ENCLOSURE

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REGION IV

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Licensee:	Southern California Edison Co.
Facility:	San Onofre Nuclear Generating Station, Units 2 and 3
Location:	5000 S. Pacific Coast Hwy. San Clemente, California
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ATTACHMENT: Supplemental Information

EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 and 3
NRC Inspection Report 50-361/97-09; 50-362/97-09

This routine announced inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Operations during this inspection period were characterized by careful execution of the activities associated with the beginning of the Unit 3 refueling outage. Operational decisions by operators and management were generally conservative, with due regard for nuclear safety, and activities in Unit 2 were minimized to avoid distracting Unit 3 operators, particularly during significant outage evolutions (Section O1.1).

- Operator rounds and system engineer walkdowns were generally effective at identifying minor deficiencies (Section O2.1).

- Operations procedures reviewed were technically adequate and usable; however, they were occasionally not clear, and contained transition and component identification errors, detracting from usability. They were also often changed by operators, using the procedure modification process, prior to use. The Operations Procedures group table top and review process, in some instances, was not rigorous. The backlog of changes to Operations procedures was being effectively managed so as to incorporate changes in relation to their significance (Section O3.1).

- Operators demonstrated good annunciator response by clearly communicating and performing the correct actions as specified by the alarm response procedure (Section O4.1).

- A noncited violation was identified for failure of operators to follow a procedure, resulting in not performing a required compensatory surveillance test for verification of offsite AC sources when an emergency diesel generator (EDG) was inoperable (Section O4.2).

- A nuclear plant equipment operator (NPEO), performing a high pressure safety injection (HPSI) pump discharge stop check valve surveillance, utilized good self-checking and radiological work practices. The NPEO performed a detailed check of the HPSI pump before and after the pump start, and used closed loop communications when conversing with the control room (Section M3.3).

Maintenance

- Maintenance and surveillance activities were performed in a thorough manner by knowledgeable technicians. Procedures were used as required, and supervisors and system engineers were frequently present. Quality Control personnel were also observed to be present when required (Sections M1.1 and M1.2).

- The preparations for withdrawal of the four-finger control element assemblies (CEAs) into the upper guide structure (UGS), and the maintenance order (MO) for lifting CEA 91, did not provide sufficient controls to ensure that the evolutions were accomplished successfully. The licensee's root cause evaluation was thorough and probing, and identified procedural and training weaknesses (Section M1.3).

- The weld procedure specification (WPS) and procedure qualification records (PQRs) for replacement of a reactor coolant system (RCS) loop temperature element (TE) thermowell were written in accordance with the ASME Code. The process for ensuring only approved WPSs were used by the craft failed in one instance, resulting in a noncited violation. There was no technical discrepancy with the WPS, and the licensee's corrective actions were acceptable (Section M3.1).

- Maintenance procedures reviewed were technically adequate and usable. The backlog of changes was being effectively managed so as to incorporate changes in relation to their significance (Section M3.2).

Engineering

- Station Technical support to Maintenance in resolving the leakage of the volume control tank inlet diversion valve was good in that engineers identified the need for a minor design change to resolve the deficiency (Section O8.1).

- A noncited violation occurred as the result of a procedure not providing an appropriate method to determine the acceptable leakage of a HPSI discharge stop check valve (Section M3.3).

- Station Technical maintained active involvement in outage activities during this inspection period. The cognizant engineers participated in prejob briefings, assisted in evaluation of emerging issues, and provided technical perspectives to Maintenance and Operations personnel. In general, engineering support was excellent (Section E1.1).

- Engineers identified and thoroughly evaluated five Inconel 600 nozzles that were potentially, or confirmed to be, cracked (Section E2.1).

- The licensee's root cause assessment and corrective actions, associated with 26 recent failures of excore nuclear instrument channels, were excellent, and included the use of vendor technical support (Section E2.2).

- Licensee personnel were not timely in changing a licensee controlled specification (LCS) requirement that had been a problem 5 months earlier, during the Unit 2 refueling outage, and became a problem again during the Unit 3 refueling outage. The licensee promptly resolved the current problem by processing the needed LCS change (Section E2.3).

- One noncited violation was identified for the failure to follow the procedure for aligning a temporary system installed to transfer water and chemicals for steam generator chemical cleaning (SGCC). The error resulted in a spill of the SGCC rinse water. The licensee performed a thorough review of the spill and implemented extensive corrective actions prior to restart of the SGCC activities (Section E2.4).

- The action request (AR) program continued to provide an effective low-threshold tool for problem identification and correction. The ARs were thoroughly reviewed and dispositioned. Although feedback to initiators was not always required, the licensee's feedback process was still being developed (Section E7.1).

Plant Support

- Contractor personnel performing the SGCC demonstrated poor radiological work practices by not following the barrier postings and breached a potentially contaminated system. This action was identified as a noncited violation of minor safety consequences for failure to follow procedures. The licensee's corrective actions for the event were excellent. The absence of formal requirements applying to all personnel requiring compliance with radiological signs and postings was a weakness of the licensee's radiological control program (Section R4.1).

- The licensee's computer-based emergency preparedness training was very informative, accurate, and easy to use (Section P5.1).

Report Details

Summary of Plant Status

Both units began this inspection period operating at essentially 100 percent reactor power.

Unit 2 operated at essentially 100 percent reactor power throughout this inspection period.

On April 10, 1997, Unit 3 began a power reduction, and was taken off-line on April 12, 1997, beginning the Unit 3 Cycle 9 refueling outage. The unit entered Mode 5 on April 13, Mode 6 on April 18, and was defueled on April 29, 1997. The unit entered Mode 6 at 10:30 a.m. on the last day of this inspection period. The unit was in the 35th day of the Cycle 9 refueling outage.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Operations during this inspection period were characterized by careful execution of the activities associated with the beginning of the Unit 3 refueling outage. Operational decisions by operators and management were generally conservative with due regard for nuclear safety, and activities in Unit 2 were minimized to avoid distracting Unit 3 operators, particularly during significant outage evolutions.

O2 Operational Status of Facilities and Equipment

O2.1 Various System Walkdowns - Units 2 and 3 (71707)

The inspectors assessed the general condition of selected electrical distribution equipment, auxiliary feedwater equipment, and balance of plant and safety-related equipment located in the main steam safety valve area of Unit 2. The general condition of the equipment, and the number and threshold of deficiencies identified in the licensee's AR system, indicated that operator rounds and system engineer walkdowns were generally effective at identifying deficiencies. A small number of minor deficiencies were identified which the licensee promptly addressed.

O3 Operations Procedures and Documentation

O3.1 Operations Procedures Review - Units 2 and 3

a. Inspection Scope (42700)

The inspectors reviewed four Operations procedures, using the guidance in NRC Inspection Procedure 42700, "Plant Procedures." Interviews were conducted with members of the Operations Procedures group, as well as operators. Portions of the following documents were reviewed:

- Operations Procedure SO23-1-3.1, Temporary Change Notice (TCN) 8-16, "Emergency Chilled Water System Operation."
- Operations Procedure SO23-5-1.7, Revision 9, "Power Operations."
- Operations Procedure SO23-3-1.1, Revision 13, "Reactor Startup."
- Operations Procedure SO123-0-2, Revision 3, "Control Room Supervisor's Authority, Responsibilities and Duties."

