ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Facility:	Palo Verde Nuclear Generating Station, Units 1, 2, and 3
Location:	5951 S. Wintersburg Road Tonopah, Arizona
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Inspectors:	K. Johnston, Senior Resident Inspector J. Kramer, Resident Inspector D. Garcia, Resident Inspector D. Carter, Resident Inspector D. Acker, Senior Project Engineer G. Good, Senior Emergency Preparedness Analyst
Approved By:	Dennis F. Kirsch, Chief, Reactor Projects Branch F

ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

Palo Verde Nuclear Generating Station, Units 1, 2, and 3
NRC Inspection Report 50-528/96-17; 50-529/96-17; 50-530/96-17

Operations

- Although the conduct of operations was generally professional and safety-conscious, inspectors identified issues in each unit involving failure to follow procedures. In Unit 1, known equipment problems and human performance errors contributed to the overflow of the spray pond hypochlorite tank. In Unit 2, operators did not initiate a manual safety equipment status system (SESS) alarm for inoperable emergency core cooling system (ECCS) equipment, which was an example of a violation of Technical Specification (TS) 6.8.1. In Unit 3, inadequate communications between operations and maintenance during the performance of a work activity contributed to the degraded condition of a charging pump, which was an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (Section O1.4).

- The licensee has established an effective program for assessing and correcting operator work arounds that have an impact on event response. Although the licensee corrected operator work arounds which had an impact on routine operations, and existing work arounds were not an undue burden to operators, their program did not assure that all work arounds were assessed for their cumulative impact (Section O2.1).

- The training for clearance process changes has been acceptable and the changes were properly communicated to operators. The licensee's plans for upcoming training were acceptable (Section O5.1).

- Three issues were identified where the operations crew involved in a performance weakness or error did not promptly initiate a condition report/disposition request (CRDR) to assure that the problems were identified to management in a timely manner for their consideration and resolution (Section O7.1).

Maintenance

- The licensee did not properly apply their work control process following their decision to install a temporary restraining device to reactor coolant pump (RCP) 2B shaft impeller. No written instructions were provided to the craft for installation and the work was not adequately documented on a clearance. These issues are examples of a violation of TS 6.8.1. The licensee's initial event evaluation was inadequate in that it did not recognize these weaknesses (Section M1.3).

- The licensee identified that maintenance personnel failed to contact operations, as instructed by a work order, to secure charging pump seal lubrication water. This was an example of a violation of 10 CFR Part 50, Appendix B, Criterion V (Section O1.4).

- Maintenance personnel did not adequately communicate with site management the status of emergent gas turbine generator (GTG) issues. As a result, site management was not provided the opportunity to factor these emergent issues into planned vital equipment outages (Section M3.1).

Engineering

- Workers installing a piping modification to the essential cooling water (EW) system did not ensure that the modification was installed according to design specifications, by verifying required tolerances for the distance of piping from pipe supports. This is an example of a violation of 10 CFR Part 50, Appendix B, Criterion V. In addition, workers installing the piping had not had all the required training in pipe installations (Section E1.1).

- The licensee was proactive in addressing problems with offsite power and keeping the staff informed. The inspectors also concluded that the licensee's administrative actions were acceptable to maintain offsite power operable. However, the inspectors concluded that Revision 2 of the Licensee Event Report (LER) and CRDR 9-6-0273 were incomplete, in that they did not address the root cause of the problem (Section E8.2).

Plant Support

- The process for performing onshift dose assessments was described in the emergency plan and implementing procedures (Section P3.1).

- An escort, visitor, and supervisor failed in their responsibilities to prevent an unescorted visitor from gaining unrestricted access to an area containing vital safety equipment, which was a violation of TS 6.8.1. The corrective actions performed by the licensee and contractor were thorough (Section S4.1).

Report Details

Summary of Plant Status

All units operated at essentially 100 percent power for the duration of the inspection period.

I. Operations

O1 Conduct of Operations (71707)

O1.1 Spray Pond Hypochlorite Tank Spill (Unit 1)

a. Inspection Scope

During a review of the Unit 1 unit log, the inspectors observed an entry, on November 14, 1996, describing an incident where the spray pond hypochlorite tank had overflowed, spilling hypochlorite out of its vent and into a berm surrounding the tank. The inspectors discussed the event with operations personnel and operations management.

b. Observations and Findings

A hypochlorite addition system was provided as part of the nonsafety-related chemistry control for the spray ponds. Each unit has a hypochlorite tank, two hypochlorite addition pumps, and supply lines to each spray pond. Hypochlorite is provided to all three units from the water reclamation facility. A level control valve is provided in each supply line from the water reclamation facility to control the level in the hypochlorite tanks.

The unit log entry of 10:20 p.m. on November 14 identified that an auxiliary operator (AO) had discovered that the hypochlorite tank was overfilling and had shut a manual isolation valve, which was in series with the level control valve. Operations initiated a work request to have the level control valve repaired.

The inspectors did further inspections of the system and determined the following:

- The level control valves had a history of leaking and system operating procedures required that the manual isolation be kept closed except during fill operations.
- The hypochlorite tank had a high level control room annunciator.
- The licensee had not initiated a CRDR to evaluate the November 14 event.
- There had been a history of both equipment problems and operator performance errors on the hypochlorite system.

The inspectors discussed these concerns with operations management and on December 2, a CRDR was initiated. The shift supervisor (SS) on shift during the spill event was contacted during the CRDR evaluation. He said that he had intended for a CRDR to have been initiated but had not ensured one was written. Further discussion on situations where a CRDR was not initiated in a timely manner is contained in Section O7.1.

At the end of the inspection period, the licensee had not determined when the manual isolation valve had been opened. They did determine that some crews were not aware of the hypochlorite operations procedure requirement to have the valve closed except while filling the tank.

In addition, the licensee determined that a local level indicator was out of service and had been since May 1996. AOs had been using level control valve position as an indication of tank level. Work on the level indicator had been canceled based on plans to abandon the automatic hypochlorite addition system. This modification, however, had not yet been implemented. Accordingly, the inspectors considered that the level indicator work cancellation decision was premature and not well coordinated. Operations management considered the use of the level control valve in lieu of level indication to be an operator work around that had not been previously identified. They used it as an example to operators of the type of problem that should be brought to management attention to assure prompt repair. Further discussion on operator work arounds is contained in Section O2.1.

