the smoke with portable blowers. Smoke removal was slowed by the unavailability of electric power for the portable blowers. At 0935, a fire was reported (most likely from the spurious closure of 4.16 kV ST supply circuit breaker A2 at 0929) in the switchgear and cables above the switchgear. Operators sounded the plant fire alarm approximately 40 minutes into the event. Per procedure, the control room supervisor left to become the fire brigade leader. The fire department arrived at 0958, extinguished the fire with water at 1022 (84 minutes into the event) after attempts with dry chemical extinguishers failed. The delay in using water was due to the reluctance of fire brigade leader to allow the use of water on an electrical fire.

The root cause of the explosion in the 4.16 kV non-safety bus A2 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 A2 was damaged beyond repair. The fire 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. It was noted that the normal circuit breaker phase A contacts were totally destroyed and the phase C contacts were partially destroyed. The circuit breaker maintenance and testing did not include measurement of breaker closure time. The required manufacturer’s circuit breakers maintenance had been performed at 3-year intervals as required except that the 1989 preventive maintenance had been postponed until 1992. The fire propagated outside of the switchgear cabinets; the fire jumped across vertical cable tray fire barriers and stopped after it burnt 8 feet horizontally to another cable tray fire barrier above the switchgear. The horizontal cable fire stops were effective in preventing propagation of the fire. The vertical fire stops were not effective. Adjacent switchgear was not damaged since it was protected by a concrete block fire wall.

The NRC issued IN 95-33, “Switchgear Fire and Partial Loss of Offsite Power at Waterford Generating Station, Unit 3,” dated August 23, 1995, to alert licensees to the event and advise them to consider actions to avoid similar problems.

The control room staff maintained safety functions and responded appropriately despite the additional burden from the common-cause failure of the loop 1 & 2 shutdown cooling hydraulic isolation valves due to low oil level and the departure of the shift supervisor to lead the fire brigade. Because of the fire, the operators chose to rely on the atmospheric dump values to remove decay heat avoiding more labor-intensive activities to maintain condenser vacuum.

3.5 Oconee Unit 1 Reactor Trip

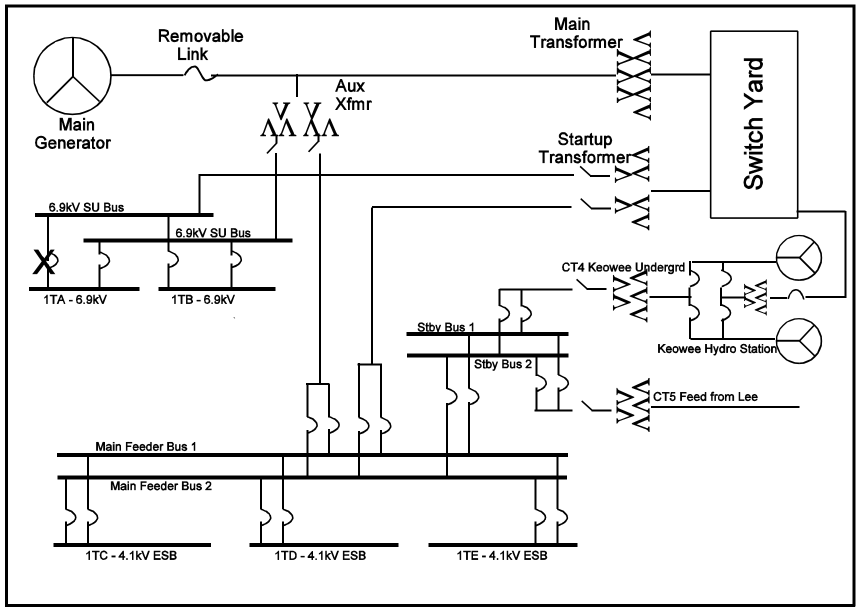

Figure 6 - Oconee 1 Electrical Single Line Diagram

At 1916 on January 3, 1989, Oconee 1 was at 26 percent power and in the process of manually transferring non-safety 6.9 kV bus 1TA from the ST to the AT. Refer to Figure 6, "Oconee 1 Electrical Single Line Diagram." Immediately after the transfer, an energetic electrical fault occurred resulting in a fire and explosion in the AT supply circuit breaker that feeds non-safety bus 1TA. The AT protective relays detected an electrical fault and tripped the turbine generator, the switchgear 1TA 6.9 kV supply circuit breaker for the AT (which failed to completely open), and the two RCPs fed from switchgear 1TA. The main generator continued to supply energy to the fault through the stuck 1TA 6.9 kV supply circuit breaker from the AT until the generator field decayed.

