UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

September 16, 1992

Docket No. 50-413

Mr. M. S. Tuckman
Vice President, Catawba Site
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Dear Mr. Tuckman:

SUBJECT: PRELIMINARY SPECIAL STUDY REPORT ON HUMAN PERFORMANCE IN OPERATING EVENTS

A preliminary special report by the NRC Office for Analysis and Evaluation of Operational Data (AEOD) entitled "Human Performance in Operating Events" is enclosed. The study describes potentially generic observations and conclusions based on onsite evaluation of 17 operating events. Due to the length of the draft report, a copy of this letter and the enclosed preliminary report has been placed in the Local Public Document Room, located in the York County Library, 138 East Black Street, Post Office Box 10032, Rock Hill, South Carolina 29731, for public review.

To briefly review for your benefit, each study was conducted by a multidisciplined team, led by an AEOD staff member, with additional NRC headquarters, regional and Idaho National Engineering Laboratory personnel. The studies focused on those factors that helped or hindered operator performance. The team usually spent 1 to 3 days on site interviewing plant personnel and gathering records. Individual reports of each site study were prepared and distributed within the NRC, to the site involved in the study, and to certain industry groups and a copy was placed in the Public Document Room. This special study describes generic observations and conclusions drawn from 17 such studies.

We believe these events represent an estimated one-fourth to one-third of the events which significantly challenged operating crews during this 2 1/2-year period. Six studies were performed in 1990, seven in 1991 and four in 1992. Ten events occurred at pressurized water reactor plants (PWRs) and seven events occurred at boiling water reactor plants (BWRs). Eleven events occurred at power and 6 occurred in standby or shutdown mode at 16 plant sites. Four studies were performed as part of an augmented inspection team effort, while 13 were performed solely under AEOD auspices.

In accordance with our "peer review" process, prior to the finalization and distribution of our special study report, we are providing you, various industry groups, experts in the field of human factors and plant management where these events occurred with a copy of the preliminary report for review and comment. We request that you focus your review primarily on the accuracy and completeness of the observations and analyses contained in the report. The conclusions are provided for your information in order that you may

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Catawba Nuclear Station

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E. Trager

understand the significance we place on these events and, therefore, obtain a more complete picture of the total report. Changes to the report will be made if the underlying information is in error, or new additional information is provided. We ask that comments be provided in writing directly to the NRC, to the attention of Mr. Thomas Novak, Director, Division of Safety Programs, Office for Analysis and Evaluation of Operational Data.

Since we wish to finalize and issue the report shortly, we ask that any comments be received by us within 3 weeks from receipt of this preliminary report. Should you require additional time beyond that point, please let us know; otherwise, it will be assumed that you have no commments.

If you or your staff have any questions regarding this study, please feel free to contact Mr. Thomas Novak or Mr. Eugene Trager on (301) 492-4496.

This letter contains no information collection requirements subject to the requirements of the Paperwork Reduction Act of 1980 (44 U.S.C 3501 et seq.).

Sincerely,

ORIGINAL SIGNED BY

Robert E. Martin, Senior Project Manager
Project Directorate II-3
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Enclosure:
Draft, Special Study, Human
Performance in Operating
Events, dated August 28, 1992

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SPECIAL STUDY

HUMAN PERFORMANCE IN OPERATING EVENTS

1992

Prepared by:
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Reactor Operations Analysis Branch
Office for Analysis and Evaluation
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ACKNOWLEDGEMENTS

We express appreciation to the licensee staffs for their cooperation in providing the information necessary to analyze human performance during the operating events. We particularly thank the operators who were on duty during the events for their cooperation during the interviews. In addition, the efforts of Orville Meyer and Bill Steinke of the Idaho National Engineering Laboratory in support of the analyses are particularly noteworthy.

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TABLES

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ABBREVIATIONS

AEOD	Analysis and Evaluation of Operational Data (NRC's Office for)
AIT	Augmented Inspection Team
BWR	boiling-water reactor
DHR	decay heat removal
EHC	electrohydraulic control
EOP	emergency operating procedure
ESF	engineered safety feature
HPCI	high-pressure coolant injection
I&C	instrument and control
I&E	instrument and electrical
IRM	intermediate-range monitor
LER	licensee event report
MSIV	main steam isolation valve
NRC	U.S. Nuclear Regulatory Commission
NSO	nuclear station operator
PORV	power-operated relief valve
PRT	pressurizer relief tank
PWR	pressurized-water reactor
RCIC	reactor core isolation cooling
RCS	reactor coolant system
RHR	residual heat removal
RO	reactor operator
RWCU	reactor water cleanup
SCO	senior control operator
SCRE	shift control room engineer
SE	shift engineer
SG	steam generator
SI	safety injection
SRO	senior reactor operator
SRV	safety relief valve
STA	shift technical advisor
TS	technical specifications
TSE	technical staff engineer

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EXECUTIVE SUMMARY

The Office for Analysis and Evaluation of Operational Data (AEOD) of the U.S. Nuclear Regulatory Commission (NRC) began a program in 1990 to conduct onsite, indepth studies of human performance that affected reactor safety during selected power reactor events.

Each study was conducted by a multidisciplined team, lead by an AEOD staff member, with additional NRC headquarters, regional, and Idaho National Engineering Laboratory personnel. The studies focused on those factors that helped or hindered operator performance. The team usually spent 1 to 3 days onsite interviewing plant personnel and gathering records. Individual reports of each site study were prepared and distributed within the NRC, the site involved in the study, industry groups, and the public. This special study describes generic observations and conclusions drawn from 17 such studies.

These events, represent an estimated one-fourth to one-third of the events which significantly challenged operating crews during this 2 ½ year period. Six studies were performed in 1990, seven in 1991, and four in 1992. Ten events occurred at pressurized-water reactors and seven occurred at boiling water reactors. Eleven events occurred at power and 6 occurred in standby or shutdown mode at 16 plant sites. Four studies were performed as part of an augmented inspection team effort, while 13 were performed solely under AEOD auspices.

The events represent a wide variety of event or accident scenarios, including: stuck open safety-relief valve, reactor trip with safety injection, reactor scram due to positive reactivity insertion, reactor scram due to control rod withdrawal, pressurizer spray valve failure, partial loss of instrument air in the containment, turbine building pipe rupture, loss of shutdown cooling, excess steam demand, main steam isolation, reactor water cleanup isolation defeated during reactor water cleanup relief valve lifting, loss of annunciators and plant computer, and loss of electrohydraulic fluid.

This special study summarizes each event and the findings drawn, observations discerned from multiple events, and conclusions concerning overall human performance. These fall into four groups: control room organization, procedures, human-machine interface and industry initiatives. Finally, the categorization of events of latent factors compares the similarities among the events. The primary observations and conclusions of the special study include:

Control Room Organization

Control room staffing level, division of responsibility, and degree of teamwork significantly affected crew response to events.

Control room management was overburdened during emergencies when task, supervision, and technical oversight were not appropriately allocated.

The use of the "dual-role" shift technical advisor impaired crew performance by overloading other senior reactor operators when one senior reactor operator assumed the shift technical advisor role. The "dual-role" shift technical advisors sometimes lacked independent "fresh eyes" because of involvement in shift activities. Other tasks, such as notifications, also detracted from the shift technical advisor's safety function.

Teamwork during events improved human performance in complex, high-stress situations.

This special study concludes that an examination of control room staffing and structure vs. emergency functions would better utilize shift resources and allocate tasks so that no individuals are overburdened. This would be especially worthwhile with regard to the "dual-role" shift technical advisor function.

Procedures

Some operators were found to have acted during events without using a procedure. Procedure problems were key contributors in the less successful events, but were not found in the more successful events when the procedures were accurate, complete, and management required their use.

Operators experienced difficulty in applying knowledge to unusual plant conditions during events, which resulted in delays in recognizing and responding to events. Training and teamwork was shown to be useful in increasing the effectiveness of knowledge-based performance.

Preconditioning from past experience, training, or management direction strongly affected how operators recognized and responded to events, and led operators to disbelieve valid indications or take inappropriate actions.

In two events, operators inappropriately defeated the automatic operations of engineered safety features during valid system demands. Some licensees have not provided sufficient guidance that limits defeating engineered safety features, allowed for by technical specifications, and emergency or administrative procedures.

This special study found that improper defeating of engineered safety features in two events during a 4 month period showed that the NRC and industry control of engineered safety feature has not been completely effective and that further action would have high safety return in the reduction of risk of operator error.

Human-Machine Interface

A lack of appropriately ranged, direct-reading, control room instrumentation to monitor reactor pressure, temperature, and level caused operators to have difficulty in recognizing and responding to shutdown events, when operator actions were required to accomplish the safety functions of disabled, automatic safety systems.

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Annunciator and computer alarms were important operator aides in recognizing and responding to events. Operators failed to recognize conditions that were off-normal, but which were not alarmed during events.

Lack of direct control room indication of flows affecting the reactor coolant system inventory, including discharges of safety and relief valves connected to the reactor coolant system has impaired operator response to events. Conversely, direct control room indication of flows affecting the reactor coolant system inventory has facilitated operator response.

Industry Initiatives

There is a wide variance in the effectiveness of licensee's studies of human performance. While some licensees have missed such opportunities, other have initiated worthwhile plant specific corrective actions because of their human performance studies. However, AEOD has seen little evidence that either the industry or individual licensees systematically analyze and evaluate human performance in operating events and disseminate the results so that the lessons of operating experience are shared.

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1.0 INTRODUCTION

Operating events have shown the importance of human performance in reactor safety. To obtain additional information, the Office for Analysis and Evaluation of Operational Data (AEOD) of the U.S. Nuclear Regulatory Commission (NRC) began a program in 1990 to conduct onsite, indepth studies of human performance during selected power reactor events. This report is provided to describe potentially generic observations and conclusions from these studies.

Over the past 2 ½ years, AEOD has investigated 17 events as part of this program. These are representative of events that were strongly influenced by human performance during this time period. They can be considered real-time tests of the operators and the factors that affected their performance.

Individual reports of each site visit were prepared and distributed within the NRC, to the sites involved in the studies, and to industry groups, and AEOD tried to get feedback on the studies. During 1990, AEOD met with consultants, Dr. Tom Sheridan of the Massachusetts Institute of Technology, and Dr. Ali Mosleh of the University of Maryland. Telephone conferences were held with management at the sites where studies had been conducted and a presentation to the ACRS was made in order to obtain comments and advice on ways to improve the studies. On March 23, 1992, AEOD met with Professor James Reason of the University of Manchester, Dr. Harold Van Cott of the National Academy of Sciences, and Dr. Sheridan to obtain their comments and suggestions regarding continued progress with the studies (Ref. 1).

The events were complex, with human performance influenced by many, often interrelated, factors. The analysts looked broadly to identify the most significant contributing factors that helped or hindered operator performance. The event reviews provided insights to multiple factors affecting human performance, including examples of existing good practices and changes that could improve human performance.

An interim report was issued in May 1991 (Ref. 2) to describe the observations and findings from the first six studies performed. This report describes the 6 original studies and 11 additional studies performed since then, summarizes the results of the studies, and describes the analysts observations and conclusions.

Section 1 contains an introduction and description of the AEOD program to investigate human performance during operating events. Section 2 contains a brief description of each event studied, including important findings. Section 3 is the detailed analysis section and contains observations, background discussion, and examples. Section 4 contains a brief discussion of future program events. Section 5 contains conclusions regarding actions that can be taken to improve human performance in response to operating events. Section 6 contains references. Section 7 contains an Appendix that provides additional background regarding the shift technical advisor (STA) position.

Events were selected for onsite evaluation when human performance appeared to be an important factor in the progression of the event. Each onsite analysis team was multidisciplinary and led by an NRC staff member with additional NRC headquarters, regional, and Idaho National Engineering Laboratory personnel. Site visits were usually conducted within 1 to 3 days after the event so the operators' recollections of the events might be as fresh as possible. Data acquisition and preliminary analysis required from 1 to 3 days onsite per event.

Interview guides were prepared in advance of the site visits. The specific details of each event uniquely determined what data was relevant. The principal sources of data for the analysis of each event were plant logs, computer records, and interviews with operators on duty during the event. Licensee management and operators cooperated greatly in the data collection for the analyses.

A more detailed program description is provided in Reference 1.

2.0 HUMAN PERFORMANCE STUDIES

AEOD, so far, has performed 17 human performance studies; 6 in 1990, 7 in 1991, and 4 in 1992. Results of the individual studies are summarized below. More detailed descriptions can be found in the individual event reports. The events occurred at power and during shutdown. Ten events occurred at pressurized-water reactors (PWRs) and 7 occurred at boiling-water reactors (BWRs). The events spanned a broad range of conditions, happenstance, and challenge.