Operations reviewed annunciator printouts and determined that there had not been a high tank level alarm. They subsequently determined that the alarm, which receives its input from the level control valve controller, was not functioning. This condition was subsequently repaired.

Operations discussed this event with the crew involved and distributed a night order to inform other crews. In addition, the level instrument and control room alarm were repaired. The licensee plans extensive modifications to the system, which would retire the hypochlorite pumps and tank.

O1.2 Control Room Observations (Unit 2)

a. Inspection Scope

On November 25, Unit 2 was performing a post accident sampling system surveillance. The inspectors were performing a routine walk down of the control boards and noticed an ECCS valve out of its normal position. The inspectors questioned operators, reviewed logs and observed the performance of operator actions.

b. Observations and Findings

The inspectors, while walking down the control boards, observed the licensee performing a post accident sampling system surveillance in accordance with Procedure 74ST-9SS03. During this surveillance the Train A low pressure safety injection pump was running on full flow recirculation to allow a sample to be taken. While in this condition the inspectors observed valve SIA-UV-660 (the combined miniflow recirculation valve from the ECCS pumps back to the refueling water tank) closed. The inspectors questioned the SS regarding the reason that a manual SESS alarm input was not initiated. The SS indicated that the A train of ECCS was declared inoperable and that a manual SESS input was not required.

The inspectors reviewed the Conduct of Shift Operations procedure which indicated that a manual SESS alarm was required. The inspectors discussed this with the SS who agreed with this conclusion. Subsequently, the inspectors polled other crews and supervisors and found that there was not a consistent understanding of the requirements. The ability to initiate a manual SESS was provided so that operators, in response to an event, would have a visual reminder of equipment status. Operator action would have been required to prevent ECCS pump damage in the event of a safety injection actuation signal with reactor coolant system (RCS) pressure above the ECCS pump discharge pressure.

The failure of the operations staff to initiate a manual SESS alarm, as required by procedure, was an example of a violation of TS 6.8.1 (Violation 50-529/96017-01).

The licensee issued a Night Order describing this occurrence and stated that operators should have inserted a manual SESS alarm. In addition, the licensee initiated an instruction change request to add a step to Procedure 74ST-9SS03, to have a manual SESS alarm input initiated when performing these sections of the procedure. The operations department planned to review the conduct of shift operations procedure for possible clarification and/or improved guidance on specific use of the manual SESS.

The licensee did not promptly initiate a CRDR to evaluate the implications of this occurrence. The licensee's program requires that a CRDR be initiated when it is identified that personnel failed to follow a procedure. Although, operations otherwise took appropriate corrective action in response to this issue, a CRDR would have been useful in establishing performance trends. A CRDR was subsequently written on December 23, recommending the above actions. See Section O7.1 for further discussion of instances where operations did not promptly initiate a CRDR.

O1.3 Water Intrusion in Charging Pump B (Unit 3)

a. Inspection Scope

The inspectors reviewed CRDR 3-6-0197 issued on November 15, 1996, describing the water intrusion to charging Pump B crankcase oil during a routine preventative maintenance task on charging Pump E on November 7. The inspectors also reviewed the evaluation performed by mechanical maintenance engineering.

b. Observations and Findings

In the past, the drain lines have become clogged, causing a backfill of water to flood the well (see NRC Inspection Report 50-528/95-16; 50-529/95-16; 50-530/95-16). The accumulated water in the well would drain directly into the pump crankcase through drainage holes in the oil baffle packing region. As part of the corrective action, a preventive maintenance task was initiated to perform a periodic flush of the drain lines.

On November 7, 1996, a maintenance team performed a routine drain line flush on charging pump E, in accordance with work order (WO) 0775357. There are three charging pumps, each with a well that drains to a common header leading to a charging pump oil drain tank. The well is located between the power block and the oil crankcase. The well drain collects both seal lubricating water leakage and oil leakage, and directs it to the tank for processing.

After maintenance completed the drain line flush of charging Pump E, and had not identified any problems, an AO identified that it appeared that the oil level in charging Pump B had increased and suspected that charging Pump B well drain had backed up with water. The SS initiated a work request to sample the oil in the pump crank case for possible water intrusion. Both charging Pumps B and E were placed in service. An oil sample was drawn sometime before noon on November 8.

On November 14, the oil sample revealed 27,000 ppm water in the charging Pump B oil. The acceptance criteria for water in the oil was 1000 ppm. On November 15, the mechanical maintenance engineer notified the control room and charging Pump B was declared inoperable. The oil was changed and the pump was returned to service. The mechanical maintenance engineer initiated CRDR 3-6-0197 to evaluate the event.

The inspectors reviewed the evaluation performed by the mechanical maintenance engineer. The following missed barriers were identified in the evaluation:

- WO 0775357 had a precaution for maintenance to contact operations to secure seal lube if one of the pumps has excessive seal lube leakage. On November 2, a work request was initiated for excessive seal lube leakage on

charging Pump B. The evaluation found that while operations was aware of the condition they were not informed of the WO precaution by maintenance and seal lube was not secured for this pump.

- WO 0775357 included a step for maintenance to stand by and observe the other two pumps to ensure that water did not back up into those drains. Maintenance subsequently observed that the plexiglass covers over the wells were difficult to see through due to condensation.

The inspectors observed that it had taken eight days to receive the results of the oil analysis and take action to change the oil in the pump. On November 7, operations had not informed the site shift manager or engineering of the situation and had not documented the event by either a log entry or a CRDR. The inspectors were concerned that operators had not promptly responded with sufficient urgency in light of the circumstances surrounding the increased oil level. The Unit 3 Unit Department Leader shared this concern and discussed it with operations personnel.

The licensee conservatively concluded that charging Pump B was inoperable, although it had operated satisfactorily for 8 days and showed no signs of wear. However, during this period, they maintained the TS minimum requirement of two operable charging pumps. In addition, the licensee concluded that this event should be tracked as a functional failure in accordance with 10 CFR 50.65. The inspectors determined that the failure to isolate seal lube water to charging Pump B was an example of a violation of 10 CFR Part 50, Appendix B, Criterion V, for failure to follow work instructions (Violation 50-530/96017-02). Although the violation was identified by the licensee, they missed an opportunity to promptly correct the condition. As a result, charging Pump B was in a degraded condition for 8 days.

