TRIP REPORT:
ONSITE ANALYSIS OF
THE HUMAN FACTORS OF AN EVENT
AT PALO VERDE 3
ON FEBRUARY 4, 1993

LOSS OF MAIN FEEDWATER PUMP WITH
REACTOR TRIP AND SAFETY INJECTION

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EXECUTIVE SUMMARY

The Office for Analysis and Evaluation of Operational Data of the U.S. Nuclear Regulatory Commission has a program to study human performance during operating events. As part of this program, a team was formed to conduct an onsite analysis of an event that occurred at the Palo Verde Nuclear Generating Station during the day shift on February 4, 1993. Unit 3 had been operating at 100% power, when a control system problem developed on the A main feedwater pump decreasing the speed of the pump to the point where it no longer was producing flow. Control room operators were alerted to the abnormal condition by the A main feedwater pump high vibration annunciator. Steam generator levels decreased rapidly with the reduction in feedwater flow. The operators identified the need to reduce reactor power and to trip the A main feedwater pump to initiate an automatic reactor power cutback to 50%, when the reactor automatically tripped on low steam generator levels. Auxiliary feedwater actuation signals 1 and 2 were received two seconds after the reactor trip. Forty seconds later, a safety injection and containment isolation actuation occurred as a result of the reactor coolant system cooldown and depressurization. Emergency procedures were implemented by the control room operators to return the plant to a stable condition.

The human factors analysis focused on the factors that influenced the performance of operations staff and technical support personnel throughout this event. The analysis was based on data derived from interviews with operations and technical staff personnel, plant logs and recordings, and review of operations procedures and training material.

Plant dynamics gave the operators only one minute from the first audible annunciator until the automatic trip was received. The operators immediately began a verification of the annunciator on the main feedwater pump. A trip of the main feedwater pump from any one of several abnormal conditions would have initiated a reactor power cutback and turbine load reduction to about 50%, well within the capacity of one operable main feedwater pump. The shift supervisor, after his assessment, ordered a trip of the A main feedwater pump.

Prior to the secondary operator carrying out the order, the reactor tripped on steam generator low level.

The failure method of the main feedwater pump had produced a heatup and increase of pressure of the reactor coolant system. The steam bypass control system was activated by the transient causing several of the valves to cycle providing a heat sink. This additional steam load during the transient increased plant cooldown and depressurization actuating safety injection.

The assistant shift supervisor, who was the control room supervisor, directed the crew through their post trip actions which were contained in safety function flowcharts. The crew then entered procedure 43EP-3R001, Reactor Trip, and recovered the plant from existing safety injection, containment isolation, and auxiliary feedwater system actuations.

A Notification of Unusual Event was declared by the Unit 3 shift supervisor due to the safety injection. The event classification was terminated after safety injection throttle criteria were verified as satisfactory according to the emergency procedures and the high and low pressure safety injection pumps were overridden and secured.

The following is a summary of the results of the analysis of the human factors in this event.

Operator Response

Licensee personnel performed well during this event. They quickly diagnosed the problem, made a decision to trip the feedwater pump, and initiated recovery actions. Supervision had empowered the secondary operator with authority to trip the feedwater pump, if a condensate pump was lost. Had that authority included the feedwater pump condition experienced in this event, the plant may have been recovered without a reactor trip.

Operating Procedures

The crew implemented recently reformatted emergency operating procedures that had been in place for about 6 months. When returning the electrical distribution system to normal, operator knowledge of the normal operating procedures was required to supplement missing information in the emergency procedures. Procedures directed operators to shutdown the running main feedwater pump and use essential auxiliary feedwater pumps. An enhancement, suggested previously by a Unit 2 operator, to include using the main feedwater pump, if running, had not been incorporated into the new procedures.

Procedural direction to take "manual control" of systems, such as pressurizer spray, which are not malfunctioning, should be closely evaluated under all situations for each operator. Alternate methods to manual control, if available, should be used (e.g. using control board recorders for identifying valve cycles). Manual control was also taken of the feedwater downcomer valves to restore steam generator levels from the reactor trip override condition of 40% to 72%. These actions were not addressed in the emergency procedures and were primarily knowledge-based. An incorrect decision, as to which feedwater downcomer valve was malfunctioning, was made based on downcomer flow indication and SG level trends. This decision did not impact the recovery and was later diagnosed by the crew to be in error.

After running unloaded for four and one-half hours, shutdown of the emergency diesels was finally accomplished only near the end of the reactor trip procedure.

Command, Control and Communications

There were several factors associated with the command, control and communication. The shift supervisor and assistant shift supervisor worked together, normally on another crew, and on this day were working with operators who had been together as a crew for one month. The practice of keeping supervisory teams intact, when possible, seemed to be a positive influence. Also, the shift supervisor purposefully exerted extra effort for

clear communication, which he felt was necessary for good performance of a crew which had very little time working together as a team. The reactor operators contributed to good communications by repeating instructions.

