ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-361/96-02
50-362/96-02

Licenses: NPF-10
NPF-15

Licensee: Southern California Edison Co.
P.O. Box 128
San Clemente, California

Facility Name: San Onofre Nuclear Generating Station, Units 2 and 3

Inspection At: San Onofre, San Clemente, California

Inspection Conducted: February 11 through March 23, 1996

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EXECUTIVE SUMMARY

San Onofre Nuclear Generating Station, Units 2 & 3
NRC Inspection Report 50-361/96-02, 50-362/96-02

This routine announced inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an announced inspection by a regional project inspector.

Operations

- The inspectors identified that the licensee's processes for procedure changes and abnormal alignments failed to ensure compliance with the Technical Specification (TS) 6.8.2 requirement for management approval of procedures prior to implementation. This was identified as a violation (Sections O3.1 and O3.2).

- Operators quickly and properly diagnosed a loss of voltage signal actuation in Unit 3, and responded appropriately (Section O1.1).

- A noncited violation was identified as the result of the licensee's determination that reactor coolant system pressure boundary leakage had occurred in Unit 3 during Cycle 7 operation (Section O8.1).

Maintenance

- The inspectors observed multiple maintenance activities during the report period. Overall, the maintenance and surveillance activities were thorough and performed professionally (Sections M1.1 and M1.2).

- The inadvertent actions of a test technician while taking voltage readings caused Transformer 3XR1 to trip and resulted in a loss of voltage signal actuation start of the emergency diesel generators (Section M8.3).

- While repacking a charging pump, machinists had to depart from the maintenance procedure in use in order to achieve the desired tightness of the crosshead bearing. The machinists were not sensitive to the opportunity to improve the procedure until prompted by the inspector (Section M3.1).

- Instrumentation and Control technicians properly performed a monthly surveillance of the Unit 3 safety channel excore nuclear instrumentation. However, in one instance the technician failed to energize a test current source when the procedure directed that a current be inserted, contrary to licensee management expectations for skill of the craft (Section M1.4).

- In a sampling audit of maintenance orders assigned to the "Work-It-Now" team, the inspectors concluded that the scope of activities being assigned and performed by the team was appropriate (Section M6).

- The maintenance for repair of a boric acid makeup system relief valve in Unit 2 was weak in that the valve required a second repair because effects of backpressure were not considered. The licensee's actions to address this weakness appeared appropriate (Section M1.5).

- A licensee planner's discovery that a VT-2 visual examination of a boric acid makeup system relief valve in Unit 2 had been outstanding since July 1994 was good. Although the ASME Code does not require a VT-2 for this component, one had been scheduled and not performed. The previous identification of a programmatic weakness in this area by the Quality Assurance (QA) organization was good (Sections M1.5 and M7.2).

- The licensee's practice of tightening battery cell terminal bolts prior to taking terminal resistance readings could reduce resistance, affecting the surveillance test results. The inspectors determined that this practice was recommended by IEEE Standard 1980-450, to which the licensee was committed, and was therefore acceptable (Section M1.3).

- A noncited violation was identified in Unit 3 after the licensee reported that operators had failed to recognize that the hydrogen monitor on the waste gas holdup system was inoperable during a daily channel check, and consequently failed to implement the actions required by TS (Section M8.2).

Engineering

- In response to the overspeed trip of Unit 3 turbine-driven auxiliary feedwater pump during an inservice test, the licensee's initial root cause investigation and operability assessment were thorough and appropriately concluded that the pump was operable with the conditions specified. The Vice President, Nuclear Generation's decision to shut down the unit if the pump tripped before the maintenance could be accomplished was conservative and appropriate (Section E2.1).

  Engineering involvement in the data collection and analysis and in the development of the plan to prevent future overspeed conditions was excellent, and the 10 CFR Part 50.59 safety evaluation appeared to be thorough. The identification of some historical anomalies in the trip-throttle valve pilot delay time reflected thoroughness on the part of the licensee's staff. Observed maintenance and testing activities were well-controlled, with good engineering involvement (Section E2.1).

- The licensee's actions to ensure that the Unit 3 hydrogen monitors would reset and restart, in response to their failure to reset after the loss of voltage signal actuation, appeared appropriate (Section M8.2).

- The inspectors identified one instance in which the UFSAR was inconsistent with respect to local controls for starting and stopping motor-driven auxiliary feedwater pumps (Section M7.1).

Plant Support

- The licensee's response and corrective actions regarding the February 28, 1996, electrical extension cord fire were appropriate (Section F1.1).

Report Details

Summary of Plant Status

Both units operated at approximately 100 percent power throughout this inspection period, except for power reductions to approximately 75 percent power for heat treating the circulating water system in Unit 2 on February 17 and March 15-17, 1996, and to bump the circulating water pumps in Unit 3 on March 14, 1996.

I. Operations

01 Conduct of Operations

01.1 Loss of Voltage Signal Actuation

a. Inspection Scope (71707)

The inspector reviewed the licensee's investigation and response to the March 4, 1996, loss of voltage signal actuation in Unit 3.

b. Observations and Findings

On March 4, 1996, an test technician taking inservice electrical readings on the Reserve Auxiliary Transformer 3XR1 differential relay accidentally brought in the Phase A differential trip with a test lead. As a result, the inlet and outlet supply breakers opened for all three Unit 3 reserve auxiliary transformers, the Unit 2 slow transfer protection scheme provided power from the Unit 2 emergency power buses to the Unit 3 emergency buses, and the Unit 3 emergency diesel generators (EDGs) started. All systems responded as designed.

