UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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April 20, 2001

Harold B. Ray, Executive Vice President
Southern California Edison Co.
San Onofre Nuclear Generating Station
P.O. Box 128
San Clemente, California 92674-0128

SUBJECT: SAN ONOFRE NUCLEAR GENERATING STATION NRC SPECIAL TEAM INSPECTION REPORT 50-362/01-05

Dear Mr. Ray:

On March 21, 2001, the NRC completed a special team inspection at your San Onofre Nuclear Generating Station, Unit 3, facility. The enclosed report documents the inspection findings which were discussed on March 21, 2001, with Mr. R. Krieger and other members of your staff.

This inspection examined activities associated with an unusual event declared on February 3, 2001, in response to a secondary circuit breaker fire and subsequent partial loss of offsite power to Unit 3. The inspection focused on operations and fire protection personnel performance, electrical equipment failures, and the root cause analysis that you conducted for this event.

Based on the results of the inspection, the team identified one issue of very low safety significance (Green). This issue was determined to involve a violation of NRC requirements. However, because of its low safety significance and because it has been entered into your corrective action program, the NRC is treating this issue as a noncited violation, in accordance with Section VI.A of the NRC's Enforcement Policy. If you deny this noncited violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region IV; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the San Onofre Nuclear Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

Charles S. Marschall, Chief
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Docket: 50-362
Licenses: NPF-15

Enclosure:
NRC Inspection Report
50-362/01-05

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket Nos.:	50-362
License Nos.:	NPF-15
Report No.:	50-362/01-05
Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Unit 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
Dates:	February 3 through March 21, 2001
Team Leader:	C. Osterholtz, Resident Inspector, Fort Calhoun Station
Inspectors:	J. Knox, Senior Electrical Engineer, NRR J. Kramer, Resident Inspector, San Onofre Nuclear Generating Station R. Mullikin, Senior Reactor Inspector, NRC Region IV
Approved By:	Charles S. Marschall, Chief, Project Branch C

ATTACHMENT: Supplemental Information

SUMMARY OF FINDINGS

San Onofre Nuclear Generating Station
NRC Inspection Report 50-362/01-05

IR05000362-01-05: 02/03/01-03/21/01; Southern California Edison; San Onofre Nuclear Generating Station, Unit 3; Special Team Inspection Report.

The inspection was conducted by four team members consisting of two resident inspectors, an electrical engineering specialist, and a fire protection specialist. This inspection identified one Human Performance finding in the area of Mitigating Systems. The significance of the issue is indicated by its color (Green, White, Yellow, Red) using IMC 0609 “Significance Determination Process.”

Cornerstone: Mitigating Systems

- Green. The team identified a noncited violation for the licensee's failure to properly implement procedures which resulted in a valve misalignment that rendered a secondary auxiliary feedwater supply inoperable (Technical Specification 5.5.1.1.a).

  This finding was of very low safety significance because a nonsafety makeup water source was available and all other emergency core cooling equipment remained operable. In addition, since the unit had just exited a refueling outage and had a low reactor decay heat load, operators would have had significantly more time to restore the secondary auxiliary feedwater supply as a source of water (Section 02.04c).

Report Details

SPECIAL INSPECTION ACTIVITIES

01 Inspection Scope

The team conducted a special inspection to better understand the cause and impact of a nonsafety-related 4160V circuit breaker failure. The breaker failure resulted in a fire in the secondary switchgear room, a Unit 3 turbine and reactor trip, and transfer of the safety and some nonsafety-related electrical loads to Unit 2 sources. The team evaluated operator and fire protection personnel effectiveness in response to the fire and loss of control room annunciators and determined whether the Site Emergency Plan was properly implemented. The team used Inspection Procedure 93812, “Special Inspection Procedure,” to conduct the inspection and gather information regarding equipment and personnel performance. The team reviewed procedures, conducted field observations, and interviewed plant personnel during the course of the inspection.

02 Special Inspection Areas

02.01 Overview and Sequence of Events

On February 3, 2001, San Onofre Nuclear Generating Station Unit 3 was operating at 39 percent power following a refueling outage. Operators were transferring nonsafety-related buses from the reserve auxiliary transformer (RAT) to the unit auxiliary transformer (UAT) in accordance with routine operating procedures. At 3:13 p.m., operators closed the unit auxiliary feeder circuit breaker (3A0712) from the UAT onto nonsafety-related 4160 Bus 3A07, and the RAT feeder breaker (3A0714) to Bus 3A07 automatically opened as designed. The following sequence of events then occurred:

3:13 p.m. Transferred Bus 3A07 to the UAT with unit at 39 percent power

3:14 p.m.

