# TRIP REPORT:
# ONSITE ANALYSIS OF
# THE HUMAN FACTORS OF AN EVENT
# AT FORT CALHOUN
# ON JULY 3, 1992

(LOSS OF INSTRUMENT INVERTER AND SUBSEQUENT LOSS OF COOLANT)

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## EXECUTIVE SUMMARY

On July 3, 1992, Fort Calhoun was operating at 100 percent and had experienced (within the last 20 hours) three occurrences of a nonsafety-related electrical inverter No. 2 switching from its normal lineup to a bypassed condition. Inverter No. 2 supplies 120 Vac power to various instrumentation and components in the plant. After the first two times the inverter changed operating mode, inspections by operations or maintenance personnel found no problems and the inverter was returned to service without incident. Maintenance personnel replaced two circuit boards after the third event and at 11:35 p.m. on July 3, 1992, the operating crew transferred the inverter back to the normal position connecting it to the loads on the instrument bus. Immediately following the transfer, a control room operator observed indication of the affected bus voltage oscillating 20 to 40 volts and local inverter voltage indication was observed oscillating between 0 and 120 Vac. The voltage oscillations caused an electrical supply breaker which provides power to electrical panel AI-50 to trip open on high current.

Control circuitry for the main turbine, supplied by panel AI-50, lost power causing the main turbine control valves to shut while the main turbine stop valves remained open. No alternate heat sink was available to the reactor coolant system at this point because an enabling signal was absent which would allow the steam bypass valves to the condenser to open. As reactor coolant system temperature and pressure increased, the main steam safety valves opened to provide a heat removal path. When pressure in the reactor coolant system reached approximately 2400 psia, a reactor and turbine trip occurred, and the pressurizer power-operated relief valves opened. As pressure continued to rise, a pressurizer code safety valve opened to reduce reactor coolant system pressure.

Following the unit trip, reactor coolant pressure decreased to 1745 psia and began to recover as operators implemented procedure EOP-00, Standard Post Trip Actions. When pressure reached 1925 psia, quench tank alarms were received and the primary licensed operator reported rapidly decreasing pressure. In response to alarms for the quench tank and decreasing pressure indication, the block valves were shut isolating the power-operated relief valves. Pressure continued to decrease which initiated safety injection, containment and ventilation isolation signals. Pressurizer code safety valve RC-142 had opened and remained partially open. Later investigation found that the initial pressure increase, which had caused the safety valve to actuate, also resulted in a lowering of the valve setpoint. Failure of the safety valve created an unisolable loss of coolant from the pressurizer to the quench tank with the tank rupture disc blowing as designed when the tank filled allowing the reactor coolant to spill into the containment sump.

At the completion of the diagnostic section of procedure EOP-00, a transition was made to Procedure EOP-20, Functional Recovery, based on multiple problems of an inverter failure and unisolable loss of coolant. The event was classified as an Alert at 11:52 p.m. in accordance with procedure EPIP-OSC-1, Emergency Classification. Activation of the emergency response organization and notification of offsite agencies was initiated in accordance with procedure EPIP-OSC-2, Notifications. Several key personnel were already onsite due to involvement in the inverter maintenance activities and were immediately available to assist the shift supervisor in emergency plan activities.

Implementing emergency procedural steps of EOP-20, the operations crew secured reactor coolant pumps, verified natural circulation and initiated a plant cooldown and depressurization to shutdown cooling entry conditions. Reactor coolant system leakage was minimized during the cooldown by performing emergency procedure floating (continuous action) steps for "stop and throttle" of safety injection flow.

The emergency classification was downgraded to a notification of unusual event at 6:30 a.m. on July 4, 1992, with the reactor coolant system at 290 °F and 360 psia. Following the establishment of shutdown cooling, emergency procedure EOP-20 was exited and the operating crew entered normal shutdown procedures. The emergency plan was exited at 6:40 p.m. that evening with the plant on shutdown cooling at about 120 °F and depressurized.

The factors that affected human performance during this event are summarized below:

Procedures

In general, the recently revised procedures seemed to work well for the operators. A new system of placekeeping (i.e., a separate step check-off list) and floating steps (i.e., steps with continuous applicability) assisted the operators in using the procedures. There were at least three examples of where procedures needed to be supplemented by operator knowledge. These examples illustrate that knowledge-based behavior can, and often is, used to support procedures, but can not and should not be relied upon for factual information that needs to be incorporated in the procedures and in training.

Training

All operators agreed that plant-specific simulator training had assisted in their ability to respond to this event. The operators were trained on loss of coolant accidents and loss of inverter scenarios. They were also trained specifically on implementing the Emergency Plan which aided them in carrying out the emergency response requirements.

Human-Machine Interface (HMI)

Several HMI issues were identified. In two cases, related displays and controls were located at some distance from each other. Windows on each annunciator panel to indicate "loss of power" for the other annunciator panel were available to confirm that power was lost. Computer displays normally used for containment temperature and RCS subcooling parameters were malfunctioning. Although the information was available on control board panels or other, less frequently used, computer screens, the operators reported that not having the values available on the normally used screens was a hindrance to performance. This suggests that operators should be exposed to computer malfunctions as well as plant malfunctions during simulator training. What to do and how to obtain needed information should be addressed in training for degraded computer operation.

Stress

Stress did not seem to degrade human performance in this event.

## Staffing

Staffing was sufficient to perform required actions. Having a dedicated person to act as communicator for notifications left the shift supervisor free to oversee activities and confer with others, including the operations manager and the maintenance supervisor, during the recovery efforts. The shift technical advisor provided support to the shift supervisor, including assistance with notifications, calculations, safety function monitoring, and involvement in technical discussions and decisions. The shift technical advisor position was not a dual role, but a dedicated role for an engineer.

## Task Awareness

A major part of the success of the human performance associated with this event was related to the degree of task awareness on the part of the operators. Awareness of plant conditions and status appeared to be heightened during the event, but the heightened awareness did not result in stress levels that degraded performance. On the contrary, the heightened awareness was exhibited in pro-active monitoring and action, thinking ahead as to what actions might be needed and to anticipate and preempt undesirable plant conditions. Several examples illustrate a high level of task awareness.

## Command and Control/Teamwork

Normal command and control existed. Communications and support from the emergency response organization functioned smoothly. All personnel involved seemed to function as a team. Such teamwork contributed to the successful response to the event.

## Maintenance Activities

Several latent factors associated with maintenance activities contributed to the failure of inverter No. 2, hence to the initiating event. There was no way to perform post maintenance testing without placing the inverter in service. Information was not available from the vendor regarding correct circuit board configuration or the torque required for the setpoint locking nut of the safety-relief valve.

ACKNOWLEDGEMENTS

We express appreciation to the Fort Calhoun staff for their cooperation for freely providing information necessary to analyze the human factors of the operating event. We particularly thank the facility Investigation Team for their cooperation for responding so promptly to our requests for information and for making arrangements for and scheduling the requested interviews. Also, we thank the operators and technical staff who were on duty during the event for their cooperation during the interviews.