As the number of people in the control room increased, the shift supervisor demonstrated proper command and control by asking these personnel to move to the satellite technical support facility to lower noise levels and minimize control board operator distractions. In addition, the shift supervisor stationed himself in the control room in a manner that provided him a good overview, out of the operators way, but yet made him readily available to the crew.

The shift technical advisor provided backup by reminding the crew of a procedural action to energize source nuclear instruments, mentioned early in the procedure, but accomplished an hour later when plant conditions were satisfied. He also conducted an independent assessment to verify the shift supervisor's classification of the event.

Training

All operators interviewed at Palo Verde Nuclear Generating Station had previous work experience at other commercial nuclear facilities or Navy nuclear experience. Combined crew experience and training was judged to be above industry norm and a contributing factor to successful crew performance.

License simulator training had scenarios involving a main feedwater pump trip. However, this event, involving the loss of feedwater flow without a pump trip, required the operators to diagnosis conditions not previously seen in the training sessions.

Shift Staffing

Staffing was more than adequate in this event, given the relief and dayshift personnel available at 3:00 pm on a normal work day, who volunteered to help. The third reactor operator on shift was particularly noteworthy,

since the extra operator allowed the two control board operators to address their safety function flowcharts in the event without diverting attention to backpanels and alarms.

Stress

During the recovery phase, additional personnel in the control room were a source of reported stress to the control room operators. Increased noise levels and personnel entering the control area to gather information from control board recorders added to the existing stress of the operators.

Human Machine Interface

The control room CRT trend display was considerably behind actual plant conditions and may have mislead an operator to believe more time was available before protection setpoints were reached. CRT trend displays available to the operators are only useful during steady state conditions or relatively slow transients, due to existing update times for these systems.

Auxiliary feedwater flow recorders were not available, to provide historical information to the operators, for determining if flow had been present during the event. Safety injection flow, like auxiliary feedwater flow, does not have a recorder to readily identify the amount of water injected into the reactor coolant system during an safety injection actuation for post event analysis.

With its audible alarm intentionally disabled, the RJ computer alarm system relied entirely on operator awareness through visual detection thereby reducing its effectiveness. However, in this event, it would have not made a difference considering the dynamics of the plant and subsequent audible annunciator alarms.

ACKNOWLEDGEMENTS

We express appreciation to the Palo Verde staff for their cooperation for freely providing information necessary to analyze the human factors of the operating event. We particularly thank the facility Incident Investigation Team for their cooperation and for responding so promptly to our requests for information and for making arrangements for and scheduling the requested interviews. We want to thank the Unit 3 operators and technical staff who were on duty during the event for their cooperation during the interviews. Also, we wish to extend our thanks to Susan Hill, who participated in the technical review process.

CONTENTS

ACRONYMS

AEOD	Analysis and Evaluation of Operational Data
AFAS	Auxiliary Feedwater Actuation Signal
CIAS	Containment Isolation Actuation Signal
CRS	Control Room Supervisor
DSP	Division of Safety Programs
ESFAS	Engineered Safety Function Actuation System
EOP	Emergency Operating Procedures
INEL	Idaho National Engineering Laboratory
MFWPT	Main Feedwater Pump Turbine
NRR	Nuclear Reactor Regulation
NRC	Nuclear Regulatory Commission
NUE	Notification of Unusual Event
PVNGS	Palo Verde Nuclear Generating Station
RCS	Reactor Coolant System
RJ	Plant Computer Alarm System
RK	Main Control Board Alarm System
RMS	Radiation Monitoring System
RO	Reactor Operator
ROAB	Reactor Operations Analysis Branch
RPM	Revolutions Per Minute
SBCS	Steam Bypass Control System
SESS	Safety Equipment Status System
SEIS	Safety Equipment Inoperable Status
SEAS	Safety Equipment Actuation Status
SIAS	Safety Injection Actuation Signal
SS	Shift Supervisor
STA	Shift Technical Advisor
TSC	Technical Support Center

1. INTRODUCTION

1.1 Purpose

The Office for Analysis and Evaluation of Operational Data (AEOD) of the U.S. Nuclear Regulatory Commission (NRC) has a program to study human performance during operating events. As part of this program, AEOD formed a team to conduct an onsite analysis of an event that occurred at the Palo Verde nuclear generating station during the day shift on February 4, 1993. Unit 3 had been operating at 100% power, when a control problem developed on the A main feedwater pump decreasing the speed to the point where it no longer was producing flow. Control room operators were alerted to the abnormal condition by A main feedwater pump high vibration annunciator. Steam generator levels decreased rapidly with the reduction in feedwater flow. The operators had identified the need to reduce reactor power and to trip the A main feedwater pump to initiate an automatic reactor power cutback, just before the reactor automatically tripped on low steam generator levels. Auxiliary Feedwater actuation signals 1 and 2 were received 2 seconds after the reactor trip. Forty seconds later, a safety injection and containment isolation actuation occurred as a result of the reactor coolant system cooldown and depressurization. Emergency procedures were implemented by the control room operators to return the plant to a stable condition. The station emergency plan was implemented by the Unit 3 shift supervisor at the Notification of Unusual Event level.