2.1 1990 Event Studies

The 1990 human performance studies concerned the following six events:

2.1.1 Peach Bottom Unit 3 – Loss of Electrohydraulic Fluid (1/28/90)

The Peach Bottom Unit 3 event (Ref. 3) occurred at 8:55 a.m. on January 28, 1990, while the plant was at 99.8-percent power. A major leak of electrohydraulic control (EHC) fluid was observed from a main turbine control valve. Anticipating a potential turbine trip without bypass transient (if EHC was lost), the shift manager ordered a fast power reduction to about 50-percent power and then a manual scram of the reactor.

Feedwater pumps A and B were manually tripped to prevent overfill; however, the high reactor vessel level transient following the scram caused a trip of feedwater pump C. The operator was unable to restart feedwater pump C and did not attempt to restart feedwater pump A or B. The trip reset indicating light configuration for the Unit 3 reactor feedwater pump turbines was different from the Unit 2 configuration and the simulator. After the event, the licensee identified that a common error in the maintenance of reactor feedwater pump turbines would have prevented restart of

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turbines B and C. However, reactor feedwater pump turbine A could have been restarted.

The shift manager directed a fast reactor pressure reduction. The pressure set point on the turbine bypass valves was lowered to dump steam to the condenser to feed the reactor with condensate pump A. This also provided a greater pressure margin against opening of a safety relief valve (SRV). The technical basis for the emergency operating procedures (EOPs) cautioned against unnecessary heating of the Mark I suppression pool by opening the SRVs. The crew was unable to establish reactor feed flow from condensate pump A because they did not close the suction valves for reactor feedwater pumps A and B. The open suction valves permitted the flow from condensate pump A to be returned to the condensate tank through all three of the 6-inch minimum flow lines from the three reactor feedwater pumps. The procedure for reactor feed with condensate pump A was written for plant startup when the feedwater pump suction valves were initially closed.

With no reactor makeup available from the feedwater and condensate systems, the crew placed reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems in service because the RCIC system alone was unable to maintain reactor level. This required the crew to control HPCI turbine speed and the test return line throttle valve. The HPCI flow instrument measured total flow from the HPCI pump. With the return line open, there was no quantitative measure of injection flow to the reactor vessel. Reactor level fluctuated between a minimum of -10 inches and a maximum of +60 inches. At 9:35 a.m., the crew shut the main steam isolation valves (MSIVs) and stopped the EHC pumps ending the hydraulic fluid leak. Operators stabilized the reactor level at about 9:50 a.m., approximately 1 hour after reactor scram.

Peach Bottom Unit 3 findings:

- The strategic direction of the control room crew was proactive and in accordance with the technical bases for the EOPs.

- Reactor operator (RO) actions were in accordance with procedures and training, which were insufficient to support use of condensate pump A after reactor scram or use of reactor feed pump A or B to back up reactor feed pump C. Procedures were written for startup rather than recovery.

- The control room crew experienced a high level of stress caused by the anticipation of a potential turbine trip without bypass and the need to overcome human-machine interface problems.

- Good control of HPCI flow to the vessel could not be achieved because of the lack of a direct-reading flow instrument.

- Prior training and good communications helped the crew shut down the plant safely.

2.1.2 Catawba Unit 1 – Reactor Coolant System Overpressurization (3/20/90)

The Catawba Unit 1 event (Ref. 4) occurred at about 9:20 a.m. on March 20, 1990, while the plant was in cold shutdown. The operators were performing reactor fill and vent operations following a refueling outage. During the initial pressurization of the reactor coolant system (RCS) to 100 psig, the operators overpressurized the RCS and the residual heat removal (RHR) system because they were monitoring pressure instrumentation that was inoperable.

The oncoming day shift on began pressurizing the RCS at about 7:05 a.m. The pressurizer was filled until water exited the power-operated relief valves (PORVs). The operators shut the PORVs and placed them in the low temperature overpressure protection mode. The operators increased charging makeup flow from centrifugal charging pump 1B to 100 gpm and decreased letdown flow to 30 gpm. The target RCS pressure was 100 psig.

Similar previous pressurizations had required 4 to 6 hours to reach 100 psig. Because gases are usually trapped in the steam generator (SG) U-tubes, the pressure rise is hyperbolic, and is not detectable over the early, longer part of the charging period. The operators had three indicators of RCS pressure: two wide-range (0 to 3000 psig) and one narrow-range (0 to 800 psig). However, the operators were not aware that all three RCS pressure instrument transmitters were still isolated following welding of the tube fittings during the refueling outage. The two wide-range RCS pressure instruments were also the sensors for the low-temperature over-pressure protection mode for the PORVs.

Possibly because the previous shift extended venting for 1 to 2 hours longer than on previous fill-and-vent operations the RCS pressure rose faster than anticipated. At 9:38 a.m., the RHR pump B suction relief valve lifted and limited RCS pressure to 455 psig maximum and the RHR pump A discharge pressure to 625 psig. The operators did not observe these pressure rises, although the RHR discharge pressure indicator was operable. The RHR suction relief valve remained open, passing the RCS charging flow to the pressurizer relief tank (PRT). When the operators observed the rising PRT level indication, they began searching for the leakage path from the RCS. However, the operators did not know that the RCS and the RHR system were pressurized. A systems engineer entering the control room at this time noticed the high RHR system pressure and brought it to the attention of the control room operators. No annunciators alarmed during this sequence since the maximum RHR pressure that was reached was slightly below the actuation set point of the alarm pressure switch and the computer alarm came off the inoperable pressure transmitters.

Catawba Unit 1 findings:

- Plant procedures failed to ensure that the RCS pressure instruments were returned to service, and no formal independent review of outstanding work requests was made before initial fill and vent.

- The tagging procedure did not require placing out-of-service tags on inoperable control room indicators.

- The operators did not monitor the letdown chemical and volume control system pressure and the RHR pump discharge pressure indicators, both of which are located near the RCS pressure indications. Monitoring pressure changes in the chemical and volume control system and RHR systems could have been used to confirm changes in RCS pressure.

- While the increasing PRT level indication alerted the operators that the RCS response was abnormal, their initial mind set was that the PORVs were leaking and that the RCS was not pressurized. A previously-uninvolved RCS system engineer did not have this mind set and alerted the operators to the high RHR system pressure.

- The operators vented the RCS longer than usual before system pressurization without considering that this might cause the pressure to rise more rapidly than on prior occasions.

- No annunciator alarmed when the RHR system was overpressurized, because the maximum RHR pressure was below the actuation set point of the pressure switch. Also, the computer alarm was inoperable because it used a signal from the isolated pressure transmitters.

2.1.3 Nine Mile Point Unit 2 – Partial Loss of Instrument Air (5/14/90)

On May 14, 1990, at about 8:50 p.m., Nine Mile Point Unit 2 (Ref. 5) experienced a partial loss of instrument air. As a result of this loss, the offgas system was affected, subsequently causing a decrease in condenser vacuum and ultimately causing the operators to scram the reactor at about 9:20 a.m.

Unit 2 was at 100 percent power before the event. Numerous alarms were received from the offgas system during the shift that the operators believed were caused by condenser air in-leakage. At approximately 8:52 p.m., the offgas system steam pressure alarm was received. The operators found that the steam supply valves to the offgas system had closed. At approximately the same time, an RO in the control room observed a seal water discharge valve to the mechanical vacuum pumps was open. The operator immediately suspected a localized loss of instrument air. He knew the valve should not open unless it failed because of loss of either instrument air or an electrical problem. But no electrical problem was detected. The operator discussed this with the Unit 2 chief shift operator.

A nonlicensed operator was dispatched to investigate. The operator had supervised the contractor who installed the instrument air system and had sufficient knowledge of the system to suspect that only a partial loss of instrument air had occurred. He confirmed this by walking down the systems and opening the instrument air test connections. From

8:58 p.m. to 9:19 p.m., the control room operators noticed decreasing condenser vacuum and lowered power by reducing recirculation flow and then inserting some control rods. The operators scrammed the reactor from 45 percent power at 9:19 p.m.

The operators entered the EOPs when the reactor water level fell to 144 inches and exited the EOPs when water level was restored to its normal band at 9:25 p.m.

On May 15, 1990, the licensee staff found a ruptured instrument air line in the turbine building. An excess flow check valve had prevented the partial loss of instrument air from becoming more widespread.

This event can be summarized as a successful shutdown of the reactor after the operators properly diagnosed the problem. The operators took a symptomatic approach after the reactor was scrammed even though they had diagnosed a specific event.

Nine Mile Point Unit 2 findings:

- The control room crew diagnosed the equipment problem accurately and responded quickly in spite of numerous nuisance annunciators.

- Troubleshooting of the problem was hampered because the piping and instrument diagrams for the air system were not complete. The diagrams only showed piping up to the major isolation valves, and for an instrument air loss, the operators had to watch for individual failure alarms or walk down the system.

- The "Instrument and Service Air System Procedure" was written primarily to address a total loss of instrument air rather than partial losses in specific legs of the system.

- The operators had undergone simulator training on a loss of instrument air scenario, which aided in the diagnosis and mitigation of this event.

2.1.4 Dresden Unit 2 – Stuck Open Safety Relief Valve (8/02/90)

At 1:05 a.m., on August 2, 1990, Dresden Unit 2 operators manually scrammed the plant after trying unsuccessfully to shut an SRV that had failed open (Ref. 6). Over the next hour the plant cooldown rate reached about 129 °F/hr. This exceeded the technical specification (TS) normal cooldown rate limit of 100 °F/hr.

Unit 2 had been at approximately 80-percent power and decreasing load at 100 MWe/hr when an acoustic monitor actuated and other indications (50 MWe drop in electrical output, rapidly rising torus water temperature, and increasing SRV tailpipe temperature; although this was not consistent with the SRV position indicating lights) were received of a stuck open SRV . The shift control room engineer (SCRE) (degreed, "dual-role" senior reactor operator [SRO] and STA) decided that an SRV was open and notified the

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shift engineer (SE). The SE relieved the SCRE and began directing the activities of the control room crew. The SCRE assumed the responsibilities of STA.

Using the abnormal operating procedure, the operators unsuccessfully tried to reclose the relief valve. The SE then ordered the crew to prepare for and perform a manual reactor scram. Following the scram the SE became concerned about the unexpected high rate of heatup of the suppression pool and without procedural guidance ordered opening two turbine bypass valves to reduce system pressure to approximately 600 psi. The SE believed it was necessary to reduce heat input to the torus and hoped the SRV would reseat.

The open SRV blowdown to the torus initially caused the temperature of the torus to rise rapidly (1.3 °F/minute). Opening the two turbine bypass valves for 2 minutes reduced the total heat input to the torus but contributed to a 129 °F plant cooldown in 1 hour, which was in excess of the 100 °F/hour normal cooldown limit. (Plant cooldown without opening the turbine bypass valves would not have caused the torus temperature to approach its heat capacity temperature limit.) Thereafter, plant cooldown and decay heat removal (DHR) were affected primarily by the SRV blowdown to the torus, although all auxiliary steam loads were not secured until later in the event.

Dresden Unit 2 findings:

- The control room emergency organization provided little assistance to the SE. When the SE became responsible for analyzing the condition of the plant and for determining and directing the emergency response and control room activities, the SCRE was making telephone notifications and the two shift foremen were out in the plant.

- The turnover of control room supervision during the event resulted in reduced and discontinuous SRO advice and communications in the control room. This may have contributed to misjudgments that were made during the event. In addition, one order by the SE was not carried out because of a communication problem.

- Although spurious opening of an SRV is an anticipated event for a boiling water reactor, there was no event-specific guidance for plant cooldown in the plant procedures or training material. The TS basis for this event stated that if the reactor is scrammed before the torus reaches 110 °F, the torus can safely absorb the heat load from plant cooldown caused by an SRV blowdown.

- The operators were generally unaware of generic industry problems involving stuck open SRVs at other BWRs.

2.1.5 Braidwood Unit 1 -- Loss of Reactor Coolant (10/04/90)

The Braidwood Unit 1 event (Ref. 7) occurred at 1:24 a.m., on October 4, 1990, while in cold shutdown, when approximately 600 gallons of reactor coolant were inadvertently discharged through a vent valve, resulting in contamination of licensee personnel. A study of the event was performed as part of a Region III Augmented Inspection Team (AIT) investigation.