The fire was detected promptly. Switchgear 1TA dc control power was isolated at 1929. At 1933 and 1949, attempts to use carbon dioxide and dry chemical extinguishers failed. The reactor was manually tripped at 1956. Nearby switchgear 1TB was de-energized at 2002 in preparation for using water. The fire was extinguished with water 59 minutes after it started.

Later inspections could not determine the cause with any certainty. Records review eliminated the failure to perform maintenance, incorrect maintenance, and use of improper parts as causes. 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. Insulators and load side connects in the compartment vaporized. The fire damaged the integrated control system (ICS) wiring in the switchgear cubicle next to the AT supply circuit breaker and the cables in trays above the switchgear. Upon replacing the damaged cables above the switchgear, the licensee discovered redundant main feeder bus control/protective cables in one cable tray. The cable damage and the lack of separation were evaluated and determined not to be safety significant.

The control room staff maintained safety functions and responded appropriately despite the distractions from: the excessive cooldown rate as a result of overfeeding the SGs to mitigate a primary system pressure increase; smoke in the main control room; manual actions needed as a result of burnt ICS cabling affecting SG level control; SG block valve failure; and feedwater control valve calibration drift. Although there was no detailed information about the smoke effects, the licensee noted that the operator distraction from smoke in the control room and damaged ICS cables was consequential.

3.6 Palo Verde Unit 1 Reactor Trip

At 1208 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 1E-NAN-S02. 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. Figure 7 "Palo Verde 1 Electrical Single Line Diagram" shows the equipment involved in the event. 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 AT sudden overpressure relay tripped the generator output circuit breakers in the switchyard, opened the 13.8 kV AT supply circuit breakers to buses 1E-NAN-S01 and 1E-NAN-S02, and blocked the automatic transfer of the 13.8 kV buses to the STs, resulting in a loss of power to the RCPs and a reactor trip.

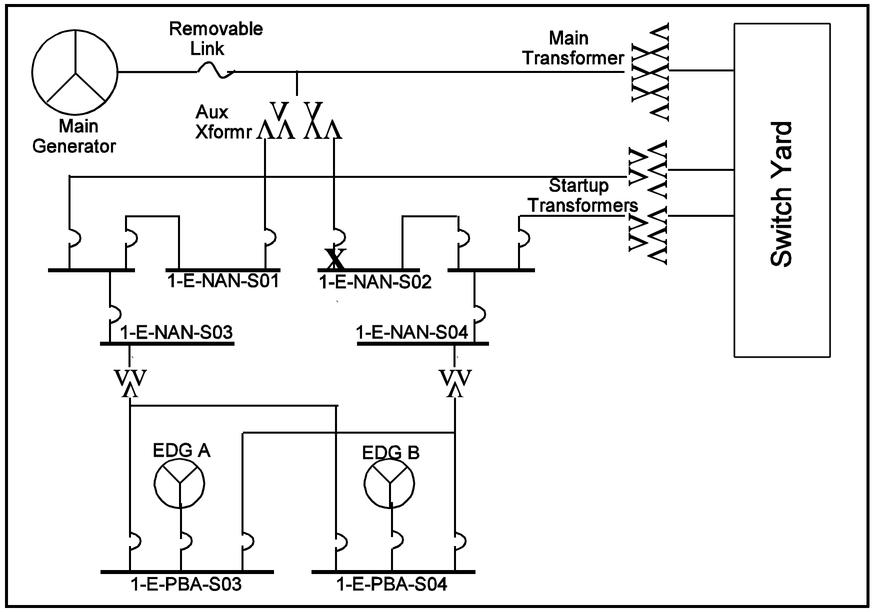

Figure 7 - Palo Verde 1 Electrical Single Line Diagram

The control room was notified of the AT fire and a Notification of Unusual Event was declared. An area auxiliary operator (AO) saw smoke in the turbine building, and found the transformer explosion had damaged a wall and a panel on the inside of the wall that was used to verify deluge flow to the transformer sprinklers. The deluge system is activated by the electrical portion of the fire protection system that was lost due to the transformer failure. The AO manually activated the deluge valves to all transformers and left the area. The AT fire was extinguished at 1224, 13 minutes after it started, and the Notification of Unusual Event terminated.