O1.4 Conclusions on Conduct of Operations

Although the conduct of operations was generally professional and safety-conscious, inspectors identified issues in each unit involving failure to follow procedures. In Unit 1, known equipment problems and human performance errors contributed to the overflow of the spray pond hypochlorite tank. In Unit 2, operators did not initiate a manual SESS alarm for inoperable ECCS equipment. In Unit 3, inadequate communications between operations and maintenance during the performance of a work activity contributed to the degraded condition of a charging pump.

O2 Operational Status of Facilities and Equipment

O2.1 Operator Work Arounds

a. Inspection Scope (71707)

The inspectors reviewed the licensee's methods for addressing operator work arounds. In addition, the inspectors reviewed different operator aids found in the control room and discussed the observations with control room operators and licensee management.

b. Observations and Findings

The inspectors found that operator work arounds did not appear to have a significant impact on plant operators during routine operations and would not be expected to have a significant impact during a plant event. The licensee had developed a formal Procedure 79DP-9ZZ01 which required the shift technical advisors to perform a weekly review of plant conditions which could impact their response to an event. The resultant lists were submitted to operations management and work control to assure that the condition receives priority for repair. In addition, the lists were reviewed by the plant review board every month.

The inspectors found that there were a number of methods used to assure that operator work arounds, which did not impact event response, were promptly addressed. The control room deficiency log (CRDL) items, which included deficiencies with an impact on control room controls and annunciation, were addressed with high priority. In addition, other conditions identified as operator work arounds were added to the operations, engineering, and management concerns list, which were routinely discussed in the operations morning meeting.

The inspectors performed a review of "temporary notes" active in the Unit 3 control room. Temporary notes, controlled in operations Procedure 40DP-90P14, "Control of Operator Information Aids," were defined as supplementary information, of a temporary nature, concerning the operation or maintenance of plant systems, subsystems, or components. At the time of the inspector's review, there were 43 active temporary notes in Unit 3. The inspectors found that a significant number could be considered operator work arounds in that they represented deficiencies that complicated normal operation of plant equipment and were compensated for by operator action. Most of these had not been addressed in the programs used to highlight work around conditions.

Many of the conditions listed in the temporary notes were appropriately scheduled for repair during the next scheduled refueling outage, to begin in late February 1997. The remaining conditions appeared to be addressed in the work control process with sufficient priority. However, since the licensee had not included most of these items in their processes to identify operator work arounds, they had not

provided themselves the opportunity to assess the cumulative impact of the conditions on plant operators. The inspectors also found four notes for which the associated work had been completed and the condition no longer existed. This indicated a weakness in the process for removing the notes.

Based on discussions with the inspectors and independent review, licensee management initiated an evaluation of their program for assessing operator work arounds.

c. Conclusions

The licensee had established an effective program for assessing and correcting operator work arounds that have an impact on event response. Although, the licensee corrected operator work arounds which had an impact on routine operations, and existing work arounds were not an undue burden to operators, their program did not assure that all work arounds were assessed for their cumulative impact.

O3 Operations Procedures and Documentation

O3.1 Operations Shift Turnover

a. Inspection Scope (71707)

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) Section 18.I.C.2 and compared it to Procedure 40DP-9OP33, "Shift Turnover." UFSAR Section 18.I.C.2 documented the licensee's response to NUREG 0737 item requirements for shift relief and turnover procedures.

b. Observations and Findings

The inspectors found that the shift turnover procedure was consistent with UFSAR Section 18.I.C.2, with one exception. The UFSAR included a reference to a jumper/bypass checklist. Procedure 40DP-9OP33 did not have a specific check of jumpers or bypasses. The inspectors informed the licensee of the apparent discrepancy.

The licensee initiated a CRDR to evaluate the guidance provided in Procedure 40DP-90P33. The licensee found that most jumpers and bypasses would be reviewed as part of other portions of the shift turnover. For example, jumpers were used on the plant protection system parameters during modes of operation when aspects of the plant protection system were not required. These jumpers were documented in the technical specification component condition record and reviewed during shift turnover. Additionally, the licensee has periodically jumpered malfunctioning annunciator inputs. These jumpers have been documented as CRDL entries, with blue stickers placed near the annunciator window to indicate a

discrepancy. There was no explicit direction provided in the turnover checklist to review CRDLs, however, reactor operators were required to perform control board walkdowns, which includes control room annunciators.

The inspector concluded that the lack of an explicit step in the shift turnover procedure for the review of jumpers and bypasses was a minor deficiency and was being appropriately addressed through the licensee's corrective action program and other licensee administrative control methods.

O5 Operator Training and Qualification

O5.1 Clearance Process Training

a. Inspection Scope (71707)

The inspectors reviewed the licensee's clearance process and discussed the training aspects of the process with the training department personnel, licensed operators, and nonlicensed operators.

b. Observations and Findings

Plant operators indicated that their biggest challenge with the clearance process was that the program requirements were often changing. The inspectors discussed this concern with the clearance process owner. The process owner indicated that their evaluation of the program also identified that the numerous revisions to the clearance procedure have caused difficulties for the operators. As a result, only minor word clarifications were planned for the procedure revision prior to the Unit 3 outage in February 1997.

Training department personnel indicated that all operations department personnel were required to receive training on the clearance process during the training cycles. The licensee performed a clearance training session prior to the Unit 1 outage in the fall of 1996. However, the inspectors noted that although operators were tested on the clearance process early in 1996, they have not been tested on the revisions that have since been implemented to the clearance process.

Training department personnel indicated that previous clearance training highlighted only the changes in the clearance process. The training planned prior to the Unit 3 outage would include a comprehensive review of the entire clearance process to reinforce the fundamentals of the process and ensure that all operators have a clear understanding of the entire program, not just the recent changes.

To improve the quality of the recent clearance training, the licensee ensured that the clearance procedure and process owner was available to answer detailed questions about the procedure changes and to provide background as to why the changes were performed. In discussions with operators, the inspectors noted that operators

found the training more beneficial when the system or process expert was available to answer detailed questions beyond the normal expected knowledge of the instructor. In addition, operators indicated that the overall training received on the clearance changes was acceptable.

c. Conclusions

The training for clearance process changes has been acceptable and the changes were properly communicated to operators. The licensee's plans for upcoming training were acceptable.