At the time of the incident, Braidwood Unit 1 was in cold shutdown with the RCS at approximately 180 °F and 360 psig. Technical staff engineers (TSEs) were executing two procedures in parallel: BwVS 4.6.2.2-1, "Reactor Coolant System Pressure Isolation Valve Leakage Surveillance," and BwVS 0.5-2.RH.2-1, "Residual Heat Removal Valve Stroke Test." The two surveillances had begun on the third shift (3 p.m. to 11 p.m.) and were still ongoing at shift changeover from shifts 3 to 1 (11 p.m. to 7 a.m.). At approximately 1:20 a.m., TSEs 1 and 2, stationed in the control room, instructed TSE 3, stationed in the 364 foot elevation of the Unit 1 auxiliary building penetration area, to have the equipment attendant close a vent valve, which was being used to collect leakage across an RCS pressure boundary isolation valve. At approximately 1:24 a.m., TSE 1, without receiving confirmation from TSE 3 that the vent valve had been closed, instructed the auxiliary nuclear station operator (NSO) to open a different valve as part of the RHR valve stroke test. When the auxiliary NSO did this, the RCS was aligned to the inlet of the still open vent valve. Flow through the vent suddenly surged and burst the tygon tubing attached to the valve, and the hot water sprayed personnel in the auxiliary building. The total indicated loss of pressurizer level was 5 percent , from 40 to 35 percent , which represented a loss of approximately 600 gallons.

TSE 3, another TSE present in training with TSE 3, and the equipment attendant were decontaminated following the incident. The equipment attendant received a second-degree burn approximately 2 inches in diameter on his left forearm when he shielded his face from the spraying water. After being decontaminated, he was taken to a local hospital to have the burn treated.

Coordinating two procedures in parallel without any written guidance represents a fairly complex, dynamic task, which required knowledge-based as opposed to rule-based performance by the TSEs. The probability of making an error or mental slip (e.g., momentarily forgetting a step) is relatively high in such situations, and may be increased if the person involved is fatigued. TSEs 1 and 2 had been on the job for 17 to 19 hours. In executing dynamic tasks, it is critical that system redundancies or checks be in place to catch or prevent such errors. However, no such redundancies were in place.

Operational and TSE personnel exhibited three levels of task involvement or task awareness during this event:

(1) The SCRE, the Unit 1 NSO, the SE, and the shift advisor had a low level of task awareness and, in fact, were not aware that two procedures were being conducted. This lack of awareness was attributed to insufficient information being transferred during the shift turnover and the SCRE and the Unit 1 NSO

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not closely monitoring the activities being conducted in the Unit 1 control room.

(2) TSE 3 and the auxiliary NSO had a moderate level of task involvement and awareness. Although they directly participated in executing some of the activities associated with the two procedures, both individuals appeared to lack an overall understanding of the system's configuration. The auxiliary NSO did not involve himself in monitoring the state of the system while executing the valve manipulations and thus did not serve to provide redundancy to the activities of TSEs 1 and 2.

(3) TSEs 1 and 2 had a high state of task awareness and were directly involved in conducting and coordinating the two procedures.

This task involvement/awareness configuration was such that overall task success was essentially a function of TSEs 1 and 2's performance. However, their performance was affected by conducting a difficult coordination task while subject to fatigue. Without redundancies or checks on their performance by other operational personnel, which would be expected in an effective structure, the likelihood of committing some type of error was quite high.

Command, control, and communication were not effective during the execution of these two surveillances. The SE, the SCRE, and the Unit 1 NSO were not sufficiently in command to offer oversight of the TSE activities nor be aware of changes in the RCS configurations.

Braidwood Unit 1 findings:

- The control room crew was not sufficiently aware of or involved in the surveillances that were underway.
- The TSEs were performing a relatively complex, dynamic task while in a state of fatigue and there were no redundancies in place to help prevent errors.
- These surveillances were conducted with ineffective command, control, and communications.

2.1.6 Quad Cities Unit 2 – Reactor Scram Due to Control Rod Withdrawal (10/17/90)

The Quad Cities Unit 2 event (Ref. 8) occurred at 3:39 p.m. on October 27, 1990, while in hot standby. The reactor scrammed on hi-hi intermediate range flux because the operator withdrew rods to increase reactor pressure without recognizing the need to follow the normal procedures for reestablishing reactor criticality. NRC Information Notice 91-04 "Reactor Scram Following Control Rod Withdrawal Associated With Low Power Turbine Testing," (Ref. 9) was later issued as a result of this event.

The objective of Unit 2 operations during this event was to support a special test to precisely determine the torsional resonant frequencies of the turbine-generator rotors. A temporary change was issued on October 24, 1990, to the normal operating procedure for "Shutdown From Power Operation to a Standby Hot Pressurized Condition," to allow the use of recirculation pumps and control rods to reduce power and thereby provide greater flexibility during power reduction to hot standby. The temporary change did not add any special instructions or cautions.

Shift 1 (11:00 p.m. to 7:00 a.m.) had attempted the test on October 27, 1990. The Unit 2 NSO had inserted control rods to reduce reactor pressure to shut the turbine bypass valves and permit connection of special test circuitry to the EHC system. During this maneuver the NSO noticed high control rod notch worths. This information was passed on orally from shift 1 to shift 2, but not from shift 2 to shift 3. No log entry was made of this information.

Operators again attempted to perform the special test on shift 3. On shift 3, in addition to the special test, there were other conditions that were of concern to the SE and the SCRE:

(1) two intermediate-range monitor (IRM) channels were "bypassed," because one IRM had a spurious trip, and one IRM remote detector drive was inoperable with the detector inserted,

(2) the drywell had been deinerted to permit entry.

There is limiting condition for operation in the plant's TS that required reinerting within 24 hours or the plant would have to be put in hot shutdown.

At 3:10 p.m. plant management decided to abort the special test and return to power. The SE telephoned the SCRE and directed him to take the EHC off line to permit removing the special test circuits. The SCRE directed the Unit 2 NSO to insert control rods to reduce reactor pressure to less than 800 psig. The NSO inserted control rods, a total of 84 steps, while observing the reactor pressure decrease. The reactor pressure decreased to 770 psig, but at the same time the reactor power had decreased to Range 1 of the IRM (the lowest range of the IRMs; the reactor was significantly subcritical). At 3:58 p.m., the NSO began rod withdrawal to increase pressure and withdrew one group of four rods one notch. He then withdrew one rod one notch. Reactor power increased sharply and the reactor scrammed from an IRM hi-hi trip on a 25-second period at 3:59 p.m.

Quad Cities Unit 2 findings:

- The plant staff had a low level of awareness that the reactor conditions required by the turbine torsional test would be difficult to maintain. This low level of task awareness began with the planning and preparation of the special test and carried on through all activities to culminate in the reactor scram. This was also reflected

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in the procedures, which had no special instructions for reactivity management and no cautions about possible high rod notch worths.

- The SROs did not adequately monitor control rod manipulations by the Unit NSO.
- Requalification training had not covered reactor operation in hot standby, and the operators had no special training or briefing for the special test.
- Information on similar events at other stations had not been disseminated to the ROs.
- The Unit 2 NSO did not report back any information to the SCRE while executing the SCRE's command to insert control rods, although the changes in rod positions and reactor power level were significant enough to justify supervisory overview by the SCRE.
- The communications between the SE and the SCRE and between the SCRE and the NSO were minimal and did not contain cautions or directions to report information back.
- The Unit 2 NSO performed the procedure alone but failed to monitor reactor power when moving control rods.
- Although shift 1 observed high-notch worth, this was not recorded nor passed on to shift 3.

2.2 1991 Event Studies

The 1991 human performance studies concerned the following seven events:

2.2.1 Millstone Unit 3 -- Turbine Building Pipe Rupture (12/31/90)

The Millstone Unit 3 (Ref. 10) event occurred at 4:33 p.m. on December 31, 1990, while the unit was operating at 86-percent power. Two 6-inch diameter moisture separator condensate return drain lines ruptured and discharged hot condensate system steam and water to the turbine building. A Region I AIT investigated the event and issued the AIT report on February 12, 1991 (Ref. 11).

The catastrophic piping failures took place shortly after a licensed senior control operator (SCO) (an SRO responsible for supervising control room operations) had manually closed a valve in one of the lines as part of the process to isolate and repair a leak in the line. The SCO narrowly escaped injury and returned to the control room to report the fail· e. The control room operators manually initiated a reactor trip and a main steam line isolation and began recovery activities.

Following the trip, the operators found that they had lost automatic control of pressurizer level. The operators and instrument and control (I&C) technicians deduced that moisture in the turbine building caused a loss of power that isolated instrument air to the letdown valves and pressurizer spray valves. They devised a method to restore instrument air to containment and thus normal control of RCS inventory and pressure.

Millstone Unit 3 had no administrative procedure governing the steps that should be taken to evaluate through-wall leaks in this system. Although licensed operator error was not a factor contributing to this event, it may have been less than prudent for plant personnel to try to evaluate the significance of the through-wall leak without obtaining assistance from engineering.

When the SCO elected to personally isolate the leaking pipe section, control room command and control was temporarily degraded. He was working alone in the turbine building without direct means of communication with the control room and without the knowledge of, or assistance from, the turbine building plant equipment operator. The SCO escaped injury following the pipe rupture and returned to the control room, where he played an important role in recovery activities.

The problem in maintaining control of reactor pressure and inventory was created by the loss of instrument air to the pneumatic-operated control valves within containment. The indications of this problem were the increasing pressure and level in the pressurizer, which the RO diagnosed as caused by closed letdown and pressurizer spray valves. The SCO and RO realized that the pressure increase would be limited by the automatic action of the PORVs or by the pressurizer safety valves. The SCO took action to limit the rate of increase in level by manually reducing the charging flow to the minimum required for the reactor coolant pump seals. A team consisting of the SCO, the RO, and the I&C specialist then moved efficiently through problem identification, diagnostics, action selection, and action to restore normal control of pressurizer pressure and level.

A number of Unit 3 operations, maintenance, engineering, and other plant personnel had observed the steam leak before the pipe rupture. There was apparently a lack of awareness by these individuals that the through-wall pipe leak could be a precursor to a catastrophic failure. While other through-wall leaks in the secondary systems piping had been experienced during Unit 3 operation, these had been due to localized flaws, such as those caused by jet impingement, where a small pipe teed into a larger diameter pipe. Plant personnel had little awareness that a through-wall leak might be due to thinning of the pipe wall by erosion-corrosion mechanisms. As a result, they did not take precautions to protect personnel against a pipe rupture.

Millstone Unit 3 findings:

- Operator error was not a factor contributing to this event.

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- Command and control at the plant was diminished when the SCO operated valves in the turbine building.
- Station procedures did not cover actions to be taken for through-wall pipe leaks in the system and did not caution personnel that these could be a precursor to a catastrophic failure.
- Teamwork by the licensed operators and the I&C technicians identified the cause for the loss of instrument air to containment and corrected the problem.
- The event occurred at a relatively good time of the day; there were personnel available who were coming on shift, who had not gone off shift, and who were working on the Unit 2 outage.

2.2.2 Oconee Unit 3 – Loss of Shutdown Cooling (3/08/91)

The Oconee Unit 3 event occurred at approximately 9 a.m., on March 8, 1991 when the unit lost DHR capability for about 18 minutes during a refueling outage (Ref. 12). Several hours before the event, instrument and electrical (I&E) technicians had obtained authorization to perform testing on valve 3LP-19 Train A emergency sump suction valve. (A low pressure injection system valve that is a boundary valve of the decay heat removal system when shutdown). When the technicians opened the valve, a gravity drain path was created from the hot leg. A blank flange, which was supposed to be installed between the valve and the sump, had been installed on the B train line. The water level in the reactor vessel fell to the bottom of the hot leg causing a loss of shutdown cooling until the valve could be reclosed and the water level restored. A Region II AIT investigated the event (Ref. 13).

Approximately 2 weeks earlier, two maintenance personnel were assigned to install a blank flange on the emergency sump suction line to valve 3LP-19. Since the procedure for installation of the flange did not address how to identify the correct line, the maintenance supervisor, on the basis of a review of a drawing, suggested that the flange be installed on the left emergency sump suction line. However, the drawing used was a schematic and not intended to provide information on true physical location. In reality, the suction line to valve 3LP-19 was the one to the right. When the maintenance personnel reached the emergency sump location, a handwritten, nonstandard label on the wall above the sump also designated the left line as 3LP-19. They proceeded to install the flange on the left, which was the line leading to emergency sump suction valve 3LP-20. Once the flange was installed on the line to valve 3LP-20, opening 3LP-19 drained reactor coolant through the open DHR system hot leg suction line into the emergency sump.

Over the last several years, the licensee had established a labeling program for plant components. However, this program did not consider a pipe or flange to be a component. Although the pipe penetration was labeled correctly, the only identification on the flange was the incorrect nonstandard label. Following this event, piping flanges were added to the labeling program.

Control operators acted promptly and effectively to diagnose the decreasing reactor vessel water level. Determination of the location of the water loss was quickly established and appropriate actions to isolate the leak and restore water level were rapidly performed. The combination of training in system procedures and theory and prior recognition of the maintenance activity being performed was evident in the positive operator's response.