In response to this event, operators quickly diagnosed the cause and secured the diesel generators. After review of alarm status, plant computer alarms, and a walkdown of all affected electrical components, the reserve auxiliary transformers were re-energized.

Maintenance aspects of this event are discussed in Section M8.3.

c. Conclusions

Operator response to the loss of voltage signal actuation was prompt and accurate. Actions taken to evaluate the cause of the transformer trip and subsequent restoration actions were appropriate.

03 Operations Procedures and Documentation

03.1 Management Review of Procedures

a. Inspection Scope (92901)

Section 2.4 of NRC Inspection Report 50-361, 362/95-201 (the Integrated Performance Assessment of San Onofre) described an apparent violation of TS 6.8.3, Temporary Changes. The inspector followed up on the report to determine if a violation had occurred. The inspector reviewed the report, discussed the issues with licensee operations personnel, and reviewed additional operations procedures and procedure changes.

b. Observations and Findings

TS 6.8.2 requires that safety-related procedures and procedure changes, including those recommended by Appendix A of Regulatory Guide 1.33, Revision 2, shall be approved by senior site management prior to implementation. TS 6.8.3 allows senior site management up to 14 days after implementation to approve nonintent temporary changes to the same safety-related procedures covered by TS 6.8.2.

NRC Inspection Report 50-361, 362/95-201, Section 2.4, discussed Temporary Change Notices (TCNs) 6-20, 6-21, 6-32, and 6-34 to Procedure SO23-5-1.7, "Power Operations." The NRC considered that these TCNs appeared to be changes of intent and were required to be approved prior to implementation, per TS 6.8.2. However, the licensee defined intent as "the objective of the document." The inspector noted that the document title, "Power Operations," and the licensee's broad definition of intent made it possible for the licensee to define all changes in power operations as being nonintent changes.

The inspector reviewed the licensee's procedure for issuing TCNs, Procedure SO123-VI-1.0.1, Revision 7, TCN 1, "Temporary Change Notices (TCNs)/Editorial Corrections (ECs) Preparation, Review, Approval, Incorporation and Distribution." The licensee's TCN process followed TS 6.8.3, in that it allowed for senior site management approval of TCNs after implementation. However, the inspector determined that the licensee had no timeliness requirement for incorporating TCNs into permanent changes, revisions, or new procedures. The inspector noted that Procedure SO23-5-1.7 currently had 36 TCNs, with the last revision issued in 1988. The inspector reviewed other operating procedures and determined that many had not been revised since the mid-1980's, despite having a number of TCNs. The inspector considered that the TCNs were not temporary, because the licensee had no process which required incorporating the TCNs into permanent changes, revisions, or new procedures. Therefore, TS 6.8.3, which only covers temporary changes, was not applicable to the licensee's TCN process. The inspector determined that TCNs 6-20, 6-21, 6-32, and 6-34 to Procedure SO23-5-1.7, and numerous other TCNs, were not approved by senior site management prior to implementation. This is one example of a violation of TS 6.8.2 (VIO 361, 362/96002-01). Based on the above discussion, the inspector determined that the apparent violation of TS 6.8.3 discussed in NRC Inspection Report 50-361, 362/95-201, Section 2.4, was actually a violation of TS 6.8.2.

The inspector reviewed a number of TCNs and did not identify any technical errors which would have or should have been found by senior site management review prior to implementation. The inspector discussed the TCN process with the licensee. The licensee stated that its TCN process was very formal, and that failure to comply with TS 6.8.2 was an oversight. The licensee stated that for operating procedures, the entire procedure was typically reissued with each TCN.

The Operations manager stated that the licensee intended to revise its program so that TCNs would be reviewed and approved by the appropriate manager within 14 days of implementation, and that the TCNs would then be considered permanent changes. Additionally, the licensee intended to review all existing TCNs during the next two years, with the result being that all TCNs would be considered permanent procedure changes. To address the large numbers of TCNs associated with some procedures, the licensee stated that it intends to provide programmatic guidance that procedures should not normally have more than five TCNs between revisions. The inspector considered these actions appropriate.

O3.2 Procedures for Control of System Alignments

a. Inspection Scope (92901)

Section 2.4 of NRC Inspection Report 50-361, 362/95-201 (the Integrated Performance Assessment of San Onofre) described an apparent violation of TS 6.8.2, Procedure Approval. The inspector followed up on the report to determine if a violation had occurred. The inspector reviewed the report, discussed the issues with licensee Operations personnel, and reviewed additional Operations procedures and procedure changes.

b. Observations and Findings

NRC Inspection Report 50-361, 362/95-201, Section 2.4, discussed the licensee's process for abnormal alignments, Procedure SO123-0-23, "Control of System Alignments," Revision 0, TCN 20. The NRC determined that the licensee had used a Procedure SO123-0-23 process to perform special test procedures. A number of these special test procedures were not approved by senior site management prior to implementation in accordance with TS 6.8.2.

The inspector determined that Procedure SO123-0-23 was normally used for control of abnormal alignments. The inspector reviewed the process and a number of abnormal alignments and determined that they were in compliance with TS 6.8 requirements. However, the inspector verified that

Procedure SO123-0-23 was also used for a number of special test procedures, including the check valve testing discussed in NRC Inspection Report 50-361, 362/95-201, Abnormal Alignments 2-95-138, 2-95-140, and 2-95-141. These abnormal alignments, which included nonstandard operation of high pressure safety injection pumps, multiple valve manipulations, and testing of associated check valves, were not approved by senior site management prior to implementation. This is a second example of a violation of TS 6.8.2 (VIO 361, 362/96002-01). The cause of this violation was failure of the licensee's abnormal alignment and document change processes to ensure compliance with TS 6.8.2 requirements.