O7 Quality Assurance in Operations

O7.1 CRDRs Not Promptly Initiated for Operations Issues

a. Observations and Findings

Sections O1.1, O1.2, and O1.3 of this report identify a common element involving CRDRs not being initiated in a timely manner; although CRDRs were eventually issued.

- Section O1.1 described a spray pond hypochlorite overflow event in Unit 1. In this event, where operator error and equipment problems were contributors, the SS had delegated CRDR initiation, but had failed to ensure his direction was accomplished.

- Section O1.2 described the failure of operators to input a manual SESS alarm for a condition which rendered a train of ECCS equipment inoperable. Although the licensee initiated corrective actions such as a procedure revision and a night order, they did not initiate a CRDR.

- Section O1.3 described an event where water inadvertently got into the crankcase oil of a charging pump. In this instance, operators waited for the results of the oil sample to initiate a CRDR, rather than at the time of the event.

The inspectors discussed these issues with the Director of Operations, who took action to discuss the threshold for initiating CRDRs with all crews and was evaluating the clarity of initiation criteria. The inspectors found that in 1996, the licensee initiated approximately 3000 CRDRs and, overall, did not identify any lowered sensitivity to initiating CRDRs. However, the inspectors were concerned that these, seemingly, isolated situations may indicate a negative trend in the thoroughness of problem identification and resolution.

b. Conclusions

Three issues were identified where the operations crew involved in a performance weakness or error did not promptly initiate a CRDR to assure that the problems were identified to management in a timely manner for their consideration and resolution.

O8 Miscellaneous Operations Issues

O8.1 TS Interpretations

The inspectors conducted a survey of the licensee's TS interpretations and determined that none of the documents contained informal references to NRC review and approval without formal NRC documentation. The inspectors emphasized to the licensee that any informal reference to NRC review and approval in a TS interpretation is not recognized by the Commission and is not an acceptable practice.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activities:

- WO 781258: test K227 relay and associated contacts for the essential chiller (Unit 3)
- WO 070666: shim emergency diesel generator (EDG) B fuel pumps for adjustment of firing pressure (Unit 1)
- WO 780386: reactor switchgear undervoltage and short trip circuit testing (Unit 2)

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks and demonstrated good communications between work groups.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance activities:

- 43OP-3DG01: EDG A
- 43ST-3CH03: Boron Injection Flowpaths Operating
- 70TI-9EC01: Essential Chilled Water (EC) System Flow Balance
- 43ST-3EC01: EC Valve Verification.

The inspectors found these surveillance were performed acceptably and as specified by applicable procedures.

M1.3 RCP Restraining Device Failure - Unit 1

a. Inspection Scope

On October 24, 1996, while Unit 1 was in Mode 5 after the completion of refueling, maintenance personnel installed a temporary device to prevent reverse rotation of the shaft of RCP 2B. After initial RCP sweeps, the device was found wrapped around the shaft of RCP 2B, clearly indicating that the impeller had rotated in the reverse direction during the start/stop cycles of the other RCPs. The inspectors observed the damage and the licensee's subsequent repairs. In addition, the inspectors evaluated the thoroughness and depth of the licensee's event investigation.

b. Observations and Findings

Event Description

On October 22, 1996, Unit 1 was in Mode 5 on shutdown cooling and operators were in the process of restoring the RCS for operations. Maintenance was in the process of testing RCP 2B motor, a refurbished motor installed to replace the existing motor, which was scheduled for refurbishing. During initial uncoupled motor testing, the motor was energized in reverse rotation due to an error in wiring. Although the motor antirotation device prevented the motor from turning backwards, the motor experienced a locked rotor condition for approximately 20 seconds. Maintenance subsequently performed testing on the motor to assure it had not been damaged.

Concurrently, as part of the RCS restoration, Operations planned to start RCPs for short runs to sweep the air from the steam generator tubes. However, the inspection and testing of RCP 2B motor had delayed the coupling of this motor to the impeller shaft. Since the motor has the antirotation device, without the motor coupled to the impeller shaft the impeller was free to spin in either direction. The

licensee planned to start RCPs 1A and 2A for pump sweeps, but was concerned that this would cause the impeller of RCP 2B to spin in reverse with no restraint. Mechanical maintenance engineering was requested to evaluate whether there was a means to temporarily restrain the shaft.

Mechanical maintenance engineering recalled that, in 1986, a tool, used to move the impeller shaft to line up the coupling to the motor, had been used to restrain an impeller so that its motor could be uncoupled while the other three pumps were running. This was documented in an engineering evaluation request (EER); a technical review process no longer used by the licensee. On the night shift of October 22, mechanical maintenance installed the device to temporarily restrain the shaft of RCP 2B.

The restraining device consisted of a U-shaped, 6 inch radius 5/8 inch thick plate, which had three 2 inch holes fitted perpendicularly with 3 inch lengths of stainless steel pipe. These were designed to fit over the impeller coupling bolts. The center of the U had a fitting for a 48 inch length of 1/2 inch schedule 80 stainless steel pipe. This shaft had a hole near its end used to pass the hooks for two chain falls. The two chain falls were directed horizontally and perpendicular to the restraint shaft. One chain fall was secured to a handrail and the other to scaffold used to support shielding.

Maintenance workers installed the restraining device as an add-on to RCP 2B motor installation WO 0756527. No work steps or instructions were provided for the installation of the restraining device. In addition, the 1986 EER, used as the basis for installing the restraining device, was not referenced by or attached to WO 0756527. The only documentation of the installation was in a work activities sheet attached to the WO following the maintenance, stating: "Install holdback on upper rigid coupling, tied come-a-longs to handrail and scaffold. Tied tool onto rigid [coupling] with tie wraps."

A maintenance engineer inspected RCP 2B after both RCPs 1A and 2A had been run. The shaft of the restraining device was found completely wrapped around the shaft of the RCP. The hooks for the chain falls were still secured to the shaft of the restraining device. Both the scaffold and the handrail had been deformed; drawn towards the shaft. One of the chain fall hooks was slightly deformed. The licensee's subsequent inspection of the shaft identified that only a RCP speed probe had been damaged.

On October 24, the licensee initiated CRDR 1-6-0269 to document the inspection, repairs, and event investigation. The CRDR was determined by the CRDR review committee to be "significant," requiring a root cause evaluation, and the evaluation was assigned to maintenance for review. Maintenance completed their review on November 25.