In followup to the review of the documents listed above, the following documents were also reviewed:

- Licensee Document, Revision 10, "Operations Procedures Group Writer's Guide."
- Procedure SO123-VI-0.9, Revision 5, "Author's Guide for Preparation of Orders, Procedures, and Instructions."
- Procedure SO123-0-20, Revision 4, "Use of Procedures."
- Operations Procedure SO23-3-2.2, Revision 10, "Makeup Operations."
- Operations Procedure SO23-3-2.1, TCN 14-1, "CVCS Charging and Letdown."
- Operations Procedure SO23-5-1.8, Revision 5, "Shutdown Operations (Modes 5 and 6)."
- Unit 2 Technical Specifications (TS) and LCS
- Design Basis Document DBD-SO23-800, "Emergency Chilled Water."

b. Observations and Findings

Procedure Quality

All Operations procedures inspected had been reviewed and approved by the licensee in accordance with TS and were technically adequate and usable. Accomplishing a task sometimes involved multiple transitions within a procedure and amongst procedures, contributing to the interlaced nature of the procedures. Some procedural steps described below were not clear, due to multiple factors including: information incorporated into procedural steps; the step not correctly transitioning to another step: or, the step having erroneous nomenclature. Also, there was one instance in which a safety evaluation for a proceduralized interpretation of a TS requirement was not applicable, and another instance in

which a step was confusing with respect to TS requirements. Examples of each of these are described below:

- Information incorporated into procedural steps:

  Procedure SO23-5-1.7, Attachment 13, Step 3.12, stated, "A dilution to 100 percent power results in 98 percent power with T-cold at the programmed level. By picking up slightly more Turbine Load, T-cold will decrease and Reactor Power will increase to 100 percent. Then as xenon burns out or builds in, allow T-cold to move to the limits of its normal operating band." Attachment 13 was titled "Power Operations Limits and Specifications," and was a mix of requirements and informational steps. Step 3.12 was confusing because it was not clear whether or not this was an expectation for each power increase to 100 percent, and, if so, what the target for the amount of dilution should be (98 percent or 100 percent). Also, xenon building in would add negative reactivity, decreasing reactor power, lowering T-cold, and causing T-cold to drop further from its normal operating band.

  Procedure SO23-3-2.1, Step 6.3.8, stated that the volume control tank level is maintained between 37 percent and 51 percent. The inspectors reviewed plant monitoring data and observed that normal volume control tank level for Unit 3 was approximately 55 percent for February 26, 1997. The Operations superintendent informed the inspectors that the step was information, not direction, to maintain level at the lower values. A total of three attachments and six steps, separate from the attachments, were identified as examples of information incorporated into steps or attachments. The licensee also had some attachments labeled as "guidelines." The use of "guidelines" further blurred the distinction between information and procedural requirements. This was because information and requirements were mixed together in the guidelines attachments or sections. The Operations Writers' Guide encouraged notes and cautions to be converted to steps, contributing to the lack of distinction.

- Incorrect transitions:

  Procedure SO23-1-3.1, Attachment 16, directed the operator to initiate Attachment 18 if component cooling water inlet temperature to an emergency chiller dropped to 55°F. Attachment 18 provided direction to raise or lower refrigerant level. A total of two steps were identified with incorrect transitions.

- Incorrect nomenclature:

  Procedure SO23-1-3.1, Step 6.1.3.2, incorrectly identified the chiller compression tank pressure indicator as PI-9883A/B. The correct

identification was PI-9884A/B. A total of two steps with incorrect nomenclature were identified.

- Safety evaluation not strictly applicable:

  Procedure SO23-5-1.8, Step 4.1.1, instructed the operators to maintain RCS temperature ±20°F when a startup channel was inoperable in Modes 5 or 6. TS 3.3.13 directed no positive reactivity addition operations for this situation. The licensee's basis for allowing a 20°F positive reactivity addition was a memorandum to file from R. Waldo, dated November 7, 1985, which was written to demonstrate that, while in Mode 6 with the RCS at more than 2000 ppm boron, the 20°F would provide negligible reactivity change. Mode 5 TS boron concentration was given in terms of shutdown margin, and since the memo had been written, more highly enriched fuel had been used. In response to the inspectors' observation, the licensee initiated action to revise the justification, and addressed this in the TS basis.

- Step not clear with respect to TS requirements:

  Procedure SO23-5-1.7, Step 3.1.5, allowed operators to deviate from CEA program overlap in Modes 1 and 2, in order to control axial shape index. Step 3.1.5 stated that, if Regulating Group 5 was necessary to be inserted for axial shape index control, then Regulating Group 6 should be inserted to 80 inches withdrawn or the transient insertion limit, whichever was most limiting; then Regulating Group 5 should be inserted (maintaining at least 15 inches above Group 6), maintaining regulating Group 6 at 80 inches or the transition insertion limit. For these conditions, Group 5 was prohibited from insertion above approximately 70 percent power and, for Group 5 to be inserted to the allowable 15 inches above Group 6, reactor power would have to be at approximately 35 percent. Since the step did not reference any power restriction to the movement of Group 5 CEAs, the inspectors found the step was conducive to TS violation. In response, the licensee was evaluating enhancing the step.

Operations Backlog

Operations procedures were periodically reviewed by the licensee and, if necessary, revised. The backlog of suggested individual changes was approximately 586 assignments on a computerized system and consisted of all Priority 1, 2, 3, or 4 assignments greater than 90 days old. Priority 1 changes were to be relatively immediate and Priority 3 were those changes that should be implemented within approximately 2 months. The Priority 4 items had mainly changes to be made during scheduled revisions. Procedure changes generally involved members of Operations, Station Technical, and the Operations procedure writers' group. The Operations procedures group was attempting to table-top and review about 50 procedures a year, out of the approximate 500 total Operations procedures.

Procedure SO23-5-1.7 had undergone this review and revision in November 1996, but retained some steps that were confusing. Based on this, the inspectors found that the table top and review process, in this instance, were not rigorous.

Based on a sampling of the backlog, the inspectors determined that the backlog was being managed so as to incorporate changes in relation to their significance. As such, the backlog was being managed effectively

Use of Procedure Modification Permits (PMPs)

A PMP was a procedure change performed by a senior reactor operator and reviewed by the Operations manager within 14 days. It was a pen-and-ink change applicable for as long as the procedure remained in use. PMPs were later evaluated for permanent incorporation via the TCN or revision process. The inspectors reviewed selected PMPs performed by Operations personnel from November 1996 to April 1997. The PMPs were performed for Unit 2 operations and the time frame encompassed the Cycle 9 refueling outage.