Oconee Unit 3 findings:

- Procedures used for installing and testing the blank flange did not provide sufficient information for identifying the line.
- Erroneous, nonstandard labels at the flange location misled the installation crew and the verifiers.
- During the installation sequence, maintenance personnel did not act independently when performing an independent verification of the flange location.
- Miscommunication between the control room supervisor and the maintenance technician led to opening the valve without the knowledge of control room personnel.
- Diverse reactor vessel level instrumentation helped ensure that the control operators had no doubt that there was a real drop in level rather than a false indicated level.

2.2.3 Diablo Canyon Unit 1 – Reactor Trip and Safety Injection (5/17/91)

The Diablo Canyon Unit 1 event occurred at 6:28 a.m., on May 17, 1991, when Unit 1 tripped from 100-percent power because of an error by an I&C technician (Ref. 14). The technician took a nuclear instrumentation channel out of service with another channel already out of service, which satisfied the necessary 2-out-of-4 trip logic. Following the reactor trip, multiple steam dump valves failed open causing an excessive cooldown and depressurization of the primary system, which initiated a low pressurizer pressure safety injection (SI).

The operators understood that the SI initiated because of cooldown and shrinkage of reactor coolant and not because of a loss of coolant. After verifying that the conditions in EOP E-0, "Emergency Procedure Reactor Trip or Safety Injection," were met, they entered EOP E-1.1, "SI Termination."

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A number of factors contributed to the error by the shift control technician that resulted in the reactor trip. The calibration procedure did not follow guidelines that would have made the error less likely, the technician had not completed training in self-verification, and the goal of completing the surveillance before shift change may have created a time-based stress. In addition, the technician was without direct supervision although still in training. Thus a number of factors, including procedures, training, stress, and supervision adversely effected on-line surveillance testing.

There was a potential problem with the annunciator system. The annunciator system acknowledge circuit in the control room causes all blinking annunciator tiles to go to solid illumination and silences the alarm. Other plants' control room system designs divide the annunciators into several groups, each of which has its own audible signal and acknowledge button. Since Diablo Canyon's single acknowledge circuit affects all the alarms, there is an increased possibility that an incoming alarm may not be detected.

The licensee could improve the post trip event review process. At the conclusion of the event, the operators and other involved personnel were required to give written individual statements on what they recalled. However, some of the statements were quite terse -- perhaps because they were written following shift turnover at 8 a.m. The statements contained notes on observations, and did not comment on how the event might have been avoided or how the response might have been improved.

Diablo Canyon Unit 1 findings:

- The control room operators responded effectively to the reactor trip and SI.
- Several factors contributed to the technician's error in pulling the wrong fuse, including surveillance procedure deficiencies, time-based stress, and lack of supervision.
- The design of the annunciator acknowledge circuit in the control room did not help differentiate or prioritize incoming alarms.
- Prior problems with steam dump valves and other equipment were addressed by procedural restrictions but made the normal procedures and EOP more complex to follow.
- Although individual written statements were prepared by operators involved in the event, the statements were often terse and did not contain information on preventing recurrence or improving the response.

2.2.4 Monticello – Hi-Hi IRM Scram (6/06/91)

The Monticello event occurred at about 4:40 p.m. on June 6, 1991 (Ref. 15) when operators terminated a reactor startup and began a reactor shutdown to repair a leaking

SRV. The reactor automatically tripped when both the A and B intermediate-range monitor (IRM) channels reached their hi-hi trip set point. The method used to shut down the reactor was notch insertion of control rods. Because the decay heat rate was less than steam loads, the reactor cooled and positive reactivity was added to the core. The RO did not compensate for this cooldown; reactor power increased and resulted in the reactor scram when the operators did not maintain the IRMs in mid-range. The operators subsequently closed the MSIVs to limit the reactor vessel cooldown.

The operating crew did not recognize that the steam loads combined with a low decay heat rate would cause a cooldown resulting in increased reactivity. In addition, the crew did not react to the alarms and indications of the cooldown or the reactor power increase. Shift supervisors did not discuss such reactivity effects as low decay heat rate, xenon buildup and redistribution, and temperature changes. Procedures and training did not specifically address a shutdown with low decay heat levels. Taken together, these conditions left the crew poorly prepared for the reactivity management task.

Shift turnover and crew briefings before the event did not communicate to the crew a full understanding of the planned evolution. This contributed to an unnecessary level of stress during the shutdown. Better planning and detailed personnel assignments may have identified the unusual characteristics of this shutdown and better allocated shift resources. Shift resources and attention were directed toward near-term actions to support reactor maintenance activities rather than on the immediate steps required to monitor the plant activities to safely shut down and depressurize the reactor. Command and control of the operator at the controls was diminished because other control room personnel were involved in preparations for containment entry.

The shutdown procedure did not contain cautions or notes regarding the positive reactivity when the steam load was greater than the decay heat rate or options to counter a significant cooldown. This event occurred when a normal startup was terminated and transition was made to the shutdown procedure. Because the startup was terminated at an early stage, the crew had to determine where they were in the shutdown process and which steps in the procedure were applicable.

Monticello findings:

- The operating crew was not sufficiently aware of how existing conditions would affect the reactivity management task.

- Command, control, and communications were not focused on monitoring plant activities to safely shut down and depressurize the reactor.

- The operating crew lacked an adequate understanding of observed plant response as plant conditions changed.

- Procedures did not adequately cover the transition from a point in the startup procedure to an appropriate step in a shutdown procedure.

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- The control room crew were not asked to prepare individual written statements to preserve their individual observations and insights. Therefore, the event analysis process was flawed because of the lack of these statements, even though the control room crew discussed this event to help their recall.

2.2.5 Waterford Unit 3 – Excess Steam Demand (6/24/91)

The Waterford Unit 3 event (Ref. 16) occurred at 1:24 p.m., on June 24, 1991, when the unit experienced an excessive cooldown following a manual reactor trip at 1:24 p.m. The event began at 11:19 a.m., when a lightning strike resulted in a turbine trip, which caused an automatic power cutback to about 35 percent. At 1:15 p.m., operators noticed SG #2 level was increasing and could not be controlled. Because the SG high-level alarm was set at 86.7 percent and the high-level reactor trip setpoint was at 87.7 percent, the operators had no time to attempt to lower the SG level to avoid a reactor trip and manually tripped the reactor. Following the trip, primary system temperature and SG pressure dropped rapidly because both a startup feedwater regulating valve and a steam bypass valve had failed open, prompting the operators to manually initiate a main steam isolation.

After the event, the operators did not prepare individual statements on what they recalled but they concurred on a joint statement prepared by the STA. Although there is no evidence that this group statement resulted in an incomplete description of the event, it is possible that it did not capture important individual observations and insights

Waterford Unit 3 findings:

- Teamwork by the control room operators resulted in an effective and timely response.

- The operators were well prepared for the event by simulator training, particularly for excessive steam demand events.

- The SG high-level alarm set point was so close to the high level trip set point that there was insufficient time to try to take control of level.

2.2.6 Quad Cities Unit 2 – Main Steam Isolation (9/18/91)

The Quad Cities Unit 2 event (Ref. 17) occurred at 6:05 p.m., on September 18, 1991, when the reactor was in an end-of-cycle coastdown and the main steam line B isolated causing power to spike from 83 percent to 98 percent. However, the control room crew did not identify this power spike until over 3 hours later. The inboard B MSIV disc had separated from the stem and restricted flow in main steam line B, causing reactor pressure to increase from 984 psig to 1018 psig. Although this increased reactor pressure resulted in fluctuations in power, level, and core flow, it caused no alarms to annunciate because no set points were exceeded.

A number of factors contributed to the delay in recognizing that MSIV had closed. The plant did not have detailed guidance on panel monitoring. Clearly, the Unit 2 NSO who was responsible for monitoring the panels overlooked the indicated loss of flow in main steam line B, the momentary spike in level and power, and the sustained elevation in reactor pressure. There are indications that he may have been distracted by a malfunctioning strip chart recorder, by equipment surveillances he was performing, by activities in the on-the-job training and evaluation of trainees present in the control room, and by other things. However, the operating shift crew acknowledged during the interviews that such activities were routine. Perhaps more significantly, the control room organization failed to catch this oversight until the off-normal condition was identified by chance during a surveillance by another NSO. The SCRE normally performed detailed panel checks only at the beginning and end of the shift and relied completely on the unit NSO during the shift, in accordance with station policy, even though this particular NSO was the least experienced on shift. During normal operations near 100-percent power, the plant probably would have tripped after loss of main steam line B. However, the plant was in a power coastdown and initial power level was about 83 percent. The delayed recognition of the closed MSIV could have been avoided if alarm set points had been reset to take the lower power level into consideration.

Quad Cities Unit 2 findings:

- The loss of steam flow in one line was not recognized for 3 hours because there was a low level of awareness of reactor operating parameters by the crew and by the Unit 2 NSO, in particular.

- Teamwork by the control room crew was not sufficient to identify the condition in a timely manner, which may have been the result of the shift organizational structure.

- Procedures and training contained negligible technical guidance for abnormal conditions that are within alarm set points.

- Operator aids, such as computer programs, may assist in operations by highlighting off-normal conditions.

- The MSIV failed because of incomplete instructions in the work package for maintenance that had been performed on the valve.

- The current shift organization and practices may not ensure effective monitoring of plant status.

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2.2.7 Crystal River Unit 3 – Pressurizer Spray Valve Failure (12/08/91)

The Crystal River Unit 3 event (Ref. 18) occurred at 3:09 a.m., on December 8, 1991, after the plant was starting up after a short maintenance outage, at about 10-percent power, preparing to roll the main turbine, when a slow loss of RCS pressure became apparent to the operators. The actuator for the pressurizer spray line control valve had failed, which left the valve partially open but indicating that it was closed. The operators did not realize why the RCS pressure was decreasing until the pressurizer spray line isolation (block) valve was closed about an hour later. An operator further withdrew control rods after the RCS pressure decrease began in an effort to control pressure. The reactor tripped on low pressure, but the operating crew bypassed automatic engineered safety features (ESFs) (high pressure injection, emergency feedwater, emergency diesel generators, and partial containment isolation) actuation for about 6 minutes.

The initial bypass of the ESF, while the plant pressure decrease was not understood, not directed by abnormal or emergency procedures, and not directed by shift supervision. ESFs were then unbypassed and the high pressure injection and other systems activated. Operators then established manual control of the high pressure injection system to maintain RCS pressure above 1500 psig.

The second bypass of ESF was in accordance with procedures. However, the second bypass was not conservative for maintaining an adequate subcooling margin, suggesting a lack of procedural guidance for ESF termination.

The event was complicated by the failure of the pressurizer spray valve and its indication. As a result, significant spray flowed to the pressurizer while the closed-position indicating light for the pressurizer spray control valve was lit and the 40-percent open and the full-open indicating lights were not lit.

The operators had difficulty with command, control, and communications. Examples include: the operators' failure to use the annunciator response procedure for low RCS pressure; the initial bypass of ESF without direction or concurrence by shift supervisors and shift supervisors being unaware or uninformed that an ESF was bypassed for about 6 minutes; shift supervision's late declaration of an unusual event and related notifications; and a shift turnover process that did not ensure that all crew members were aware of recent significant changes in the observed operating characteristics of the pressurizer spray valve. If those changes had been investigated, the equipment problem with the spray valve may have been identified and corrected, and the event averted. The involvement of "management on shift" for the reactor startup contributed positively to the event progression by noting that ESF was bypassed and by recommending the pressurizer spray isolation valve be closed.

There were weaknesses in procedures. The annunciator response procedure for low RCS pressure addressed responses to control circuit faults, but did not cover appropriate actions to diagnose and correct the cause of the pressure decrease like those contained in one of the station's abnormal procedures. Operators did not execute all steps of an abnormal procedure that contained direction to close the pressurizer spray line isolation valve, because ESF termination criteria were met. The station's administrative procedures did not caution against or prevent exiting an abnormal or emergency procedure before checking remaining sections of the procedure.

Crystal River Unit 3 findings:

- The initial bypass of the ESF was an inappropriate operator action, not directed by abnormal or emergency procedures or by shift supervision. The licensee developed procedural guidance to prevent recurrence.

- The event was complicated by failure of the spray valve position indication.

- A number of problems in command, control, and communications, and in procedures contributed to this event.

2.3 1992 Event Studies

The 1992 human performance studies concerned the following three events:

2.3.1 Prairie Island Unit 2 – Loss of Shutdown Cooling (2/20/92)

The Prairie Island Unit 2 event (Ref. 19) occurred at 11:10 p.m., February 20, 1992, when a loss of shutdown cooling resulted from insufficient water level in the RCS. The operators responded promptly and initiated recovery procedures to restore water level in the reactor vessel and re-establish shutdown cooling flow. On February 21, 1992, NRC Region III sent an AIT to investigate the event.