In their initial CRDR evaluation, mechanical maintenance engineering determined that there were substantial differences in the conditions for which the 1986 EER was initially used and its use during the Unit 1 outage. In 1986, the device was installed on an idle pump before the motor and impeller were decoupled. This ensured that the restraining device saw only a static load. During the Unit 1 outage, the restraining device experienced a dynamic load when other pumps were started to sweep the generators. Additionally, the licensee postulated that as air was swept from the steam generators, there could have been a substantial load change at the restraining device as the voids were collapsed.

Nuclear Assurance performed an evaluation, requested by the maintenance department, in accordance with their "Human Performance Evaluation System" program. The evaluation found that personnel did not use documents that fully evaluated current plant conditions when determining actions to be taken to restrain an RCP shaft from reverse rotation and that no policy was provided for guidance to personnel evaluating a course of action using engineering information evaluated for similar, yet different conditions.

Mechanical maintenance proposed corrective actions to determine the appropriate method for using previous engineering information for similar, yet different, conditions and to develop the basis necessary for installing the modification in the Fall, 1997, Unit 2 refueling outage.

Review of Initial Cause Evaluation

The inspectors reviewed the licensee's evaluation and found that, while it had addressed significant aspects regarding the lack of technical rigor, it failed to address the failure to implement processes and procedures for the control and documentation of work activities.

The licensee's evaluation included a discussion of the use of the WO process and concluded that no work instructions were necessary since the restraining device use was within the skill of the qualified worker. The inspectors found that the installation of the restraining device was not within the skill of the qualified worker in that there were several aspects of the job which required technical and procedural guidance. For example, the craft chose to restrain the device with rigging equipment secured to a handrail and to scaffolding. The inspectors noted that maintenance had not referenced the licensee's procedural requirements on the use of scaffolding to support rigging equipment. Additionally, the use of the handrail should have required a specific evaluation considering the load at the handrail, since handrails at Palo Verde have been typically designed to support a 200 pounds force.

The evaluation stated that RCP 2B was tagged out under Clearance 96-01325 at the time the restraining device was installed. The inspectors found that this was not accurate. The motor had been restored from this clearance on October 21 to

allow the uncoupled motor run and was not tagged out on this clearance until October 24. Additionally, Clearance 96-01325, the clearance initially specified for WO 0756527, applied only to the motor for RCP 2B. To provide adequate protection to the workers installing the restraining device, it would have been necessary to provide a clearance that tagged out all four RCP motors. The licensee's work control procedure, Procedure 30DP-9WP02, required that an expansion of the clearance boundary was an expansion of work scope requiring a WO amendment by the job planner.

The inspectors noted that the event evaluation had considered the use of the restraining device as similar to the use of a maintenance tool on equipment that was out of service. The inspectors found that considering the restraining device as a tool was an error in judgement and a significant causal factor in the event. The restraining device was installed to protect the RCP seals in that the licensee did not have an evaluation of the impact on the seals of the shaft rotating in reverse. The RCP seals were in service as an RCS boundary when the restraining device was installed. Therefore, the restraining device was relied upon to perform a function to protect the RCP during a routine startup procedure and should have received reviews consistent with a procedure change or system modification.

Response to Inspector Issues

The licensee reperformed the evaluation of the event following discussions with the inspectors. They determined that the WO was incomplete, deficient in detail and direction, and not in compliance with the work control program. Additionally, they determined that the addition of the restraining device constituted a change in work scope requiring a WO amendment in accordance with Appendix O of Procedure 30DP-9WP02. This is an example of a violation of TS 6.8.1 for failure to follow procedure (50-528/96017-01).

The licensee determined that installing the restraining device had been adequately covered by a Clearance 9-6-01734, which tagged out all four RCP motors. The inspectors agreed that this clearance provided adequate protection; however, the inspectors found that WO 0756527 was never listed as an active job on this clearance. The mechanical maintenance work group supervisor noted that although this WO was not listed on the clearance, another job under his responsibility was. He stated that he verified all four pumps were tagged out of service prior to allowing his crew to install the device. However, the clearance control procedure required that the specific WO associated with a clearance be listed on that clearance. This assures that all work listed on the clearance is completed before the clearance is removed. This is an example of a violation of TS 6.8.1 for failure to follow procedure (50-528/96017-01).

c. Conclusion

The licensee did not apply their work control process following their decision to install a temporary restraining device to RCP 2B shaft impeller. No written instructions were provided to the craft for installation and the work was not adequately documented on a clearance. The licensee's initial event evaluation was inadequate in that it did not recognize these weaknesses.

M3 Maintenance Procedures and Documentation

M3.1 Assessing the Impact of Emergent GTG Maintenance on Planned Maintenance Activities

a. Inspection Scope (62707)

Beginning on December 3, 1996, the licensee experienced several start attempt failures of the two GTGs. The inspectors observed maintenance activities and reviewed the application of maintenance rule requirements for assessing the risk of the resultant emergent work on planned maintenance activities.

b. Observations and Findings

Palo Verde has two GTGs for coping with loss of offsite power during a station blackout event. These generators are installed in parallel, and can be connected to each of the three units at Palo Verde. The licensee considered only one of these GTGs as required to cope with a station blackout event. The GTGs are not included in plant TS and their availability has been controlled through administrative procedures. Although the GTGs are maintained by site maintenance, they are outside the protected area and are operated by the site water reclamation facility staff.

Since the installation testing of the GTGs, the licensee has had problems with starting the GTGs during peak high and low temperatures, and has included the generators in 10 CFR 50.65 Maintenance Rule Category (a)1. The licensee had performed some adjustments on GTG 1 during warmer weather and had not established confidence that it would start with cooler weather. However, the licensee had previously established some confidence that the low temperature start issue had been addressed for GTG 2.

On the morning of December 3, 1996, the licensee initiated testing of GTG 1 as part of their Maintenance Rule Category (a)1 action plan to test the GTG 1 with lowering ambient temperatures (temperatures around 35°F). GTG 1 failed to start on four successive start attempts. Later in the day, following adjustments, GTG 1 was started successfully. However, since ambient temperatures had increased, maintenance personnel had not established confidence that the adjustments enabled the GTG to start during lower temperatures. Additionally, based on findings with

GTG 1, maintenance personnel developed concerns that GTG 2 may not start. They planned to test both GTGs the following morning as temperatures dropped.