- UAT Circuit Breaker 3A0712 combustion
- Turbine/generator trip
- Automatic fast transfer of nonsafety-related Buses 3A01, 3A02, and 3A03 to the Unit 3 RAT
- Bus 3A07 Breaker 3A0714 experiences arc due to ionized gases from fire
- RAT trip on differential current
- Automatic transfer of Vital Buses 3A04, 3A06, and reactor coolant pump (RCP) Buses 3A01 and 3A02 to the Unit 2 RATs
- Automatic reactor trip on “low departure from nucleate boiling ratio” from the core protection calculator due to decreased RCP speed caused by the transfer to Unit 2 power

- Turbine dc lube oil pump failed to start

3:15 p.m.	Operations personnel implement Emergency Operating Instruction (EOI) SO23-12-1, “Standard Post Trip Actions”
3:18 p.m.	Loss of annunciator power to Unit 3
3:19 p.m.	Operators implement Abnormal Operating Instruction (AOI) SO23-13-22, “Loss of Control Room Annunciators,” and dispatch the fire department after receiving a report of smoke and flame in the Unit 3 nonvital switchgear room
3:22 p.m.	Firefighters arrive at the Unit 3 switchgear room and report seeing heavy smoke to control room operators
3:27 p.m.	Operators declare an Unusual Event due to the fire
3:32 p.m.	Control room annunciators restored
3:44 p.m.	Firefighters' report of “no flames visible” communicated to the control room as “the fire is out”
3:48 p.m.	Chart recorders indicate turbine thrust bearing temperature of 600°F. Shift Technical Advisor (STA) advises control room operators not to manually start the turbine dc lube oil pump (oil flash point 347°F)
	Operators report declaration of Unusual Event to NRC.
4:20 p.m.	Operators exit Unusual Event
5:20 p.m.	Firefighters open cabinet door to Cubicle 3A0712 and observe flames. Portable fire extinguishers used to extinguish flames, but reflash occurs repeatedly
5:40 p.m.	Fire department receives permission from control room operators to apply water to the Cubicle 3A0712 cabinet
6:11 p.m.	Fire reported out

02.02 Risk Significance of Event Based on Conditional Core Damage Probability

a. Inspection Scope

The team reviewed the licensee’s risk assessment of the Unit 3 fire for accuracy and completeness.

b. Findings

The team concluded that the risk assessment was conservative based on the models and assumptions used. The assessment was based on the reported component failures during the event and their nonrecoveries. Using the current living probabilistic risk assessment model in the San Onofre safety monitor, the Unit 3 conditional core damage probability for the event was calculated as 1.4E-4. The team noted that the assessment did not take credit for the Unit 2 RATs, which added additional conservatism to the analysis.

02.03 Equipment Performance

02.03a 4160V Switchgear Failure

a. Inspection Scope

The team reviewed the performance of the 4160V circuit breakers that connect Unit 3 secondary Bus 3A07 to the Unit 3 UATs (Breaker 3A0712) and the Unit 3 RATs (Breaker 3A0714) to better understand the sequence of events that led to the partial loss of offsite power to Unit 3. Section 03, Root Cause Analysis, documents inspection of the licensee's root cause evaluation.

b. Findings

The team concluded that an equipment failure in Circuit Breaker 3A0712 resulted in the secondary switchgear fire and that protective relaying, responding to the equipment failure, functioned as designed.

Operators were in the process of transferring the unit’s offsite power supply from the RATs to the UATs when a fault occurred in Breaker 3A0712 approximately one minute after the transfer. The licensee determined that this failure resulted in a fault to ground and created a circuit overcurrent condition. The as-found position of the breaker’s main contacts and the position of the trip springs indicated that protective relaying sensed the overcurrent condition and sent a trip signal to the breaker. The Phase A and B main and arcing contacts were found in an open position, and no arcing damage was observed on either Phase A or B contact surfaces. The Phase C main contacts only were found to be close to their normal open position (about 10 degrees less open than the Phase A contacts). The Phase C arcing contact melted as part of the failure. The Phase C main contacts were observed to have experienced significant arcing (melting) damage on both the stationary and movable contact surfaces. In addition, the breaker’s trip springs were found to be in the tripped position.

Circuit Breaker 3A0712 failed to isolate the initial fault to ground condition from the UAT power supply. This failure resulted in a continued overcurrent condition and a current imbalance between Phases A, B, and C in the UAT. Protective relaying associated with the UAT is designed to detect overcurrent and/or a current imbalance (i.e., differential current) and generate signals to isolate the UAT power supply and initiate a fast transfer to alternate power supplies. Protective relaying generated a trip signal to the switchyard circuit breaker supplying offsite power to the UAT through the main transformer, isolating the switchyard offsite power supply from the UAT and the fault. Similarly, the main generator tripped and nonsafety-related buses (the power supply buses for RCPs and other nonsafety loads) automatically transferred to their alternate power supplies (i.e., the unit's RATs).