1.2 Scope

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

1.3 Onsite Analysis Team

The onsite analysis team was at the site February 9-10, 1993 and was composed of the following members:

Jose Ibarra, NRC/AEOD/DSP/ROAB (team leader)
Robert Spence, NRC/AEOD/DSP/ROAB
William Steinke, INEL/EG&G Idaho, Inc.

2. DESCRIPTION OF THE EVENT ANALYSIS

2.1 Background

The Palo Verde Nuclear Generating Station, located in western Arizona, is owned and operated by Arizona Public Service Company. The three, nearly identical, pressurized water reactors, are rated at 3800 MW-thermal each, with Combustion Engineering nuclear steam supply systems and dry containment buildings. The units are operated from individual control rooms. Units 1 and 2 have been in operation since 1986 and Unit 3 since 1988.

On February 4, 1993, Unit 3 was operating at 100% power. A mixed crew was on shift. The shift supervisor and assistant shift supervisor, who was the control room supervisor (CRS), were filling in for the normal SS and CRS who were attending a training workshop. The three regular control room operators for crew D were on duty for their first twelve hour shift (6:00 am to 6:00 pm) of a four-day rotation. Normal shift manning consisted of a shift supervisor (SS), assistant shift supervisor, and three reactor operators (ROs). The ROs were designated as primary, secondary and backboard operator (see figure 1). A shift technical advisor (STA) was assigned to the unit on a 24 hour shift. Both the SS and the STA have adjacent offices in the back of the control room with windows permitting a view of the control panels. The CRS was in the SS office when the first audible alarm was received.

Two alarms for the A main feedwater pump were received on the computer alarm CRT at 3:22:48 and 3:22:49 pm. No audible alarm accompanied the visual CRT messages. At 3:22:52 pm, a high vibration annunciator alarmed for the A Main Feedwater Pump Turbine (MFWPT). The secondary operator responded to the alarm and went to control board panel BO-6 where he observed the speed of the A main feed pump decreasing rapidly on the control board digital indication. The pump, which normally operates at 4500 rpm for full power conditions, was at approximately 1500 rpm and decreasing. He also noted that the computer alarm CRT indicated "BYP VLV OPEN PERM" for all eight steam bypass valves, in addition to the feedwater pump alarms. Instrument technicians had been working on the steam bypass control system (SBCS) during the shift and had

actuated alarms in the process. The secondary operator hesitated momentarily deciding the alarms were not related to the maintenance activities. This time the SBCS permissive alarms were due to increasing reactor coolant system pressure resulting from decreasing feedwater flow. Directing his attention to the feedwater system parameters, the secondary operator observed steam generator (SG) levels decreasing rapidly from a normal level of 75%. Feedwater flow to the SGs had decreased significantly with one running feedwater pump capable of only producing about 65% of required full power feedwater flow.

The primary operator checked for a reactor power cutback which would have been initiated by a MFWPT trip. A reactor power cutback reduces primary power to a range where flow from one feedwater pump is sufficient. Reactor power was at 100% with no reactor power cutback in progress. The primary operator then made a hand signal through the windows of the SS office to alert the SS and the CRS of the problem. The CRS obtained the abnormal procedure for the feedwater system. The SS immediately went to panel BO-6, main feedwater section, to assess the condition of the plant. Now numerous alarms were actuating, including low levels on the SGs and low suction pressure on the B MFWPT. The secondary operator recommended tripping the A MFWPT to the SS to initiate a reactor cutback. The SS authorizated the secondary operator to trip the pump, but the MFWPT trip was not accomplished before automatic reactor protection occurred. The reactor tripped on low SG #2 level of 44.2% wide range at 3:23:53 pm (65 sec after the first indication of a problem). An auxiliary feedwater system actuation 1 and 2 signals (AFAS 1 and 2) followed immediately. The secondary operator completed the manual trip of A MFWPT 7 seconds later.

The CRS entered his safety function flowchart. He directed the primary and secondary operators to their respective safety function flowcharts. These flowcharts contain post trip actions each reactor operator must perform and communicate the results of to the CRS. Placards, displaying primary and secondary operator safety functions flowcharts, are mounted on the control boards. The CRS flowchart has high level action steps for verifying all safety functions are satisfied and a diagnostic logic tree for procedure

selection. The STA, hearing the multiple alarms and seeing the control element assembly bottom lights lit from his office, entered the control area and began reviewing plant conditions using his safety function flowchart. The STA safety function flowchart serves as a backup to the CRS's flowchart. Procedurally, the STA independently performs this verification/diagnostic three times.