At 1250 and 1254, EDGs A and B were manually started, loaded, and separated from the plant distribution system. During separation of the safety and non-safety distribution systems, one non-safety circuit breaker could not be opened from the control room and had to be opened manually. Operators initiated the LOOP because the 13.8/4.16 kV engineered safety features transformers that fed the safety buses were being sprayed and to protect the safety buses while attempting to re-energize the 13.8 kV bus from the switchyard. At 1303, an attempt was made to re-energize 13.8 kV bus 1E-NAN-S02 from the ST. When the 13.8 kV circuit breaker that connects the ST to the bus was closed, the circuit breaker tripped again, and a second fire occurred in the 13.8 kV bus 1E-NAN-S02. The switchgear fire was extinguished in 19 minutes. Following visual inspections, cleaning, and testing, power was restored to 13.8 kV 1E-NAN-S01 at 1749. EDG A and EDG B were shutdown after being loaded for approximately 9 and 13 hours, respectively.

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. IN 89-64, "Electrical Bus Bar Failures," dated September 7, 1989, alerted licensees to the problems at Palo Verde and four other nuclear power plants as a result of the failure of cracked 4.16 and 6.9 kV bus bar insulation and debris or moisture buildup in the switchgear that housed the bus.

The control room staff maintained safety functions and responded appropriately even though the loss of non-safety power resulted in the loss of compressed air, the loss of the control room and vital power distribution room ventilation, and the loss of non-class nuclear cooling water (NCW) for RCP cooling. The operators also successfully responded to reports of: (1) breathing problems in the auxiliary building due to leakage of nitrogen from air-operated valves (nitrogen is used as backup following the loss of compressed air), (2) a failed attempt to restart the RCP due to low non-safety battery voltage dual-position indications on one main steam isolation valve and the non-class/class NCW cross tie valve, and (3) a mis-wired isolation letdown valve that did not close as expected when the operator was maintaining pressurizer level and bleeding the RCP seal.

4 OBSERVATIONS

The conditional core damage probabilities (CCDPs) for these events are mixed, varying four orders of magnitude between the largest and smallest values. The CCDP for the Maanshan SBO was 2.2E-03. For the U.S. events, the CCDP was approximately 9E-05 for two events and less than E-05 for three events. The NRC ASP which provides a safety significance perspective of nuclear plant operating events, considers events with a CCDP greater than or equal to E-04 to be important accident precursors, those greater than or equal to E-05 to be events of interest, and those smaller than E-05 to be of no interest from an ASP perspective.

RES previously compared the individual plant total fire CDFs to the internal events CDF and found that the total fire CDF is generally on the same order of magnitude as the total internal events CDF – fire is a major risk contributor. Typically, IPEEE results show that the CDF for switchgear fires is on the order of E-06 and smaller. However, for U.S. plants with safety bus configurations similar to Maanshan, the risk due to energetic faults in switchgear can be significant. For example, the Palo Verde IPEEE internal fire analysis estimated CDF of 3E-04/RY from a fire in the safety related switchgear room that destroys everything in the room and causes a LOOP to both safety buses (see section 4.2.3).

RES review of nuclear plant risks previously found that: (1) SBO remains a dominant contributor to the risk of core melt even after implementation of the SBO rule; (2) electrical panel fires were found by most licensees to be one of the most significant potential contributors to fire risk and the methods of analysis applied to panel fires remains an area of quantification uncertainty and debate; and (3) while the overall structure of a PRAs can capture dominant factors involved in a fire incident, several areas of methodological improvement were identified that fall outside of the scope of the PRA.

Table 3, “Summary of 4.16 to 13.8 kV Switchgear and Bus Duct Fire Observations,” includes information on the five events including: circuit breaker manufacturer, cause, circuit breaker function and performance, and fire risk characteristic not modeled in a typical fire risk PRA. Table 3 and other observations are discussed below.

4.1 Event Similarities

None of the energetic switchgear fires described in this report impacted public health and safety. All six fires occurred at pressurized-water reactors. The detection of the fires was generally prompt, usually within a minute. The longest detection time was 8 minutes at Waterford. The fires were caused by energetic electrical faults in safety and non-safety-related medium voltage (4.16 to 13.8 kV) switchgear or equipment connected to the switchgear. The safety and non-safety-related medium voltage switchgear have similar electrical and mechanical design and construction features.

Table 3 indicates that energetic electrical faults were due to degradation of electrical equipment: (1) degraded insulation in the presence of dirt or moisture, (2) failure of circuit breakers to open because of slow opening mechanism, and (3) thermal failure of a loose bus bar connection following its replacement. Four of the six events took place following a bus transfer and involved a stuck or slow bus supply circuit breaker. Typically, one of the three breaker poles of the breaker was more severely damaged, indicating that pole may have been stuck or slow. The failed breakers were produced by several different manufacturers.