The protective relaying associated with the UAT was also expected to generate a signal to automatically transfer Bus 3A07 (containing power supply Breaker 3A0712 with the fault to ground condition) to its alternate power supply. Protective relaying on Bus 3A07 was designed to sense a fault condition and block automatic transfer of the power supply to an alternate power supply. The licensee determined that the protective relaying functioned as designed, since the alternate supply breaker (3A0714) did not close after the failure of Breaker 3A0712. If the breaker had closed, arcing damage and melted bus insulation would have been expected, neither of which were found.

Following the trip of the main turbine generator and the offsite power supply breaker described above, the coastdown of the main turbine and motor loads continued to supply electrical energy to the ground fault. The continued supply of electrical energy provided the heat source for the fire in Cubicle 3A0712. Also, because of the continued supply of electric energy through the UAT, the UAT transformer experienced high current and sustained current imbalance between Phases A, B, and C. These conditions resulted in high transformer winding temperatures and caused the transformer's grounding resistor bank to overheat, burn, and fail. The resistor bank was designed to dissipate intermittent short duration current imbalances which occur during the opening and closing of breakers.

The licensee concluded that the fire in Circuit Breaker 3A0712 generated ionized gases resulting in multiple arcing faults in Breaker 3A0714, causing the unit's RATs to trip from their offsite power source. Trip of the offsite power supply breaker to the unit's RATs caused loss of offsite power to safety and nonsafety system loads. On loss of offsite power, the ac electrical system is designed to:

- Start the emergency diesel generators
- Transfer safety loads to their alternate offsite power supply through the Unit 2 RATs or to the emergency diesel generators
- Continue the automatic transfer of RCP loads from the RATs to their alternate offsite power supply from the Unit 2 RATs
- Transfer nonsafety 125 and 250 volt dc loads from the charger to the battery power supply
- Start emergency oil pumps from the 250 volt dc system battery power supply

The plant protection system is designed to generate a reactor trip signal on the low RCP speed that occurs during the transfer of power from Unit 3 to Unit 2. The system design for transferring the RCPs to alternate power supplies required residual bus voltage to be less than 25 percent in order to complete the transfer. A bus voltage of less than 25 percent will cause RCP speed to drop below the plant protection system's setpoint for reactor trip. The licensee concluded that bus voltage dropped below 25 percent (the transfer of power supplies to RCPs was successful), the speed of the RCPs dropped below the trip setpoint for reactor trip, the plant protection system generated a reactor trip signal, the reactor trip breakers opened, and the reactor tripped.

In response to the loss of offsite power, the emergency diesel generators started and safety system and RCP loads transferred to their alternate offsite power supplies. Nonsafety Buses 3A03, 3A08, 3A07, and 3A09 (which do not have an alternate power supply from Unit 2) became de-energized, and 125 and 250 volt nonvital dc system loads transferred to their battery power supplies.

02.03b Turbine dc Lube Oil Pump Failure to Start

a. Inspection Scope

The team reviewed the licensee's as-found data to better understand the turbine dc lube oil pump failure to start. Section 03, Root Cause Analysis, documents inspection of the licensee's root cause evaluation.

b. Findings

The team concluded that the turbine dc lube oil pump failed to start as a result of the failure of its load breaker (3D603). The turbine dc lube oil pump motor is powered from the 250 volt nonvital dc system battery through a 1600 amp power supply breaker, the 250 volt dc Bus 3D6, a 400 amp Load Breaker 3D603 (found in the tripped position), and a motor controller. Control power is supplied from the 125 volt dc system through dc Bus 3D5, distribution Panel 3D5P2 (which did not lose dc power from the battery) and panel Breaker D5P228. The as-found current trip point for Breaker 3D603 was 510 amps. The motor starting current is approximately 650 amps. The breaker tripped at a value of current below the motor starting current, resulting in a breaker trip during the start of the lube oil pump motor. Examination of the breaker after the event found the trip setting device damaged and incapable of responding to setting adjustments.

02.03c Loss of Control Room Annunciators

a. Inspection Scope

The team reviewed the circumstances surrounding the equipment failures to better understand the cause and impact of the loss of the Unit 3 control room annunciators. Section 03, Root Cause Analysis, documents inspection of the licensee's root cause evaluation.

b. Findings

The team concluded that the loss of Unit 3 annunciators resulted from secondary control power shorts generated by the secondary switchgear fire. The team also determined that the loss of annunciators resulted in a minimal impact in the control room operator's ability to recover from the event, as the associated control room indicators remained operable.

The loss of Unit 3 annunciators occurred approximately 4 minutes after the switchgear failure. A 125 volt nonvital dc system distribution panel supply breaker (3D506) tripped open on overcurrent, causing the loss of dc power to the control room annunciators and other nonsafety-related dc system loads. The dc power to control room annunciators was reestablished within about 14 minutes; throughout the period, the associated control room indications remained operable. Operators attempted to reestablish power by first closing the distribution panel's tripped dc supply breaker. The supply breaker again tripped on overcurrent. The operators then opened all of the distribution panel's load breakers to clear the overcurrent condition, closed the panel's tripped dc supply breaker, and reclosed the panel's load breaker to the control room annunciators. These actions successfully restored power to the annunciators. The licensee indicated that a short circuit condition created by the fire caused the overcurrent condition and resulting trip of Circuit Breaker 3D506.