At 5 a.m. on December 4, 1996, the licensee initiated a planned outage of Train A EDG and associated train components in Unit 1. At 7 a.m. on December 4, 1996, the licensee initiated a planned outage of the turbine-driven auxiliary feedwater (AFA) pump, and the A train high pressure safety injection (HPSI) pump in Unit 3.

At around the same time, the licensee attempted to start both GTGs and both failed to start on the first attempt. Both GTGs did start on a second attempt. The licensee subsequently considered GTG 1 unavailable, and continued troubleshooting, and GTG 2 available, based on its ability to start within 3 start attempts.

Palo Verde has a risk matrix, generated, in part, to comply with the Maintenance Rule, to assist operations and maintenance personnel in determining the risk of various components being out of service. The inspectors determined that site management was not fully aware of the concerns maintenance had developed on December 3 regarding the ability of both GTGs to start during cold weather. As a result, they did not consider the GTG availability impact on the plan with the December 4 outages of the Unit 1 EDG and the Unit 3 AFA and HPSI pumps.

The licensee's risk matrix, which rates activities on a low, medium, and elevated risk scale, identified that both the EDG and AFA/HPSI outages were medium risk. The addition of a GTG outage would not have increased the risk out of the medium range. However, the matrix notes stated that a GTG outage and an EDG outage should not be performed concurrently.

The shift manager recognized that had he been aware of maintenance concerns regarding the performance of GTG 2 in cold weather, further discussion would have taken place on the need for testing GTG 2 and the planned outages in Units 1 and 3.

The license issued an operations night order for unit operations to maintain status of the gas turbine availability. Additionally, the licensee initiated a CRDR for this risk management issue.

c. Conclusions

Maintenance personnel did not adequately communicate with site management the status of emergent GTG issues. As a result, site management was unable to factor these emergent issues into planned vital equipment outages.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) LER 528/95011-01: inadequate main steam isolation valve and feed water isolation valve operating air inservice tests in all three units. The licensee noted that they had not considered all appropriate uncertainties in testing the subject valves, therefore, the existing tests did not insure operability in violation of TS 4.0.5. The licensee developed interim procedures to maintain operability, updated their test procedures, and satisfactorily tested the valves. The inspectors verified the acceptability of the interim procedures and verified the completed test data for Unit 1 valves, including procedure adequacy. The inspectors concluded that the licensee's corrective actions were adequate.

This licensee-identified issue is being treated as a noncited violation consistent with Section VII of the NRC Enforcement Policy (50-528;529;530/96017-03).

III. Engineering

E1 Conduct of Engineering

E1.1 Modifications to the EW System Supply to the Essential Chillers

a. Inspection Scope (37551 and 92903)

During this inspection period, the licensee completed portions of a modification to the EW return from the EC condensers in both trains of each unit. The inspectors observed portions of the field work in each unit, reviewed the design modification, and discussed the modification with the craft, maintenance, and design engineering personnel.

b. Observations and Findings

The modification was designed to reduce the overcooling of the EC condensers in the winter when low EW temperatures and low system loading have resulted in low condenser pressure. This has caused refrigerant to migrate from the evaporator to the condenser and has resulted in low refrigerant level trips (see NRC Inspection Report 50-528/95-25; 529/95-25; 530/95-25). To reduce overcooling, the licensee installed a pressure control valve in the EW return line that modulated closed with decreasing condenser pressures. A manual bypass valve was placed in parallel with the pressure control valve to address worst case design basis conditions involving EW supply to the spent fuel pool and EC heat loads.

The inspectors, based on interviews in the field, had questions regarding the familiarity of the installation work group supervisors with the piping design specification as it applied to the piping installation and cold spring requirements. The inspectors discussed the concern with licensee management. Nuclear

Assurance reviewed training requirements and the qualifications of the contract personnel performing the work. They determined that the work group supervisor had not completed all the required classroom training in pipe installation.

The licensee performed a review of the work group supervisor's experience at Palo Verde and other nuclear facilities and determined that he had experience in the work performed. They also determined that his work on the EW modification had adequate engineering and Nuclear Assurance oversight. The licensee initiated a CRDR to evaluate this issue.

The pressure control valve was the final component installed to complete the piping portion of the EW modification and it was installed using bolted flange connections. Downstream of the pressure control valve was an elbow, followed by a box style hanger. Upstream of the pressure control valve was a piping tee with one end going to the bypass valve, and the other end going to a flanged connection to the chiller.

The inspectors observed that as the piping modification was completed in Units 2 and 3, the piping passing through the box style hanger was in contact with the hanger on the pressure control valve side. The work instructions for the modification referenced Specification 13-PN-204 for installation details. This specification allowed piping to be in contact with the hanger, as long as the piping was free to slide. The inspectors were concerned that, had the piping been in contact with the hanger on the pressure control valve side prior to bolting the valve in place, the act of bolting the flanges would have resulted in cold spring of the piping and stressing both the hanger and the piping. Specification 13-PN-204 stated that all situations involving cold spring should be evaluated by engineering.

The inspectors discussed this concern with the design engineer, who subsequently initiated CRDR 9-6-1371 to evaluate this concern. Design engineering estimated that bolting the flanges would provide roughly 0.1 inches of spring. Engineering calculated the additional stress that would be added to the hanger, the additional stress added to the piping, and any impact this condition had on the response to a seismic event and to expected thermal expansion and contraction. Engineering determined that the initial stresses on the hanger and the piping corresponded to roughly half of the code allowable initial stress limits. In addition, calculations showed the system tended, with minor exceptions, to respond better to seismic and thermal movement.

The inspectors asked if this condition had been caused by weaknesses in either the work instructions or the specification, or had it been caused by weaknesses in their application. The licensee determined that both the work instruction, which included a step requiring the verification that the hanger was free-to-slide, and the specification, which included specific verification methods, were adequate. They also determined that all six trains were in similar configurations with the pipe in contract with the hanger and no means available to determine if the pipe was free

to slide. The failure to perform the verifications required in the specification was an example of failure to implement work instructions in violation of 10 CFR Part 50, Appendix B, Criterion V (Violation 50-528/96017-02; 50-529/96017-02; 50-530/96017-02).

c. Conclusion

Workers installing a piping modification to the EW system did not ensure that the modification was installed according to design specifications and may have added unanticipated stress to the piping and hanger. In addition, workers installing the piping had not had all requisite training in pipe installations.