By 3:24:34 pm, reactor coolant system temperature had decreased to about 550°F and pressurizer pressure decreased to 1837 psia as a result of the cycling of SBCS valves and feedwater induced cooldown. A safety injection actuation signal (SIAS) and containment isolation actuation signal (CIAS) were received and the safety equipment status system (SESS) alarmed. The backboard operator directed a relief reactor operator to acknowledge the alarms on the SESS panel and follow up on the abnormal indications.

The purpose of the SESS panel is to alert the operators when any automatically actuated engineered safety function equipment is bypassed or rendered inoperable. The panel has two categories of indications. White lights indicate inoperable or bypassed equipment, called the safety equipment inoperable status (SEIS) indication. The safety equipment actuation status (SEAS) indications are blue lights that indicate safety equipment that did not transfer to the required position following an actuation signal. Four components were in alarm after the time required to achieve their correct state:

- White lights were lit for hydrogen containment isolation valve HPB-UV-4 and auxiliary feedwater supply from the essential motor-driven pump to SG 1, HPB-HV-30, indicating inoperable status.
- Blue lights were lit for control room ventilation dampers MO2/MO3 and SG 1 blowdown sample isolation valve, SG-UV-211, indicating incorrect position.

Pressurizer level had decreased below the pressurizer heater cutoff point of 25% to about 18% following the reactor trip and the primary operator had started B charging pump to restore level in accordance with his safety

function flowchart. The primary operator secured the 1B and 2B reactor coolant pumps, as directed by the primary operator safety flowchart, for a safety injection actuation in progress. When the secondary operator reached the section of his safety function flowchart directing checking him to check SG levels and flow, all eight auxiliary feedwater valves were closed. Blue lights were also lit on the SEAS panel for the eight valves, indicating they were closed and providing no auxiliary feedwater flow to the SGs at that time. The secondary operator reported this condition to the CRS. SG levels had recovered to approximately 40% wide range, the controlling setpoint for the system following a reactor trip and AFAS. SG 1 level at that time was slightly higher than SG 2 level. The B MFWPT was still running at minimum speed. The CRS and secondary discussed the option of using it to feed the SGs if needed, although the emergency procedure did not address its use.

The backboard operator assisted the primary and secondary operators by maintaining "alarms silenced," informing each operator verbally of annunciators as they alarmed. He also checked the radiation monitoring mini-computer for any alarming channels, as required by the secondary operator safety function flowchart. The RMS mini-computer was subsequently lost several minutes after the reactor trip. With no effluent radiation monitor values available in the control room, the backboard operator contacted the effluents operator by phone to check locally each radiation channel identified on the secondary operator safety flowchart for abnormalities.

The CRS completed his safety function flowchart and directed the control board operators to enter procedure 43EP-3R001, Reactor Trip. The relief operator informed the CRS that auxiliary feedwater valve AFB-HV-30 had both white and blue lights on the SESS panel, indicating that the valve was not only inoperable, but also out of the required position. CRS informed the SS of the condition of auxiliary feedwater valve AFB-HV-30 and essential feedwater pump, AFB-P01. Both were declared inoperable by the SS, in accordance with technical specification, at 3:37 pm. After the secondary operator completed his safety function flowchart, he informed the CRS of his concerns with SG 2 level, which was decreasing and indicating 35% wide range, while SG 1 was still increasing above 40% wide range. At 3:39 pm, the CRS

instructed the secondary operator to take manual control of the SG 2 downcomer valve and continue feeding to the desired trip recovery level of 72%.

The SS declared a Notification of Unusual Event (NUE) at 3:46 pm due to a reactor trip with actuation of SIAS/CIAS. After making the initial classification of the event, emergency coordinator duties were transferred to another SS who had arrived in the control room shortly after the reactor trip. As emergency coordinator, the second SS then began the required notifications. The STA had completed his safety function flowchart and concurred with the classification made by the first SS. The NRC was notified of the NUE at 3:50 pm. The unit 1 STA came to the Unit 3 control room and assisted a relief reactor operator in making notifications.

Throttle criteria to terminate safety injection flow were verified satisfactory at 3:51 pm. The primary operator then overrode high pressure safety injection (HPSI) and low pressure injection (LPSI) by securing the pumps per step 5.31 of emergency procedure 43EP-3R001 and closing low pressure injection valves. The primary operator subsequently monitored the reinitiation parameters on a one to two minute interval.