CONTENTS



FIGURES

## ACRONYMS

| | |
|---|---|
| AEOD | Analysis and Evaluation of Operational Data (NRC's Office for) |
| AIT | Augmented Inspection Team |
| CCW | component cooling water |
| EAL | emergency action level |
| EHC | electrohydraulic control |
| EOP | emergency operating procedure |
| ERO | Emergency Response Organization |
| HMI | human-machine interface |
| HPSI | high-pressure safety injection |
| INEL | Idaho National Engineering Laboratory |
| LED | light-emitting diode |
| LOCA | loss-of-coolant accident |
| LSO | licensed senior operator |
| LTOP | low-temperature overpressure protection |
| NOUE | notification of unusual event |
| NRC | Nuclear Regulatory Commission |
| NRR | Nuclear Reactor Regulation (NRC's Office for) |
| PLO | primary licensed operator |
| PORV | power-operated relief valve |
| PPLS | pressurizer pressure low signal |
| PSIA | pounds per square inch absolute |
| QSPDS | qualified safety parameter display system |
| RCP | reactor coolant pump |
| RCS | reactor coolant system |
| SIAS | safety injection actuation signal |
| SLO | secondary licensed operator |
| SS | shift supervisor |
| STA | shift technical advisor |
| TBO | turbine building operator |
| TMI | Three Mile Island |
| TSC | technical support center |
| Vac | Volts alternating current |

## 1 INTRODUCTION

### 1.1 Purpose

On July 4, 1992, the Nuclear Regulatory Commission (NRC) Region IV formed an Augmented Inspection Team (AIT) for an event at Fort Calhoun Nuclear Power Station. The purpose was to investigate the loss of a nonsafety-related electrical inverter which led to a high pressure reactor trip followed by a partially failed open safety relief valve on July 3, 1992. A similar event involving an inverter-induced high pressure reactor trip had occurred at this facility in July, 1986.

### 1.2 Scope

The human factors analysis focused on the factors that influenced the performance of the maintenance staff leading up to this event, as well as the operations staff and technical support personnel throughout this event. The analysis was based on data derived from plant logs and recordings; interviews with plant management, maintenance, operations, and training personnel; and review of plant procedures and training lesson plans. Idaho Engineering Laboratory (INEL) provided assistance to the AIT as part of the program at the NRC's Office for Analysis and Evaluation of Operational Data (AEOD) to study human performance during operating events.

### 1.3 Onsite Analysis Team

The human performance specialists were at the site July 4 through July 9. The onsite AIT consisted of the following members:

| | | |
|---|---|---|
| Phillip Harrell | NRC/Region IV | (team leader) |
| Philip Wagner | NRC/Region IV | (assistant team leader) |
| Charles Paulk Jr | NRC/Region IV | |
| Terrence Reis | NRC/Region IV | |
| Chu-Yu Liang | NRC/NRR/DST/RSB | |
| John Kauffman | NRC/AEOD/DSP/ROAB | |
| William Steinke | INEL/EG&G Idaho, Inc. | |

## 2 DESCRIPTION OF THE EVENT ANALYSIS

### 2.1 Background

The Fort Calhoun Nuclear Power Station, located in eastern Nebraska about 19 miles north of Omaha, is owned and operated by the Omaha Public Power District. The pressurized water reactor is rated at 1500 MWt with Combustion Engineering Nuclear Steam Supply Systems and a dry containment building. The unit has been in commercial operation since September 1973.

On July 3, 1992, the unit was at 100 percent of rated power when the operating crew began experiencing problems with a nonsafety-related electrical inverter. The crew was working the fourth of a 7-day 8-hour shift (11:00 p.m. - 7:00 a.m.) rotation. The control room personnel consisted of a shift supervisor (SS), licensed senior operator (LSO), primary licensed operator (PLO) and a secondary licensed operator (SLO). The normal LSO and PLO for the crew were on vacation and two replacement personnel from another crew were filling in for them (see Figure 1). An operations department engineer was at the plant fulfilling the shift technical advisor (STA) requirement.

At 4:33 a.m. on July 3rd, an inverter trouble alarm and inverter fan failure alarm were received in the control room. Investigation of the alarms found that inverter No. 2 had automatically shifted to the bypass mode of operation and an electrical "hot smell" was present in the area by the inverter cabinet. The normal mode of inverter operation utilized dc power from safety related, 125 Vdc Battery Bus 2. The dc power was converted to a 120 Vac 60 hertz source for important instrumentation and control loads. The inverter control circuitry automatically transferred the instrumentation and control loads to an alternate 125 Vac source when a problem was detected with either the 120 Vdc power source or an internal conversion (inverter) circuit. This transfer to the bypass mode was accomplished by a solid state switching circuit referred to as the static switch.

A maintenance work order was initiated for craft personnel to evaluate the cause of the inverter alarms and the electrical "hot smell" that had been detected by the operations personnel. The craft personnel performed an inspection of the inverter No. 2 and found no evidence of overheating or any other problems. The inverter was subsequently returned to the normal mode of operation at 6:36 a.m. and functioned normally.

Later that day, at 3:10 p.m., the trouble alarm and fan alarm were received again with inverter No. 2 transferring to the bypass mode of operation. Operations personnel checked inverter No. 2 and did not observe any problems. The inverter was returned at 3:27 p.m. to the inverter (normal) mode of operation without incident.

At 7:21 p.m., the same control room inverter alarms were received again accompanied by a transfer of inverter No. 2 to the bypass mode. An internal inspection of inverter No. 2 was conducted by craft personnel, revealing possible overheating indication (small discolored section) on two of the printed circuit boards, the inverter drive and static switch drive. Discussions between the system engineer and the work planner ended with a decision to replace the two discolored circuit boards. Concurrence was received from the maintenance supervisor who was also at the plant to assist in the repair. A briefing between the SS, maintenance supervisor and operations manager was conducted to discuss technical specification time requirements for the inoperable inverter and repair activity in progress.

Maintenance activities on inverter No. 2 were completed that evening at the end of the shift and the SS of the on-coming crew then authorized placing the inverter back in service at 11:30 p.m. following the shift briefing. The turbine building operator (TBO) began placing the inverter back in service with Attachment 6 "Inverter 2 (EE-8Q) Operation" of operating instruction OI-EE-4. At 11:35 p.m., the manual transfer switch was moved from the bypass mode to the normal static-switch position. The SLO was monitoring AI-42B bus voltage in the control room on a back panel, which is supplied by inverter No. 2, and observed several voltage oscillations with voltage dropping 20 to 40 volts. Similar voltage oscillations were observed on the local indication at the inverter. These voltage oscillations caused a number of problems, including the trip of a circuit breaker AI-42B-CB2 and the blowing of numerous fuses for control board annunciators.

Power was lost to distribution panel AI-50 which provided electrical power to sections of the nonsafety-related electrohydraulic control (EHC) circuity for the main turbine. Throttle compensation pressure transmitter PT-943 and first stage turbine pressure transmitter PT-945 were deenergized and the EHC system responded by initiating an immediate full closure of the turbine control valves creating a full load rejection with no immediate heat sink for the reactor.