For Unit 2, a total of 270 PMPs were performed, or approximately 45 per month for the approximate 6-month period. Procedure SO123-0-20 described the purpose of a PMP as facilitating use of a procedure for current plant conditions when such conditions are different than those assumed by the original procedure. Various PMPs were reviewed and found to change numerical limits, the methodology of an evolution, the sequence of steps, or plant configuration required for an evolution. In addition, PMPs were used to add or delete required actions used to verify system configuration. Examples included the use of a PMP to change the method of collapsing a pressurizer bubble from not using heaters and only intermittent spray, to having heaters and spray on continuously. Also, PMPs were used to correct operator actions in response to a dropped part-length CEA, to specify location of instrumentation to correct procedural transitions, and to change a list of surveillances required to be completed prior to reactor startup. As such, the reasons for using a PMP were more than just a difference in plant conditions. The reasons also were, among other things, to correct errors, change limits and/or methodology, and to change the amount of verification required. Based on the number of PMPs performed, the inspectors determined that procedures often required change by operators prior to implementation. The changes were made for enhancement as well as accuracy, indicative of procedures that were comprehensive.

c. Conclusions

Operations procedures reviewed were technically adequate and usable; however, they were occasionally not clear, and contained transition and component identification errors, detracting from usability. Also, they were often changed by operators, using the PMP change process, prior to use. The Operations procedures group table top and review process, in some instances, was not rigorous.

The backlog of Operations procedure changes was being effectively managed so as to incorporate changes in a timely manner related to their significance.

O4 Operator Knowledge and Performance

O4.1 Annunciator Response - Units 2 and 3 (71707)

On April 23, 1997, the inspectors observed control room operator response to an annunciator for low respiratory/service air system (RSAS) air pressure. RSAS was not safety-related, but provided compressed air for breathing, spent fuel pool gate seals, and manifolds throughout the plant. The annunciation was due to a low air pressure condition caused by high demand due to Unit 3 outage activities, and a failure of the two dedicated backup compressors to start. Operators minimized system usage and manually started a backup compressor. The inspectors identified that normal operating pressure for the RSAS was listed as 90 to 110 psig in annunciator response Procedure SO2(3)-15-61.C, Revision 1, "Annunciator Panel 61.C, SFP/RCDT," Step 3.1. The normal operating pressure was marked as 100 to 110 psig on the control room lumigraph. The normal operating pressure was listed as between approximately 85 to 110 psig in operating Procedure SO23-1-2, Revision 11, "Respiratory and Service Air System Operation," page 54, depending on the status of the backup compressors. The Unit 2 control room supervisor initiated an AR to reconcile the green band on the lumigraph and the annunciator response, so that all procedures and indications used by operators would agree in terms of what was normal pressure. The common control operator and the Unit 2 control room supervisor, who had responsibility for systems common to both units, displayed good communications and good use of annunciator response and normal operating procedures during the occurrence. The shift superintendent provided effective oversight.

The inspectors concluded that the operator demonstrated good annunciator response by clearly communicating and performing the correct actions as specified by the alarm response procedure.

O4.2 Failure to Follow Procedure and Complete Surveillance - Unit 3

a. Inspection Scope (61726, 71707)

The inspectors reviewed the circumstances surrounding operators' failure to perform the AC sources surveillance as directed by Procedure SO23-3-3.23, "Diesel Generator Monthly Test," reviewed AR 970400078, and discussed the event with Operations management.

b. Observations and Findings

On April 2, 1997, operators started EDG 3G002 for a monthly surveillance test in accordance with Procedure SO23-3-3.23. When synchronized to the bus in the

droop mode, the EDG was considered inoperable due to configuration of the droop circuitry. Procedure SO23-3-3.23, Step 6.7, required, in part, that if an EDG is determined to be inoperable or is going to be inoperable, that Attachment 7 be performed to demonstrate the operability of the remaining AC sources. This was consistent with TS Surveillance Requirement (SR) 3.8.1.1. The operators declared EDG 3G002 inoperable, but did not perform Attachment 7 to demonstrate the operability of the remaining AC sources.

The licensee determined the following time line for the inoperable EDG. At 12:23 a.m., the operators loaded EDG 3G002 to the bus and declared the EDG inoperable. At 1:23 a.m., SR 3.8.1.1 had not been performed and, therefore, TS 3.8.1 (AC Sources Operating) required the unit to be in Mode 3 by 7:23 a.m. At 2:06 a.m., the EDG was removed from the bus and declared operable. At 4:00 a.m., the operators recognized that the verification of operability of AC sources had not been performed. At 4:26 a.m., the operators completed the AC sources verification. At the time the AC sources verification was performed, it was no longer a required action, since both EDGs were operable. The inspectors concluded that the actions required by TS 3.8.1 were satisfied because the EDG was returned to service prior to 7:23 a.m.

The event was discussed with the Operations supervisor, who indicated that the control operator and control room supervisor discussed the performance of AC sources verification prior to removing the EDG from service, but failed to perform the required verification. The Operations supervisor discussed the operators' performance with the individuals involved in the event and explained that management expectations were not met. In addition, the Operations supervisor indicated that a procedure change had been initiated prior to the event to include a sign-off step to perform the actions of Step 6.7 if an EDG is declared inoperable. The procedure change was subsequently approved on April 10, 1997. Procedure SO23-3-3.23 was reviewed and the change was verified to be implemented. Additionally, the licensee had initiated a design change being implemented in the current refueling outage, correcting the EDG governor circuitry so that the EDG could be loaded to the grid and remain operable.

The failure to follow Procedure SO23-3-3.23 was a violation of TS 5.5.1.1.a. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NCV 362/97009-01).

c. Conclusions

A noncited violation was identified for failure of operators to follow an EDG surveillance procedure, resulting in not performing a required compensatory surveillance test (Verification of AC Sources Operating).

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Violation 50-362/96015-01: volume control tank inlet diversion valve controller in wrong mode.

This violation was for failing to place the controller in manual, contrary to an abnormal alignment that was in effect. The abnormal alignment was written because the volume control tank inlet Divert Valve 3LV0227A leaked by to rad waste when it was positioned to direct flow to the volume control tank. The inspectors verified the corrective actions described in the licensee's response letter, dated January 15, 1997, to be acceptable and complete. Procedure SO23-3-3.37, Revision 12, "Reactor Coolant System Water Inventory Balance," had been changed to incorporate the abnormal alignment. At the end of the inspection period, Unit 2 had the same abnormal alignment in effect and Unit 3 had the abnormal alignment in effect prior to shutting down for the Cycle 9 refueling outage. Both units' LV0227A valves continued to leak by. The inspectors reviewed maintenance history for these three-way, Hammel Dahl, 3" air-operated valves and interviewed cognizant personnel and found that the licensee was attempting to correct the leakage by adjusting stem travel length in Unit 3. If the results were positive, the licensee planned on making the same correction in Unit 2. The licensee was machining off physical stops on the valve stem in order to increase stem travel, with vendor concurrence.

The inspectors concluded that Station Technical support to Maintenance was good in attempting to resolve the leakage.