Shutdown and stabilization of the plant continued with the following minor problems:

- SG 1 level continued to increase above 80% narrow range indication, with the downcomer valve indicated closed. At 4:01 pm, the downcomer control valve was taken to manual and verified as closed, but SG 1 level continued to increase. The secondary operator, with authorization from the CRS, had the manual isolation valves for the downcomer control valve closed locally and SG 1 level stabilized.

- While the primary operator was restoring letdown flow in procedure 43EP-3E001 Appendix N, Resetting Containment Isolation Actuation Signal and Equipment Restoration, the letdown control valve CHN-LV-110P did not indicate closed when the controller was taken to manual with zero output. A local verification was done. The report to the

control room was that the valve appeared to be closed. Letdown containment isolation valves were opened and 20 to 30 gpm flowed through valve CHN-LV-110P, which still indicated closed. During this delay in reestablishing letdown, pressurizer level increased causing charging pump A to automatically stop on level deviation.

- When the control room operators attempted to restore the switchyard 525 KV electrical lineup, the emergency procedures did not include resetting a protective 186 lockout relay associated with breaker PL-985 and PL-988. The crew used normal procedure guidance that directed them to reset the relay before closing the required breakers.

Letdown flow was restored at 4:31 pm and maximized to lower pressurizer level following the problems noted with letdown valve CHN-LV-110P. At 4:47 pm, the primary operator placed pressurizer spray control in manual, in accordance with emergency procedure 43EP-3R001 Appendix A. Spray actuation data, attachment A-1 to appendix A, was maintained by the primary operator to log spray valve cycling.

Operators continued to reestablish normal post trip conditions for Unit 3. After the safety injection systems had been overridden, the NUE classification was terminated at 5:00 pm. Procedure 43EP-3E001 Appendix M, Resetting Safety Injection Actuation Signal and Equipment Restoration, was entered and SIAS/CIAS signals were reset at 6:00 pm. Diesel generators A and B, which had started on the SIAS and never loaded, were stopped at 8:05 pm and 8:10 pm, respectively.

Post trip maintenance activities did not identify any faulted component or circuitry problem that would have led to the speed control problem for the main feedwater pump. The pump performed normally on subsequent testing during a unit restart.

2.2 Time Line of the Event

The following event time line sequence was developed from interviews with the on-duty shift personnel and technical staff, copies of the control room logs, and plant computer printouts.

TIME	EVENTS
3:22:48 pm	FWPT A 1ST STG PRESS computer alarmed on CRT (no audible)
3:22:49 pm	FP TURB (A) STEAM FLOW computer alarmed on CRT (no audible)
3:22:52 pm	FWPT A HP BRG VIB - control board annunciator alarmed with audible alarm. Secondary operator responded. The alarm cleared immediately after alarming.
3:22:57 pm	STEAM BYPASS OPEN PERMISSIVE - alarmed on annunciator panel and CRT, due to to increased pressurizer pressure (2300 psia), as result of decreased feed flow. RCS heatup (Tave increased about 5°F from 590°F to 595°F), as SG levels decreased.
3:23:30 pm	(time approx.) CRS and SS entered control area to assess plant conditions. Discussed possibility of recovering feedwater pump or initiating a reactor cutback, either manually by the primary operator, or automatically, by tripping pump.
3:23:52 pm	(time approx.) SS authorized tripping MFWPT A.
3:23:53 pm	LO SG 2 LEVEL REACTOR TRIP annunciator alarmed.
3:23:54 pm	LO SG 2 LEVEL AFAS 2 and LO SG 1 LEVEL AFAS 1 annunciators alarmed.
3:23:55 pm	STEAM BYPASS GP X QUICK OPEN and STEAM BYP VALVES 1,3,4,6 POS N-CLSD annunciators alarmed on the control board.
3:24:01 pm	FWPT A tripped by the secondary operator. The CRS entered his safety function flowchart and instructed primary and secondary operators to initiate their respective safety function flowcharts.

3:24:34 pm	SIAS/CIAS actuations initiated HPSI flow into the RCS. Alarms received on the SESS panel for ESF components. Backboard operator assigned relief operator to respond to the SESS alarms.
3:34 pm	RMS mini-computer was lost. Effluents operator was directed to evaluate the RMS system locally, to verify required items on secondary operator's safety function flowchart.
3:37 pm	SESS panel indicated auxiliary feedwater valve AFB-HV-30 not functioning correctly and was declared inoperable. "B" essential auxiliary feedwater pump was also declared inoperable, per technical specifications.
3:39 pm	CRS and secondary operator discussed indications on SG flow and level trend. SG 2 level had decreased to 35% wide range. SG 1 level was increasing (40 - 50%). SG 2 downcomer valve was taken to manual to feed SG 2 to 72%.
3:46 pm	SS declared a Notification of Unusual Event. Emergency Coordinator duties were immediately transferred to another qualified SS present in the control room who began notifications. STA contacted the Unit 1 STA who came to Unit 3 control room and assisted in notifications.
3:50 pm	NRC was notified of NUE.
3:51 pm	High and low pressure safety injection were overridden. Pumps were shutdown and low pressure safety injection valves closed.
4:01 pm	SG 1 level continued to rise and downcomer valve was taken to manual control by secondary operator to stabilize level. Level continued to increase with the downcomer control valve closed. Downcomer manual isolations were closed and level stabilized.
4:31 pm	After some difficulty with letdown valve CHN-LV-110P, letdown was restored.
4:47 pm	Pressurizer spray control was transferred to manual
4:50 pm	Electrical lineup was restored (Ring Bus)
5:00 pm	NUE classification was terminated.