Control power to the Bus 3A07 switchgear (affected by the fire) was supplied from the nonsafety-related 125 volt battery through a 1600 amp breaker (3D501), the 125 volt dc bus (3D5), a 500 amp distribution panel supply breaker (3D506) that tripped due to the fire, a distribution panel (3D5P4), and a 100 amp load breaker (3D5P4A2) that remained closed following the fire. The 100 amp load breaker supplied power to the control circuit located in the Bus 3A07 switchgear. From this control circuit, dc control power is distributed to the various loads within the Bus 3A07 switchgear through breakers and fuses. Control power to Breaker 3A0712, for example, was supplied through a 30 amp breaker located in its breaker cubicle. Breaker 3A0712 along with the 30 amp control power breaker and its associated control circuit wiring located in the breaker cubicle were destroyed by fire.

The original plant design for the nonsafety-related dc system specified appropriate coordination between the 1600 amp (3D501) breaker and the distribution panel breakers such as Breaker 3D506. The system design does not require breaker coordination between the distribution panel's supply breaker (i.e., 3D506) and load breakers (e.g., 3D5P4A2). For the fault which occurred on the dc circuit at Switchgear 3A07, the system functioned as designed. Breaker 3D501 stayed closed and Breaker 3D506 opened. As a result of the fault, 125 volt power was not lost to other nonsafety-related distribution panels and their loads.

The safety-related dc system utilizes a similar design. The 125 volt dc power to the safety-related 4160V switchgear is provided from the battery through a 1200 amp breaker, the dc bus, a 300 amp distribution panel breaker, and a 100 amp load breaker. If a similar failure were postulated in safety-related 4160V Switchgear 3A04 or 3A06, either the 300 amp or the 100 amp load breaker would be expected to open to isolate the fault. The 1200 amp supply breaker would be expected to remain closed. The dc bus would thus remain energized and available to safety-related instrumentation loads through the 1200 amp supply breaker from the battery.

02.03d Fire Detection and Suppression Equipment

a. Inspection Scope

The team reviewed the performance of fire detection and suppression equipment and interviewed fire department personnel to determine the adequacy of the equipment.

b. Findings

The team concluded that automatic fire detection equipment and manual fire suppression equipment performed as required. The team also determined that the portable fire extinguishers were located as described in the licensee’s prefire plans and were operable and that the two fire hose stations that were used by the fire department were also found to be operable.

The fire occurred in Turbine Building Switchgear Room T3-203 - Elevation 30' - 0", Fire Zone 3-TB-30-153. This fire zone is monitored by nine ionization smoke detectors which cover the entire 4176 square foot area of the room and provide an early warning alarm to the control room and onsite fire department. The room contains no automatic fire suppression features. Manual fire suppression is accomplished by use of portable Halon and dry chemical fire extinguishers which are located nearby. Additional manual suppression equipment is supplied by the licensee’s onsite fire department. Two water hose stations are also located near the room. The team reviewed the alarm data history report and noted that the smoke alarms in Room T3-203 went into alarm at 3:15 p.m. on February 3, 2001, which was approximately one minute after the start of the event.

02.04 Human Performance

02.04a Operator Response and Emergency Plan Evaluation

a. Inspection Scope

The team reviewed operations personnel's performance to better understand their effectiveness in mitigating the event. The team interviewed three senior reactor operators and a shift technical advisor that were present in the control room during the event. The team also reviewed the following procedures to determine if they were adequately implemented:

- EOI SO23-12-1, “Standard Post Trip Actions,” Revision 16
- AOI SO23-13-22, “Loss of Control Room Annunciators,” Revision 1
- Emergency Plan Implementing Procedure (EPIP) SO123-VIII-I, “Recognition and Classification of Emergencies,” Revision 13, Attachment 2

b. <u>Findings</u>

The team concluded that operator performance during the event to stabilize plant conditions, restore control room annunciators, and coordinate field activities was effective. The team also determined that the site emergency plan was appropriately implemented.

A normal crew complement consists of two senior reactor operators (a shift manager and control room supervisor), two reactor operators, and an STA. At the time the event occurred, Unit 3 was resuming power operations following a refueling outage. The team noted that, since the unit was starting up, seven extra licensed operators were available on shift.

When the reactor tripped automatically on “low departure from nucleate boiling ratio,” the operators appropriately implemented procedure EOI SO23-12-1 to perform standard posttrip actions. The operators also recognized that a partial loss of offsite power had occurred, and they manually closed the main steam isolation valves. Approximately 4 minutes after the reactor trip, a loss of all control room annunciators occurred, and the crew entered AOI SO23-13-22. At the same time, the shift manager received notification that a fire had occurred in the secondary switchgear room and dispatched the fire department. The shift manager used the extra operators available on shift to diagnose plant conditions, respond to the fire, and restore control room annunciators.