O8.2 (Closed) Violation 50-361/97002-03: inadvertent transfer of water to the RCS and failure to maintain RCS pressure within limits.

The inspectors verified the corrective actions described in the licensee's response letter, dated April 14, 1997, to be acceptable and complete. Both of these examples involved operator inattention to procedural requirements, and, as documented in NRC Inspection Report 50-361/97-05, dated April 15, 1997, licensee operators continued to have some lapses in attention to detail. However, the inspectors considered that the corrective actions for these violations were adequate and that, overall, Operations was not exhibiting excessive personnel errors.

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:

- Replace RCS hot leg (HL) thermowell Nozzle 3TE0121X2 (Unit 3)
- Repair bonnet leak in Valve 3HV9378 (Unit 3)
- Replace impeller on low pressure safety injection Pump 3P016 (Unit 3)
- EDG 3G002 preventative maintenance inspection (Unit 3)

b. Observations and Findings

All work performed under these activities was thorough and performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

In addition, see the specific discussions of maintenance observed under Section M1.3, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

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

- Test of main steam safety valve lift setpoint
- CEA position verification (Unit 2)
- Main turbine control circuit check and trip test (Unit 3)
- High pressure turbine overspeed trip test (Unit 3)

b. Observations and Findings

All surveillances performed under these activities were thorough and performed with the work package present and in active use. Technicians were knowledgeable and professional. The inspectors frequently observed supervisors and system engineers monitoring job progress, and Quality Control personnel were present whenever required by procedure. When applicable, appropriate radiation controls were in place.

M1.3 Mechanically-bound CEA - Unit 3

a. Inspection Scope (62707)

On April 19, 1997, Unit 3 refueling personnel were withdrawing CEA 91 from the core to the UGS, in preparation for removing the UGS to begin core offload. CEA 91 was one of four four-fingered CEAs that were used for two fuel assemblies each. Normally, the licensee left CEAs inserted in fuel assemblies when offloading the core. However, CEAs that were inserted into two assemblies had to be pinned to the UGS and moved with it. Prior to CEA 91, the licensee had successfully pinned one four-fingered CEA to the UGS. CEA 91 became mechanically bound by guides located on the extension shaft housing. The CEA was bound because the spider arrangement did not enter the guides in an aligned manner to pass the guides. The spider bent both guides up, and the lip of the extension shaft then became wedged on the top of the guides, with the spider wedged beneath the guides. The inspectors interviewed operators; observed a subsequent four-finger CEA withdrawal; reviewed MOs 97041304001, 97041304002, and 96051885000; and reviewed Procedure SO23-I-3.15, TCN 6-7, "In Core Instrumentation Assembly Withdrawal and Removal of the Upper Guide Structure." This procedure was appropriate to the circumstances of removal of the four-fingered CEAs, when used by trained and experienced personnel, because the operation had been performed successfully several times during past refuelings. The inspectors also reviewed the licensee's root cause evaluation, which was documented in a Maintenance division event report dated April 5, 1997.

b. Observations and Findings

In order to free the bound CEA, refueling group personnel attached a rope to CEA 91, uncoupled the CEA, lowered it back into the core, and then drained the refueling cavity down to slightly above the vessel flange. The damaged guides were then removed, and the water level raised. CEA 91 was then raised by a rope, because the licensee wanted to place a bar between the spider and the guide tube in order the inspect the spider. The CEA was raised too far, and the CEA fingers became disengaged from the lower support plate. The CEA was then left supported by the lower support plate, was reconnected to the extension shaft, then raised slightly and pinned to the UGS. The remaining two four-finger CEAs were then raised and pinned to the UGS, and the UGS was lifted from the vessel, in order to move fuel.

During the initial CEA 91 withdrawal attempt, two refueling personnel were stationed on the UGS, and a refueling supervisor and a rigger were on a walkway adjacent to the UGS. One refueling person was assigned to watch a load cell and measure the amount of CEA withdrawal with a tape measure. The other refueling person was assigned to guide the extension shaft up the guide tube. The supervisor had communication with the UGS personnel and the rigger had communication with the polar crane operator. The procedure did not address the

guide ears. The personnel on the UGS were not aware that the guide ears were in place. The refueling supervisor thought that the guides were self aligning and that the orientation of the spider could not cause the spider to damage, or get stuck on, the guides. The auxiliary hoist of the polar crane was being used when the initial damage occurred. Travel speed was approximately 7.2 inches per minute. A subsequent bump up of the hoist was at 1.5 inches per minute.

Procedure SO23-I-3.15 did not address the possibility that the CEA could become caught in the guides. The personnel performing the evolution had not been trained so as to be aware of the requirements for CEA orientation to pass through the guides. In addition, the method of communication and use of the polar crane auxiliary hoist were not conducive to quickly stopping the upward movement of the CEA in the event that a high load cell weight had been detected. The inspectors found that all of these omissions contributed to the error.

The personnel who were raising CEA 91 by rope, after the CEA had been decoupled from the extension shaft, were aware of management expectation that the CEA not be raised so as to provide for the fingers coming out of the lower plate. However, the orientation of their view, looking down on the assembly while holding the assembly with a rope, did not provide sufficient angle of sight to properly estimate the amount the CEA had been raised. This was another example of the plan (the MO) not providing controls to ensure the evolution was accomplished successfully.

c. Conclusions

The preparations used to withdraw the four-finger CEAs in the UGS, and the MO used to lift CEA 91, did not provide sufficient controls to ensure that the evolutions were accomplished successfully by technicians with less knowledge or experience than had been used during past refuelings. The licensee's root cause evaluation was thorough and probing, and identified procedural and training weaknesses.

M3 Maintenance Procedures and Documentation

M3.1 WPS Review - Unit 2

a. Inspection Scope (62707)

The inspectors reviewed a weld package that had been used for replacement of TE 2TE9178-3. This was a Unit 2 cold leg Loop 1A narrow-range temperature detector that had been replaced on December 21, 1996, in order to provide data for a root cause investigation into the failure of Unit 3 TE 3TE9179-3. The weld reviewed was a socket weld between the Inconel 600 nozzle and the Inconel 600 thermowell. The welding process used was manual gas tungsten arc-welding. The weld was required to be performed in accordance with the ASME Code. The inspectors reviewed MO 9620497000, Weld Record WR2-96-345, WPS 43-GT, and PQRs 33 and 36, which supported the WPS.

b. Observations and Findings

The PQRs were required because they documented all essential variables used during test welds performed in support of the methodology in the WPS. The essential variables were identified for the gas tungsten arc-welding process in Section IX of the ASME Code. The essential variables were then required to be maintained, within the bounds specified in the ASME Code, by the WPS. All essential variables were identified in the PQRs and maintained in the WPS.