The inspector discussed the abnormal alignment process with licensee personnel. The licensee acknowledged that the abnormal alignment process was being used to perform special tests, which were covered by TS 6.8.2. The licensee issued immediate instructions to obtain senior site management approval prior to implementation of any future abnormal alignments which would accomplish test evolutions, and revised the affected administrative procedure to reflect that requirement. The inspector considered the licensee's corrective actions appropriate.

During the discussion, the licensee stated that NRC Inspection Report 50-361, 362/95-201, Section 2.4, contained an error, in that a high pressure safety injection pump was not dead-headed, as reported. The inspector reviewed all the associated test procedures, reviewed nuclear oversight division records, and discussed the issue with nuclear oversight and nuclear operations personnel. The inspector determined that the pump had not been dead-headed. Therefore, although the licensee procedure violated TS 6.8.2, it did not cause a dead-headed pump, as noted in NRC Inspection Report 50-361, 362/95-201.

O3.3 Conclusions on Operations Procedures and Documentation

The licensee improperly considered TCNs to be temporary and, consequently, was not obtaining the management reviews required by TS 6.8.2 prior to implementation. This was a violation of TS 6.8.2.

The licensee improperly used an abnormal alignment process to develop and approve procedures without obtaining the management reviews required by TS 6.8.2 prior to implementation. This was a violation of TS 6.8.2.

08 Miscellaneous Operations Issues

08.1 (Closed) Licensee Event Report (LER) 50-362/95-001-00: reactor coolant system (RCS) pressure boundary weepage.

a. Inspection Scope (92700)

The inspector reviewed the LER, selected nonconformance reports, and selected FCNs associated with the corrective actions identified in the LER. Engineering aspects of this issue are discussed in Section E3.1.

b. Observations and Findings

This LER described the discovery of evidence of RCS pressure boundary weepage during inspections of Alloy 600 and 690 instrument nozzles during the Unit 3 Cycle 8 refueling outage that commenced in July 1995. The weepage was from one pressurizer level instrument nozzle and two RCS hot leg instrument nozzles. The licensee determined that the leaks were minute and had been inactive for more than 1 year prior to discovery.

The licensee implemented design changes to correct and prevent further pressure boundary leakage from these nozzles.

TS 3.4.5.2(a) requires that RCS leakage be limited to no pressure boundary leakage. Contrary to the above, as reported by the licensee, pressure boundary leakage existed for approximately 1 year during operation in Modes 1 through 4 prior to the July 1995 refueling outage. The licensee's identification and corrective actions regarding the RCS pressure boundary leakage were thorough and timely. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC of the Enforcement Policy (NCV 362/96002-02).

c. Conclusions

A noncited violation was identified as the result of RCS pressure boundary leakage existing in Unit 3.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments on Maintenance Activities

a. Inspection Scope (62703)

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

- 96020624: Calibrate high lube oil temperature switch on Unit 2 EDG 2G003 Engine 1
- 96091287: Adjust fuel injectors on Unit 2 EDG 2G003
- 96011337: Change oil and oil filter on Unit 3 auxiliary feedwater bypass Valve 3HV4763
- 94060143: Replace sightglass on governor for Unit 2 EDG 2G003, Engine 2
- 96032541: Replace Woodward governor controls for Unit 3 turbine-driven auxiliary feedwater (AFW) Pump 3P140
- 96020805: Repair sticking ammeter for Unit 2 component cooling water Pump 2P024
- 96011483: Replace Unit 3 non-1E uninterruptable power supply air conditioning unit Compressor 3ME677
- 96033131: Replace the speed probe for Unit 3 turbine-driven AFW Pump 3P140
- 96010007: Add oil to Unit 3 salt water cooling Pump 3P112 motor upper bearing

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. The inspectors frequently observed supervisors and system engineers monitoring job progress, and quality control (QC) 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 Sections M1.5, M1.6, M3.1, M7.1, and M8.3, below.

M1.2 General Comments on Surveillance Activities

a. Inspection Scope (61726)

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

- SO23-3-3.60.6, Attachment 6, Revision 0; "Unit 2 Auxiliary Feedwater Pump 2P504 Test"
- SO23-3-3.13, Attachment 1; "ECU Surveillance," Unit 3
- SO23-II-1.1.5, TCN 3-5; "ESFAS Logic Matrix Relay Test," Unit 3
- SO23-3-3.35, Attachment 1, TCN 7-2; "PAMI Monthly Channel Check," Unit 3
- SO23-3.3.21, Attachment 2, TCN 13-2; "Toxic Gas Monitoring," Unit 3

b. Observations and Findings

The inspectors found all surveillances performed under these activities to be professional and thorough. All surveillances observed were performed with the surveillance procedure present and in active use. Technicians were experienced and knowledgeable of their assigned tasks.

In addition, see the specific discussions of surveillances observed under Sections M1.3 and M1.4, below.