On February 20, 1992, Prairie Island Unit 2 was ? days into a refueling outage. Late on day shift, reactor vessel draining to midloop had commenced and then been terminated for shift change. The evening shift (6:00 p.m. to 6:00 a.m.) conducted beginning-of-shift briefings and re-established draining. The two ROs conducting the draindown were extra personnel from another shift used to supplement the normal duty shift. The extra ROs were in communication with operators in the containment building to accomplish the draindown.

Newly installed electronic level instrumentation was considered operable during the evolution. When the draindown started, the electronic level instrument display on the control room emergency response computer system was off-scale high. A tygon tube was the only instrument providing usable level information during the draindown. To obtain actual level within the system, tygon tube levels were transformed, via manual calculation, to correct for the nitrogen pressure effects.

A systems engineer was on duty to provide assistance with the draindown and also to perform a preoperational check on the electronic instrumentation when it was indicating

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on-scale. After approximately 2 hours of draining, at 9:30 p.m., the electronic instrumentation was still off-scale high. The systems engineer conferred with an instrument technician and made a decision to leave the control room to investigate the level transmitter valve lineup in the containment building. This effort was interrupted by the announcement that shutdown cooling was lost. The systems engineer returned to the control room at that time.

At 10:55 p.m., the drain down ROs were having difficulty calculating actual level and became concerned about reactor vessel water level. A containment building operator was sent to open a vent in the suction line of the RHR system to check for air (nitrogen). One of the draindown ROs decided nitrogen pressure was higher than it should have been at this point in the draindown and opened a reactor head vessel vent to vent off some of the excess pressure. The containment operator reported back that nothing but air was coming from the vent on the RHR suction line. He was ordered to close the vent and drain valves. Electronic level had suddenly changed from off-scale to an indication of about 723 feet (5 inches below midloop), and a low level alarm was received. Based on interview data, the indicated level was as low as 722 feet 6.5 inches (10 inches below midloop). Alarms on the emergency response computer system for RHR pump low suction pressure, low motor-amps, and low flow were received at 11:08 p.m. The shift manager ordered the running 22 RHR pump stopped at 11:10 p.m.

The shift supervisor took direct command of the operations and entered abnormal procedure D2 AOP1, "Loss of Coolant While in a Reduced Inventory Condition," which directed the starting of a charging pump to raise the reactor vessel water level. The operators were monitoring RCS temperature using available in-core thermocouples. The temperature was about 133 °F at the time of the running RHR pump trip. One entry condition for EOP 2E-4, "Core Cooling Following Loss of RHR Flow," required RCS temperature to be at 190 °F. However, operators observed from the rate of level increase and heatup that actions of the abnormal procedure were insufficient to mitigate the transient before reaching entry conditions of the emergency procedure. The emergency procedure was immediately implemented when the temperature reached 190 °F. The 21 RHR pump was aligned to the refueling water storage tank and started to inject water to the reactor vessel. Reactor vessel level was promptly regained. The 21 RHR pump was then stopped and realigned for shutdown cooling and restarted. A peak temperature of 221 °F was reached before re-establishing shutdown cooling and returning the plant to pre-event conditions.

A containment evacuation of 42 people was accomplished, with the exception of two operations personnel. They were directed to stay in the containment by the control room staff to continue monitoring tygon tube level and be available to operate valves for the draindown. Containment integrity was verified to be intact as directed by the emergency procedure.

Prairie Island Unit 2 findings:

- Procedures and training did not provide sufficient direction in nitrogen pressure control. The significance of round-off errors during water level calculations was not recognized by the ROs and had not been addressed during training. As a result, incorrect information was used for the draindown.

- There was uncertainty as to who had responsibility and authority to make the decision to hold or stop draindown activity. The shift supervision assumed the ROs were experienced and did not require continual supervision. An apparent hesitation by the draindown crew to communicate some concerns to the supervisors may have resulted from the ROs not working with their normal crew.

- The draindown ROs lacked awareness of how higher nitrogen pressures affected the draining process.

- There was a lack of questioning attitude regarding the response of the electronic display indicators even when it was identified in the procedure that the displays should be operable.

- It would have been appropriate to hold or stop the draindown because of discrepancies and uncertainties regarding water level but this was not done.

- A man-machine interface issue was identified when the local operator had difficulty reading the level correctly in the tygon tube due to parallax problems, poor lighting and tube visibility degraded by the tube penetrating the next floor.

2.3.2 LaSalle County Unit 2 – RWCU Isolation Bypass (4/20/92)

The LaSalle County Unit 2 event (Ref. 20) occurred at 8:47 a.m. on April 20, 1992, when a reactor water cleanup (RWCU) system shut down lifted an RWCU regenerative heat exchanger relief valve for 3 ½ minutes, while an operator had the automatic RWCU isolation erroneously bypassed.

Several weeks earlier, an RWCU isolation had occurred because of a spurious RWCU high-differential flow signal. Both RWCU containment isolation valve motors had failed because of thermal expansion effects on the limit switch settings and licensee management had criticized the operators for allowing the spurious isolation. The motors had to be replaced and a testing program was established to verify the limit switch settings as the plant power level increased.

On April 20, Unit 2 was at 20 percent power. The NSO shut down the RWCU, as part of the procedures for verifying the limit switch settings, by closing the system return valve before stopping the RWCU pumps, which was in reverse order to that stated in the procedure substeps. About a minute later, the RWCU high-differential flow alarmed, indicating the start of a 45-second delay timer preceding the RWCU isolation.

The NSO wanted to preserve the test and obtained the shift foreman's permission to bypass the automatic ESF closure of the RWCU containment isolation valves. The NSO removed keys from other front control board switches and gave them to a second NSO. The second NSO used them to bypass the RWCU isolation, but reported a continuing RWCU differential flow of 95 gpm.

About 3 minutes later, the operators worked as a team to verify that the alarm was not spurious. An equipment attendant identified flow through an RWCU regenerative heat exchanger relief valve. A third NSO found reactor building equipment drain tank level increasing, while the 95 gpm RWCU differential flow continued. The NSO asked the SCRE and the shift foreman how they wanted to isolate the RWCU. Both agreed to allow the automatic RWCU isolation, despite the partially erroneous precaution in the special test procedure that valve operation without thermal overload protection (as in the case of automatic operation) could damage the motor or the valve if the limit switches settings had drifted because of thermal expansion. The operators returned the RWCU bypass key switch to normal, allowing the RWCU to automatically isolate, which terminated the loss of inventory from the RWCU through the open relief valve.

LaSalle County Unit 2 findings:

- The operators lacked understanding of the required order of performance of procedural directions.
- The special test procedure did not address response to an automatic isolation signal.
- While the alarm response procedure for the RWCU high-differential flow alarm did not address determination of alarm validity or criteria for ESF bypass key use, teamwork with auxiliary operators was a positive factor in verifying its validity.
- There was no direct RWCU relief valve discharge flow indication in the control room and other instruments used to diagnose this event were located on different panels.
- Control room operators performed recovery actions without consulting applicable procedures because of their frequent revision and level of detail.

2.3.3 Palo Verde Unit 3 – Loss of Annunciators (5/04/92)

The Palo Verde Unit 3 event (Ref. 21) occurred at 4:36 a.m. on May 4, 1991, when the unit lost most plant annunciators and some plant computer functions while at 100-percent power due to an electrician short circuiting a 24-V dc plant annunciator system lead to a 480-V ac bus in a nonsafety-related breaker cubicle in the turbine building. The control room operators were aware of the electrician's work with the annunciator system, surmised this caused the problem, and left the plant at its steady state condition. Since the redundant plant computer alarms were available, no emergency declaration was necessary. The licensee augmented the operating crew with two reactor operators and five auxiliary operators to monitor important plant parameters direc:ly.

At 7:08 a.m., the core monitoring computer ceased calculating reactor parameters. The operators reduced reactor power to 70-percent through boration to comply with TS. At 8:19 a.m., the licensee declared an alert after the remaining plant computer monitoring functions failed.

The operators maintained the plant at 70-percent power during several days of plant annunciator system and computer trouble-shooting. After demonstrating the functionality of the alarm system, the licensee terminated the alert at 11:231 p.m., May 6, 1992, and commenced a plant shutdown at 11:40 p.m. for further annunciator testing. The shutdown was completed with a manual reactor trip from 20 percent power at 4:20 a.m. on May 7, 1992.

On May 8, 1992, Region V sent an NRC AIT to the site. The AEOD study of the factors influencing operator performance during this event was performed as part of the AIT inspection.

Palo Verde Unit 3 findings:

- Procedures did not cover loss of annunciators, loss of annunciators and plant computer, or define plant computer operability.
- Operators may have become less vigilant as they continuously monitored control boards without periodic breaks during 12 hour shifts.
- The duration of a 24-hour shift detracted from the STA function in the control room.

2.3.4 Fort Calhoun – Stuck Open Relief Valve (7/03/92)

The Fort Calhoun event (Ref. 22) occurred at 11:36 p.m. on July 3, 1992, when a nonsafety-related inverter was returned to service following repairs. When connected to its bus, the inverter output voltage oscillated and caused an electrical supply breaker to electrical panel AI-50, to trip open on a high current condition.

Electrical panel AI-50 supplied various instrumentation and components in the plant, including the control circuitry for the main turbine. When power was lost, the circuitry caused the main turbine control valves to close to protect the main turbine. With the turbine control valves shut, the heat sink for the RCS was temporarily lost, resulting in an RCS pressure increase. The reactor and turbine tripped at approximately 2400 psia. As pressure continued to increase, the PORVs, main steam safety valves, and a pressurizer code safety valve opened to reduce RCS pressure. The PORVs shut at 2350 psia. When pressure reached approximately 1750 psia, a pressurizer code safety valve

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shut and RCS pressure increased to approximately 1925 psia. At this point, pressure began to drop rapidly. The operator shut the PORV block valves when the pressurizer quench tank level was observed to rise. The pressure drop continued and SI, containment isolation, and ventilation actuation signals were received. All safety systems functioned as designed. The open pressurizer code safety valve partially closed at approximately 1000 psia. The licensee declared an alert when the SRV stuck open.

The operators implemented the emergency operating procedures and secured the four reactor coolant pumps. The plant was subsequently cooled down, using natural circulation and shutdown cooling to cold shutdown conditions.

Fort Calhoun findings:

- The operations staff quickly diagnosed the plant status and took appropriate actions in a timely manner.
- A number of factors contributed to the successful operator response including; loss of coolant from the RCS event was included in simulator training, EOPs were upgraded and provided sufficient guidance, emergency planning actions were practiced weekly in simulator training sessions, and control room organization and staffing provided a sufficient number of personnel with appropriate partitioning of responsibilities.
- A number of areas where the technical content of EOPs could be improved were revealed by the event.

3.0 ANALYSIS SECTION

3.1 Introduction

The analysis section contains observations and conclusions from AEOD's onsite analysis of operating events. Examples are provided to support the observations but are not intended to be exhaustive. To better capture the operating experience, examples from other sources are used, where appropriate. Discussions are provided to give background or perspective on some topics. The reader is cautioned that this section is essentially our expert opinion and the study events were not selected randomly.

In Sections 3.2 through 3.5, control room organization, procedures, human-machine interface, and industry initiatives are discussed. In Section 3.6, a more holistic approach is taken to performance shaping factors that influenced crew response.

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3.2 Control Room Organization

The review of operating events identified control room organizational factors that significantly affected crew response to events. These factors include the staffing level, division of responsibilities, and degree of teamwork. Additional observations are presented concerning the STA position.

3.2.1 Staffing and Responsibilities

Observation

Control room staffing levels and other organizational weaknesses impaired some crews in performing their emergency functions. At these plants control room management were overburdened during emergencies when tasks, supervision, and technical oversight were not appropriately allocated. At other plants, with proper staffing and periodic training, responses to events were performed well.

Examples

The studies of the events at Commonwealth Edison plants (Refs. 6, 7, 8, 17, 20,) identified an organizational structure in which problems frequently arose during events that required implementation of the STA function. The STA function was assumed by the SCRE, who normally directed control room operations. The control room supervisory function transferred to the SE. Other SROs on shift (referred to as the shift foremen) were often outside the control room directing auxiliary operators. The SE directed and verified the actions of the control room operators and became the emergency director. During the event at Dresden, for example, this control room organization resulted in the overburdening of the SE. The SCRE spent much of his time on telephone notifications and the shift foremen were outside the control room, resulting in limited redundancy and independence in control room decision-making and limited checking of important control room activities.