The WPS was used by the craft on December 21, 1996, to perform the weld without prior review or approval by the authorized nuclear inspector or the welding engineer supervisor. The WPS was signed as prepared by two different weld engineers on December 15, 1996. This was contrary to Procedure SO123-V-7.2, Revision 1, "Administrative Controls of Welding, Brazing and Soldering Procedure Qualifications," Step 6.2.4, which stated that "All welding procedure specifications . . . shall be approved by the Welding Engineering Supervisor, or his designee, prior to issuance for use." Failure to obtain proper authorization for WPS 43-GT was a violation of 10 CFR Part 50, Appendix B, Criteria V, which stated, in part, that activities affecting quality shall be accomplished in accordance with procedures. The inspectors considered this to be of minor safety consequence because the WPS was later approved, without change, on January 2, 1997. The Welding Engineering supervisor stated that the reason for the error was personal error on his part, because the WPS, along with another WPS which was not used, was submitted to Central Document Management and issued for use on December 18, 1996, without being signed as approved. The Welding Engineering supervisor initiated an AR, and planned on conducting training for all welding engineers in order to heighten awareness in this area. The inspectors concluded that these corrective actions were acceptable. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 50-361/97009-02).

c. Conclusions

The WPS and PQRs reviewed were written in accordance with the ASME Code. The process for ensuring only approved WPSs were used by the craft failed in one instance, resulting in a noncited violation; however, there was no technical discrepancy with the WPS, and the licensee's corrective actions were acceptable.

M3.2 Review of Maintenance Procedures

a. Inspection Scope (42700)

The inspectors reviewed two Maintenance procedures, using the guidance in NRC Inspection Procedure 42700, "Plant Procedures," interviewed members of the Maintenance procedures group, and interviewed Maintenance craft personnel. Portions of the following documents were reviewed:

- Maintenance Procedure SO23-3-3.43, Revision 5, "ESF Subgroup Relays Semiannual Test."

- Maintenance Procedure SO23-I-8.231, TCN 3-1, "Reactor Coolant Pump Bearing Inspection and In Place Maintenance."

b. Observations and Findings

All Maintenance procedures inspected were reviewed and approved in accordance with TS and were technically adequate and usable. Procedural requirements were clear, the format was easy to follow, and a clear distinction between procedural requirements and useful information was made, through the use of cautions and notes. Two minor errors regarding acceptance criteria were identified in Procedure SO23-I-8.231, for which the Mechanical Maintenance Procedures supervisor initiated corrective actions.

Maintenance procedures were periodically reviewed by the licensee, and, if necessary, revised. The backlog of suggested individual changes was approximately 321 assignments on a computerized "Non Regulatory Action Tracking System," with an additional approximately 800 suggested individual changes on a paper system. The computerized backlog listed all Priority 1, 2, or 3 assignments, greater than 90 days old. Priority 1 changes were to be relatively immediate and Priority 3 were those changes that should be implemented within approximately two months. The paper system had mainly changes to be made during scheduled revisions. Procedure changes generally involved members of the craft, Station Technical engineers, and members of the procedure writers' group. Each Maintenance procedure was assigned an individual responsible for the procedure, either from the craft or the writers' group.

Over the last few years, Maintenance had attempted to streamline procedures and to give lower-level supervisors the ability to change procedures to facilitate work and procedural compliance by the craft. Based on a sampling of the backlog, the backlog appeared to be managed effectively and changes incorporated in relation to their significance. Based on a review of Procedure SO23-I-8.231, which had been streamlined, the procedure appeared to be more usable, retaining sufficient guidance to enable the craft to perform the work in a technically adequate manner.

c. Conclusions

Maintenance procedures reviewed were technically adequate and usable. The backlog of changes was being effectively managed so as to incorporate changes in relation to their significance.

M3.3 HPSI Discharge Stop Check Valve Test - Unit 3

a. Inspection Scope (61726)

The inspectors observed the portions of Procedure SO23-3-3.31.2, "ECCS Valve Testing - Cold Shutdown and Refueling Interval," and discussed the test with the safety injection system engineer and supervisor of performance monitoring.

b. Observations and Findings

NPEO Performance

On April 23, 1997, the inspectors observed a NPEO perform Procedure SO23-3-3.31.2, Sections 2.9 and 2.20, to test HPSI Pump 3P019 discharge stop check Valve 3MU015. The NPEO used self-checking techniques when manipulating valves, performed a detailed check of the HPSI pump before and after the pump start, and used closed loop communications when conversing with the control room. In addition, the NPEO followed the requirements of the radiation exposure permit for entry into contaminated areas to manipulate valves.

Procedure Adequacy

The purpose of the test was to determine the leakage of discharge stop check Valve 3MU015. The valve leakage was required to be less than 5 gpm to protect the HPSI pump suction piping from overpressurization, because the capacity of the suction side relief valve was only 5 gpm. During the performance of the test, a HPSI pump was operated to provide back pressure on Valve 3MU015 and the leakage through the valve was measured. The acceptance criteria used in Procedure SO23-3-3.31.2 for Valve 3MU015 was that the safety injection (SI) mini flow to the refueling water storage tank be less than 40 gpm. The 40 gpm criteria assumed that the operating pump mini flow was 35 gpm and the leakage through Valve 3MU015 was less than 5 gpm.

During the test performed on April 23, the NPEO observed an initial SI mini flow reading of 46 gpm. The initial flow reading was not that required by the procedure. After aligning the system for the test, the NPEO recorded the SI mini flow of 41 gpm, the only required flow reading. Engineering evaluated all the data obtained from the NPEO and concluded that the test was invalid since the SI mini flow (controlotron) was not in calibration because the initial SI mini flow reading was greater then the expected 35 gpm and the final value was less than the initial value.

The inspectors determined that, with the controlotron flow device drifting low or the running HPSI pump mini flow less than 35 gpm, the 40 gpm acceptance criteria of the test could be satisfied with leakage past the stop check valve greater than the 5 gpm. The inspectors discussed the concern with the system engineer and

supervisor of performance monitoring. The system engineer concurrently concluded that the test methodology needed enhancement. The engineer planned to change the procedure to require a before and after reading of the SI mini flow and compare the difference to an acceptance criteria of 5 gpm. In addition, the engineer indicated that the HPSI discharge stop check valves have historically not had a leakage problem. The inspectors concluded that the procedure change was appropriate.

10 CFR Part 50, Appendix B, Criterion V, states, in part, that activities affecting quality shall be prescribed by procedures appropriate to the circumstances. Contrary to this, Procedure SO23-3-3.31.2, Section 2.20, did not provide an appropriate method of determining the stop check valve leakage. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 362/97009-03).

c. Conclusions

The NPEO performance of the HPSI stop check valve surveillance utilized good self-checking techniques and radiological work practices. The NPEO performed a detailed check of the HPSI pump before and after the pump start, and used good closed loop communications when conversing with the control room. A noncited violation occurred as a result of Procedure SO23-3-3.31.2 not providing an appropriate method to determine acceptable stop check valve leakage.

M8 Miscellaneous Maintenance Issues (90712)

M8.1 (Closed) Licensee Event Report (LER) 50-361/97008-00: failure to perform pressurizer cooldown rate surveillance. This event was discussed in NRC Inspection Report 50-361; 362/97-05. No new issues were revealed by the LER.