The shift manager reviewed Emergency Plan Implementing Procedure (EPIP) SO123-VIII-1, Attachment 2, and recognized that there were two possible emergency action level conditions which could result in an Unusual Event declaration. Tab E1-1 of the EPIP calls for declaration of an Unusual Event if a fire that threatens vital or safety-related equipment lasts for greater than 15 minutes. Tab D1-2 of the EPIP calls for Unusual Event declaration if a loss of control room annunciators occurs for greater than 15 minutes. The shift manager also noted that the Alert criteria for loss of control room annunciators requires declaration of an Alert if a loss of control room annunciators occurs for greater than 15 minutes with an unstable or uncontrolled safety system The shift manager determined that the Alert criteria was not met, as both safety buses were powered from Unit 2 and stable. However, the shift manager did not know the extent of the fire or the potential for an impact on safety-related equipment. As a result of the potential for affecting safety-related equipment, he declared an Unusual Event. The shift manager noted that the criteria for an Unusual Event based on loss of annunciators also applied, but concluded that the fire posed a greater concern than the loss of annunciators. Operators reported the Unusual Event to the NRC headquarters operations officer 21 minutes after declaration (approximately 34 minutes after the reactor trip).

After the Unusual Event declaration, operators successfully restored control room annunciators as previously described in Section 02.03c. This annunciator response procedure did not include the specific operator actions that were needed to restore the annunciators. The team concluded, however, that the operators took appropriate and timely action, with resultant restoration of the annunciators in 14 minutes.

The operators noted that chart recorders indicated a turbine thrust bearing temperature of 600°F; concurrently, an operator found the load breaker for the dc lube oil pump tripped. The STA advised the shift manager not to manually start the dc lube oil pump since the oil flash point was 347°F, and the possibility of another fire would exist. The shift manager appropriately decided to keep the turbine dc lube oil pump secured.

Seventeen minutes after entry into the Unusual Event, control room operators received a report that the fire was out. This was an erroneous report, however, because the fire chief had really directed that a report of “no flames visible” be made. For over another hour, the fire department attempted to extinguish the smoldering fire through the closed Cubicle 3A0712 cabinet door using portable extinguishers (see Section 02.04b).

Based on the erroneous report, the shift manager exited the Unusual Event at 4:20 p.m. Approximately one hour later, after the fire department opened the door to the breaker cubicle, the shift manager received a report that the fire had “reflashed.” At that time, the shift manager determined that he now knew the fire was not affecting, and was not adjacent to, areas and structures containing vital, safety-related, or safe shutdown equipment. Therefore, the shift manager did not re-enter the Unusual Event.

During the course of fighting the fire, the fire chief at the scene requested permission several times to use water on the fire. The shift manager was reluctant to grant permission, as portions of the cabinet still had 125 volt dc and low voltage ac applied to it. During the course of operator interviews, the team discovered that operators had received no training on firefighting techniques beyond the use of portable fire extinguishers, while fire department personnel had received detailed training on fighting electrical fires with water. Despite the lack of training, the shift manager was the person responsible for approving the use of water in fighting the fire. The team concluded that the lack of firefighting training for operators, in conjunction with the shift manager's responsibility to approve the use of water for firefighting, contributed to an approximate 16 minute delay in completely extinguishing the fire. The licensee viewed this as a command and control issue, entered the problem into their corrective action program, and planned to address it. The team also concluded that, despite the delay in using water, the fire department effectively controlled the fire, and the delay had no impact on the outcome of the event.

02.04b Fire Department Response

a. Inspection Scope

The team reviewed the fire department’s performance to better understand their effectiveness in mitigating the fire. The team also conducted interviews of firefighting personnel, and reviewed the following fire department procedures to determine if they were adequately implemented:

- SO123-XIII-4.10.1, “Fire Department Communications, Protected Area (PA) Entry and Radiologically Controlled Area Entry procedures,” Revision 3
- SO123-XIII-4.10.2, “Fire Department Dispatch Procedures,” Revision 4

- SO123-XIII-4.10.3, “Fire Department Fire Fighting Response Procedures,” Revision 2

b. Findings

The team concluded that the licensee’s fire department adequately controlled and extinguished the fire. The team noted a communication deficiency between the fire department and the control room, but concluded that the deficiency did not preclude the fire department from mitigating the effects of the fire.