The failures of the type which caused these events are maintenance preventable by periodic inspection and tests for degraded electrical insulation, dirt and moisture, and sluggish operation. Correctly timed operation of ST/AT supply circuit breaker mechanisms is critical to preventing fires in switchgear following bus transfers.

4.2 Fire Risk Model Considerations

Many of the fire risk characteristics not modeled in a typical fire risk PRA were identified in NUREG/CR 6738 as discussed in Section 2 of this report; the following observations expand upon those characteristics.

Table 3 Summary of 4.16 to 13.8 kV Switchgear and Bus Duct Fire Observations

Plant/Circuit Breaker Manufacturer	**Cause**	**Circuit Breaker Function/ Performance**	**Fire Risk Characteristic Not Modeled in a Typical Fire PRA**
Maanshan General Electric Circuit Breaker	switchgear insulation failure of unknown cause	both 4.16 kV supply circuit breakers faulted on line side following manual bus transfer	–HRR values corresponding to energetic fault energy levels –an initiating event that results in a LOOP and loss of EDG. –the loss of plant offsite power circuits instead of a LOOP –that a fire inside a cabinet propagates outside of the cabinet (e.g., arcing, smoke, ionized gases damaged five more switchgear cabinets) –smoke propagation beyond fire area
SONGS Asea Brown Broveri Circuit Breaker	equipment failure of unknown cause	4.16 kV AT supply circuit breaker FTO following manual bus transfer	–HRR values corresponding to energetic fault energy levels –that a fire inside a cabinet propagates outside of the cabinet (e.g., arcing, smoke, ionized gases damaged four more switchgear cabinets) –a failed fire suppression attempt –fire-induced and independent equipment failures that challenge the operator
Diablo Canyon	thermal failure of bolted bus bar connection	all circuit breakers performed as expected	–HRR value corresponding to energetic fault energy levels –effects of an arc from jumping from faulted equipment to other equipment
Waterford Asea Brown Broveri Circuit Breaker	improper automatic bus transfer due to slow circuit breaker caused by hardened grease	4.16 kV AT supply circuit breaker FTO following automatic bus transfer	–HRR value corresponding to energetic fault energy levels –that a fire inside a cabinet propagates outside of the cabinet (e.g., arcing, smoke, ionized gases damaged four more switchgear cabinets; and overhead cables are damaged in part from failure of a cable tray fire barrier). –fire-induced and independent equipment failures that challenge the operator
Oconee Asea Brown Broveri Circuit Breaker	equipment failure of unknown cause	6.9 kV AT circuit breaker FTO following manual bus transfer	– develop higher HRR value corresponding to energetic electrical fault energy levels –smoke propagates outside fire area (e.g., smoke control room from turbine building switchgear fire) –failed fire suppression attempt –equipment unavailability to use water to suppress the fire –fire-induced and independent equipment failures that challenge the operator –other accident sequences (e.g., an overcooling event)
Palo Verde General Electric Circuit Breaker	13.8 kV bus insulation failure	13.8 kV AT circuit breaker slow to open due to protective relay timing	–HRR values corresponding to energetic fault energy levels –fire-induced and independent equipment failures that challenge the operator

4.2.1 Bypass of Fire Initiation and Growth Stages Assumed in Fire Risk Models

As shown in Table 3, all 5 of the events generated much higher HRRs than are assumed in typical fire risk models. Fire risk models would be improved by using HRR values which more closely correspond to actual energetic electrical fault energy levels. NUREG/CR-6738 describes the typical fire risk analysis of a switchgear fire as one which assumes HRRs of 100–200 kW, and a fire progressing in stages through initiation and growth. The 5 events described here started with HRRs much greater than 200 kW and almost instantaneously bypassed the fire initiation and growth stages. Due in part to debate over the magnitude of the HRR level, NUREG/CR-6738 states that the methods of analysis applied to panel fires remains an area of quantification uncertainty and debate.

The events indicate that energetic electrical faults release large amounts of energy instantaneously so as to bypass the fire initiation and growth stages. The equipment that caught fire was connected directly to the ST or AT that are powered from the grid or main generator so that if a circuit breaker was stuck or slow, there was sufficient energy available to cause explosions and vaporize metal in a few cycles. Information from the Palo Verde LER provides insights into the amount of energy suddenly released following an energetic bus fault. At Palo Verde a bus fault and a slow circuit breaker caused the AT, a large steel tank with copper windings and several hundred gallons of oil, to fail its windings, rupture its tank, and ignite the oil within 20 cycles. In each of the Maanshan, SONGS, Diablo Canyon, and Waterford events, the fault was so energetic it melted and vaporized electrical equipment designed to interrupt faults of 250 to 1000 MVA. Even if only 20 percent of the 250 to 1000 MVA (50 to 200 mW) is assumed to have a heating effect, the fault mW exceeds HRR assumed in fire risk models by a factor of 1000. Values currently assumed for HRR values are too low.