M1.3 Safety Related Battery Surveillance - Unit 2

a. Inspection Scope (61726)

On February 28, 1996, the inspector observed electricians performing a surveillance on Unit 2 safety-related Battery 2B008 in accordance with Maintenance Order (MO) 95111665 and Procedure SO123-I-2.4, Revision 2, "Physical Inspection of Batteries."

b. Observations and Findings

The inspector noted that the surveillance, which included a battery cell inspection and terminal resistance readings, was required by TS and had been performed within the required surveillance interval, once per refueling outage. During the surveillance the inspector noted that the electricians were required by the surveillance procedure to torque the cell terminal bolts prior to taking resistance readings. The inspector determined that this practice could decrease the resistance across the battery post terminal and bar and, therefore, was preconditioning of the battery for the surveillance. The inspector was concerned that this practice could mask potential degradation of the connections.

In response, the licensee provided the inspector a copy of IEEE Standard 1980-450, "Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," which recommended that the terminal bolts be tightened before taking resistance readings. The inspector verified that the licensee's TS referenced IEEE Standard 450-1980 as the basis used for establishment of the surveillance criteria to test the resistance across the battery posts and terminals. In addition, the inspector reviewed the UFSAR and verified that the licensee had committed to IEEE Standard 450-1980. Based on review of IEEE Standard 450-1980, the inspector determined that the licensee appropriately implemented the recommended guidance. As a result, the inspector concluded that the surveillance method used was appropriate and met the intent of the surveillance requirement.

M1.4 Management Expectation for Turning On Test Current Sources During Routine Surveillances

a. Inspection Scope (61726)

On February 15, 1996, the inspector observed performance of Procedure SO23-II-5.8, TCN 11-6, "Surveillance Requirement Nuclear Instrumentation Safety Channel D Drawer Test Linear Power Subchannel Functional Test and Channel Calibration," and reviewed completed documentation for the same monthly surveillance of Channels A, B, and C in Unit 3. The inspector also reviewed electrical nuclear instrument safety channel Schematic ELJ304-3010 and had discussions with Instrumentation and Control (I&C) technicians, supervisors, and management.

b. Observations and Findings

The inspector observed that the technician failed to energize a test current source when appropriate. This error was self-evident when the technician later attempted to read an output voltage. The technician corrected his error. The inspector discussed this with the I&C manager, who stated that no error had been made, although he agreed with the facts of the observation. On March 21, 1996, the inspector discussed this observation with the Maintenance manager, who agreed that an error had been made, and that his expectation was that test instrumentation would be energized when appropriate. The Maintenance manager stated that this expectation would be reinforced with all I&C technicians.

The inspector found that the technician had not met management expectation in this instance, and that reinforcing this expectation was prudent.

M1.5 Boric Acid Makeup System Relief Valve Maintenance - Unit 2

a. Inspection Scope (62703)

On January 24, 1996, the inspector observed postmaintenance testing associated with repair of a leak to Unit 2 boric acid pump discharge relief valve 2PSV9243 in accordance with MO 95041320000.

b. Observations and Findings

During postmaintenance testing of the relief valve, leakage was observed from the same location as that which had required the maintenance. The licensee determined that the cause of continued leakage was not corrected or detected during repair due to failure to note that the leak was caused by system backpressure. The licensee subsequently repaired the leak and tested the valve. The inspector verified the test was satisfactory.

Based on this repeat work on the relief valve the inspector concluded that maintenance for repair of the relief valve was weak in that the effects of backpressure were not effectively considered as part of the repair and postmaintenance testing process. In response to the inspector's observation the licensee stated that expectations regarding consideration of applicable system pressure would be reemphasized to planners and craftsmen during routine continuing maintenance training. The inspector concluded that the licensee's proposed corrective action was adequate.

The inspector subsequently determined that the planner for the valve repair had discovered that an ASME Code Section XI (the Code) visual examination test (VT-2) on the relief valve had been outstanding since July of 1994. As a result, the planner rescheduled the VT-2 to be performed after repair of the relief valve. The inspector reviewed the previous maintenance documentation and determined that the VT-2 had been requested but had not been performed after maintenance was completed in 1994. The inspector noted that the Code exempted components of a nominal pipe size of 1 inch, so there was no Code requirement for a VT-2 on this relief valve.

The inspector considered that the licensee's programmatic controls failed to insure the test was performed irrespective of knowing it was not required by the Code. In addition, once the omission was discovered, the licensee had not initiated an investigation to determine the root cause. The inspector discussed this issue with licensee management. The licensee agreed that an investigation was appropriate.

The inspector reviewed the maintenance history for the relief valve and determined that the associated MO had not been closed out because the VT-2 inspection had not been performed. However, the inspector noted the licensee had no programmatic requirement to audit outstanding MOs to insure timely resolution of outstanding Code requirements.

The inspector noted that the licensee's QA organization had recently issued a corrective action request to maintenance and engineering because an audit had revealed several visual examinations were outstanding and considered untimely. The inspector determined that as a result of the corrective action request maintenance and engineering were in process of actions to formally address untimely VT-2 inspections.

At the end of the inspection period Maintenance and Engineering had not finalized corrective actions. However, the licensee issued interim corrective action to insure that VT-2 inspections were performed in a more timely manner. The inspector considered the interim action appropriate.

c. Conclusion

The inspector concluded that planning for the valve repair was weak, in that the cause for the leak was not initially identified or repaired. In addition, the inspector concluded that the licensee's VT-2 program requirements had not ensured timely completion of required inspections.

M1.6 Saltwater Cooling System Painting - Unit 2

a. Inspection Scope (62703)

On February 7, 1996, the inspector performed a walkdown of ongoing painting activities in the Unit 2 saltwater cooling pump room.

b. Observations and Findings

The inspector noted that painters had painted a Unit 2 saltwater cooling pump normal seal water supply valve limit switch (a minor moving part). The inspector determined that the paint did not interfere with the function of the switch. The inspector informed the licensee and the paint was removed.