The normal shift fire department staff consists of five firefighters and one dispatcher. After the fire alarm was received, the five firefighters arrived at the scene of the fire within 7 minutes with full gear, including a fire truck with additional firefighting equipment. The dispatcher remained at the fire station to make notifications. Heavy smoke was observed venting from the east side wall vents of Room T3-203. The fire department captain and a firefighter made the initial entry into the room through the north door to evaluate the overall conditions and to determine whether any plant personnel were affected. The firefighters observed that the room was completely filled with heavy smoke and visibility was essentially zero. The source of the heavy smoke and heat was determined to be within the closed Cubicle 3A0712 cabinetry. The only flames noted were the burning of the instrument gauges on the front of Cubicle 3B14, directly across from Cubicle 3A0712.

After the initial search was completed, the firefighting command post was established outside of Room T3-203. Ventilation of Room T3-203 in order to remove smoke became the priority and was initiated. The south roll-up and pedestrian doors were opened for smoke removal and an air ejector was placed at the opened north door to provide positive pressure venting. The station fire chief arrived from off site and assumed command as the incident commander. A reactor operator was also present at the firefighting command post to act as an operations liaison between the fire chief and the operations shift manager. The shift manager had responsibility for coordinating the firefighting effort.

The operations liaison advised the fire chief that 125 Vdc power was still active within Cubicle 3A0712 and the energization of other circuits within the cubicle was unknown. There was no visible fire, but smoke production was very active. The door to the cabinet was closed and the decision was made to leave it closed until power could be isolated in order to make it safe for firefighting activities. The firefighters injected portable Halon and dry chemical extinguishing agents through the cabinet vents to attempt to extinguish any active fire within the cabinet. The extinguishing agents had no noticeable effect on the production of smoke. At 3:44 p.m., the operations liaison reported to the operations shift manager that the fire was out, although the fire chief only advised the operations liaison that there were no visible flames. Due to the unknown electrical hazards involved, the door to the cabinet was not opened until the cabinet was safely deenergized and sufficient smoke had been removed from the room.

At 5:20 p.m. all power except for some low voltage circuits was isolated to Cubicle 3A0712, and it was determined that the cubicle door could be safely opened. The firefighters observed flames within the cubicle, and dry chemical was introduced to extinguish the flames. The cubicle door was then closed as a containment measure. The cubicle door was subsequently opened several times and, each time the door was opened, the air which was introduced caused the fire to reflash. Firefighters used dry chemical to extinguish the fire each time it reflashed.

The fire chief then advised the operations liaison that the fire could not be extinguished completely unless water was introduced to the fire. The dry chemical would temporarily remove air from the fire, but it did not reduce the heat which would result in a re-flash once air was re-introduced. The operations liaison relayed this request to the shift manager but the use of water was denied. At approximately 5:40 p.m., the fire chief spoke directly with the operations shift manager to advise him that the fire could not be extinguished unless water was introduced. The shift manager then granted permission to use water to extinguish the fire. Water was then put on the fire and the fire was extinguished.

Despite the communications deficiency, firefighters had contained the fire within the cubicle. The fire remained under control with the use of dry chemical extinguishers until water was finally introduced. Therefore, the team concluded that the delay in the use of water did not impact the outcome of the event (see Section 02.04a).

02.04c Condensate Storage Tank (CST) T121 Overfill

a. Inspection Scope

The team reviewed the overfilling of CST T121 and discussed the event with the cognizant engineer. The team reviewed Action Requests (ARs) 010200346, 010200572, and 010200932 which covered various aspects of the event. The team reviewed Procedure SO23-9-5, “Condensate Storage and Transfer System,” Revision 14, and AOI SO23-13-3, “Earthquake,” Revision 6, Attachment 1, “Post Operating Basis Earthquake Inspections.”

b. Findings

The team concluded that operators did not sufficiently follow procedures for aligning makeup to CST T121 and overfilled the tank. This resulted in filling the vault surrounding the tank with approximately 12 feet of water. The valves required to provide makeup from CST T120 to CST T121 are located in the vault that had flooded. Therefore, the crosstie capability was lost. In addition, the operators did not recognize the crosstie capability was inoperable.

Technical Specification 3.7.6, “Condensate Storage Tank,” requires two tanks to be operable and contain a minimum volume of water. CST T121, the suction source for the three auxiliary feedwater pumps, is designed to Seismic Category I requirements, is enclosed in a Seismic Category I vault, and is required to contain $\geq$ 144,000 gallons of water. CST T120 was not designed to Seismic Cateogry I requirements, but is enclosed in a Seismic Category I structure designed to retain water following an earthquake. A Seismic Category I makeup crosstie is provided to CST T121 from both CST T120 and from its enclosure.

During the Unit 3 fire, the operators used auxiliary feedwater to maintain steam generator level. This resulted in lowering the water level in CST T121. To restore level, operators aligned the CST for automatic makeup from the demineralized water storage tank. Upon loss of power, the automatic level control valve had failed open. Operators did not recognize that the valve had failed open and filled the tank for approximately 1 hour. The tank overflowed into the vault surrounding the tank before operators identified the problem. The operators secured the automatic fill and used a manual fill method to maintain T121 above its Technical Specification minimum level; however, the vault was filled with approximately 12 feet of water.