A turbine trip signal is required to enable the steam dump valves to the condenser to provide an alternate heat sink. A turbine trip signal is generated when two of the four turbine stop valves leave their fully open seat, which did not happen in this event. Only the turbine control valves were affected by the power loss. A reactor trip signal would have also been generated from a turbine trip condition as anticipatory protection to limit the primary coolant system stored energy and pressure caused by a cessation of normal steam removal from the steam generators. Consequently, the reactor coolant system (RCS) temperature and pressure increased, and the main steam safety valves opened to provide a heat removal path. When pressure in the RCS reached approximately 2400 psia, a reactor and turbine trip occurred and the pressurizer power-operated relief valves (PORVs) opened. As pressure continued to rise, a pressurizer code safety valve opened to reduce RCS pressure.

Immediately following the voltage oscillations, control room annunciator panels AI-65B and AI-66B alarmed completely (all windows lighted). The SS, who was standing in the center of the control room, looked at the EHC panel and saw that it was dark, indicating that there had been some loss of power to the system. At the secondary feedwater control station, the LSO saw all the parameters start to change rapidly. Within a matter of seconds, the main steam safety valves lifted in response to the load rejection with no steam dump bypass valves available. The PLO, hearing the steam generator safety valves open, in anticipation of a high pressure reactor trip, initiated a manual reactor trip. The automatic high pressure reactor trip setpoint (2400 psia) was reached before the manual trip was achieved. Pressure peaked on the narrow range pressure chart recorder at approximately 2430 psia (the best available data).

The LSO entered emergency operating procedure (EOP) EOP-00, Standard Post Trip Actions, and began directing control room operators' response. The PLO informed the LSO that he had received pressurizer PORV tail pipe temperature alarms with associated quench tank alarms during the transient and that pressurizer pressure was recovering in a normal manner. Backup charging pumps started and letdown flow was isolated by the PLO to restore pressurizer level to normal. The SLO, performing procedure immediate actions, reported turbine stop valves 1, 3, and 4 were indicating 50 percent open and initiated a contingency action of stopping the EHC pumps to fully close the valves. A running condensate pump was also tripped by the SLO at this time to reduce electrical load per step 13.d of procedure EOP-00 which required that only one condensate pump be in operation.

Seven minutes after the reactor trip, the crew had completed all steps in section 5.0 of procedure EOP-00, verifying proper response of equipment to the reactor trip. Pressurizer pressure was increasing and was at approximately 1925 psia when quench tank alarms were received again. The PLO informed the LSO that pressurizer pressure was decreasing rapidly with a corresponding increasing quench tank level and then closed the PORV block valves to eliminate the PORVs as a potential cause of the depressurization. The rate of pressure decrease was unchanged and the PLO informed the LSO that pressure was approaching the setpoint for a pressurizer pressure low signal (PPLS). Automatic PPLS occurred at the setpoint (1600 psia) and the PLO verified proper response of engineered safety feature pumps and valves. After checking tailpipe temperature indications on the control board and the acoustic flow indication on the back of the main control board for the safety valves and PORVs, the PLO informed the LSO that he had indication that pressurizer safety valve RC-142 had lifted and failed to reseat. Reactor coolant pumps (RCPs) RC-3B and RC-3D were stopped by the PLO with LSO concurrence at 1350 psia as directed by EOP-00. Pressurizer level channels LT-101X and LT-101Y were in disagreement during this time period. Channel LT-101X was increasing and near 100 percent while LT-101Y had oscillated several times and then indicated 0 percent level. Pressurizer cold calibrated channel LT-106 was still on scale high.

The STA was in the control room for shift turnover and present when the reactor tripped. He went to the Emergency Response Facility Computer System (ERFCS) screens in the control room. Vital auxiliaries were indicating normal and a check of safety functions for a reactor trip recovery (EOP-1) were also normal. Indications for containment sumps and pressure were unchanged. All safety functions were satisfactory with the exception of containment integrity which could not be assessed until the containment hydrogen analyzers were placed in service. The STA informed the LSO of the safety function check.

At 11:46 p.m. with the completion of EOP-00 diagnostic section 6.0, two applicable procedure paths were identified for the existing plant conditions. Either the loss-of-coolant accident (LOCA) procedure (EOP-3) or the Functional Recovery Procedure (EOP-20) was an appropriate path. The SS, LSO and STA conferred on the procedure transition with an existing 120 Vac instrument power problem and a loss of coolant. Because of the multiple problems, the decision was made to enter procedure EOP-20 Functional Recovery. Ten minute interval verifications of safety functions including review of floating steps were maintained by the STA with results given to the LSO. Assistance was provided by the STA to the SS in completing the immediate notification forms and a shutdown margin calculation was performed by the STA upon the request of the LSO.

Upon entering EOP-20, safety injection flow was reduced by stopping safety injection pumps SI-2B and SI-2C in accordance with floating step 19.A of the procedure. Section 19 of the procedure contains floating steps which are continuous action steps and can be performed at any time the specified conditions are met. Also, RCPs RC-3A and RC-3C were stopped at this time per the floating step requirements. With pressurizer level channel LT-101X reading greater than 100 percent and PORV block valves closed, the PLO was concerned about overpressurization if the suspected open safety valve (RC-142) were to close while all three nonsafety-related positive displacement charging pumps were operating. The LSO concurred with the PLO and charging pumps CH-1B and CH-1C were stopped.

The SS entered procedure EPIP-OSC-1, Emergency Classification, to determine the classification of the event. The plant conditions met two emergency action levels (EAL) in the procedure. Conditions for EAL 1.10, failure of a fission barrier and EAL 1.5, RCS leakage greater than 40 gpm, called for a declaration of an Alert. An Alert was declared at 11:52 p.m. and a subsequent procedure EPIP-OSC-2, Notifications, was implemented. An initial accident notification form was completed by the SS. Emergency response shift assignments included a dedicated control room communicator who immediately initiated phone notification of key personnel and paging of the emergency response organization (ERO). The operations manager and the maintenance supervisor were immediately available to assist in emergency plan activation. By 12:30 a.m., July 4, ERO personnel had established communications between the control room and the technical support center (TSC) and relieved the onshift crew of communications with offsite organizations.

The LSO followed procedure EOP-20 and implemented section 16.0, RCS core and heat removal, to accomplish the plant cooldown and depressurization. A natural circulation cooldown was initiated at 12:04 a.m. by the PLO. According to the procedure steps, the PPLS was blocked at 1:03 a.m. for the purpose of restoring low-temperature overpressure protection (LTOP) (the PORV block valves were still closed at this time). A check of the acoustic sonic flow indicators at 1:10 a.m. indicated no flow through the pressurizer safety valve RC-142.

The Site Director responsibilities were transferred at 1:20 a.m. from the control room to the TSC. Backfeed through the 345 kV transformer was established and plans were made to sample the steam generators, containment building and the RCS for radioactivity levels. The conditions in the RCS at this time were about 800 psia and 417 °F with a 50 to 60 °F per hour cooldown in progress.