E5 Engineering Staff Training and Qualification

E5.1 Training and Qualification of Workers Performing EW Modifications

Section E1.1 discussed weaknesses in the training and qualification of workers performing the installation of EW modifications.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Violation 50-529/94031-03: two examples of inadequate corrective actions. The violation discussed failure of the licensee to take adequate corrective actions for degraded battery cells and for spurious tripping of the Train N AFA pump.

As part of their corrective actions the licensee replaced the degraded battery cells, corrected the cause of the spurious tripping of the Train N AFA pump, and improved the administrative directions for evaluation of technical problems. The inspectors reviewed the licensee's program for monitoring individual battery cells and determined that the licensee was trending individual cell data in sufficient detail to predict individual cell degradation.

This violation had highlighted weaknesses in the licensee's corrective action program to resolve longstanding equipment deficiencies. The inspectors reviewed the administrative changes made by the licensee associated with the CRDR program and determined that the administrative directions had been improved in the area of facilitating development of adequate corrective actions. Based on this review, the inspectors concluded that the licensee had adequately resolved this item.

E8.2 (Open) LER 50-528/93011-02: potential safety-related equipment problems due to degraded grid voltage.

a. Background

Revision 2 of this LER, dated June 17, 1996, added two new potential conditions, Scenarios 3 and 4, which could lead to double sequencing of safety-related equipment during a loss of coolant accident, concurrent with low offsite (grid) voltages and described administrative controls that were put in place to maintain operability of offsite power and safety-related equipment.

In addition, subsequent to issue of the LER, the licensee identified a potential unreviewed safety question associated with their offsite power arrangement. A new power line, not associated with Palo Verde, had recently been installed which crossed over two (Westwing) of the five total offsite power lines providing offsite power to Palo Verde, although the UFSAR addresses four offsite power sources. Thus, a single failure of the new line, dropping across the two existing Westwing lines could cause loss of these two lines to Palo Verde. The licensee's existing analysis considered the loss of only a single line, of the total four provided, reducing the offsite sources to three, a condition equivalent to loss of both Westwing lines.

On July 11, 1996, members of the licensee's staff met with the NRC staff to provide an update of the degraded voltage and double sequencing issue identified by Palo Verde. On August 2, 1996, the licensee responded to questions raised by the NRC in a docketed memorandum to the staff.

On September 18, 1996, members of the licensee's staff again met with the NRC staff in Rockville, Maryland, to provide a second update for the NRC staff. A summary of this meeting was issued on November 13, 1996.

b. Inspection Scope

The inspectors reviewed Revision 2 of the LER, the results of information Palo Verde supplied the staff associated with the July 11 and September 18 meetings, the current status of Palo Verde actions associated with offsite power, and selected technical documents which supported Palo Verde determinations that their offsite power remained operable with existing administrative controls.

c. Observations and Findings

Palo Verde studies and calculations concluded that offsite power to the site would remain operable as long as the grid voltage level was maintained at 100 percent or above. This conclusion was based on computer modeling of the grid from a model provided by the Western States Coordinating Council (WSCC). The licensee had not done any software validation of the model. The Palo Verde offsite power operability study did not include any uncertainty for the modeling and inquired

whether the model had been validated by modeling any of the recent grid disturbances in the western area and comparing the model results to what actually happened. The licensee found one study which modeled a local disturbance for short term dynamic response. The model results were similar to the actual event, but voltage levels after the disturbance were not included.

The first new potential problem, added by Revision 2 of the LER, called Scenario 3, concerned potential uncontrolled AFA flow to intact and/or ruptured steam generators during a secondary line break. The scenario assumed double sequencing and no operator intervention. The licensee administrative controls to block transfer of nonsafety busses adequately addressed this scenario.

The second new potential problem, added by Revision 2 of the LER, called Scenario 4, concerned operators potentially overloading a startup transformer when one of the three transformers was out of service. Scenario 4 appeared to be the same technical issue identified by the NRC in NRC Inspection Report 50-528/90-42; 50-529/90-42; 50-530/90-42. The licensee's response to this finding was to establish administrative controls to preclude potentially overloading the startup transformers. The inspectors questioned the licensee concerning the difference between Scenario 4 and the previous NRC finding and found that they were the same and the licensee had failed to maintain their administrative controls. Licensee engineering personnel had noted that licensee procedures could allow overloading the startup transformers in March 1996 and had initiated CRDR 9-6-0273. A preliminary review of CRDR 9-6-0273 indicated that the CRDR was closed without addressing several issues, including the root cause of how the licensee lost administrative control of the potential for overloading the startup transformers.

Revision 2 of the LER appeared to be incomplete, in that it did not indicate that the root cause of Scenario 4 was recent failure of the licensee to maintain committed administrative controls, in lieu of licensee engineering identifying a new problem with the existing design. The inspectors also considered that CRDR 9-6-0273 appeared to have been closed without adequately addressing the issue.

The inspectors noted that NRC Inspection Report 50-528/96-16;529/96-16; 530/96-16, Section E8.3, identified that LER 528/95007, Revision 1, was incomplete. Other weaknesses in the licensee's evaluation of CRDRs are discussed in Section M1.3

The inspectors discussed this consideration with the licensee. The licensee initiated CRDR 961355 to evaluate the acceptability of the closing of CRDR 9-6-0273. This new CRDR indicated that the licensee planned to issue Revision 3 to the LER to address the root cause inconsistency noted by the inspectors.

The inspectors determined that the licensee administrative controls to block transfer of nonsafety busses adequately addressed Scenario 4.

This LER will remain open pending:

- Submittal of the information concerning loss of the two Westwing lines to the staff and staff approval.
- Inspector review of the conservatism used by Palo Verde to offset the unknown accuracy of the WSCC modeling program.
- Inspector review of offsite power studies which include lines out of service.
- Inspector review of the results of the licensee's investigation of the adequacy of LER Scenario 4 and CRDR 9-6-0273 (CRDR 9-6-1355).

d. Conclusions

The licensee was proactive in addressing problems with offsite power and keeping the staff informed. The inspectors also concluded that the licensee administrative actions were acceptable to maintain offsite power operable. However, the inspectors concluded that Revision 2 of the LER and CRDR 9-6-0273 were incomplete, in that they did not address the root cause of the problem.