The team noted that Procedure AOI SO23-13-3, Attachment 1, step 2.3.3, requires operators to close the Condensate Transfer Pump P049 suction from Tank T120 within 90 minutes of a seismic event at the plant. The cognizant engineer indicated that the P049 suction valve was near the bottom of the vault. The team concluded that the valve was inaccessible because the valve was under water. The engineer also indicated that AR 010200572, generated on February 8, 2001, documented two other valves as being inaccessible in the vault while it was flooded. The inaccessible valves were 3MU476, the header supply to CST T121 from CST T120, and 3MU088, the crosstie to CST 121 from the CST T120 tank vault. These two normally closed valves allow operators to crosstie the tanks to ensure adequate auxiliary feedwater makeup following a seismic event.

Technical Specification 5.5.1.1.a requires, in part, that written procedures shall be established and implemented covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, recommends procedures filling the auxiliary feedwater system. Procedure SO23-9-5, a procedure used to fill an auxiliary feedwater system component (CST T121), step 6.5.3, requires, in part, isolation of the automatic makeup if it cannot maintain level between 98 and 99 percent. Contrary to the above, on February 3, 2001, operators aligned the CST for automatic makeup and did not isolate the makeup when level could not be maintained between 98 and 99 percent. As a result, with the automatic makeup valve failed open, water overfilled the tank, and flooded the CST vault with 12 feet of water. The flooded vault rendered the 500,000 gallon CST T120 inoperable since its crosstie valves were closed and under water. This violation is being treated as a noncited violation (NCV 362/2001005-01) consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as AR 010200572.

The team also learned that the Unit 2 level control system had been modified so that the CST automatic makeup valve fails closed on a loss of power. The modification had not been performed on Unit 3. The licensee documented the differences in a caution statement in Procedure SO23-9-5 at the beginning of Section 6.5 for aligning CST T121 for automatic operation. The licensee planned to evaluate performing the modification to Unit 3.

This issue had a credible impact on safety because it rendered a Technical Specification required alternate auxiliary feedwater source inoperable. When evaluated using the Significance Determination Process, this issue was determined to be of very low safety significance because, throughout the period of inoperability, a nonsafety makeup water source was available to fill CST T121, and all other ECCS equipment remained operable. In addition, since the unit had just exited a refueling outage and had a low reactor decay heat load, operators would have had significantly more time to restore CST T120 as a source of water.

02.05 Quality Assurance

a. Inspection Scope

The team reviewed maintenance and surveillance tests to verify preventive maintenance and testing activities adequately verified equipment operability. The following activities were reviewed:

- Maintenance Order 96042371000, Maintenance Procedure SO123-1-9.8, "4.16KV Air Circuit Breaker Inspection, Cleaning, Lubrication and Adjustment," completed on May 8, 1997, for Breaker 3A0712

- Maintenance Order 96042361000, Maintenance Procedure SO123-1-9.8, "4.16KV Air Circuit Breaker Inspection, Cleaning, Lubrication and Adjustment," completed on April 30, 1997, for Breaker 3A0714

- Maintenance Order 96042344000, Maintenance Procedure SO123-1-9.8, "4.16KV Air Circuit Breaker Inspection, Cleaning, Lubrication and Adjustment," completed on May 10, 1997, for safety-related Breaker 3A0618

- Maintenance Order 40002071000, "Unit 3 Outside Containment Early Warning Fire Detection Surveillance," completed August 8, 2000

- Maintenance Order 00520000003, "Monthly Portable Fire Extinguisher Inspection," completed January 8, 2001

- Maintenance Order 00560000001, "Fire Hose Station and Standpipe Hose Connection Inspections," completed January 29, 2001

- Maintenance Order 00440000006, "36 Month Fire Hose Station Functional Test," completed November 21, 1999

b. Findings

The team concluded that the reviewed activities were satisfactory.

03 Root Cause Analysis

a. Inspection Scope

The team reviewed the licensee's root cause analysis to better understand why:

(1) Breaker 3A0712 failed
(2) Unit 3 RATs tripped after the Breaker 3A0712 failure
(3) The Unit 3 turbine dc lube oil pump failed to start
(4) The Unit 3 control room annunciators were lost

b. Findings

Overall, the team determined that the root cause analysis was effective in identifying the failure mechanisms leading to the specified equipment failures. The scope of the analysis was broad and addressed relevant issues. The root cause team was independent and well staffed.

(1) Breaker 3A0712 Failure

The extensive damage from the electrical arcing and fire made a definitive failure mechanism for Breaker 3A0712 indeterminate. The licensee indicated that the failure mode is believed to be the failure of Phase C to close completely during the transfer of power. The licensee concluded that the most likely cause for failure of Phase C to fully close was improper pressure leading to increased electrical resistance in the moveable main contacts.