On the other hand, review of the SCSS and other databases indicates that although the 600v and smaller switchgear and electrical cabinet fires were generally instantaneous and damaged the faulted cabinet, they did not release sufficient energy to cause widespread damage or multiple fire events. Operating experience indicates that equipment rated 4.16 kV and higher is potentially vulnerable to energetic electrical faults.

NUREG-1742 noted that virtually all IPEEE analyses treat switchgear fires in the same manner as other fires, not as energetic faults which generate rapid fire propagation. Oil-filled transformers are also not treated as potential energetic sources. Oil filled transformers rated 4.16 kV and up may be vulnerable to similar energetic faults and increased fire risk.

4.2.2 Switchgear and Bus Duct Fires Propagate

NUREG/CR-6738 noted that some fire risk models discount the possibility that fires inside an electrical panel propagate outside the panel. Table 3 includes 4 events which propagated damage to other switchgear compartments, 2 events which propagated damage to overhead cable, and 1 event which propagated damage from one bus duct fire to another bus duct.

At Maanshan, SONGS, Waterford, and Oconee, explosions, arcing, smoke, ionized gases, and heat from energetic electrical faults provided the mechanism to damage more than one switchgear compartment and caused circuit failures outside the fire area. The Diablo Canyon event showed that a 4-inch separation between bus ducts was insufficient to prevent damage to the upper duct from an energetic fault on the lower duct.

At Waterford and Oconee the fire in the switchgear compartment burned overhead cable. At Waterford the cable tray fire jumped a vertical cable tray fire barrier and stopped at a horizontal cable tray fire barrier. The Waterford event demonstrated that horizontal cable tray fire stops were effective in stopping the propagation of a fire; however, vertical cable tray fire barriers did not stop propagation of a fire. Fire risk models do not consider failure of vertical cable tray fire barriers.

4.2.3 AC Power System and Equipment Configuration

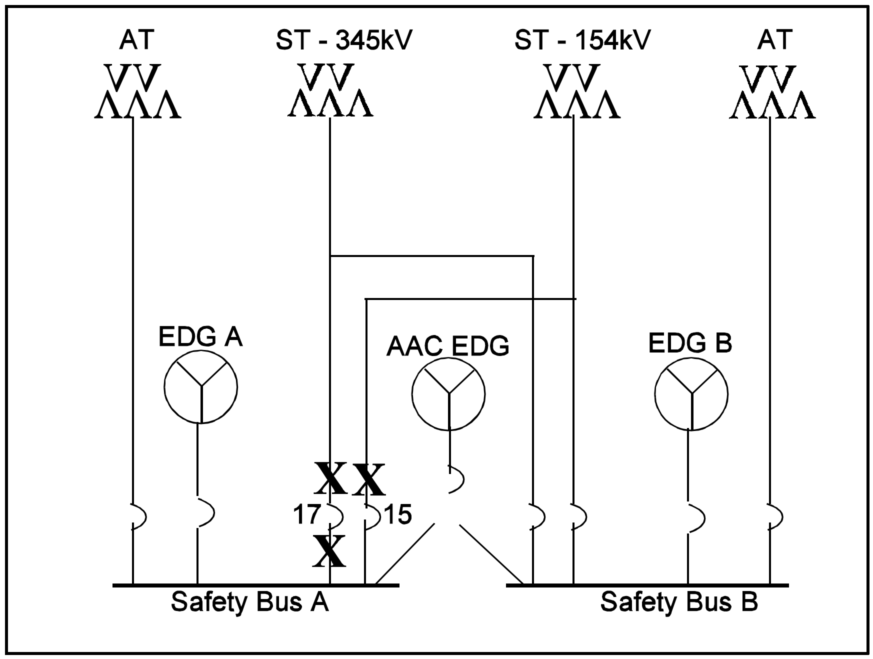

Figure 8 - Maanshan Simplified Safety Bus Diagram

At Maanshan, the offsite power circuits from both STs that feed the two safety buses are connected in parallel as shown in Figure 8, "Maanshan Simplified Safety Bus Diagram" – the electrical feed from the ST to both safety bus supply circuit breakers is common. A fault anywhere on that portion of the circuit faults the supply to both safety buses. At Maanshan, the two offsite power supply circuits are terminated in switchgear compartments 15 and 17, which are separated from each other by one other switchgear compartment. Nonetheless, the energetic electrical fault resulted in arcing and fire, generating ionized gases and smoke that diffused through bus and cable passages between five adjacent switchgear cubicles and caused multiple faults in the bus and the line side of both supply circuit breakers as indicated by the "Xs" in Figure 8. The initiating event resulted in a LOOP, the loss of one EDG, and damaged the offsite power circuit in compartments 15 and 17. In addition, the energetic electrical fault damaged the power cable feeding a load three compartments away from circuit breaker 17.