III. Engineering

E1 Conduct of Engineering

E1.1 Engineering Support of Outage Activities - Unit 2 (37551)

Engineers from Station Technical maintained active involvement in outage activities during this inspection period. The cognizant engineers participated in prejob briefings, assisted in evaluation of emerging issues, and provided technical perspectives to Maintenance and Operations personnel. In general, engineering support was excellent.

E2 Engineering Support of Facilities and Equipment

E2.1 Inconel 600 Primary Pressure Boundary Leakage - Unit 3 (37551)

During Unit 3 primary pressure boundary walkdowns conducted at the beginning of the Cycle 9 outage, licensee Engineering personnel identified five indications of leakage from RCS Inconel 600 components located on the primary coolant legs. At the beginning of each outage the licensee programmatically and visually inspected all areas of the RCS that contained Inconel 600, in order to identify leakage and make repairs. For the same purpose, the licensee also performed nondestructive examination of portions of the control rod drive mechanism nozzles on the RCS vessel head. During the Unit 3 Cycle 9 outage, boric acid residue was found on the following components (RCS loop locations of the TEs and pressure differential transmitters are provided):

- 3TW138E (Steam Generator (SG) EO89 HL)
- 3TE0121X2 (SG EO88 HL)
- 3PDT0979-3 (SG EO88 HL)
- 3TE0122-2 (SG EO88 HL)
- 3TE0121Y2 (Reactor Coolant Pump 3P002 cold leg)

Maintenance craft replaced the outer portions of these Inconel 600 nozzles with Inconel 690 partial nozzles, leaving the potentially cracked interior of the nozzle in place. This made the weld that constituted the RCS pressure boundary, which had been the interior nozzle-to-pipe weld, the new outer-diameter nozzle-to-pipe weld.

The inspectors found that the licensee had identified potential Inconel 600 leakage in accordance with the implementation of their established program, described in Procedure SO23-V-8.16, Revision 0, "Reactor Coolant System Inconel Nozzle Inspection."

E2.2 Excore Nuclear Instruments

a. Inspection Scope (61705)

During 1996 the licensee experienced 26 failures of excore nuclear instrument channels. The inspectors reviewed the circuit design, the failure history, the licensee's root cause investigation, and the licensee's corrective actions.

b. Observations and Findings

The licensee undertook an extensive root cause evaluation, including use of vendor technical support. The licensee determined that the probable cause for most of the problems was a recessed female contact on a filter module pigtail HN-type connector. The licensee considered that this recess randomly generated line transients, which damaged a circuit card.

To minimize the line transient, the licensee lowered the detector operating voltage. The licensee also lowered a circuit alarm point. During the Unit 2 outage the licensee reworked the HN connectors. Since no failures had occurred in 1997 to date, the licensee decided not to rework the Unit 3 connectors during the present outage.

c. Conclusion

The licensee's root cause assessment and corrective actions, associated with 26 recent failures of excore nuclear instrument channels, were excellent, and included the use of vendor technical support.

E2.3 LCS Change Not Timely- Unit 3

a. Inspection Scope (37551)

On April 12, 1997, operators shut down Unit 3 in preparation for the Cycle 9 refueling outage. When Startup Channel 1 was placed in service, operators observed erratic operation and declared the channel inoperable. With the unit at normal operating temperature and pressure, licensee Technical personnel began enhanced walkdowns of the primary pressure boundary, looking for indications of leakage. Two boric acid indications were observed. On later dates an additional three boric acid indications were identified. Operators entered Unit 3 TS Limiting Condition for Operation (LCO) 3.4.13 because pressure boundary leakage had been identified. The LCO required operators to cool down and depressurize the unit to Mode 5 within 36 hours. The licensee also recognized that LCS 3.3.111 applied to the inoperable startup channel, and referred the operators to TS LCO 3.3.13, which directed that, with one source range channel inoperable, all operations involving positive reactivity be suspended. TS 3.3.13 was applicable with reactor trip circuit breakers open.

b. Observations and Findings

Licensee Engineering and Licensing personnel performed a safety evaluation and changed Unit 3 LCS 3.3.111 to permit, with one startup channel inoperable, the mode transition to Mode 5. Alternate boron dilution detection was provided by 12-hour boron samples and verification that all CEAs were fully inserted every 4 hours. The inspectors observed that Unit 3 had previously, on September 23, 1996, been shut down to repair pressure boundary leakage to a leaking RCS cold leg thermowell. At that time, the licensee had noted the same apparent contradiction between TS 3.4.13, which required a cooldown for pressure boundary leakage, and LCS 3.3.111, which referred the operators to TS 3.3.13, which prohibited a cooldown with a startup channel inoperable. At that time, the licensee closed reactor trip breakers to make TS 3.3.13 nonapplicable, and planned on changing LCS 3.3.111. The licensee had not changed the LCS, despite the 5-month period between the occurrences. The inspectors found that Licensing

personnel were not timely in making this change. This resulted in Unit 3 being maintained at normal operating pressure and temperature with pressure boundary leakage for approximately 6 hours while the change was approved.

The pressure boundary leakage, due to stress corrosion cracking of Inconel 600 components, is further discussed in Section E2.1 of this report.

c. Conclusions

Licensing personnel were not timely in changing an LCS requirement that had been a problem 5 months earlier, during the Unit 2 refueling outage, and became a problem again during the Unit 3 refueling outage. The licensee promptly resolved the current problem by processing the needed change.

E2.4 SGCC Rinse Water Spill - Unit 3

a. Inspection Scope (37551, 71707)

The inspectors monitored the licensee's activities as a result of the SGCC rinse water spill and reviewed the licensee's corrective actions.

b. Observations and Findings

On April 25, 1997, a rinse water spill occurred during a fill and vent evolution in preparation for the full volume rinse of the steam generators. The licensee determined that two valves mispositioned during performance of Procedure SO23-XXVII-29.37, "San Onofre Pumpdown Steam Generators to the Process/ Storage Tanks," created a flow path to a drain tank and subsequently overfilled the tank. The rinse water exited the tank through a temporary vent hose into the atmospheric dump valve stack, spilled into the main steam isolation valve enclosure area, drained to the Unit 3 intake, pumped to the Unit 2 intake, and discharged to the ocean. The contractor performing the evolution estimated that approximately 1200 gallons were spilled, and of that, approximately 600 gallons reached the ocean. The licensee evaluated the rinse water for radioactivity and concluded that the release was not reportable.

The licensee suspended SGCC activities to evaluate and correct the cause of the spill. Although the licensee could not determine the exact cause of the valve mispositioning, the licensee concluded that it was SGCC contractor operator error. Licensee corrective actions included the following:

- Brief all SGCC personnel on the event;
- Perform a valve position check on critical systems to verify accurate status boards;
- Reinforce the methodology of logging valves and updating the SGCC status boards;

- Add an audible tank high level alarm, and improve the local level indication; and
- Designate a backup SGCC operator to provide independent verification that valves are being operated correctly.