The inspector reviewed the licensee's painting procedure and determined that it was a management expectation that moving parts generally should not be painted. The inspector discussed this observation with maintenance management and determined that the observed example did not meet management expectations.

As a result of the inspector's observation, maintenance management stated that expectations regarding painting of moving parts would be especially emphasized during the two daily tailboards given to painters. Maintenance management also indicated that periodic training would be given on sensitive components to increase painter awareness regarding what items not to paint, during weekly meetings with the painting staff. In addition, in response to problems the licensee had noted regarding prior performance of the contract painting staff, the licensee stated that a painting qualification program was in development to assure better future performance for new painters brought on site. The inspector found that the licensee's proposed and completed corrective actions appropriately addressed the issue.

M1.7 Conclusions on Conduct of Maintenance

Overall, the inspector concluded that maintenance was performed well. Maintenance management's expectation that test instrumentation be energized when its use is directed during surveillances was appropriate. In one instance, the licensee failed to effectively consider system pressure during repair and retest of a relief valve. Although the licensee planned and performed VT-2 visual examinations beyond that required by the ASME code, the licensee did not programmatically control timely performance of the inspections. The failure to manage the outstanding backlog of MOs for VT-2s was a weakness. An error during maintenance resulted in a loss of voltage signal actuation. The licensee initiated appropriate action to ensure that painters were well-trained and qualified.

M3 Maintenance Procedures and Documentation

M3.1 Procedural Enhancement Opportunity While Performing Charging Pump 3P190 Repacking

a. Inspection Scope (62703)

The inspector observed partial performance of licensee Maintenance Procedure SO23-I-8.25, TCN 2-3, "Charging Pump Repack, Lubrication, and Crosshead Adjustment," on Charging Pump 3P190, per MO 94091877. The inspector also discussed the maintenance with maintenance craft, supervision, and management.

b. Observations and Findings

On February 28, 1996, the inspector watched licensee machinists adjust new crosshead balls and sockets installed on all three plungers of the triplex pump. The inspector noted that the machinists loosened a bearing set-screw, then tightened the bearing retainer nut to plunger adapter clearance until a slight drag was felt, then torqued the bearing set-screw to lock the bearing in place, per Step 6.4.11 of the procedure. However, the inspector noted that for two of the three plungers, the action of torquing the set-screw caused the bearing retainer nut to plunger adapter clearance to decrease slightly, resulting in the bearing being on the plunger without adequate freedom of movement. (The bearing moved slightly as the pump stroked.) The inspector noted that the machinists compensated for this by backing out the set-screw and adjusting the clearance to achieve less drag, which resulted in a slight drag with the set-screw retightened. These actions had not been incorporated into the procedure but were not precluded by the procedure. The inspector also noted that the machinists did not note that the procedure as written could be enhanced, and consequently did not plan to do so. The inspector discussed this with the first line supervisor, who then agreed to change the procedure to enable it to be performed strictly as written.

c. Conclusions

Machinists were not sensitive to the opportunity to improve the procedure for adjusting the tightness of the charging pump crosshead bearings.

M6 Maintenance Organization and Administration (62703)

The inspector performed a sampling audit of work assigned to the licensee's recently implemented "Work It Now" team. The program had been in effect for about 1 year. The program requirements and guidance for the program were contained in Procedure SO123-XX-3, TCN 1-1, "Work It Now Program." On February 28, 1996, the inspector reviewed 20 MOs which were scheduled for the "Work It Now" team. The inspector concluded that all jobs planned, which were for several different disciplines, were minor and did not appear to warrant review beyond the limited scope given to MOs provided to the "Work It Now" team. The inspector concluded that, based on the sample reviewed, the scope of maintenance activities assigned to the licensee's "Work It Now" team was appropriate.

M7 QA in Maintenance Activities

M7.1 QC Inspection of Turbine-Driven AFW Steam Trap Valve Weld and UFSAR Description of Motor-Driven AFW Pump Controls

a. Inspection Scope (62703)

The inspector observed partial performance of the replacement of Unit 3 turbine-driven pump steam trap drain Valve 3MU685 and subsequent QC inspection of welding performed under MO 96011353. The inspector also reviewed Sections 7.4, "Systems Required for Safe Shutdown," and 10.4.9, "Auxiliary Feedwater System," of the San Onofre Units 2 and 3 UFSAR. The inspector also reviewed portions of the Safety Evaluation Report (SER) for San Onofre Units 2 and 3, NUREG-0712, including Supplements 1 through 6. The inspector also held discussions with maintenance workers, QC personnel, and the cognizant engineer.

b. Observations and Findings

On February 28, 1996, the inspector observed welding of the new 3MU685 valve and subsequent QC inspection of the new weld. The inspector discussed the acceptance criteria for the weld and the measurement of the criteria as well as the nondestructive examination certification process with the QC inspector. The QC inspector was knowledgeable and meticulous and was fully qualified for the visual inspection performed.

The inspector then reviewed the portions of the UFSAR and SER mentioned above and noted that UFSAR Section 10.4.9.5, Revision 8, stated that controls were provided in the AFW pump area for motor-driven pump starting and stopping. The inspector walked down the AFW pump area and noted that no such controls existed, and that the motor-driven pumps could be started and stopped only from the main control room and the Class 1E switchgear rooms. The inspector further noted that UFSAR Section 7.4 accurately described the location of the controls and that the SER was silent as to the location of these controls. The UFSAR, as described above, was inconsistent.