Fire risk models and regulatory analysis (FSAR FMEAs as discussed in Section 3.1) do not consider scenarios like the Maanshan event – an energetic fault results in a LOOP and loss of an EDG. Instead, risk models use LOOP probability as the initiator and EDG failures are treated independently. The consequential adverse effects from fire due to energetic electrical fault are not included. Consequential failures could be important contributors to risk when analyzing fire risks from energetic electrical faults.

The U.S. events all involved non-safety equipment that was connected to the main generator through a single circuit breaker. Consequently, under faulted conditions, the generator current continued to feed the fault for several seconds until the generator magnetic flux decayed. 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.

The SONGS event can be viewed as a precursor to the Maanshan event. Both events have potential generic implications. Although the Maanshan event occurred in safety related switchgear and the SONGS event occurred in non-safety related switchgear, the type of failure and the extent of the damage were similar.

RES reviewed U.S. nuclear plant electrical diagrams to identify plants that may be vulnerable to an SBO similar to Maanshan. The review found plants that are the most vulnerable have two safety buses connected in parallel (similar to that in Figure 8) to the AT through a single circuit breaker. Appendix A, "U.S. Plants With AC Power Configurations Vulnerable to Potential Switchgear Fires" lists U.S. plants with a similar safety bus arrangement.

These events and other operating experience show that the impact of an energetic electrical fault is related to the proximity of vital electrical equipment to the fault location. Switchgear compartments closest to the fault are more likely to be damaged than those at a distance. In some cases, electrical feeds to the safety buses are in close proximity, perhaps adjacent cubicles; in others, the electrical feeds are at opposite ends of the bus, separated by several cubicles. The risk implications of an energetic electrical fault depend on the extent of loss of vital electrical sources and the impact of collateral damage.

An additional concern is that for some plants the AAC and unit crossties which are relied on for response to an SBO may be vulnerable to the effects of an energetic electrical fault. Although none has been specifically identified in this analysis, these additional electrical sources could be unavailable if located in close proximity to the faulted switchgear cubicle.

The Maanshan and U.S. events show that the safety significance of a energetic electrical fault depends on factors including: (1) the ac power system design configuration, (2) the number of redundant safety buses and emergency ac power sources, (3) the proximity of the offsite power supply circuits to each other in the switchgear, (4) whether the safety buses are connected to the AT through a single circuit breaker, and (5) the degree of separation of the AAC and unit crossties.

4.2.4 Restoration Time and Actions.

NUREG/CR-6738 indicates that fire risk models typically analyze fires lasting 10 to 30 minutes. Table 2 indicates the fires which were extinguished in more than 30 minutes, including second fires and reflash. Recovery from a fire event may involve the following factors, which may be additive; the time to: (1) extinguish the fire, (2) clear smoke and carbon dioxide, (3) inspect and assess the extent of the damage, (4) assess restoration options, (5) isolate damaged equipment, (6) inspect and test equipment, and (7) re-energize equipment. At Palo Verde, reconnecting power resulted in a second fire which delayed the restoration of power for 7 hours. The implications of long power restoration times such as the impact on RCP seals and battery depletion are important. Consequently, operators would give high priority to restoration of power following an SBO. However, as discussed below, failed fire suppression attempts and reflash of a fire can extend the recovery.

4.2.5 Failed Fire Suppression Attempts and Reflash Due to Retained Heat

NUREG/CR 6738 indicates that fire risk models do not consider failed fire suppression attempts. In the Waterford event, several minutes after the initial fault and explosion, the ST supply circuit breaker spuriously closed into the fault resulting in another fire. Dry chemical failed to extinguish the fire and the plant staff's delay in using water prolonged the event. At SONGS, dry chemicals failed and a similar reluctance to use water resulted in reflash. The SONGS LER explained that dry chemical temporarily removes air from the fire but does not reduce the heat and the fire reflashes when air is reintroduced. At Oconee, after failing to extinguish the fire with chemicals, plant personnel immediately isolated the near-by electrical equipment and used water.