6:00 pm	SIAS/CIAS was reset, with procedure 43EP-3E001 appendices M and N.
8:05 pm	Diesel generator A shutdown, using procedure 43EP-3E001 appendix M.
8:10 pm	Diesel generator B shutdown, using procedure 43EP-3E001 appendix M.

2.3 Analysis

2.3.1 Operators Response

Licensee personnel performed well during this event. They quickly diagnosed the problem, made a decision to trip the feedwater pump, and initiated recovery actions. When control board indication was incorrect or unavailable, the operators properly used backup indication.

In an attempt to avoid a reactor trip, prior to the automatic reactor trip, the operators had initiated action to reduce reactor power. The path of action chosen by the crew was the expected or designed response for the loss of flow from a main feedwater pump at full power. The action would not have precluded an automatic reactor trip due to the time required for assessment and supervisory personnel to get to the control boards. Supervision had empowered the secondary operator with authority to trip the feedwater pump, if a condensate pump was lost. If that authority had also included the feedwater pump condition experienced in this event, the plant may have recovered without a reactor trip.

2.3.2 Operations Procedures

The crew entered and properly implemented a revision of emergency operating procedures that had been issued 6 months before the event. Flowcharts in the new procedures were used by the CRS, primary and secondary operators with no difficulty. The flowcharts were displayed on control board

placards for the primary and secondary operators to refer to as needed. According to operator interviews, the new procedures seemed to be an improvement over the previous method, which required the operators to record more data. Place-keeping spaces had been provided adjacent to each step number in the procedure, to check or initial.

There were several difficulties with the emergency procedures during the recovery. Restoring the electrical system to a normal lineup by "re-ringing the bus" was one example of operator knowledge of the normal operating procedures supplementing missing information in the emergency procedures. In another case, operators felt some frustration with emergency procedures that did not recognize the possibility that alternate equipment might be available. For example, the MFWPT B was running at minimum speed during the event and available to feed the SGs. However, procedures directed operators to shutdown the running MFWPT and use essential auxiliary feedwater pumps. A previously suggested enhancement from a unit 2 operator to include using the MFWPT, if running, had not been incorporated into the new procedures. Four reactor trips have occurred since implementation of the new emergency operating procedures.

Procedure 43EP-3R001 appendix A, Reactor Trip Primary Operator Actions step 3.15, directs taking pressurizer spray to manual control during the event if any reactor coolant pumps are stopped. Excessive task workload on the primary operator during this event was not a factor as a backboard operator and a relief operator were present to assist in recovery actions. Procedure direction to take "manual control" of systems which are functioning properly in emergency procedures should be closely evaluated under all situations for each operator to ensure manual control does not result in excessive task or mental workload. Alternate methods for monitoring cycles of the spray valves are available (e.g., control board recorders).

Operators took manual control of a feedwater downcomer control valve to restore SG level from the reactor trip override condition of 40% to 72%. This action was not specified in the EP and was primarily knowledge-based. Discussions had taken place regarding use of the MFWPT with procedures that

addressed only the use of auxiliary feedwater pumps. Plant conditions, with an AFAS and subsequent SIAS, produced confusion on the status of the auxiliary feedwater valves (SESS) and response of the main feedwater downcomer valves. Operators misinterpreted the response of the downcomer valves and downcomer flow indication. With RCS temperature at 550 degrees and a reactor trip override present, the SG 2 level was responding correctly and SG 1 had erroneous indication. Knowledge-based reasoning in this case led to an incorrect conclusion as to which downcomer valve was malfunctioning. This decision did not impact the recovery and was later determined by the crew to be in error.

During the interviews, operators noted that the current set of procedures were more comprehensive but took longer to complete. In this event, the reactor trip procedure, 43EP-3R001, was the controlling procedure. Completion of steps within the reactor trip procedure required completing specific appendices of Emergency Operation Procedure 43EP-3E001.

Shutdown of the emergency diesel generators was stated two ways in section 5.0 "Plant Stabilization" and section 6.0 "Procedure Exit" in the controlling procedure:

Step 5.31 <u>IF</u> the safety signal reset criteria are satisfied, <u>THEN</u> direct an operator to reset the safety signals and restore equipment to standby as needed for plant conditions.