The Crystal River Unit 3 (Ref. 18) control room organizational structure included many positive attributes including a "stand alone" STA, two SROs in the control room with divided responsibilities (one was responsible for EO.. and plant response, the other for emergency preparedness and overall site response), staffing of ROs beyon... at required by TS, and operations "management on shift" in support of the reactor start-up. Although this organization ultimately placed the plant in safe, stable shutdown condition, cognitive mistakes were made and not immediately corrected. This experience suggests that a good organizational structure provides the framework for a good response, but does not ensure a good response. Other factors such as teamwork, communications, and knowledge level of the crew may still impede the crew's response. The Crystal River event showed the value of "defense in depth" in that some mistakes were caught and corrected (such as the bypass of engineered safeguards actuation) by the "fresh eyes" of

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the management on shift. Other mistakes, such as the lack of timely event declaration and notification, occurred despite the "fresh eyes" of the STA and management on shift.

The Fort Calhoun (Ref. 22) control room organization performed well. This organization had many positive attributes including: SROs with responsibilities divided among them; with responsibilities divided between the primary and secondary plants; a "dedicated" STA; and a "dedicated" emergency communicator. The crew may also have performed well because the emergency response functions (including event declaration, event notifications, notification paperwork, and "meetings" with the "duty" onsite emergency responders such as chemistry and health physics technicians) were practiced once in the week of requalification training.

In its report, (Ref. 23) the FitzPatrick diagnostic evaluation team raised concerns that the shift staffing and structure weaknesses "limited the ability of a minimum shift crew to respond to a scenario involving activation of the plant fire brigade, implementation of the EOPs, and implementation of the emergency response plan, including assessing emergency actions levels and making protective action recommendations."

In its report, (Ref. 24) concerning an event at the Nine Mile Point Unit 2, the incident investigation team described similar difficulties that the shift supervisor serving as the emergency director during an event, encountered with "overload" while fulfilling duties involving EOP reading, event classification, fire protection concerns, and implementation of the emergency plan.

3.2.2 Shift Technical Advisor

Appendix A to this report contains a discussion on the background and history of requirements related to the STA position.

Observation

The use of the "dual-role" STA impaired crew performance because the other SRO(s) were overloaded when one SRO assumed the STA role. The "dual-role" STAs sometimes lacked independent "fresh eyes" because of involvement in shift activities. Assignment of other tasks during events sometimes detracted from the STA's safety function.

Discussion

Chapter 6 of Professor James Reason's book, Human Error, (Ref. 25) concerned the detection of human errors. Professor Reason provided evidence for his conclusion that detection by others appears to be the only way in which certain diagnostic errors are brought to light in complex and highly stressful situations. During the event at Three Mile Island Unit 2 on March 28, 1979, it was the shift supervisor of the on-coming shift who detected the possibility of a stuck-open PORV 2 ½ hours after it had opened following a reactor trip. At Oyster Creek on May 2, 1979, it was an engineering supervisor entering the control room who noted abnormal systems conditions caused when an operator had erroneously closed four (recirculation) pump discharge valves instead of two pump discharge valves 31 minutes earlier, which "effectively shut off natural circulation in the core area."

Based on David Wood's analyses of simulated emergency scenarios, Professor Reason noted that the above examples are not isolated incidents. In the simulated scenarios, none of the diagnostic errors were noticed by the operators who made them, but by fresh eyes. Professor Reason noted that these "observations are very much in keeping with what we know of knowledge-based processing in particular, and of mistakes in general. When the diagnostic hypothesis is incorrect, feedback that is useful for detecting slips is unavailable. There is no discrepancy between action and intention, only between the plan and the true state of affairs."

Utilities took the need for an STA's recommendations to be heeded into consideration when deciding the STA's position in their shift organization. Many utilities licensed the STA for this reason. This is partly the reason for the dual-role STA/SCRE supervisory operating position at the Commonwealth Edison plants. Northern States Power accomplished this by supporting existing SROs in efforts to become degreed so that they could fill the dual-role STA position at the Monticello plant. Placing the STAs on shift, however, has the potential drawback that fresh eyes may be lost because of the STA's involvement in shift activities. Conversely, an STA may have difficulty in providing technical advice or solving a problem if he/she were not familiar with on-going activities preceding the problem.

Operator Performance may be improved by the STA presence in the control room. Events and this analysis (see Section 3.4.1) show that shutdown events can be more cognitively challenging and advice may be needed before the event (to prevent the event) rather than after the event which is the more common practice.

SRO training has improved since the requirements for the STA position were developed. Thus, some aspects of the STA function may no longer be required. Also, prompt staffing of the emergency response organization reduces the need for a technical advisor for that situation.

Examples

The Dresden shift organization (Ref. 6) was typical of Commonwealth Edison, which included a dual-role STA. Questions arose about the effectiveness of this arrangement. As described earlier, during emergencies the SCRE assumed the role of STA and the SE directed control room operations. Potential problems included (1) the SE may have been less familiar with the current condition of the plant than the SCRE who he relieved (the SE's office was located out of sight from the control room panels), (2) the SCRE may have been too involved with the details of the operation to provide an objective overview of the situation to provide fresh eyes, and (3) the STA made state and local telephone notifications.

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At Monticello (Ref. 15), the shift manager was a dual-role SRO and STA. Unlike at the Commonwealth plants, the SRO filling the STA position was the senior SRO on shift. During the Monticello event, the crew's understanding and anticipation of the observed and expected plant response was weak. It is possible that with another set of eyes, unburdened by shift activities and paperwork the event would have been precluded. The value of fresh eyes became apparent later in the event when an RO returned from the field and suggested that the MSIVs be closed to limit plant cooldown.

At Diablo Canyon (Ref. 14) the STA position was a dedicated (not dual-role) individual who was not required to be licensed as an SRO. The STA serves on shift as STA for both units and participates in shift turnover activities. From our interviews it appeared that the STA was helpful during the reactor trip and SI event on May 17, 1991, although he was "not the normal crew person" and was apparently inexperienced. The STA stayed at the safety parameter display system and monitored critical safety parameters after they entered guideline E-0, "Reactor Trip or Safety Injection." He communicated to the shift supervisor that there was a red path on the heat sink critical safety function but that it was probably erroneous, because there was indication of both motor-driven and one turbine-driven auxiliary feedwater pumps injecting.

The Waterford Unit 3 STA position (Ref. 16) was a dedicated (not dual-role) individual who was not required to be licensed as an SRO. The STA was on call to support the shift crew, and he reviewed plant logs and participated in shift turnover activities. During the manual reactor trip and excess steam demand event on June 24, 1991, the STA monitored the safety parameter display system and informed the shift supervisor of plant conditions.

In the RHR system overpressurization event at Catawba (Ref. 4), it was the RCS system engineer, in the control room on unrelated matters, who participated in the diagnostics and recalled an NRC information notice on interfacing systems loss of coolant accidents. Because the RCS system engineer had been previously uninvolved, it was possible for him to get the operators out of the cognitive trap they had fallen into. Thus, the system engineer performed an STA-like function in this event.

During the pressurizer spray valve failure at Crystal River Unit 3 (Ref. 18), it was the acting operations superintendent (management on shift for the reactor startup) who suggested closing the pressurizer spray line isolation valve in series with the spray valve, because he recalled this was one response to a low RCS pressure condition. This was another example of person who was not part of the operating crew performing an STA-like function. The on-call, "dedicated" STA was present during the event. He assisted with attempts to diagnose the cause of the decreasing RCS pressure and in the verification of the execution of the abnormal procedures.

3.2.3 Teamwork Findings

Observation

Teamwork improved performance in complex, high-stress situations.

Discussion

As used in the AEOD human performance studies, the term "teamwork" includes more than simply command, control, and communications. AEOD views teamwork as including all factors related to performance of the operating crew as a unit as opposed to a group of individuals.

A recent article titled "Cognitive Psychology and Team Training: Training Shared Mental Models of Complex Systems" (Ref. 26) stated that critical performance in many complex systems depends on the coordinated activity of a group of individuals. It further notes that the nature of specific teamwork skills and how best to train team members to perform together effectively is not well understood, despite the amount of research that has been done.

The NRC also recognizes the importance of team performance. Since 1987-1988 NRC operator licensing personnel have given increasing interest and attention to command and control, communications, and other factors that are important to crew performance. In a pilot program that is currently underway, the licensed operator requalification program was changed so that operators are requalified on the simulator as part of a crew and not as individuals. Licensed operators are still tested as individuals in the written and walk-through portions of the requalification.

Examples

During the Dresden Unit 2 stuck open SRV event (Ref. 6), there were problems with teamwork and communications. The SE made a cognitive mistake in directing the opening of the turbine bypass valves that was not challenged or corrected by other crew members. Suppression pool cooling was not initially maximized as required by procedure, because of either miscommunication or misunderstanding. During the opening of the bypass valves, the operator was not given specific instructions as to the number of valves to be opened, the desired pressure at which the valves should be closed, or the desired rate of depressurization. Because the SCRE was busy performing event notifications and the shift foremen were performing manual valve manipulations in the plant, diagnostic support and checking of the SE's direction was lacking.

During the Peach Bottom event (Ref. 3), communications and crew actions demonstrated cooperation and teamwork. Training of control room crews as a team was effective in establishing confidence and trust among the team members. This allowed the crew to function well in spite of the stressful situation.

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Palo Verde Unit 3 (Ref. 21) teamwork was effective in coordinating the activities of the crew to monitor and control the plant when the annunciators became unavailable. The shift supervisor held a briefing within a minute after the loss of annunciators. Extra operators were effectively used to monitor parameters that no longer had alarms.

3.3 Procedures

The operation of nuclear power plants is based on the premise that rule-based performance is more reliable than knowledge-based performance. Procedures were developed as an aid to the operators for safe plant operation and represent the best available thinking on proper operator response, assuming sufficient personnel are available to enact them.

EOP implementation involved years of effort by owners' groups, licensees, vendors, and the NRC. (Symptom-based EOPs are intended to assure operator response to achieve safe plant conditions without requiring diagnosis of the specific event.) Decision points are thought out beforehand to guide the operators to the proper response when a choice needs to be made. Deviations from procedures should not occur except under conditions addressed by administrative procedures.

However, an operator's use of procedures depends upon his perception of their adequacy, his level of expertise, management expectations of their use, and group norms. Operators do not always use or follow their procedures. In some cases, it was found that operators did not follow procedures because they contained errors. Procedures of high quality are more likely to be used, and procedures which are used are more likely to be maintained.

While procedures are available for a large number of potential accidents and transients, some situations will arise where existing procedures do not apply. Thus, knowledge-based performance will be necessary at times, to return the plant to a safe condition.

3.3.1 Procedural Adherence

Observation

Some operators acted during events without using a procedure. Procedure content, ease of use, and management policy and practices influenced procedure use.

Examples

The LaSalle County Unit 2 event (Ref. 20) was partially caused by an RO who failed to shut down the RWCU system in the order stated in the procedure, and then bypassed a valid RWCU isolation signal. The alarm response procedures did not direct the operators how to verify the validity of an RWCU isolation alarm. The special test procedure did not address how to isolate the RWCU. if necessary. The operators allowed the RWCU isolation to occur without referring to any procedure, despite a special test procedure being used which contained a precaution to avoid operating the valves without thermal overload protection. The RO stated in an interview that he normally relied on memory and experience to handle emergencies, then used procedures afterward to check his actions, because of frequent procedure revisions and having to go through three pages to find the one step needed.

During the study of the Crystal River Unit 3 event on December 8, 1991, (Ref. 18), a number of procedure-related observations were made. The annunciator response procedure for low RCS pressure was not used by the operators. Hence, the investigation of the reactor depressurization was not systematic; and operators withdrew control rods to raise reactor power, temperature, and pressure even though actual Tave was stable and not the cause of the pressure decrease. The event declaration and notifications were late because the shift supervisor relied on "knowledge" of the requirements rather than checking the applicable procedures. Procedure deficiencies were identified in that (1) the associated alarm response procedure addressed only control system failures, (2) not all steps of the applicable abnormal procedure were executed (including directions to close the pressurizer spray block valve) because administrative procedures allowed the abnormal procedure to be exited once ESF termination criteria were met, (3) administrative guidance was lacking concerning bypass of ESF prior to abnormal or emergency operating procedure entry, and (4) guidance for effective control room communications was either lacking or not effectively implemented.

During the Nine Mile Point Unit 2 partial loss of instrument air event (Ref. 5,) the applicable procedure was written to address a total loss of instrument air, not partial losses in specific legs of the system. The operators may have had a better understanding of which systems were available if the procedure was written to address partial losses of instrument air. During the Nine Mile Point Unit 2 IIT event (Ref. 24), operators experienced difficulty restarting the feedwater pumps because the startup procedures did not address quick restart of feedwater and condensate pumps under emergency conditions, an anticipated available water source required in the EOPs. In addition, the scram procedure did not segregate and make a distinction between immediate actions and supplemental actions.