To minimize leakage from the RCS during the natural circulation cooldown, the PLO was performing floating step 19.A, high-pressure safety injection (HPSI) stop and throttle, from procedure EOP-20. Subcooling was being minimized by lowering safety injection flow and consequently reducing the flow through the open pressurizer safety valve. While the PLO was reducing flow and lowering pressure, reactor vessel indication on quality safety parameter display panel (QSPDS) (located behind the control board) was being monitored by extra personnel. As pressure was decreased to less than 700 psia, personnel at the QSPDS informed the PLO that the reactor vessel level indication had changed to less than 100 percent. The PLO immediately increased pressure to 750 psia to regain 100 percent level indication.

Normal letdown and charging was established as the cooldown progressed and at 3:29 a.m. injection flow through the HPSI pumps had decreased to zero. It was identified at this time the PORV block valves must be opened to have LTOP available. Block valve HCV-151 was opened first without problems. When the second block valve HCV-150 was opened, high tail pipe temperature indication and alarms were received. The block valve was reclosed immediately to isolate the leaking PORV (PCV-102-2). It was later determined that this valve did not leak; the leak indications were due to backflow from the open pressurizer safety valve.

Pressurizer level indication was regained at 4:07 a.m. when cold calibrated channel LI-106 came off scale high and was indicating 68 percent (corrected). Shutdown/cooldown activities continued such as isolating safety injection tanks and making preparations for initiating normal shutdown cooling. At 6:30 a.m. with the RCS at 400 psia and 329 °F, the emergency classification was downgraded to an notification of unusual event (NOUE) in accordance with station procedures.

During the next six hours, the operating crew continued with procedure EOP-20 and started a RCP to cool the reactor vessel head following the natural circulation cooldown and established shutdown cooling. After placing the shutdown cooling system in service, procedure EOP-20 was exited and normal shutdown procedures entered. Draining of the quench tank was accomplished at this time. With the plant cooled to 120 °F and stable on shutdown cooling, the NOUE was terminated at 6:40 p.m. and the emergency plan exited.

All safety related equipment functioned as designed during the event with the one exception of pressurizer safety valve RC-142 which remained partially open. Operators experienced other problems in plant support systems during the early stages of the reactor trip recovery including:

1) Fire alarms in two areas of the plant (later determined to be caused by steam from steam generator safety valves and a malfunctioning steam trap associated with the steam driven auxiliary feedwater pump).

2) The running air compressor (CA-1B) shutdown (located in area with fire alarm present).

3) Toxic gas alarms shifted control room ventilation (monitors de-energized on loss of electrical bus AI-42B).

4) Electric fire pump auto started (the fire jockey pump lost power when the inverter tripped, so later the electric fire pump auto started due to low system pressure).

5) Turbine plant cooling water flow gauge by the secondary sample panel ruptured causing some minor local flooding before being isolated (TBO dispatched to isolate).

6) Pressurizer heaters developed grounds as a result of the LOCA in the containment building (diagnosed as related to containment environment).

7) Apparent total loss of condensate flow (system modification during last refueling automatically tripped two pumps on a safety injection actuation signal (SIAS), pumps were restarted).

8) Component cooling water (CCW) to the RCPs isolated when CCW pumps were sequenced on during the PPLS/SIAS (suspected problem with system design). PLO reestablished flow immediately.

Each of these items required additional operator attention and time to investigate during the process of performing the plant cooldown and depressurization.

## 2.2 Time Line of the Event

To establish this time line, the onsite analysis team interviewed all control room personnel shown on Figure 1. Copies of control room strip chart recordings, the control room logs, post trip review and the annunciator printout were also provided by the station. The training staff also reproduced the initial 10 minutes of the event sequence, which included a failed pressurizer safety valve after a seven minute delay, for the analysis team on the plant specific simulator to observe pressurizer pressure response. The simulator trace matched the actual recorder trace very closely collaborating the belief that a safety valve had opened and remained open after pressure decrease during the plant recovery from the reactor trip.

<u>Note: all times are Central Daylight Time</u>

<u>July 3,1992</u>

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|---|---|
| 4:33 a.m. | Inverter No. 2 Trouble Alarm received. Inverter automatically shifted to bypass. Engineering and maintenance personnel investigated and found no specific cause for the alarms. |
| 6:36 a.m. | Inverter No. 2 returned to [illegible]al (Inverter) mode and operated normally. |
| 3:10 p.m. | Inverter No. 2 Trouble Alarm received. Inverter automatically shifted to bypass. Again no specific cause could be determined. |
| 3:27 p.m. | Inverter No. 2 Trouble alarm cleared and the inverter was returned to service by operations personnel without incident. |
| 7:21 p.m. | Inverter No. 2 Trouble Alarm received a third time. Inverter automatically shifted to bypass as in previous instances. On-call maintenance and engineering personnel contacted for assistance. |
| 8:54 p.m. | Inverter No. 2 was deenergized for maintenance and engineering personnel to perform an inspection. Two circuit boards were replaced that had indications of overheating. |
| 11:30 p.m. | SS authorized return to service of inverter No. 2. Procedure OI-EE-4, 120 Vac system normal operation was used. |
| 11:35 p.m. | Inverter No. 2 transferred back to normal mode. Voltage output indications locally and in control room (bus AI-42B) oscillated. Distribution breaker to electrical panel AI-50 tripped open de-energizing the main turbine control circuitry. |

11:36 p.m.
- Reactor tripped on pressurizer high pressure of 2400 psia.
- RCS pressure peaked at approximately 2430 psia.
- Steam generator RC-2A pressure reached 1033 psi and main steam safety valves lifted.
- Operating crew entered EOP-00, Standard Post Trip Actions.
- Operating crew received quench tank pressure/level alarms.
- Backup charging pumps (CH-1A and CH-1B) started.
- Multiple alarms were received due to the inverter voltage fluctuations blowing fuses and causing loss of power.
- ERFCS display values for containment temperature and RCS subcooling were not available on summary pages.

11:37 p.m.
- SLO placed both EHC pumps in "pull-to-lock" to ensure all turbine stop valves were shut.
- Pressurizer pressure dropped to 1745 psia and began to recover. Letdown isolation valve TCV-202 was closed to conserve inventory.

11:40 p.m. Containment pressure reduction system secured by SS direction.

11:43 p.m.
- Pressurizer pressure reached 1925 psia, then started to decrease. Quench tank level started increasing at a higher rate.
- Primary licensed operator closed pressurizer power operated relief block valves (HCV-150 and HCV-151) based on decreasing pressure and increasing quench tank level.
- RC-142 safety valve tail pipe temperature increased.
- PPLS actuation occurred with the associated containment isolation signal, SIAS and ventilation isolation actuation signal.
- CCW isolation valves closed and are reopened by the PLO.

11:44 p.m. RCPs RC-3B and RC-3D were shutdown per procedure EOP-00 guidance (reactor coolant pressure less than 1350 psia).