With an SIAS signal present, the detailed instruction then directs the operator to complete Procedure 43EP-3E001, Appendix M, where the emergency diesel generator shutdown is addressed in section 4.

Step 6.1 <u>IF</u> the diesels are running, <u>AND</u> are <u>NOT</u> required to supply the following buses: .... <u>THEN</u> shut down <u>any</u> unloaded diesel generator.

After running unloaded for four and one-half hours, the emergency diesel generators were shutdown in accordance with step 5.31.

The unloaded running of the emergency diesel generators for long periods could be eliminated by stating the information in step 6.1 earlier in the controlling procedure.

2.3.3 Command, Control and Communications

There were several observations associated with the command, control and communication. The SS and CRS worked together, normally with another crew, but on the day of the event, were working with operators who had been together as a crew for only one month. Keeping SS and CRS teams intact, when possible, seemed to be a positive influence. At the onset, the SS and CRS were quickly notified of the problem by the control room operators and involved in the assessment of the situation. The nature of the problem, coupled with existing plant conditions, provided much less than one minute for discussion of contingency actions. Effective teamwork between the SS and CRS allowed assessment and decision-making to occur, leading to a decision to trip the MFWPT A. Command and control was effectively shifted from the SS to CRS. The SS initially went to the control board panels and took charge until the CRS could obtain the correct procedure. Then the CRS assumed command and control of operator actions as he directed them in responding to the reactor trip and subsequent SIAS/CIAS.

Dayshift plant staff personnel responded to the control room immediately following the reactor trip. As the number of people increased, the SS demonstrated proper command and control by asking any unnecessary personnel to move to the satellite technical support facility to lower noise levels and minimize control board operator distractions. In addition, the SS stationed himself in the control room in a manner making him readily available to the crew.

The decision to transfer the emergency coordinator duties to an available qualified person enhanced the oversight capability of the SS, allowing him to concentrate on procedure and equipment problems during the recovery. Other plant management and maintenance personnel were readily available to the SS for supporting recovery efforts.

Operators reported that communications were good during the course of the event; they used repeat backs to ensure directions and information were exchanged correctly. The shift supervisor purposefully exerted extra effort for clear communication, which he felt was necessary for good performance of a crew which had very little time working together as a team.

The STA reminded the crew of a procedural action to energize source range nuclear instruments, mentioned early in the procedure, but accomplished an hour later when necessary and prerequisite plant conditions were satisfied. He also independently verified the SS's classification of the event.

A training course that had included the topic of command and control, had been conducted by a consultant for operations personnel. During interviews, supervisory personnel stated that this course had been very helpful in improving their command and control.

2.3.4 Training

All operators interviewed at PVNG had previous work experience at other commercial nuclear facilities or the Navy Nuclear program. Crew experience was judged to be above the industry norm and a contributing factor to the crew performance.

The operators acknowledged the usefulness of the licensee's simulator training. Operating crews had been trained with scenarios involving a trip of the main feedwater pump. However, this event required the operators to diagnose conditions from a feedwater flow loss without a feedwater pump trip, which they had not previously seen in training sessions. The plant dynamics provided limited time for investigation, analysis, and decision-making. The crew demonstrated the ability to arrive at a reasonable decision of tripping the feedwater pump to initiate an automatic reactor power cutback and avoid a challenge to the reactor protection system.

Training on the emergency procedure network appeared to have been sufficient. The procedures were used effectively to restore plant conditions

following the event. HPSI and LPSI systems were overridden in accordance with procedures and reinitiation criteria were monitored closely by the primary operator. The new EOPs and flowcharts had been used during simulator training sessions, to establish crew proficiency prior to procedure issuance. A positive aspect of operator response during the plant recovery was their systematic handling of equipment problems, which they attributed to their training program. Training included situations in which the operators were intentionally misdirected by spurious information (e.g., SESS indications vs local indications), forcing verification, use of alternate methods, or rediagnosis, while using the procedure network.

2.3.5 Shift Staffing

Staffing was more than adequate in this event, given the relief and dayshift personnel available at 3:00 pm on a normal work day, who volunteered to help. The third reactor operator on shift was particularly noteworthy, since the extra operator allowed the two control board operators to address their safety function flowcharts during the event without diverting attention to backpanels and alarms. Also, an administrative aide on shift was available to notify offsite agencies and assist the emergency coordinator in emergency plan activities. A dedicated STA for each of the three units also provided an additional resources.

2.3.6 Stress

During the recovery phase, dayshift personnel responding to the control room increased the noise level and were a source of reported stress to the control room operators. Additional personnel entered the control area to gather information from control board recorders. While this information gathering did not prevent control board operators from performing their functions, it added to overall reported stress levels during recovery. If such information is available in other locations, personnel should be directed to these other resources, to minimize traffic and conversation in the control area.