The inspector brought the erroneous UFSAR statement to the attention of the cognizant engineer, who agreed that no local controls existed, and stated he would submit appropriate changes to the UFSAR to incorporate the correct licensing basis for the system. The inspector will review the licensee's actions in a future inspection (IFI 361, 362/96002-03).

M7.2 VT-2 Visual Examinations

QA identified a programmatic weakness in the control and timeliness of VT-2 visual examinations. The licensee determined that nobody had assumed programmatic responsibility for VT-2 examinations. As a result of a corrective action report, the station technical manager was designated to be responsible for the program. This issue is discussed in Section M1.5.

c. Conclusions

The QC inspector was knowledgeable and meticulous and was fully qualified for the visual inspection performed.

The QA organization appropriately identified a programmatic weakness regarding the timeliness of VT-2 visual examinations, and took necessary action to encourage the line organizations to assign responsibility for program oversight.

UFSAR Section 10.4.9.5 inaccurately stated that controls to start and stop the motor-driven AFW pumps were located in the vicinity of the pumps, although Section 7.4 accurately described the controls. An inspector followup item was opened to review the licensee's actions to correct the licensing basis for this item.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-361/94009-01: failure to adequately control out-of-calibration measuring and test equipment (M&TE). (92902)

This violation noted a continuous large number of M&TE that was out of calibration, in violation of licensee requirements. The licensee reduced the backlog of out-of-calibration M&TE. The inspector reviewed licensee records and determined that the licensee had maintained a low backlog of out-of-calibration M&TE for the last year. The inspector concluded that the licensee corrective actions were adequate.

M8.2 (Closed) LER 50-361/96001-00: inoperable waste gas system hydrogen monitor.

a. Inspection Scope (92700)

The inspector reviewed the LER and the surveillance procedure used to perform the channel check. The inspector also interviewed a radwaste operator and the operations superintendent, and observed the explosive gas monitoring system normal indications.

b. Observations and Findings

This LER documented the licensee's failure to recognize that the hydrogen monitor on the waste gas holdup system was inoperable during a daily channel check required by TS 4.3.3.9, and its consequent failure to implement the actions required by TS 3.3.3.9.b to align the remaining operable instrumentation channel to the waste gas surge tank or to obtain 4-hour grab samples. The monitor was reading zero, while the normal reading was 20-40 percent. While the radwaste operator and assistant control operator recognized and discussed the reading as abnormal, they did not realize that the monitor could be inoperable and did not report it to the control room personnel. The radwaste operator on the next shift recognized and reported the condition.

The licensee determined that a fuse had blown. The licensee replaced the fuse and performed a channel calibration and channel functional test. All operating crews were briefed on the normal values of the monitor and advised that a zero reading should be considered a monitor failure until proven otherwise. The personnel involved were coached on performance expectations.

The licensee determined that the oxygen concentration in the waste gas system was not high enough to result in a flammable gas mixture during the time that the hydrogen monitor was inoperable. The licensee concluded that the hydrogen monitor failure had no actual safety significance.

The inspector discussed the normal system conditions with a radwaste operator, and directly observed that the hydrogen monitors (one aligned to the decay tank and one aligned to the surge tank) were both reading between 15 and 20 percent. The inspector also reviewed Surveillance Procedure SO23-3-3.21.1, Attachment 1, TCN 7-1, "Radiation Monitoring and Common Daily Surveillance," and determined that the only acceptance criteria for the hydrogen monitor was that it exhibit "normal channel behavior." The radwaste operator indicated that a zero reading was very unusual.

c. Conclusions

The inspector concluded that the licensee's corrective actions were appropriate, and that the safety significance of the event was minimal. However, the licensee's performance of the channel check was unsatisfactory in that the inoperable monitor was not recognized.

TS 4.3.3.9 requires that each explosive gas monitoring instrumentation channel be demonstrated operable by performance of a daily channel check. On February 5, 1996, a channel check was performed, but the observed performance of the channel was not properly assessed with regard to channel operability, contrary to the intent of the channel check. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII of the NRC Enforcement Policy (NCV 361, 362/96002-04).

M8.3 <u>(Closed) LER 362/96001-00</u>: loss of voltage signal actuation due to inadvertent differential relay trip.

a. <u>Inspection Scope (92700)</u>

This LER described a March 4, 1996, loss of voltage signal actuation in Unit 3 caused by a maintenance error. Operational aspects of this event are discussed in Section O1. The inspector reviewed the maintenance-related aspects of this event.

b. <u>Observations and Findings</u>

The superintendent of electrical maintenance initiated a division investigation to determine the cause of this event. The licensee determined that a lead from a portable instrument caught on a relay while a technician was manipulating the lead to take inservice readings. The tension on the lead was sufficient to cause the relay to make contact and actuate.

Preliminary corrective actions included enhancements of maintenance of electrical leads, since it was believed that current maintenance contributed to event, and reevaluation of postmaintenance testing activities that required the inservice readings.

c. <u>Conclusions</u>

An error during maintenance caused this event. The licensee's proposed corrective actions were appropriate.