11:46 p.m.
- Procedure EOP-00 completed.
- Operating crew entered procedure EOP-20 "Functional Recovery Procedure" due to two events in progress (LOCA and 120 Vac problems).
- Pressurizer level channel 101X indicated 100 percent and the other channel 101Y indicated 0 percent.

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|---|---|---|
| 11:46 p.m. (cont.) | | · Floating step requirements for HPSI stop and throttle were met. HPSI pumps SI-2B and SI-2C were shutdown with pump SI-2A still in operation. |
| 11:49 p.m. | RCPs RC-3A and RC-3C were shutdown per procedure EOP-20 guidance (reactor coolant pressure less than 1350 psia). | |
| 11:52 p.m. | Charging pumps CH-1B and CH-1C were shutdown. | |
| 11:52 p.m. | SS declared an Alert (based on EAL 1.10). RCS leakage was estimated at greater than 40 gpm at this time. | |
| 11:55 p.m. | Quench tank rupture disk ruptured and depressurized to the containment. Quench tank level indication oscillated. | |
| 11:56 p.m. | Emergency Feedwater Storage Tank low level alarm (tank level 90.9 percent). | |
| 11:58 p.m | | · Charging pumps CH-1B and CH-1C started for emergency boration. |
| | | · Containment sump level in alarm (level indicators L599 and L600 read 25.22" and 25.82" respectively). |
| 11:59 p.m. | ERO page initiated with notification to report to their assigned locations. | |

<u>July 4, 1992</u>

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|---|---|
| 12:04 a.m. | Natural circulation confirmed by the PLO. SS directed the initiation of a plant cooldown in accordance with EOP-20. (RCS temperature 524 °F and pressure at 1100 psia) |
| 12:06 a.m. | Containment fan cooler units VA-7C and VA-7D started to lower containment pressure (peak pressure was 2.5 psi). |
| 12:07 a.m. | Charging pump CH-1C was shutdown by PLO. |
| 12:10 a.m. | Emergency Plan initial notification to Iowa and Nebraska completed. |
| 12:16 a.m. | Charging pump CH-1C was started by PLO. |
| 12:20 a.m. | Senior NRC Resident Inspector notified of the Alert. |
| 12:24 a.m. | Hydrogen analyzer placed in service. |
| 12:29 a.m. | NRC headquarters duty officer notified of the Alert. |
| 12:30 a.m. | Acoustical monitor still showed flow through pressurizer safety valve RC-142. |
| 12:34 a.m. | Group N nontrippable rods were fully inserted. |

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|---|---|
| 12:44 a.m. | Charging pumps CH-1B and CH-1C shutdown by the PLO. RCS temperature was 495 °F and pressure 1100 psia. |
| 12:46 a.m. | Emergency boration terminated as directed by EOP after one hour of boration. |
| 12:48 a.m. | Charging Pump Ch-1A shutdown by PLO. |
| 1:02 a.m. | Steam generator low signal blocked per procedure during plant cooldown. |
| 1:03 a.m. | PPLS blocked per procedure to establish LTOP. |
| 1:10 a.m. | · Emergency Feedwater Storage Tank low level alarm cleared (level 93.1 percent)<br>· PORV/Safety Sonic flow lights out (no flow). |
| 1:12 a.m. | Main turbine/generator on turning gear. RCS pressure was at 950 psia and temperature 470 °F. |
| 1:13 a.m. | Low pressure safety injection pumps SI-1A and SI-1B shutdown in accordance with procedure EOP-20 floating step. |
| 1:21 a.m. | Site Director responsibilities transferred to the TSC from the SS. |
| 1:22 a.m. | Electrical buses 1A1 and 1A2 were transferred to 345 kV system. |
| 1:31 a.m. | Turbine driven auxiliary feedwater pump secured (FW-10 shut). |
| 1:38 a.m. | Atmospheric dump valve HCV-1040 isolated. |
| 1:40 a.m. | Shutdown margin verified. RCS pressure was at 934 psia and temperature 448 °F. |
| 1:46 a.m. | Completed reset of safeguards. |
| 1:51 a.m. | Started charging pump CH-1C o re-establish charging and letdown along with RCP seal leakoff to the volume control tank. |
| 1:52 a.m. | Opened containment isolation valves for radiation monitors RM-050 and RM-051 to obtain an atmospheric sample in the containment. |
| 1:56 a.m. | Received a ventilation isolation actuation signal and containment high radiation signal from radiation monitors RM-050 and RM-051. |
| 2:00 a.m. | Opened electrical breakers to the containment sump pumps due to submergence resulting in electrical bus grounds. RCS pressure was at 800 psia and temperature 417 °F. |
| 2:09 a.m. | Opened containment isolation valves for steam generator blowdown for sampling purposes. No activity was detected. |

| | |
|---|---|
| 2:16 a.m. | Opened RCS sample valves to obtain RCS sample. The results indicated all isotopic activities were normal. |
| 2:18 a.m | Reactor vessel level on QSPDS display indicated less than 100 percent (possible voiding in reactor vessel head). PLO immediately increased RCS pressure from 650 to about 750 psia. |
| 2:33 a.m. | Reset electrical 86 relay and shutdown diesel generator D1. |
| 2:39 a.m. | Reset electrical 86 relay and shutdown diesel generator D2. |
| 3:20 a.m. | Zero power mode switch was placed in bypass. |
| 3:29 a.m. | HPSI flow to RCS decreased to zero. |
| 3:34 a.m. | PORV block valve HCV-151 opened. |
| 3:37 a.m. | PORV block valve HCV-150 opened and reclosed when tail pipe temperature increased. |
| 4:07 a.m. | Pressurizer level channel LI-106 reading 68 percent corrected (cold calibrated channel). |
| 4:20 a.m. | HPSI pump SI-2A shutdown. |
| 4:31 a.m. | Safety injection tanks were isolated. RCS pressure was at 400 psia and temperature 329 °F. |
| 5:25 a.m. | Placed steam dump control in INHIBIT. |
| 6:30 a.m. | Downgraded emergency classification to Notification of an Unusual Event. RCS pressure was at 360 psia and temperature 290 °F. |
| 10:24 a.m. | Started RCP RC-3C to assist in cooling the reactor vessel head. |
| 1:12 p.m | Shutdown cooling established in accordance with procedure EOP-20. |
| 1:52 p.m. | Exited procedure EOP-20 with TSC concurrence and entered normal shutdown procedures. |
| 6:40 p.m. | Exited the emergency plan with the plant stable on shutdown cooling at 120 °F and depressurized. |

## 2.3 Analysis

In many respects, parallels between this event and the Three Mile Island (TMI) event can be drawn. They both had a loss of coolant from the relief valves at the top of the pressurizer. They had the same indications of increasing pressurizer level with maximum injection flow to the system with pressure decreasing or at saturation. Much of the TMI event was blamed on the human operators. However, the Fort Calhoun event had a successful conclusion. The following analysis suggests some of the factors which contributed to human performance in this event.