IV. Plant Support

P3 Emergency Preparedness Procedures and Documentation

P3.1 Licensee Onshift Dose Assessment Capabilities (TI 2515/134)

a. Inspection Scope

Using Temporary Instruction 2515/134, the inspectors gathered information regarding:

- Dose assessment commitments in the emergency plan
- Onshift dose assessment emergency plan implementing procedure
- Onshift dose assessment training

b. Observations and Findings

On December 16, 1996, the inspectors conducted an in-office review of the emergency plan and implementing procedures to obtain the information requested by the temporary instruction. The inspectors conducted a telephone interview with the licensee on December 17, 1996, to verify the results of the review. Based on the documentation review and the licensee interview, the inspectors determined that the licensee had the capability to perform onshift dose assessments using

real-time effluent monitor and meteorological data and that the process was described in the emergency plan and implementing procedures.

c. Conclusion

The process for performing onshift dose assessments was described in the emergency plan and implementing procedures.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Loss of Visitor Control (Unit 2)

a. Inspection Scope (71750)

During a routine tour of the EDG room, the inspectors observed a contract employee, performing escort duties, not maintaining control of a visitor. The inspectors discussed the observation with the supervisor present at the scene, the licensee, and contractor management.

b. Observations and Findings

On November 22, the inspectors observed a contract employee cleaning the floor in the Unit 2 Train A EDG control cabinet room. Although the employee possessed an escort badge, the inspectors did not observe a visitor. The escort's supervisor, also present in the room, indicated that the visitor was in the adjacent engine room painting the floor. The supervisor subsequently obtained possession of the escort badge and gave it to another employee working in the vicinity of the visitor. The inspectors determined that the visitor had been out of visual sight of the escort in the control cabinet room.

Procedure 20AC-0SK04, Revision 17, "Protected/Vital Area Personnel Access Control," step 3.7.5.4 required that escorts maintain positive control of visitors at all times while in the protected/vital area, and step 3.7.6.2 required that visitors shall remain in the line of sight and in positive control of their escort. The failure of the employees to follow procedure and maintain positive control of the visitor within a vital area was a violation of TS 6.8.1 for failure to follow procedures (50-529/96017-04).

The inspectors questioned the escort about the duties and responsibilities of an escort. The escort indicated that there was only one exit out of the EDG room and that the visitor could not get out of the EDG room without going past the escort. The inspectors noted that the escort failed to realize that the visitor was already in a vital area; in addition, there was another exit out of the room. The inspectors also noted that the supervisor knew the location of both the escort and visitor and had allowed them to become separated.

The inspectors informed security of the event. Security personnel responded to the scene, obtained personnel statements, and reminded the personnel involved of their escort responsibilities. Security contacted the SS and the SS dispatched an operator to verify the status of the EDG. The operator identified no discrepancies to the EDG. Another badged individual, who had been working with the visitor in the EDG room, subsequently stated that the visitor had been within his sight for the duration.

The inspectors discussed the event with the contract project manager. The project manager indicated that on the day of the event, the contractor stopped all work in the EDG room and performed a training session on escort duties. In addition, separate counseling was performed for the escort and visitor. The following day, the contractor performed prejob briefings to discuss the duties of an escort. The project manager indicated that the contractor planned to develop a computer based interactive training program on escort responsibilities by early 1997.

The inspectors discussed the event with the Director of Emergency Services. The director planned to issue news flashes and flyers to reinforce the requirement of escort responsibilities, and that a security department leader would meet with the new classes of employees and explain security requirements. The inspectors found these actions to be thorough.

c. Conclusions

An escort, visitor, and supervisor failed in their responsibilities to prevent an unescorted visitor from gaining unrestricted access to an area containing vital safety equipment. The corrective actions performed by the licensee and contractor were thorough.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 30, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT 1

PARTIAL LIST OF PERSONS CONTACTED

Licensee

R. Flood, Department Leader, System Engineering
R. Fullmer, Director, Nuclear Assurance
J. Hesser, Director, Design Engineering
W. Ide, Vice President, Engineering
D. Kanitz, Engineer, Nuclear Regulatory Affairs
A. Krainik, Department Leader, Nuclear Regulatory Affairs
D. Mauldin, Director, Maintenance
R. Myrick, Department Leader, Mechanical Maintenance
G. Overbeck, Vice President, Nuclear Operations
M. Powell, Department Leader, Civil/Mechanical Design Engineering
C. Seaman, Director, Emergency Services
G. Shanker, Department Leader, Nuclear Assurance Maintenance
D. Smith, Director, Operations
J. Taylor, Department Leader, Operations
M. Windsor, Section Leader, Mechanical Maintenance Engineering
C. Zell, Department Leader, Operations

Others

L. Gourley, Project Manager, Fluor Daniel

INSPECTION PROCEDURES USED

37551	Onsite Engineering
61726	Surveillance Observations
62707	Maintenance Observations
71707	Plant Operations
71750	Plant Support Activities
92901	Followup- Plant Operations
92902	Followup-Maintenance
92903	Followup-Engineering
TI 2515/134	Licensee Onsite Dose Assessment Capabilities

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-528; 50-529/96016-01	VIO	failure to follow procedures by operators with three different examples
50-528; 50-529; 50-530/96017-02	VIO	failure to follow written procedures in the maintenance area with two different examples
50-528; 50-529; 50-530/96017-03	NCV	inadequate tests of main steam and feedwater isolation valve air operating systems did not insure operability in violation of TS 4.0.5
50-529/96017-04	VIO	failure to follow security procedure visitor control requirements

Closed

50-528/95011-01	LER	inadequate main steam and feedwater isolation valve operating air inservice tests in all three units
50-529/94031-03	VIO	two examples of inadequate corrective actions

Discussed

50-528/93011-02	LER	Potential safety-related equipment problems due to degraded grid voltage

LIST OF ACRONYMS USED

AFA	auxiliary feedwater
AO	auxiliary operator
CRDR	condition report/disposition request
CRDL	control room deficiency log
EC	essential chilled water
ECCS	emergency core cooling system
EDG	emergency diesel generator
EER	engineering evaluation request
EW	essential cooling water
GE	General Electric
GTGs	gas turbine generators
HPSI	high pressure safety injection
LER	licensee event report
RCPs	reactor coolant pumps
RCS	reactor coolant system
SS	shift supervisor
SESS	safety equipment status system
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
WO	work order
WSCC	Western States Coordinating Council