? Knowledge-Based Performance During Events

Observation

Operators experienced difficulty in applying knowledge to unusual plant conditions, which resulted in delays in recognizing and responding to events.

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Discussion

Some knowledge-based performance is necessary in every event to recognize the significance of the situation, initiate use of the appropriate abnormal operating procedures or EOPs, and follow those procedures to respond to the event.

Examples

In the Monticello event (Ref. 15), the crew did not anticipate the expected plant cooldown when shutting down the reactor under conditions of low decay heat and auxiliary steam loads. The RO did not understand the intermediate range monitor response to the power increase due to RCS cooldown when rod insertion was stopped.

During the Quad Cities Unit 2 event (Ref. 8), an operator had difficulty integrating reactor theory and plant response when an operator withdrew control rods to raise pressure and received an automatic reactor scram when power increased rapidly while IRMs were not maintained on scale.

In the Crystal River Unit 3 event (Ref. 18), an operator withdrew control rods in an attempt to raise power, and hence, TAVE in response to a perceived cooldown event when, in fact, the reactor depressurization was not due to a cooldown, as evidenced by a stable TAVE.

Operators had difficulty using their knowledge in the calculation of corrected water level at Prairie Island (Ref. 19). Difficulties included not realizing that rounding would introduce unacceptable errors and performing simple additions requiring conversion of inches to feet.

3.3.3 Operator Preconditioning

Observation

Preconditioning from past experience, training, or management direction strongly affected how operators recognized and responded to events and in some cases led operators to disbelieve valid indications or to take inappropriate actions.

Discussion

Operators often react to specific plant conditions by remembering past operating experience, simulator scenarios, management direction, or classroom training. These usually combine in concert to focus operator reactions in a certain manner when an event occurs. However, previous experience with spurious alarms, malfunctioning instruments, or opposite directions for different scenarios may create confusion or misdirection.

Operator preconditioning to ESF actuations can misdirect operators: unnecessary ESF actuations are perceived to be unnecessary challenges to the systems; they may cause a scram and cause extra work. Section 3.3.4 of this report describes impromptu operator actions that have resulted, in part because of operator preconditioning to avoid ESF actuations.

Examples

Several weeks before the LaSalle County Unit 2 event (Ref. 20), an RO bypassed a valid RWCU isolation signal, partly because licensee management had previously criticized operators for allowing an automatic RWCU isolation that resulted in damage to the valve motors because of improperly set limit switches. Although the operators knew the RWCU differential flow meter indicated high, previous experience with spurious RWCU isolations during plant heatup may also have conditioned them to have expected a spurious signal. The alarm response procedures did not contain sufficient instructions on how to verify the validity of the RWCU isolation signal.

The normal bypassing of SI during plant shutdown at Crystal River Unit 3 (Ref. 18) may have conditioned the operators to respond as they had previously, instead of recognizing that the existing situation was different.

When asked about their expected response to a potential scram condition during the Palo Verde Unit 3 loss of annunciators (Ref. 21), ROs noted they are trained to scram the reactor only if a scram set point is exceeded, unless directed by an SRO.

At Dresden (Ref. 6), simulator training scenarios typically used a stuck open relief valve as the initiating event for an anticipated transient without scram (ATWS). In those scenarios, the torus heats rapidly and the torus temperature is a concern of major significance. Operators stated that they had not been trained for the simpler event to its expected conclusion. The more complicated simulator training prepared the operations personnel for the unlikely worst-case scenario. However, the lack of training for expected simple events failed to highlight the fact that the concerns and response to worst-case scenarios are often different from those of simple events. This preconditioning may explain why the crew had unnecessary, unwarranted concern for torus temperature response in this event.

3.3.4 Control of Emergency Safety Features

Observation

In two events, operators inappropriately defeated the automatic operation of ESFs during valid system demands. Some licensees have not provided sufficient guidance that limits bypassing or disabling ESFs, allowed for by technical specifications and emergency or administrative procedures.

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Discussion

In 2 of 17 events investigated by AEOD, operators defeated the automatic actions of an ESF under demand. Even though the operators corrected their mistakes, this is a higher failure rate than that found in probabilistic risk assessment calculations for emergency core cooling system failures, indicating that some of the important TMI lessons learned may not have been retained.

Not all plants had administrative guidance for control of ESFs for all plant modes, especially for situations where the operators have not entered the EOPs. Some guidance did not cover when ESFs may be bypassed or disabled, when they should be reinstituted or restarted, and priorities for event response. Procedures involving ESFs did not have a function recovery section. Not all plants allowed ESFs, once initiated, to operate until explicit termination criteria were met. Operators were generally provided adequate guidance for control of ESFs once EOPs and abnormal operating procedures were entered, although a review of LERs (Ref. 28) showed that rearming ESFs was potentially a generic weakness.

Without appropriate guidance developed beforehand, operators were forced to make rapid individual decisions in stressful situations. For situations where an SRO determines that it is necessary to deviate from technical specifications to defeat ESFs, Title 10 to the *Code of Federal Regulations* 50.54(x) and (y) apply.

Examples

In the LaSalle County Unit 2 event (Ref. 20), an RO defeated a valid RWCU isolation signal caused by an open RWCU relief valve, with the concurrence of an SRO, without using available procedures.

At Crystal River Unit 3 (Ref. 18), an RO defeated the ESF actuation system signals during a reactor depressurization event caused by an open pressurizer spray valve, without the concurrence of an SRO or procedural guidance.

3.4 Human-Machine Interface

The human-machine interface issues discussed below focus on the difference between shutdown and power operations, aids to operator awareness, and instrumentation to support operator actions.

3.4.1 Shutdown Instrumentation

Observation

A lack of appropriately ranged, direct-reading, control room instrumentation to monitor reactor pressure, temperature, and level caused operators to have difficulty in recognizing and responding to shutdown events, when operator actions were required to accomplish the safety functions of disabled, automatic safety systems.

Discussion

Of the 17 events studied, 11 of the events occurred during power operation and 6 took place while the plant was at standby or shut down. The differences between power operation and shutdown events provide some insight into the extent of required operator actions and the instrumentation needed for plant safety.

U.S. power reactors are designed to provide automatic safety response for most accidents and design-basis transients initiated during power operation. During such events, operators often intervene quickly even though the plant is provided with automatic protective systems.

For events initiated during shutdown, it is essential that operators respond. Operators usually have to diagnose the cause of a problem and correctly realign equipment to terminate a shutdown event. Many automatic safety functions are disabled during shutdown and it is likely that equipment will be out of service for maintenance and unable to perform its safety function. Any additional problems make recovery more difficult. However, operators may be hindered by lack of the necessary instrumentation, training, and procedures to effectively diagnose and terminate the event.

The French nuclear regulators and utility have recognized the risk associated with shutdown and have begun a program to establish automatic initiation of SI to restore water level during shutdown conditions.

The NRC has initiated a program to address shutdown risk that is expected to address many of these issues.

Examples

The Prairie Island (Refs. 19 and 27) shutdown event showed that new electronic reactor vessel level instrumentation, installed to meet Generic Letter 88-17, was ineffective because of faulty pressure compensation and did not respond properly because of the nitrogen overpressure in the pressurizer. The tygon tube reactor vessel level indication had to be manually compensated by operator calculation. The operators experienced difficulty in performing these calculations in a timely manner. The licensee required the core exit thermocouples to be operable only at reduced reactor vessel inventories, whereas the generic letter specified them to be operable whenever the reactor vessel head was installed.

The Catawba shutdown event (Ref. 4) involved a situation where the operators were interested in reactor pressure near 14.7 psi absolute while the only instrumentation available ranged from 0 to 3000 psi, and 0 to 800 psi. Small pressure changes of the type expected during fill and vent operations would not be noticeable on these instruments.

The Oconee shutdown event (Ref. 12) involved a decrease of 56-inches in reactor vessel water level. The operators questioned the validity of the level reading and verified it by high containment sump level and low hot leg level. The reactor vessel level decrease had been caused by an I&E technician, who had manually opened a motor operated valve after electrical power to the control room position indication had been removed. This hindered the operators from determining which valve had been opened erroneously. The operators observed the RHR loop temperature and decided that the core temperature increase was minimal and increasing slowly. They believed they had several hours before the core would heat up to the boiling point. However, because of the lack of flow in the RHR system, that temperature was not a true indication of core temperature. A calculation done after the event predicted that the core would have reached boiling in about 40 minutes.

3.4.2 Operator Awareness

Observation

Annunciator and computer alarms were important operator aides in recognizing and responding to events. In fact, operators failed to recognize conditions that were clearly off-normal, but which were not alarmed.

Discussion

Operators cannot respond to an event until they recognize that the plant is in an abnormal condition or transient. This process is facilitated by annunciators, instruments, procedures, and training.

During transients that result in a reactor trip, a large number of annunciators are activated; their usefulness to the operator is diminished as the number of low priority annunciators increases. Prioritization of annunciators could improve the effectiveness of this system.

Advances in plant computer technology provide the potential for development of more advanced aids to operator awareness of plant conditions. For example, the plant computer could be instructed to perform instrument cross-checks to alert operators to defective instruments. Where manual calculations are needed to complete a procedure, the plant computer could be programmed to perform the calculation to assure timely and accurate results.

Also, plant computer alarm points could be based on deviations from the actual operating conditions when the reactor is operating at a reduced power level, rather than

100-percent power parameters. For shutdown or refueling conditions, a full range of reactor vessel instrumentation including full range level, low range pressure, and direct reactor core temperatures, would be appropriate.

Examples

During the Catawba overpressurization of the RHR system (Ref. 4), the operators were not aware that reactor pressure was increasing until they diagnosed the cause of increasing level in the pressurizer relief tank due to the discharge of an RHR relief valve. They relied on one set of instruments that was inoperable without cross-checking another nearby instrument that showed increasing pressure.

As the Oconee RCS was losing water through an open flange (Ref. 12), the operators were alerted by wide range level instrumentation, but first suspected a faulty instrument until the RCS level loss was confirmed by narrow range instrumentation in the hot leg. The operators observed the RHR loop temperature and decided that the core temperature increase was minimal and increasing slowly. They believed they had several hours before the core would heat up to the boiling point. However, as noted in Section 3.4.1, the core would have reached boiling in about 40 minutes. The operators did not fully understand the severity of the situation during the event.

At Quad Cities Unit 2 (Ref. 17), the MSIV closed with a consequent pressure and power spike that was not noticed by the crew for over 3 hours. The power spike and the flow increase were below the alarm set points because the reactor was operating at reduced power.

At Prairie Island (Refs. 19 and 27), operating characteristics of the reactor vessel level instruments used in the drain down prevented the operators from having a true indication of the reactor water level. They attempted to perform hand calculations to generate a corrected level and the results were inaccurate and arrived at to late to prevent loss of DHR.

3.4.3 Instrumentation

Despite detailed control room design reviews, I&C weaknesses remain. These weaknesses can be important as evidenced by the TMI-2 accident where operators secured SI because they erroneously believed the pressurizer was full. TMI-2 showed that instrumentation weaknesses could lead operators into actions that furthered the accident progression.

Observation

Lack of direct control room indication of flows affecting the RCS inventory, including discharges of safety and relief valves in systems connected to the RCS, has impaired operator response to events. Conversely, direct control room indication of flows affecting the RCS inventory has facilitated operator response.

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Examples

In the Crystal River event (Ref. 18), spray line flow indication was unavailable and operators were unable to identify the cause of the depressurization because of the many potential causes to be investigated. Although the spray valve position indication erroneously indicated closed, it is likely that if spray line flow indication was available, the operators would have closed the pressurizer spray block valve and averted the reactor scram and SI.

At Peach Bottom (Ref. 3), as with other BWRs, there was no direct indication of HPCI injection flow to the reactor vessel. The HPCI flow indication was in the common header of the injection and test return lines and measured the combination of both flows. The operators throttled the HPCI flow to the reactor vessel to avoid unnecessary high reactor pressure vessel HPCI trips. The effect of the injection could only be determined by the rate of change of the reactor vessel level. The HPCI flow indicator would not provide accurate flow indication if there was leakage in one line or if both flow paths (injection and returns) were in service. Many RCIC systems are instrumented similarly.

At Quad Cities Unit 2 (Ref. 17), a valve and its indication failed. Main steam line flow indication led operators to eventually identify that one of the main steam lines was obstructed.

At Fort Calhoun (Ref. 22), the instrumentation allowed the operators to identify a failed open pressurizer safety valve that facilitated operator understanding of the observed plant response.

At LaSalle (Ref. 20), the relief valve that had lifted and remained open was not instrumented. The differential flow indicator was considered unreliable. These delayed operator identification that an actual loss of coolant event was in progress. The reactor building equipment drain tank level finally provided indirect indication of a leak.