### 2.3.1 Procedures

Many of the abnormal and emergency procedures had just been revised and issued in the preceding months. This event was the first significant "test" of the new procedures and the operational personnel interviewed indicated that the procedures and, in particular, the new system for placekeeping, seemed to work well. The previous placekeeping systems had used ribbons attached to the spine of the procedures or operator notes on pads of paper as a means to identify what steps had been accomplished and locations of cross-references. The new placekeeping system used a removable page to checkoff (or record the time) when each step was completed. An example of the new placekeeping pages is given in Figure 2.

"Floating steps" were also used in the procedures. Floating steps were procedural action steps with continuous applicability. If, at any time during the procedure, the conditional criteria of a floating step were met, then the action was to be carried out. In this system, all floating steps for a procedure were listed in a specific section. Procedure EOP-20 had 27 floating steps with 49 pages of instructions. Each operator was provided with an individual copy of the floating steps that could be referenced at any time. The STA, as part of his functions, monitored the floating steps as well. Figure 3 presents the checklist of floating steps that was used by the STA in his monitoring task. The operators reported that this organization and presentation of continuous steps seemed to work well.

There were at least three examples in this event where knowledge was needed to support the use of procedures. In the first example, an individual was able to identify a procedure deficiency based on prior knowledge and experience. In this case, a situation developed in the recovery effort where discussion was held regarding starting a RCP without offsite power from the 345 KV system. Procedurally, there was nothing to prevent the starting of the pump. One of the ERO personnel in the control room knew that an undervoltage condition could result from this causing bus stripping, and auto starting of safeguards pumps on the diesel generators which was undesirable given existing plant conditions. This concern was taken into account in the original procedure by ordering the actions steps in a specified sequence, however this sequence of steps was eliminated by floating steps in subsequent revisions. The original step sequence ensured that offsite power was established prior to starting a RCP. In this case, the personnel were able to supplement the procedures from a knowledge base.

A second example of where knowledge was needed to supplement the procedures (i.e., the procedure did not contain sufficient detail needed by the operator) concerned the tripping of condensate pumps. In this case, the operator did not have the additional knowledge base, which led to a complete loss of condensate flow during recovery. Here, the operator tripped off the B condensate pump in his initial post trip response actions. The procedure EOP-00 does not specify which one of the three condensate pumps to trip and his action was in accordance with the procedure as written. A plant modification completed during the last refueling outage automatically trips the A and C condensate pumps along with a circulating water pump when a PPLS/SIAS occurs. Therefore, when the B condensate was turned off, and the other two pumps tripped later, there was no condensate flow.

The third example of knowledge supporting procedures involved the process of placing LTOP in service. Procedurally, the operators were only directed to reset the PPLS signal to enable the protection. Actions taken early in the event had closed block valves in series with the PORVs and made the PORVs unavailable as relief protection. Later in the plant cooldown and depressurization the operators recognized this situation and opened the block valves.

These examples illustrate the point that knowledge-based behavior can, and often is, used to support procedures, but can not and should not be relied upon for factual information that needs to be incorporated in the procedures and in training.

### 2.3.2 Training

All operators reported and emphasized the importance of plant-specific simulator training in their ability to respond to this event. The plant-specific simulator training allowed the operators to practice procedures related to LOCA and loss of inverter scenarios. Although the event may not have corresponded precisely to the training scenarios, the training provided exposure to plant conditions that might exist and what kind of responses might be anticipated.

A second specific area of training was that of emergency response. Every Thursday of their training week, the operators and other support organizations (e.g., chemistry, radiological protection) participated in simulator scenarios implementing the Emergency Plan. This training provided the opportunity for personnel to learn and frequently practice emergency response plans and procedures, including notifications and form completion. The STA participated in this training as well. The personnel credited this training with aiding them in their ability to carry out emergency response requirements and activities.

### 2.3.3 Human-Machine Interface

Several human-machine interface (HMI) issues were identified. The first involved the performance of the stop and throttle procedure for the HPSI valves. For this operation, the valve controls used were located on a panel that is physically located away from (approximately 8-10 ft.) the panel with the flow and pressure indications. The indications were needed to accomplish effective control of the valve flow. Therefore, in order to accomplish this procedure, operators were stationed at each of the panels and communicated with each other. The control actions made at one panel had an immediate effect on flow and somewhat less immediate effect on pressure indications, which were needed to make appropriate control actions. It should be noted that these valves were not designed as throttle valves and do not have consistent linear control characteristics throughout the range of control. This nonlinear characteristic made it difficult to control flow and made the ability to monitor the effects of the control actions on the flow and pressure parameters for feedback desirable.

A second HMI issue involved the location of the sonic flow indication for the PORV and safety relief valves. Sonic flow indicators were added on to nuclear power plants following the Three Mile Island incident. At Fort Calhoun, there is one sonic flow alarm (along with a temperature alarm) located on the front panel. The sonic flow indicators were a series of light-emitting diodes (LEDs) located on the back panel. The LEDs were used as diagnostic indicators for flow or no flow (along with tail pipe temperature located on the main control board) and were located remote from other indications associated with the PORVs and safety valves. Grouping backup indication with other associated indications in a manner where the operator does not have leave the control area would be more helpful.

It was noted that the annunciator panels that were lost because of the electrical failures associated with the inverter problem were identified with a "loss of power" window on other panels that were powered by different sources. This "loss of power" window was used as a confirmation of an annunciator panel problem.

Emergency response facility computer inputs for containment temperature and RCS subcooling were malfunctioning on the parameter display pages that the operators normally used. These parameter values were asked for frequently by the TSC because they were not available on their computer. These same parameter values were available on other computer screen pages or on control room panels. However, the operators stated that they had a difficult time in obtaining the required information. In this case, the ERFCS normally provided a useful operator aid with all the required parameters displayed. During the computer malfunction, the display indicated (by using question marks) that valid input was not available. However, the operators found it difficult to move to alternative means of obtaining that information. This suggests that operators should be exposed to computer malfunctions during simulator training as well as plant malfunctions. What to do and how to obtain needed information should be addressed in training for degraded computer operation. As more indications and operations are displayed and controlled via computer screens, it becomes more important for the operators to understand what to do if the computer malfunctions.

### 2.3.4 Stress

The degradation of human performance by stress did not appear t, be a factor in this event. The related concepts of fatigue and workload (Sharit and Salvendy, 1982) did not appear to affect performance. Both the LSO and PLO had experienced the high pressure reactor trip resulting from a similar loss of an inverter in 1986. This was cited as one reason for personal stress not being as high as it would have been without such experience. Staffing was adequate to perform required actions. The event occurred at the beginning of the night shift, so the operators were "fresh" on their shift. Fatigue did not enter into the event because the operators did not have to stay beyond their regular shift hours.

### 2.3.5 Staffing

Staffing was sufficient to perform required actions. Because of scheduled vacations (e.g., the Fourth of July holiday), the LSO and the PLO were both relief operators from another crew. The LSO and PLO were from the same crew and had worked together. They apparently worked well together as did the entire crew. No additional operators were brought in to assist the SS, LSO, PLO and SLO because they were not needed, although management inquired if additional operators were needed.