<u>III. Engineering</u>

E2 Engineering Support of Facilities and Equipment

E2.1 <u>Overspeed Trip of Turbine-Driven AFW Pump 3P140</u>

a. <u>Inspection Scope (37551, 61726, and 62703)</u>

In response to the March 12, 1996, overspeed trip of turbine-driven AFW Pump 3P140, the inspector observed inspection and test activities, reviewed inspection and test documentation and vendor information, reviewed the licensee's operability assessment and initial root cause assessment (in Action Request 960300555), reviewed the safety evaluation (in NCR 960300555), and discussed conditions with engineering personnel. Additionally, the inspector participated in a March 15, 1996, conference call between NRC and licensee personnel regarding operability of the pump.

b. Observations and Findings

The pump tripped at 9:10 a.m. on March 12, 1996, during startup for inservice testing (IST). The licensee immediately declared the pump inoperable and entered the 72-hour action statement of TS 3.7.1.2.1.a.

The licensee performed approximately 20 test starts of the pump without a repeat failure. However, the peak speeds during the startup sequence were inconsistent. The licensee determined that the peak speeds were greater when the interval since the previous pump run was longer. Significant variation was observed for intervals between 0 and 18 hours.

The inspector observed that the overspeed trip setpoint was approximately 2904 rpm, which was within tolerance. Additionally, the governor valve stem and overspeed trip mechanism appeared to be in good condition.

The licensee's initial root cause assessment appeared to address all potential causes. Although many causes were ruled out, some were not, and the initial root cause was indeterminate. The characteristics of the performance during the test indicated that the Woodward governor controls (EG-R hydraulic subsystem and EG-M electronic subsystem) could be causing the observed variations.

Representatives of the turbine vendor and governor vendor both reviewed the test results and agreed with the licensee's conclusions, including the conclusion that the governor performance was not erratic and did not indicate an oil quality problem.

The licensee performed satisfactory ISTs on March 14 at 9 p.m. and on March 15 at 3 a.m., at which time the pump was declared operable, contingent upon running the pump every 6 hours. The 6-hour interval was based on a statistical analysis of the test results indicating that the peak speed would remain below the trip setpoint with 99 percent confidence.

During the conference call on March 15, the licensee stated its intention to replace the governor controls (EG-R and EG-M) and the governor valve stem in a maintenance activity beginning March 18, 1996. Additionally, the Vice President, Nuclear Generation, stated that Unit 3 would be shut down if Pump 3P140 tripped during testing before the maintenance activity began. Licensee management also stated that the 6-hour test interval would not be extended, as allowed in the operability assessment in Action Request 960300555. The inspector reviewed the licensee's operability assessment and the 10 CFR Part 50.59 safety evaluation and determined that they were thorough.

Maintenance activities began as scheduled on March 18, 1996. Degradation of several carbon spacers on the governor valve stem were identified by the licensee and determined not to have contributed to the overspeed condition. The EG-M was bench-tested and found to function properly, but was replaced. The oil in the EG-R appeared to be in good condition. No obvious problems with the EG-R were identified during the initial inspection, but was considered the most likely cause of the problem and was replaced. However, the cognizant engineer indicated that the EG-R, accompanied by a licensee engineer, would be sent to the vendor for further testing. The licensee completed the maintenance activities and performed a satisfactory IST on March 19, 1996. A geometric test schedule was established to provide increased confidence in the pump's performance. Testing completed through the end of this inspection period was satisfactory.

During its investigation, the licensee identified some historical irregularities in the control of the trip-throttle valve pilot delay time. The licensee initiated a review of the circumstances regarding the irregularities to determine why they occurred. The inspector considered the licensee's identification of the potential historical issue as an indication of the thoroughness of the licensee's problem solving effort.

The inspector noted excellent involvement of engineering personnel in all phases of the evaluation, repair, and testing of the turbine-driven AFW system. The inspector also noted that vendor support was obtained.

c. Conclusions

The licensee's initial root cause investigation and operability assessment were thorough and appropriately concluded that the pump was operable with the conditions specified.

Engineering involvement in the data collection and analysis, and in the development of the plan to prevent future overspeed conditions was excellent, and operability assessment and the 10 CFR Part 50.59 safety evaluation were thorough. The identification of some historical anomalies in the trip-throttle valve pilot delay time reflected thoroughness on the part of the engineering staff. Observed maintenance and testing activities were well-controlled.

Licensee management's decision to shut down the unit if the pump tripped before the maintenance could be accomplished was conservative and appropriate.

The licensee's corrective actions were appropriate. The various licensee organizations worked well together to attempt to resolve the problem.

E3 Engineering Procedures and Documentation

E3.1 Acceptability of Welding Materials for RCS Nozzles

a. Inspection Scope (37551, 92700)

The inspector reviewed LER 362/95001-00, selected nonconformance reports, and selected FCNs associated with the corrective actions to correct RCS pressure boundary leakage identified in the LER. Additionally, the inspector reviewed applicable portions of the UFSAR. Operations aspects of this issue are discussed in Section O8.1.

b. Observations and Findings

The licensee identified indications of RCS pressure boundary leakage and reported the condition in LER 362/95001-00.

The licensee determined that the cause of the weepage was primary water stress corrosion cracking (PWSCC) of Alloy 600-type weld materials. The licensee inspected all pressurizer vapor-space nozzles from inside the pressurizer and did not find any evidence of PWSCC. Inaccessibility of the inside of the RCS piping prevented confirmatory inspections of the hot leg instrument nozzles, but because the nozzles were of Alloy 600 materials, the licensee believed that PWSCC was also the cause of weepage from them. The licensee replaced the two hot leg instrument nozzles and all four pressurizer vapor space instrument nozzles with Alloy 690 materials. A weld filler material recommended by the developer of the Alloy 690 base metals was used for the pressurizer nozzles and for the accessible portions of the hot leg instrument nozzles.