After extinguishing a fire with dry chemical, water may be needed to reduce the likelihood of reflash. The affected and nearby equipment may need to be de-energized to eliminate the potential personnel shock hazard. All these activities contribute to the duration of and recovery from the event.

4.2.6 Switchgear Fires Accompanied by Additional Challenges to Operators

U.S. switchgear fires also involved additional unexpected challenges to the operators. Fires often introduce transients and equipment failures which disrupt normal plant responses and distract the operators.

Operator challenges include fire induced equipment and circuit failures, spurious actuation of circuit breakers, and latent equipment failures independent of the fire. At SONGS, the fire resulted in the unexpected loss of the annunciators, loss of the dc main turbine generator lube oil pump, and flooding from the condensate storage tank overflow after the loss of non-safety related dc power caused its level control system to fail. At Diablo Canyon, the component cooling water pump shaft-driven oil pump and the plant computer failed. At Waterford, one RCP seal failed, the shift supervisor left the control room to fight the fire, both shutdown cooling hydraulic isolation valves failed, and the ST circuit breaker closed spuriously. At Oconee, smoke entered the control room, the cooldown rate was exceeded after operators overfed the SGs, burnt ICS cabling required manual actions to control SG level, the SG block valve failed, and feedwater control instruments drifted. At Palo Verde, operators purposely initiated a LOOP to isolate the damaged circuit and start the EDGs, a non-safety circuit breaker could not be opened from the control room, one main steam isolation valve position indicated it was both opened and closed, and an NCW crosstie valve and a letdown isolation valve failed to close. Typically, control room and AOs must respond to the fire and to the above mentioned types of plant conditions during the fire. In all of the above cases, the operators' responses to these unexpected events were sufficient to maintain the plant in a safe condition.

4.3 Other Observations

4.3.1 Disconnects May Shorten Recovery Time and Improve Effectiveness of AAC Power

Plant electrical fires have resulted in unrecoverable damage to portions of the circuits that route offsite power to the plant. At Maanshan and Diablo Canyon, offsite power was available in the switchyard but could not be connected to the undamaged safety bus since the offsite power circuits that routed through the plant were damaged by the fire. Even though both offsite power supplies were available, the Maanshan event resulted in unrecoverable damage to portions of offsite power circuits routed in the plant. The Maanshan swing EDG installed as a result of the SBO rule was used and was able to limit the SBO to 2 hours because its had independent power feeds directly to either safety bus. Some U.S. SBO AAC power supplies connect to the safety buses through the offsite power circuits routed in the plant; these power supplies would be unavailable if those portions of offsite power circuits were damaged as they were at Maanshan. At some plants, in some locations, it can be accomplished from outside the fire area by links or switches.

4.3.2 RCP Seal Performance

The RCP seals at Maanshan were not damaged. At Waterford, an NRC inspection report indicates an RCP seal failed after approximately 23 minutes due to high component cooling water temperature.

5 ASSESSMENT

At Maanshan, a nuclear plant that began operation in 1985 and was built to U.S. NRC regulations and guidance, an energetic electrical fault from a switchgear fire led to an SBO having a CCDP of 2.2E-03. RES assessed the Maanshan and similar U.S. fires in the last 15 years to identify important factors and characteristics of these events that could be useful to NRC and licensee staffs to improve the effectiveness and efficiency of activities and decisions. This is consistent with the NRC Strategic Performance Plan to make NRC activities and decisions more effective, efficient, and realistic through safety insights gained from review of domestic and international reactor operating experience.

RES identified five U.S. energetic electrical faults in the same general type of equipment as the event at Maanshan – 4.16 kV to 13.8 kV switchgear and bus duct or cable connected to the switchgear. In all of the U.S. events, an energetic electrical fault caused explosions or vaporized metal. In most of the U.S. events, the fault was in the first breaker downstream of the AT or ST. In 3 of the events, the fault was fed from the generator as the generator field collapsed following generator trip. Four of the six events took place following a bus transfer and involved a stuck or slow bus supply circuit breaker. One event was attributed to degraded insulation in the presence of dirt or moisture and another to thermal failure of a loose bus bar connection following its replacement. Circuit breakers from several different manufacturers were involved.

From a risk perspective, PRAs find that SBOs and fires are both significant contributors to the risks at nuclear power plants. NRC fire protection requirements and the supporting guidance address fires due to energetic electrical faults and specifically those in electrical cabinets. The five events described in this report resulted in damage beyond that which would be modeled in IPEEEs.

The assessment of these events found fire risk model implications and potential lessons learned in the areas of plant design, maintenance, and operations.