The emergency response crew complement included a dedicated person to act as the communicator to handle notifications during the event. This left the SS free to oversee activities and confer with others in the recovery efforts.

The STA was in the control room for the shift briefing and remained in the control room for placing the inverter in service and the following event. The STA provided support functions to the SS which included assistance in notifications, shutdown margin calculations, and monitoring safety functions. The STA was involved in technical discussions and interpretations and was included in decision-making processes such as choosing EOP-20 as the alternative procedural success path upon completion of EOP-00. It was part of the STA's safety function to monitor the status of the floating steps (see Figure 3). A check list was provided to the STA as an operator aid to assist in the floating step status checking. It is important to note that the STA [illegible] was not a dual role, but was a dedicated role for an engineer. [illegible] also trained with an operational crew and participates in the Thursday [illegible]ing of emergency response activities.

The operations manager and the maintenance supervisor were in the plant and available for assistance immediately after the event. Similarly, many of the ERO personnel lived with ten to twenty minutes of the plant and some ERO personnel were manning their positions within 30 to 40 minutes of the classification. The immediate availability of the personnel was a factor which contributed to the success of the event. The presence of the operations manager and other personnel assisted with the workload regarding notifications, provided the opportunity for the SS to conference with his superiors, and allowed the SS to focus on the decision making involved in the recovery efforts.

### 2.3.6 Task Awareness

A major part of the success of the human performance associated with this event was related to the degree of task awareness on the part of the operators. Awareness of plant conditions and status appeared to be heightened during the event, but the heightened awareness did not result in stress levels that degraded performance. On the contrary, the heightened awareness was exhibited in pro-active monitoring and action, thinking ahead as to what actions might be needed to anticipate and preempt undesirable plant conditions. One example of this task awareness involved the CCW pumps. The time to sequence from normal to emergency power supply for the CCW pumps on the diesel generator and increased flow to containment fan coolers during a PPLS/SIAS was long enough to allow pressure and flow to decrease in the CCW system to the point where an automatic isolation of the RCP cooling did occur. This could have resulted in unnecessary tripping of the RCPs. However, the PLO identified this automatic isolation and restored the RCP cooling immediately. There were no cautions in the procedures to assist the operator.

Another example of task awareness was demonstrated by the SLO. He had reviewed the abnormal procedure for the loss of inverter and was monitoring parameters on the back of the control boards. He maintained an awareness of what was and what might happen, and took actions to investigate and prepare for possibilities.

A final example of task awareness was demonstrated by the PLO. The PLO expressed concern about possible overpressurization if the safety valve closed while all three positive displacement charging pumps were operating. Although there was no prediction that the safety valve would close, the PLO was anticipating a scenario where the consequences (overpressurization) may cause reopening of the relief valves. The charging pumps were stopped after discussions with the LSO. The pumps were started later to accommodate procedural requirements for emergency boration.

### 2.3.7 Command and Control/Teamwork

Normal command and control existed without change due to the staffing configuration. Communications and support from the ERO functioned smoothly. Because of the staffing organization, the SS was able to oversee activities without being unduly burdened with notification activities. The SS was also able to confer with his superior (i.e., the operations manager) and the maintenance supervisor directly because of their presence in the control room. Even though the SS and LSO were members of different crews, information flow and decisions were made in a timely manner. All personnel involved seemed to function as a team. Any personnel with input, even if not part of the operating crew, felt they could contribute and have their input evaluated. An example, mentioned previously, was that an ERO person contributed his knowledge concerning the need to ensure offsite power before starting a RCP. Such teamwork contributed to the successful response to the event.

### 2.3.8 Maintenance Activities

There were several latent factors associated with maintenance activities which contributed to the initiating event (the failure of the inverter No. 2). A latent design factor was that when the inverter board was replaced, there was no way to perform post maintenance testing without placing the inverter in service. This was significant in that the circuit board which was installed by maintenance personnel was missing a small jumper between two terminals. Information was not available from the vendor in the technical manual to ensure that the correctly configured circuit board was being used as a replacement.

Another latent factor was that the technical manuals did not provide the torque required for the setpoint locking nut on the safety relief valve. As a result, the setpoint locking nut was loosened during the first actuation of the safety valve which contributed to the reduction in setpoint and further damage of the safety valve to extent the valve remained partially open.

## 3 SUMMARY

The factors that affected human performance during this event are summarized below:

### Procedures

In general, the recently revised procedures seemed to work well for the operators. A new system of placekeeping (i.e., a separate step check-off list) and floating steps (i.e., steps with continuous applicability) assisted the operators in using the procedures. There were at least three examples of where procedures needed to be supplemented by operator knowledge-base. These examples illustrate the point that knowledge-based behavior can, and often is, used to support procedures, but can not and should not be relied upon for factual information that needs to be incorporated in the procedures and in training.

### Training

All operators agreed that plant-specific simulator training had assisted in their ability to respond to this event. The operators trained on loss of coolant and loss of inverter scenarios, and also trained specifically on implementing the Emergency Plan which assisted them in carrying out the emergency response requirements.

Human-Machine Interface (HMI)

Several HMI issues were identified. In two cases, related displays and controls were located at some distance from each other. Windows on each annunciator panel to indicate "loss of power" for the other annunciator panel were available to confirm that power was lost. Computer displays normally used for containment temperature and RCS subcooling parameters were malfunctioning. Although the information was available on control board panels or other, less frequently used, computer screens, the operators reported that not having the values available on the normally used screens was a hindrance to performance. This suggests that operators should be exposed to computer malfunctions during simulator training as well as plant malfunctions. What to do and how to obtain needed information should be addressed in training for degraded computer operation.

Stress

Stress did not seem to degrade human performance in this event.

Staffing

Staffing was adequate to perform required actions. A dedicated person to act as communicator to handle notifications left the SS free to oversee activities and confer with others, including the operations manager and the maintenance supervisor, during the recovery efforts. The STA provided support to the SS, including notifications, calculations, safety function monitoring, and involvement in technical discussions and decisions. The STA position was not a dual role, but was a dedicated role for an engineer.

Task Awareness

A major part of the success of the human performance associated with this event was related to the degree of task awareness on the part of the operators. Awareness of plant conditions and status appeared to be heightened during the event, but the heightened awareness did not result in stress levels that degraded performance. On the contrary, the heightened awareness was exhibited in pro-active monitoring and action, thinking ahead as to what actions might be needed and anticipate and preempt undesirable plant conditions. Several exampl s illustrated the task awareness.