The inspector reviewed FCNs F11553M, F11445M, F11456M, F11457M, F11458M, and F11459M, which related to the pressurizer nozzle rewelding. Similar FCNs (F11542M and F11465M) related to the RCS instrument nozzles. These FCNs describe the weld filler materials used, which were as described in the LER.

The inspector reviewed applicable sections of the UFSAR and noted that Table 5.2-4 listed the RCS materials, including base materials and weld materials. The inspector noted that the material specifications, listed under Item 9 in the Table 5.2-4 for the pressurizer nozzles, were not updated in the March 1996 UFSAR update submitted to NRC. The original weld filler materials, ERNiCr-3 and ENiCrFe-3, were replaced with INCONEL-52. In response to the inspector's questions, the licensee also determined that changes made in the materials for nozzle safe ends for the pressurizer instrument nozzles and RCS piping pressure measurement nozzles were not reflected in Table 5.2-4, as required. The licensee stated that the materials used were reviewed in accordance with Article IWA-4000 of ASME XI, which allowed the substitution. In response to this finding, the licensee agreed to review and update Table 5.2-4. In the licensee's initial response to the inspector's questions, the licensee indicated that the UFSAR table should not be updated because any material substitutions must be reviewed against the original material specifications, and that updating the UFSAR could inadvertently lead to reviewing against the revised materials. This response indicated a weakness in the licensee's understanding of the stature of the UFSAR as a document intended to reflect the actual plant design.

NRC Inspection Report 50-361/95-26; 50-362/95-26 discussed several minor examples in which the UFSAR did not accurately reflect the plant design. In a February 19, 1996, response to the inspection report, the licensee committed to review the accuracy of the UFSAR and provide its conclusions and any corrective actions to the NRC. The inspector noted that the licensee's review was not yet completed. This issue is similar to those previously identified in NRC Inspection Report 50-361/95-26; 50-362/95-26. Accordingly, the issue of UFSAR accuracy and the licensee's corrective actions will be resolved during NRC's evaluation of the licensee's response.

c. Conclusions

The NRC considers this another example of Violation 361; 362/9526-02 which was cited on January 19, 1996, and for which corrective actions have not been completed. Thus, this will be tracked as an unresolved item pending the NRC's review of the corrective actions for Violation 361; 362/95-26-02. (Unresolved Item 362/96002-05)

IV. Plant Support

F1 Control of Fire Protection Activities (71750 and 93702)

F1.1 Fire in Radwaste Truck Bay

On February 28, 1996, at approximately 8:22 a.m., plant personnel reported smolder coming from a storage shed used for storage of scaffolding components in the 30-foot common radioactive materials storage area. The site fire department responded to the scene within 4 minutes; however, the smoldering had stopped itself by that time. Fire department personnel determined the cause was an electrical extension cable, and quickly isolated power to the plug and removed the cable. The inspector also responded to the scene and confirmed the incident did not last beyond 10 minutes. The licensee noted that part of the extension cord was in a pool of water from recent rains and initiated a walkdown of all other outside electrical outlets to identify any other potential electrical hazards. The inspector concluded the licensee's response and corrective actions were appropriate.

V. Review of UFSAR Commitments

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

- Weld materials listed in Table 5.2-4 were not updated to reflect recent design changes. This is discussed in Section E3.1.
- Remote controls for the AFW pumps and control valves were described accurately in UFSAR Section 7.4 but inaccurately in UFSAR Section 10.4.9.5. This is discussed in Section M7.1.

VI. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the exit meeting on March 27, 1996. 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.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Brieg, Manager, Station Technical
J. Fee, Maintenance Manager
G. Gibson, Manager, Compliance
D. Herbst, Manager, Site Quality Assurance
R. Krieger, Vice President, Vice President, Generating Station
D. Nunn, Vice President, Engineering and Technical Services
K. Slagle, Nuclear Oversight Manager
T. Vogt, Plant Superintendent, Units 2 and 3
R. Waldo, Operations Manager

NRC

M. Fields, San Onofre 2&3 Project Manager

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 61726: Surveillance Observations
IP 62703: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 90712: In Office Review of LERs
IP 92700: Onsite Review of LERs
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance

ITEMS OPENED AND CLOSED

Opened

50-361/96002-01 50-362/96002-01	VIO	failure to review and approve of procedures as required
50-361/96002-03 50-362/96002-03	IFI	review the UFSAR design basis for motor driven AFW pump controls.
50-362/96002-05	URI	failure to update the UFSAR for changes in RCS pressure boundary weld materials

Opened and Closed

50-362/96002-02	NCV	failure to prevent RCS pressure boundary leakage
50-361/96002-04 50-362/96002-04	NCV	failure to perform an adequate channel check surveillance

Closed

50-362/95001-00	LER	RCS pressure boundary leakage
50-361/96001-00	LER	inoperable waste gas system hydrogen monitor
50-362/96001-00	LER	loss of voltage signal actuation
50 361/94009-01	VIO	failure to adequately control out-of-calibration M&TE

LIST OF ACRONYMS USED

AFW	auxiliary feedwater system
EDG	emergency diesel generator
FCN	field change notice
FSAR	Final Safety Analysis Report
I&C	instrumentation and control
IST	inservice testing
LER	licensee event report
M&TE	measuring and test equipment
MO	maintenance order
PDR	Public Document Room
PWSCC	primary water stress corrosion cracking
QA	quality assurance
QC	quality control
RCS	reactor coolant system
TCN	temporary change notice
TS	technical specifications
UFSAR	updated Final Safety Analysis Report