The failure to follow Procedure SO23-XXVII-29.37 was a violation of TS 5.5.1.1.a. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 362/97009-04).

c. Conclusions

One noncited violation was identified for the failure to follow procedure for aligning the temporary system installed to transfer water and chemicals for SGCC. The error resulted in a spill of SGCC rinse water. The licensee performed a thorough review of the spill and implemented extensive corrective actions prior to restart of the SGCC activities.

E7 Quality Assurance in Engineering Activities

E7.1 AR Programmatic Review

a. Inspection Scope (71707)

The inspectors reviewed the licensee's AR system and the corrective actions resulting from conditions identified in ARs. The inspectors reviewed summaries of all 1,973 ARs initiated in April 1997. Also, from a list of 339 closed ARs that had been initiated between April 1 and April 15, 1997, the inspectors selected 15 ARs (13 classified as "important to safety") for further review:

970400011	970400383	970400646
970400078	970400499	970400656
970400133	970400541	970400688
970400231	970400591	970400697
970400304	970400602	970400764

The inspectors reviewed General Procedure SO123-XV-5, Revision 7, "Nonconforming Material, Parts, or Components," regarding the licensee's criteria for initiating nonconformance reports (NCRs), and Work Process Procedure SO123-XX-1, Issue 2, Revision 6, "Action Request/Maintenance Order Initiation and Processing," regarding AR closure review.

b. Observations and Findings

Many of the ARs were for very minor discrepant conditions. The threshold for initiating ARs was very low.

Each of the 15 ARs selected for further review was dispositioned with corrective action, evaluation, and/or trending assignments appropriate for the circumstances. Operability determinations and reportability evaluations were performed and documented when assigned. All assignments were prioritized and assigned to specific individuals. No deficiencies in the dispositions were identified.

None of the conditions in the 15 selected ARs required an NCR to be initiated. However, a small oil leak on the HPSI Pump 2P017 bearing oil sightglass (AR 970400688) was evaluated as an acceptable deficiency, and no further action was assigned. However, the operability assessment in AR 970400688 stated that the hole for the sightglass in the bearing housing was not drilled and tapped correctly, and no action was taken to disposition the discrepancy. The AR committee review resulted in the cognizant engineer being contacted to confirm the disposition as "accept as is," but did not further challenge the closure of the AR. The inspectors discussed this deficiency with licensee management, and determined that closure of the AR without action to correct even a minor oil leak did not meet management expectations. The licensee initiated another AR to correct the oil leak. The inspectors also asked the licensee if the hole not having been "drilled and tapped correctly" conformed with the pump design. The vendor installation drawing, the only available document, showed that the sightglass was to be installed "level." Based on this, the licensee conservatively initiated an NCR. The cognizant engineer also stated that he would contact the vendor to obtain the design specifications for the sightglass fabrication and installation. The inspectors considered this an isolated example of an incomplete review of a deficiency.

The licensee's policy for feedback to AR initiators was discussed with the AR program administrator. Procedure SO123-XX-1 required the AR Committee to perform a post-closure review of certain types of AR assignments, including operability assessments and NCRs. The licensee's electronic AR system automatically sends the AR initiators an electronic mail message informing the initiator of closure of selected assignment types, including evaluations for betterment, some event reports, industrial safety items, and procedural issues. These feedback mechanisms do not yet encompass all the aspects for which licensee management desires to provide feedback. For the "accept as is" conditions identified above, the initiator would not be provided feedback. However, the initiators could always review the status of the submitted AR to determine the status. The Vice President, Nuclear Generation, had in the past requested the licensee staff to establish a feedback process for ARs, and the process was still under development.

c. Conclusions

The AR program continued to provide an effective low-threshold tool for problem identification and correction. The ARs were thoroughly reviewed and dispositioned. Although feedback to initiators was not always required, the licensee's feedback process was still being developed.

E8 Miscellaneous Engineering Issues (37551, 92700, 92903)

E8.1 (Closed) LER 361/97001-01 and -02: surveillances not current upon improved TS implementation

These revisions amended the LER to include six additional TS surveillances identified as having been missed during the licensee's review of the SRs and the implementing procedures.

The first issue, regarding CEA reed switch position transmitters (SR 3.1.5.4), was previously discussed in NRC Inspection Report 50-361;362/97-02.

The licensee identified that the reactor head vent system had not been properly aligned for testing after implementation of a 1995 design change, resulting in not complying with SR 4.4.10.3 (in the TS in effect before August 5, 1996), or with LCS 3.4.102.3 (after August 5, 1996).

The licensee determined that SR 3.3.5.6, which required verification that engineered safety features response times were within limits, was not met in that the "K relay" in each circuit was not actually timed. The licensee had instead estimated a conservative value and added it to the actual timing of the rest of the circuit. This issue was discussed in a conference call between the licensee and NRC personnel on February 15, 1997, resulting in the granting of a Notice of Enforcement Discretion for Unit 3. The licensee completed the required surveillance test in Unit 2, and submitted a TS amendment request delaying implementation of the requirement for Unit 3 until the Cycle 9 refueling outage.

Another missed surveillance identified in this LER revision was a similar issue for EDG undervoltage start time testing (SRs 3.3.7.3.b and 3.3.7.4). The licensee had been timing only the loss of voltage relay (127F), and not the entire loss of voltage channel.

The licensee also determined that SR 4.8.4.1.a.1, from TS in effect before August 5, 1996, had not been met in the 1989 to 1991 time frame. This SR required testing of containment penetration conductor overcurrent protective devices. Specifically, the licensee was required to test 10 of 10 6.9 KV breakers, on a rotating basis, 10 percent per refueling cycle. The licensee should have tested one breaker each cycle and rotated through the ten breakers. However, the licensee did not maintain the rotation, and tested one Unit 2 breaker in 1986 and one again in 1989.

The licensee also identified that the old TS, and the current LCS, required testing of 39 fire detectors in an area that only had 38 installed. This was not in compliance with old TS SR 3.3.3.7.1 or LCS SRs 3.3.106.2 and 3.3.106.4.

These issues will be reviewed as part of Unresolved Item 361; 362/96018-02.

E8.2 (Closed) Unresolved Item 361; 362/96005-05: transfer of two spent fuel assemblies in the fuel transfer carriage.

The licensee identified past instances in which two spent fuel assemblies had been transferred using the two storage locations in the fuel transfer carriage. Although the San Onofre Updated Final Safety Analysis Report (UFSAR) did not specifically prohibit the simultaneous transfer of two spent assemblies, it indicated that the fuel transfer tube was sufficiently large to provide natural circulation cooling of a fuel assembly in the unlikely event that the transfer carriage should be stopped in the tube. The licensee subsequently performed design calculations which indicated that sufficient natural circulation cooling existed for two spent assemblies, and that the transfer of two assemblies would not change radiation zones near the transfer tube. The licensee submitted the design calculations to NRR for information. The inspectors reviewed the licensee's calculations, the licensee's UFSAR changes to indicate that two spent fuel assemblies could be simultaneously transferred in the carriage, and the licensee's 10 CFR Part 50.59 evaluation for the UFSAR changes. The inspectors concluded that the licensee's actions for this item were thorough. The licensee planned to include the UFSAR changes in the 1997 annual update to be submitted to the NRC.