Command and Control/Teamwork

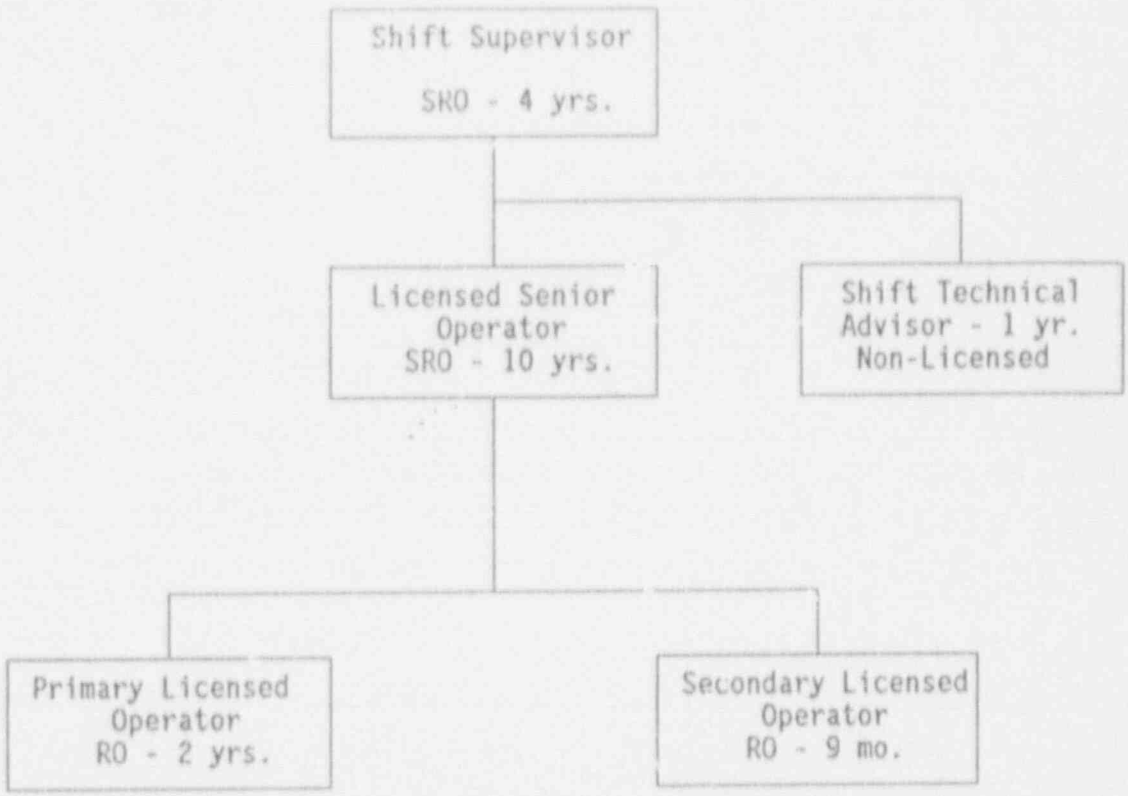
Normal command and control existed. Communications and support from the ERO functioned smoothly. All personnel involved seemed to function as a team. Such teamwork contributed to the successful response to the event.

Maintenance Activities

Several latent factors associated with maintenance activities contributed to the failure of inverter No. 2, hence to the initiating event. There was no way to perform post maintenance testing without placing the inverter in service. Information was not available from the vendor regarding correct circuit board configuration or the torque required for the setpoint locking nut of the safety relief valve.

## 4 REFERENCES

Sharit, J. and Salvendy, G. (1982). Occupational stress: Review and reappraisal. Human Factors, 24(2), 129-162.




Note 1: The licensed senior operator and primary licensed operator were crew members from another crew filling in for vacation vacancies.

Note 2: Shift technical advisors schedule rotated opposite of the operating crew.

Figure 1. Fort Calhoun Control Room Staffing.

## 16.0 PLACEKEEPER

HR-3

| Number | Step | time/√ | Page |
|---|---|---|---|
| 1 | Check CSAS initiated | | 301 |
| 2 | Check PPLS initiated | | 306 |
| 3 | Check CPHS initiated | | 308 |
| 4 | Maximize SI flow | | 311 |
| 5 | Confirm no SGTR | | 312 |
| 6 | Commence cooldown | t | 313 |
| 7 | Maintain RCS pressure | | 315 |
| 8 | Place RM-064 in service | t | 317 |
| 9 to 11 | Identify and isolate affected S/G | t | 318 |
| 12 | Depressurize RCS to < 1000 psia | t | 320 |
| 13 | Maintain RCS pressure | | 320 |
| 14 | Align blowdown sample to waste | | 321 |
| 15 | Maintain isolated S/G level | | 322 |
| 16 | Sample secondary systems | | 322 |
| 17 | Confirm no UHE | | 322 |
| 18 to 22 | Identify and isolate affected S/G | t | 323 |
| 23, 24 | Steam least affected S/G | | 311 |
| 25 | Override SGIS | t | 329 |

COMMENTS:______________________________________________

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Figure 2. Emergency Procedure Placekeeper

7. Floating Step Monitoring — DATA/√

a. Identify and inform the LSO of those Floating Steps which may need additional operator attention.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| A. | HPSI STOP AND THROTTLE CRITERIA | | | | | | |
| B. | LPSI STOP AND THROTTLE CRITERIA | | | | | | |
| C. | NATURAL CIRCULATION | | | | | | |
| D. | RCP RESTART CRITERIA | | | | | | |
| E. | RCP OPERATING PARAMETERS | | | | | | |
| F. | CONTAINMENT SPRAY TERMINATION | | | | | | |
| G. | CONTROL ROOM HABITABILITY | | | | | | |
| H. | RESET OF ENGINEERED SAFEGUARDS | | | | | | |
| I. | TURBINE AUXILIARIES | | | | | | |
| J. | EMERGENCY FEEDWATER STORAGE TANK INVENTORY | | | | | | |
| K. | SHUTDOWN OF DIESEL GENERATORS | | | | | | |
| L. | STEAM GENERATOR WATER LEVEL MONITORING | | | | | | |
| M. | SAMPLING THE CONTAINMENT SUMP FOLLOWING RAS | | | | | | |
| N. | ALIGNMENT OF CHARGING PUMP SUCTION TO SIRWT | | | | | | |
| O. | RCS HEAT REMOVAL | | | | | | |
| P. | REACTOR TRIP CHEMISTRY CHECKLIST | | | | | | |
| Q. | AUDIBLE COUNT RATE OPERATION | | | | | | |
| R. | CONTAINMENT HYDROGEN | | | | | | |
| S. | RESTORATION OF NORMAL LIGHTING | | | | | | |
| T. | STEAM GENERATOR ISOLATION | | | | | | |
| U. | PZR LEVEL MONITORING | | | | | | |
| V. | BLOCKING OF SGLS | | | | | | |
| W. | ENGINEERED SAFEGUARDS ACTUATION VERIFICATION | | | | | | |
| X. | TRIPPING RCPS | | | | | | |
| Y. | 345 KV BACKFEED | | | | | | |
| Z. | BLOCKING OF PPLS | | | | | | |
| AA. | LOCAL ALIGNMENT OF CHARGING PUMP SUCTION TO SIRWT | | | | | | |
| BB. | STOPPING OF TURBINE BUILDING SUMP PUMPS | | | | | | |

Figure 3. SUMMARY Safety Function Floating Step Checklist