From the routine maintenance history, the licensee concluded that the breaker's performance was nominal. The routine maintenance was performed on schedule. The routine maintenance met the original vendor maintenance recommendations and was consistent with industry guidance.

(2) Unit 3 RAT Trip After the Breaker 3A0712 Failure

The licensee indicated that smoke from the breaker fire in Cubicle 3A0712 (and energized circuits) caused multiple arcing faults (phase-to-phase and phase-to-ground) in the Cubicle 3A07 switchgear. The most significant of these arcing faults occurred on the offsite power circuit from the RAT at its terminal connection in Cubicle 3A0714. These arcing faults resulted in a current imbalance in the offsite circuit from the RAT. Protective relaying associated with the RAT is designed to detect overcurrent and/or a current imbalance (i.e., differential current) and generate signals to isolate the RAT. The offsite power supply breaker to the RAT, therefore, tripped as designed.

(3) Failure of the Unit 3 Turbine dc Lube Oil Pump to Start

The licensee indicated that the turbine dc lube oil pump failed to start as a result of the failure of its load breaker (3D603). The licensee procured five breakers of the same model and tested four. Three of the four breakers exhibited similar performance to that of Breaker 3D603. The fifth breaker was preserved as a control specimen.

Breaker 3D603 is a General Electric molded case circuit breaker, Type TBC 400 amps. The breaker has an adjustable current trip setpoint from 750 to 4125 amps. The current trip setpoint is mechanically changed by varying spring tension. When spring tension is increased, the current trip setpoint is increased. The breaker has a low trip setting position of 1000 amps and a high trip setting position of 3300 amps. Testing before the event (in its low setting position) determined that one pole tripped at 1250 amps and the second pole tripped at 1219 amps. The expected trip range is 750 to 1250. The breaker was reset to its high setting. During maintenance activities, Breaker 3D603 tripped during an automatic start test of the dc lube oil pump; however, after troubleshooting and two successful automatic start tests, the lube oil pump was returned to service. The licensee’s assessment indicated that they missed two opportunities for preventing the failure. First, a trip test was not conducted after the breaker was adjusted to its high trip setting position. Second, troubleshooting failed to establish the root cause for the breaker’s trip during the first automatic start of the dc lube oil pump motor. The team noted that, while failure of the dc lube oil pump contributed to damaging a significant piece of equipment in the licensee's power generation train, it did not impact the ability of the operators to mitigate the consequences of the accident and put the plant in a safe shutdown condition.

(2) Loss of Unit 3 Control Room Annunciators

The licensee indicated that the fire in Cubicle 3A0712 caused a short circuit condition between the positive and negative sides of the battery on the control circuit cable located in Switchgear 3A07. If the worst case fault is assumed for this condition (zero ohms resistance between the positive and negative side of the battery at Switchgear 3A07), the licensee estimated that as much as 800 amps of short circuit current from the battery could have been created by the fault. The licensee concluded that either Load Breaker 3D5P4A2 or the Distribution Panel 3D506 distribution panel supply breaker could have tripped from this 800 amp fault current. Load Breaker 3D5P4A2 has an instantaneous trip range from about 750 to 2000 amperes. The postevent instantaneous trip, as found by testing, was about 1200 amps. For the Distribution Panel 3D506 supply breaker, current flow could have reached 1050 amps (about 250 amps normal current plus the 800 amp fault current). Breaker 3D506 has an instantaneous trip range from about 1250 to 1750 amperes. The postevent instantaneous trip, as found by test, was about 1000 amps. The close proximity of the fault currents to their respective breaker trip settings indicated that either breaker could have tripped.

04 Meetings

04.01 Exit Meeting Summary

The team presented the inspection results to Mr. R. Krieger and other members of licensee management at an exit meeting on March 21, 2001. The licensee acknowledged the findings presented.

The team asked the licensee whether or not any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

C. Anderson, Manager, Site Emergency Preparedness
D. Brieg, Manager, Station Technical
J. Fee, Manager, Maintenance
J. Hirsch, Manager, Chemistry
R. Krieger, Vice President, Nuclear Generation
D. Nunn, Vice President, Engineering and Technical Services
R. Richter, Supervisor, Fire Protection Engineering
A. Scherer, Manager, Nuclear Oversight and Regulatory Affairs
M. Short, Manager, Site Technical Support
T. Vogt, Plant Superintendent, Units 2 and 3 Operations
R. Waldo, Manager, Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed During this Inspection

362/2001005-01	NCV	Condensate Storage Tank T121 Overfill (Section 02.04c)

LIST OF ACRONYMS USED

AOI	Abnormal Operating Instruction
AR	action request
CFR	Code of Federal Regulations
CST	condensate storage tank
EOI	Emergency Operating Instruction
EPIP	Emergency Plan Implementing Procedure
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
RAT	reserve auxiliary transformer
RCP	reactor coolant pump
STA	shift technical advisor
UAT	Unit Auxiliary Transformer