E8.3 Criticality Monitors - Units 2 and 3

The inspectors reviewed the licensee's compliance with 10 CFR Part 70.24, regarding criticality monitors. In a letter dated August 20, 1990, the NRC granted the licensee an exemption from the requirement to provide two criticality monitors. The exemption is subject to the restriction that no more than one fuel assembly be outside an approved shipping container, storage rack, or the fuel transfer carriage at any time, although two fuel assemblies may be in the fuel transfer carriage. Based on the exemption, no further inspection was performed.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiological Protection and Chemistry

R4.1 System Breach Without Health Physics (HP) Notification - Unit 3

a. Inspection Scope (71750)

On April 26, 1997, the inspectors observed SGCC contractor personnel disregard the posted instructions when breaching the SGCC system. The inspectors discussed the observation with the contractor personnel and HP supervision, reviewed AR 970401703, and various HP procedures.

b. Observations and Findings

The inspectors observed contractor personnel breach a SGCC tank level sight glass fitting labeled "caution internal contamination" that was inside a posted area labeled "radioactive materials inside components, notify HP for system breach." Liquid sprayed from the fitting onto the plywood decking inside the bermed area. The contractors indicated that HP had not been notified prior to breaching the fitting, as instructed by the posting.

The inspectors notified HP of the situation, and an HP supervisor and a technician responded to the location. The technician surveyed a bucket that had caught some of the water, the fitting, and the plywood decking and identified no contamination. The HP supervisor reminded the contractor personnel to always notify HP prior to breaching part of the SGCC system. The contractor indicated that he was aware of the instructions to notify HP for system breaches, but forgot about notifying HP in efforts to return the SGCC system to service following the spill that had occurred the previous night (Section E2.4). The contractor indicated that during the shift turnover the oncoming crews would be reminded about notifying HP prior to breaching systems.

The licensee initiated an AR to assess what happened, what should have happened, and to assign preventative and corrective actions. The contractor held crew briefings detailing the event and the licensee requirements. HP sampled the water and determined that the activity was at the lower level of detectability (approximately 1E-7 μCi/cc), and that a radiation exposure permit would not have been, and was not, required for breaching the system. The licensee concluded that the consequences of the event were minimal since there was no release of radioactive material.

The inspectors questioned HP supervision as to the correct sequence of events that should have occurred. The supervisor indicated that the contractor personnel should have contacted HP prior to the system breach. An HP technician would then respond to the area, evaluate the breach for potential contamination, and direct contractor personnel to sign onto a radiation exposure permit if deemed necessary. The technician would then monitor the evolution for potential contamination.

Maintenance Policy Guideline SO123-G-3, Revision 3, "Work Rules and Responsibilities," Section 4.6, which applies to Maintenance personnel, states that "permanent and temporary warning signs are used throughout the plant and will be obeyed by all employees." Additionally, during their initial site access training, the contractor personnel had been directed to follow radiological postings. The inspectors concluded that the contractor employee had not followed site procedures, in violation of TS 5.5.1.1.a. This failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (NCV 362/97009-05). The inspector considered that the potential consequences of opening potentially contaminated systems

without proper controls could be more severe than they were in this specific occurrence.

The licensee does not have procedures applying to all personnel requiring compliance with radiological and other warning signs and postings. While it was clearly the expectation of licensee management that such postings be followed by all personnel, the inspector considered the absence of formal guidance to that effect to be a weakness in the licensee's radiological control program.

c. Conclusions

Contractor personnel performing the SGCC demonstrated poor radiological work practices by not following the barrier postings and breached a potentially contaminated system, contrary to site procedures. The licensee corrective actions to the event were excellent. This was identified as a noncited violation. The absence of formal requirements applying to all personnel requiring compliance with radiological signs and postings was a weakness of the licensee's radiological control program.

P5 Staff Training and Qualification in Emergency Preparedness

P5.1 Computer-based Emergency Preparedness Training (71750)

On May 2, 1997, the inspectors participated in the computer-based training for emergency preparedness. The training provided the user several options for training on the specific areas manned during a plant emergency or an emergency plan overview. The training included a test on the sections completed, and provided immediate feedback on each question. The inspectors concluded that the training was very informative, accurate, and easy to use.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on May 21, 1997. The licensee acknowledged the findings presented.

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

ATTACHMENT

SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Brieg, Manager, Station Technical
J. Clark, Manager, Chemistry
J. Fee, Manager, Maintenance
G. Gibson, Manager, Compliance
R. Krieger, Vice President, Nuclear Generation
J. Madigan, Manager, Health Physics (Acting)
D. Nunn, Vice President, Engineering and Technical Services
T. Vogt, Plant Superintendent, Units 2 and 3
R. Waldo, Manager, Operations

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 42700:	Plant Procedures
IP 61705:	Incore/Excore Detectors
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 90712:	Inoffice Review of LER
IP 92700:	On Site LER Review
IP 92901:	Followup - Operations
IP 92903:	Followup - Engineering

ITEMS OPENED AND CLOSED

Opened and Closed

50-362/97009-01	NCV	failure to follow EDG surveillance procedure
50-361/97009-02	NCV	WPS used without approval
50-362/97009-03	NCV	HPSI check vaive test procedure inadequate
50-362/97009-04	NCV	failure to follow SGCC procedure
50-362/97009-05	NCV	failure to follow procedures regarding radiological postings

Closed

50-362/96015-01	VIO	volume control tank inlet diversion valve controller in wrong mode
50-361/97002-03	VIO	inadvertent transfer of water to RCS and failure to maintain RCS pressure within limits
50-361/97008-00	LER	failure to perform pressurizer cooldown rate surveillance
50-361/97001-01	LER	surveillances not current upon improved TS implementation
50-361/97001-02	LER	surveillances not current upon improved TS implementation
50-361/97005-05 50-362/97005-05	URI	transfer of two spent fuel assemblies in fuel transfer carriage

LIST OF ACRONYMS USED

AR	action request
CEA	control element assembly
EDG	emergency diesel generator
HL	hot leg
HP	health physics
HPSI	high pressure safety injection
LCO	limiting condition for operation
LCS	licensee-controlled specifications
LER	licensee event report
MO	maintenance order
NCR	nonconformance report
NPEO	nuclear plant equipment operator
PDR	Public Document Room
PMP	procedure modification permit
PQR	procedure qualification record
RCS	reactor coolant system
RSAS	respiratory/service air system
SG	steam generator
SGCC	steam generator chemical cleaning
SI	safety injection
SR	surveillance requirement
TCN	temporary change notice
TE	temperature element
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
UGS	upper guide structure
WPS	weld procedure specification