3.5 Industry Initiatives

AEOD tried to evaluate progress that licensees have made in analyzing human performance during operating events and feeding operating experience information back to the industry, through review of operating events. While the human performance study site visits have been relatively short, averaging about two days per site visit, useful insights into influences on operator performance have been gained, both positively and negatively. However, AEOD has seen little evidence that either the industry or individual licensees have made the effort necessary to systematically analyze and evaluate human performance in operating events.

3.5.1 Event Review Process

Observation

There is a wide variance in the effectiveness of licensee's studies of human performance in operating events. While some licensees have missed such opportunities, others have initiated worthwhile corrective actions because of their human performance studies.

Discussion

During the Peach Bottom Unit 3 event (Ref. 3), the operator had a difficult time controlling level and flow into the reactor using HPCI. One reason for this was that there was no direct indication of flow into the reactor vessel from HPCI. HPCI flow indication in the control room was pump discharge flow, only some of which went into the vessel. The operator used the position switches on the testable check valve on the HPCI line as an indication of flow into the vessel. When the switches showed the valve open, the operator inferred there was some flow into the vessel. Identification of problems like this would enable a licensee to plan corrective measures that might only involve simple procedure changes or hardware changes.

In some cases, the licensee had prepared a followup report that describes the event in some detail. In almost every case, the licensee had prepared an LER. AEOD reviewed some of these and compared them with the human performance study of the same event. In some cases, it was difficult to tell that the reports describe the same event. It appears in these cases, that the licensee failed to consider the human performance aspects of the event or failed to include that information in the report.

3.5.2 Industry Program to Develop Generic Findings

Observation

AEOD is not aware of an industry program that develops generic findings from events to improve human performance.

Discussion

There is a lack of a publicly available, uniform, industry-wide system to collect, manage, analyze, and disseminate data on human performance during events. Such a system would serve as a central point for collecting reports on event investigations that are generated by participating utilities, generating generic findings, and feeding back the results to all of industry. Fortunately events which challenge operating crews are rare. It is important that lessons learned at any plant be shared throughout the industry.

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3.6 Latent Factors

James Reason has proposed (Ref. 1) analyzing the data on the 13 events in 1990-91 to show how latent factors can influence crew performance. He used the following categories for data on each of the events: *defenses* (for good or ill), *acts* (either appropriate or not), *conditions* (local factors relating to the task or environment that shape operator performance), *situations* (whether the plant was in a typical or nontypical state) and *latent factors* (upstream causal agencies that originate in the managerial or organizational spheres). After categorizing the data, he then found there were six factors that could be used to discriminate between events where crew performance was "successful" (the crews were not deceived by misleading indications, and they achieved safe recovery in a relatively short time) and where it was "less successful" (safe recovery was delayed by misdiagnoses and/or inappropriate actions). He found that there were 8 "less successful" events (Peach Bottom, Catawba, Dresden, Braidwood, Quad Cities [both events], Monticello, and Crystal River), and five "successful" events (Nine Mile Point, Millstone, Oconee, Diablo Canyon, and Waterford). He summarized the data in Table 1.

Table 1 Reason's categorization of 1990-1991 events

Discriminating factors	Less successful crews (N=8)	More successful crews (N=5)
Procedural problems	8/8	0/5
Training problems	6/8	2/5
Teamwork problems (CCC)	5/8	1/5
Nontypical situations	5/8	1/5
Organizational problems	4/8	0/5
Early hours AM	4/8	0/5

On average, the factors were present in two-thirds (67 percent) of the less successful events as compared with about 13 percent of the successful events. Reason suggested that the difference between the successful and the less successful crews might be in the quality of the operators involved, but that this did not seem likely.

When AEOD analyzed the 1992 data in the same way, it was found that the Fort Calhoun event was more successful, the Prairie Island and La Salle events were less successful and the Palo Verde event was not clearly either. The data from all the events, except Palo Verde, is included in Table 2 for comparison based on the factors identified in Table 3. An additional factor has been added for human-machine interface problems. The data are summarized as follows:

Table 2 Categorization of 1990-1992 events

Discriminating factors	Less successful crews (N=10)	More successful Crews (N=6)
Procedural problems	10/10	0/6
Training problems	7/10	2/6
Teamwork problems (CCC)	6/10	1/6
Organizational problems	6/10	0/6
Human-Machine Interface problems	6/10	3/6
Nontypical situations	7/10	2/6
Early hours AM	4/10	0/6

One might note the following:

- Procedural problems contributed to all of the less successful events. This data points out the importance of procedures, training, and teamwork to operator performance. While problems in these areas contributed to operator difficulty in less successful events, such problems rarely existed in successful events.

- Nine events involved nontypical situations, 7 of which were considered "less successful".

- Four events occurred in the early hours and all were considered "less successful".

The results are consistent with those obtained earlier. On average, the first five factors, as rearranged, were present in 70 percent of the less successful events as compared with about 17 percent of the more successful events. While this analysis is highly subjective, and the discriminating factors were not equally likely, it is based on data from representative number of studies (16 studies at 15 facilities) and provides a means of examining the results as a whole. Interaction among the discriminating factors can be seen as one compensates for another. For example, good teamwork may have compensated for a procedure or training problem. In any case, it seems clear that crew performance can be made more effective by improving procedures, training, teamwork, and organizations, and by suggesting that crews exercise greater caution and teamwork in the early morning hours.

Table 3 Factors associated with the events

	Less successful events										More successful events					
	PB	Ca	Dr	Br	QC-90	Mo	QC-91	CR	PI	LS	NM	Mi	Oc	DC	Wa	FC
Procedure Problems	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	N	N	N	N	N
Training Problems	Y	N	Y	N	Y	Y	Y	Y	Y	N	Y	N	Y	N	N	N
Teamwork Problems (CCC)	N	N	Y	Y	Y	Y	Y	N	Y	N	N	N	N	N	N	N
Nontypical Situations	N	Y	Y	N	Y	Y	N	N	Y	Y	N	N	N	N	Y	Y
Organizational Problems	N	N	Y	Y	Y	N	Y	N	Y	Y	N	N	N	N	N	N
Early Hours Morning	N	N	Y	Y	N	Y	N	Y	N	N	N	N	N	N	N	N
Human-machine Interface Problems	Y	N	N	N	N	Y	Y	Y	Y	Y	N	N	N	Y	Y	Y

PB	PEACH BOTTOM UNIT 3
Ca	CATAWBA UNIT 1
Dr	DRESDEN UNIT 2
Br	BRAIDWOOD UNIT 1
QC	QUAD CITIES UNIT 2
Mo	MONTICELLO
CR	CRYSTAL RIVER UNIT 3
PI	PRAIRIE ISLAND UNIT 2
LS	LA SALLE UNIT 2
NM	NINE MILE POINT UNIT 2
Mi	MILLSTONE UNIT 3
Oc	OCONEE UNIT 3
DC	DIABLO CANYON UNIT 1
Wa	WATERFORD UNIT 3
FC	FORT CALHOUN
FC	FORT CALHOUN

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4.0 PROGRAM ACTIVITIES

AEOD has recognized the need for improved collection and extraction of human performance lessons learned across all plants (Ref. 29). To improve extraction of human performance lessons learned, AEOD has begun activities to create a human performance data base.

To improve collection of human performance data, AEOD staff has begun efforts to improve reporting of human performance data by both licensees and NRC staff. For example, AEOD management is alert to include human performance in AIT and Incident Investigation Team charters, when appropriate, and has provided staff with human performance evaluation expertise to these teams. AEOD has supported efforts of other NRC offices, such as the human performance investigation process, that are raising the awareness and knowledge of resident, regional, and headquarters inspectors. During AEOD site visits, the teams encourage the licensees to perform human performance investigations and to report the results in LERs. The teams explain that the LER rule requires human factors reporting. During the routine review of inspection reports and LERs, AEOD Division of Safety Programs staff also are alert to identify potential human performance issues.

AEOD intends to continue its human performance site visits and document its findings. Future efforts will focus on reporting of specific human performance issues, as they are developed. Accordingly, AEOD will discontinue issuing comprehensive human performance interim reports.

5.0 CONCLUSIONS

These human performance site studies have provided valuable insights into how operating crews actually cope with real events. Ideally more data would be available to support conclusions, but there does not appear to be a larger source of indepth nuclear power plant human performance data available.

A large data base will take some time to develop because these events are infrequent. This information is the result of about 2 ½ years of effort and is estimated to cover about one-fourth to one-third of the events which significantly challenged operating crews during that period.

Despite the small data base, certain conclusions can be drawn based on the observations in Chapter 3 of this report:

1. A careful examination of control room staffing and organizational structure vs emergency functions would better utilize shift resources and allocate tasks so that no individual(s) were overburdened, while maintaining appropriate levels of supervisory and technical oversight. This would be especially worthwhile with regard to the "dual-role" STA position. (3.2.1 and 3.2.2)

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2. The safety significance of inappropriately defeating ESFs warrants action to prevent such human errors. Information Notice 92-47 alerted the nuclear industry about the Crystal River event, in which operators bypassed ESFs during an undiagnosed reactor depressurization event. Further action to provide assurance that ESFs are not inappropriately defeated in the future is reasonable.

   Inappropriate defeating of ESF by operators represents a common-mode failure of these otherwise highly reliable systems. With predicted hardware unreliability of these systems of the order of 0.001 per demand and better, inappropriate operator action may be a dominant failure mode. Operators defeating ESFs significantly contributed to the worst United States nuclear accident at Three Mile Island. While technical specifications and plant procedures address ESF control, the improper defeating of ESFs in two events within a recent 4 month period shows that NRC and industry control of ESFs has not been completely effective. (3.3.4)

3. Training and teamwork can be used to increase the effectiveness of knowledge-based operator performance. Knowledge-based performance was required in responding to every event. Good teamwork was found to be an important aspect of identifying and correcting mistakes during procedure-based and especially knowledge-based performance.

   Procedures were an important determinant of crew performance. Procedure problems were key contributors in the less successful events, but were not found in the more successful events when the procedures were accurate, complete, and management required their use. (3.2.3, 3.3.1 and 3.3.2)

4. The insights drawn from these studies show that human performance of operating crews in nuclear power plants is a fertile ground for study and feedback of lessons learned. Institutionalizing the gathering of such information and analyzing it to develop generic findings, both by the NRC and the industry would be an effective means to share this important information. (3.5)

5. The observations in Section 3.4 of this report concerning instrumentation are important and have already been shared with NRR and have been incorporated into their study of shutdown risk.

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7.0 APPENDICES

7.1 APPENDIX A: Background on the Position of Shift Technical Advisor

Requirements that apply to the STA position:

SECY-92-026, dated January 21, 1992, describes the evolution of requirements for the STA at nuclear power plants. It notes that Generic Letter 86-04 was issued on February 13, 1986, to provide licensees with a copy of the *Federal Register* notice of the "NRC Policy Statement on Engineering Expertise on Shift." The policy statement was intended to ensure that adequate engineering and accident assessment expertise is possessed by the operating staff at a nuclear power plant.

The NRC policy statement offers two options to meet the STA requirements of providing engineering expertise on shift. Option 1 provides for eliminating the dedicated STA position by combining one of the required on-shift SRO positions with the STA position into a "dual-role," SRO/STA position. The SRO/STA must hold a baccalaureate degree in engineering, engineering technology, or physical science, or a Professional Engineer license. Option 2 permits a licensee to satisfy the policy by placing on each shift a dedicated STA who meets the education and knowledge criteria of NUREG-0737, Item I.A.1.1, and participates in normal shift activities.

The generic letter notes that the Commission encourages licensees to move toward the dual-role position, with the eventual goal of the shift supervisor serving in the dual-role. The Commission encourages licensees to have the dedicated STA assume an active role in shift activities if the alternative, dedicated STA position is selected. This could be accomplished by having the STAs rotate with the shift and by including responsibilities to review plant logs, participate in shift turnover activities and training, and maintain an awareness of plant configuration and status.

Background – intended function of the STA:

The *Federal Register* notice of October 28, 1985, is clear that the requirement for the STA is intended to improve the ability of shift operating personnel to recognize, diagnose, and effectively deal with plant transients or other abnormal conditions.

The STA function is to objectively evaluate the plant condition during abnormal and accident conditions and recommend action. Specific training in the plant transient response helps to accomplish this. The requirement for a bachelor's degree in engineering or equivalent helps ensure the STA has engineering expertise to contribute and can think and communicate effectively. (The baccalaureate is usually the lowest degree conferred by a 4-year college or university. This is not an unreasonable qualification for this position) Qualification as an SRO makes it more likely that the STA will be respected by the licensed SROs on shift so that the STA's advice will be adequately considered. Requiring the STA to rotate with a shift and have

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responsibilities to review plant logs, participate in shift turnover activities and training, and maintain an awareness of plant configuration and status, are other things that improve the STAs knowledge and credibility with the shift.