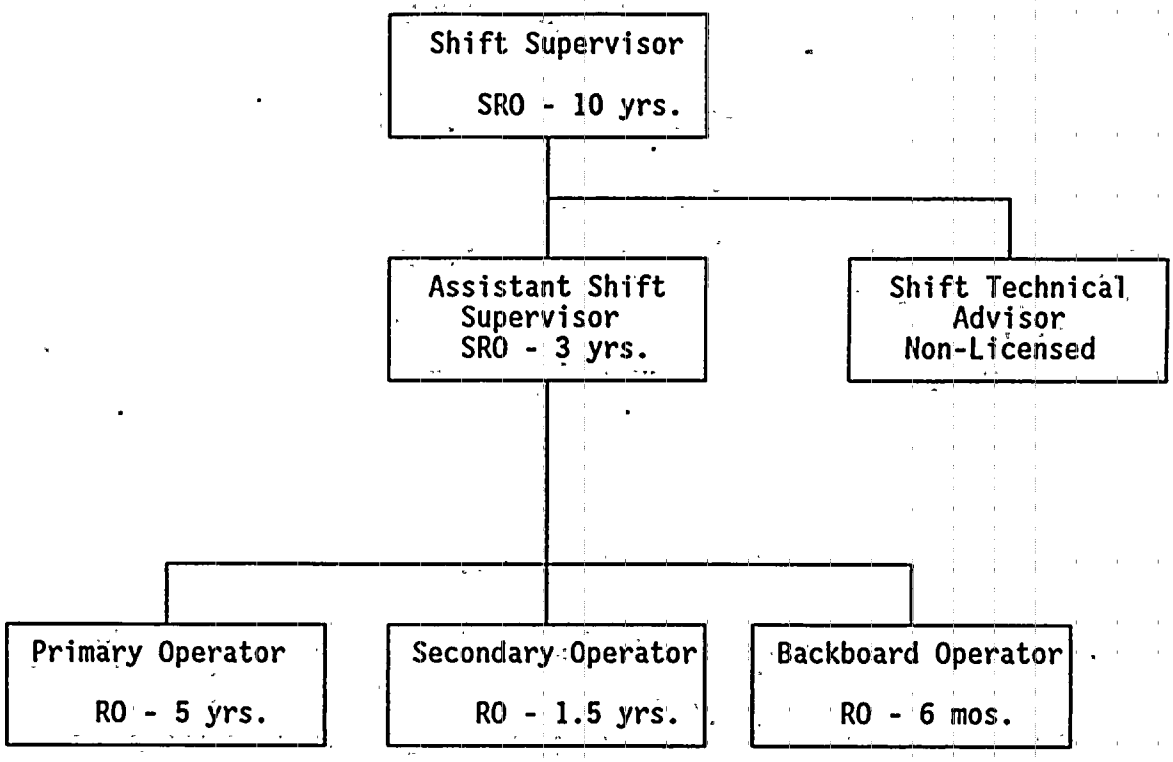
The operators indicated that the time of day and shift rotation did not have a significant effect on their stress level or performance. They were working their first day of dayshift after several days off.

2.3.7 Human Machine Interface

In this event, SG level trend on the control room CRT considerably lagged behind actual plant conditions and may have mislead an operator to believe more time was available before SG levels reached protection setpoints. CRT displays available to the operators are useful only during steady state conditions or relatively slow transients due to existing update times for these systems.

Auxiliary feedwater system status was questioned several times during the event. When operators were directed by procedure to monitor for adequate auxiliary feedwater flow, recovery of the SG levels and the closure of the auxiliary feedwater valves. No auxiliary feedwater flow was indicated on control board meters. Auxiliary feedwater flow recorders were not installed to provide historical information or determine if flow had been present during the event. Safety injection flow, like auxiliary feedwater flow, does not have a recorder to readily identify the amount of water injected into the RCS during an SIAS actuation for post event analysis.

Maintaining audible computer alarm capability under steady-state conditions would help ensure the operators are aware of abnormal conditions as they occur. Other plants maintain this capability, yet allow the operators to disable the audible alarm when alarm frequency becomes distracting. Two RJ computer alarm system points alarmed prior to the RK control board annunciator alarm that alerted the secondary operator. With its audible alarm intentionally disabled, the RJ computer alarm system relied entirely on operator awareness through visual detection which reduced the computer's effectiveness. However, in this event, it would have not made a difference considering the dynamics of the plant and subsequent audible annunciator alarms.



Note 1: The Shift Supervisor and Assistant Shift Supervisor were crew members from another crew.

Note 2: Shift technical advisors work a 24 hour shift when on duty.

Note 3: The SRO and RO license periods are for PVNG and does not include any previous years of licensing.

Figure 1. Palo Verde Control Room Staffing.