5.1 Fire Risk Modeling Implications

The events described in this report add further evidence to the finding in NUREG/CR-6738 that current fire risk modeling of energetic electrical faults in 4.16 kV to 13.8 kV switchgear does not address the following characteristics of energetic fires: (1) the fire bypasses the typical fire initiation and growth stages; (2) a fire inside an electrical panel can propagate outside the panel; (3) the fire may result in failed initial fire suppression attempts; (4) smoke propagation outside the fire area affects operator response; (5) the fire may be longer than the 10 to 30 minutes typically analyzed; and (6) the plant material condition and independent failures may influence the chain of events.

These events demonstrate that fires from energetic electrical faults contain more energy than assumed in fire risk models as evidenced by explosions, arcing, smoke, ionized gases, and melting and vaporizing of equipment. The energy release exceeds HRRs assumed in fire risk models, possibly by a factor of 1000. Lower HHR values currently used may explain why current fire risk models have not identified the potential larger effects of fires from energetic electrical faults which may include the following: bypass of the fire initiation and growth stages, propagation of the fire to other equipment and across vertical fire barriers, ac power system designs that may be vulnerable to an SBO, failed fire suppression attempts with dry chemicals and the need to use water, longer restoration time to recover, and unexpected challenges and distractions to the operator from fire-induced failures.

Fire risk models may underestimate the risks from fires due to energetic faults in 4.16 kV to 13.8 kV switchgear and bus ducts by not considering: (1) development of HRR values corresponding to energetic electrical energy levels; (2) the effects of propagation from the fault location to other switchgear compartments, bus ducts, or overhead cables; (3) plant ac safety bus and circuit breaker configuration; (4) failed fire suppression attempts; (5) additional recovery actions; and (6) multiple accident sequences from fire induced equipment failures or operator error.

It appears that plant designs with two safety buses connected in parallel (similar to Maanshan) and connected to the AT through a single circuit breaker may be the most likely to experience an SBO from a fire due to an energetic fault.

5.2 Maintenance Considerations

Maintenance Considerations

The circuit breaker failures of the type which caused these events are maintenance preventable by periodic inspection and tests for degraded electrical insulation, dirt, moisture, and sluggish circuit breakers. Correctly timed operation of ST and AT supply circuit breaker mechanisms is critical to preventing fires in switchgear following bus transfers.

5.3 Design and Operating Considerations

Plant electrical fires have resulted in unrecoverable damage to portions of the circuits that route offsite power through the plant. Offsite power was available in the switchyard but could not be connected to the undamaged safety bus because the damage could not be isolated.

After extinguishing a fire with dry chemical, experience shows that water may be needed to reduce the likelihood of reflash. Prior to using water, it is common practice to de-energize the affected and nearby equipment to eliminate the potential personnel shock hazard. All these activities contribute to the duration of and recovery from the event.

U.S. switchgear fires also involved additional unexpected challenges to the control room and auxiliary operators. Typically, some control room and auxiliary operators participate as members of the fire brigade. Also, pre-existing latent failures (i.e., valve failure not related to the fire) that manifest during a fire have contributed to operator burden. Rapid response to augment the staff following an energetic fire could compensate for many of these concerns.

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APPENDIX A

U.S. PLANTS WITH AC POWER CONFIGURATIONS VULNERABLE TO POTENTIAL SWITCHGEAR FIRES

Table A-1, "U.S. Plants with AC Power Configurations Vulnerable to Potential Switchgear Fires," lists U.S. nuclear plants whose safety bus configuration is vulnerable to a station blackout (SBO) due to an electrical fault that causes a fire that results in (1) the unavailability of offsite power, (2) unavailability of one redundant onsite power source, and (3) independent failure of second redundant onsite power source. These plants' safety bus configuration is similar to Maanshan's (i.e., two or more redundant load groups connected in parallel to two sources of power). The third column lists plants whose safety buses are powered by the AT through a single circuit breaker.

Table A-1

U.S. Plants with AC Power Configurations Vulnerable to Potential Switchgear Fires

Plants with safety bus configuration similar to Maanshan	Safety buses in parallel and AT feeds safety buses through a single supply circuit breaker	Alternate ac power supply access time
Callaway		none required
Crystal River 3	X	10 minutes
Duane Arnold		60 minutes
Kewannee	X	60 minutes
Palisades	X	none required
Palo Verde 1, 2, & 3		2 gas turbine generator and access time
Pilgrim	X	10 minutes
Summer		none required
TMI 1		10 minutes
Vogtle 1 & 2		none required
Wolf Creek		none required