January 31, 2005

Mr. Daniel J. Malone
Site Vice President
Palisades Nuclear Plant
Nuclear Management Company, LLC
27780 Blue Star Memorial Highway
Covert, MI 49043-9530

SUBJECT: PALISADES NUCLEAR PLANT
NRC INTEGRATED INSPECTION REPORT 05000255/2004012

Dear Mr. Malone:

On December 31, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Palisades Nuclear Plant. The enclosed report documents the inspection findings which were discussed on December 29, with Mr. P. Harden and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license.

The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results from this inspection period, four findings of very low safety significance (Green) were identified, two of which involved violations of NRC requirements. However, because the findings were of very low safety significance and because the issues have been entered into your corrective action program, the NRC is treating these violations as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response with a basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Palisades facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 6
Division of Reactor Projects

Docket No. 50-255
License No. DPR-20

Enclosure: Inspection Report 05000255/2004012
w/Attachment: Supplemental Information

cc w/encl: J. Cowan, Executive Vice President
and Chief Nuclear Officer
R. Fenech, Senior Vice President, Nuclear
Fossil and Hydro Operations
D. Cooper, Senior Vice President - Group Operations
Manager, Regulatory Affairs
J. Rogoff, Vice President, Counsel and Secretary
A. Udrys, Esquire, Consumers Energy Company
Director of Nuclear Assets, Consumers Energy Company
Supervisor, Covert Township
Office of the Governor
Michigan Department of Environmental Quality -
Waste and Hazardous Materials Division
Michigan Department of Attorney General

DOCUMENT NAME: E:\Filenet\ML050320365.wpd

To receive a copy of this document, indicate in the box: "C" = Copy without attachment/enclosure "E" = Copy with attachment/enclosure "N" = No copy

OFFICE	RIII		RIII					
NAME	RLerch:dtp		EDuncan					
DATE	01/31/05		01/31/05					

OFFICIAL RECORD COPY

ADAMS Distribution:
WDR
JFS2
RidsNrrDipmIipb
GEG
HBC
KGO
JAL3
CAA1
C. Pederson, DRS (hard copy - IR's only)
DRPIII
DRSIII
PLB1
JRK1
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-255
License No:	DPR-20
Report No:	050000255/2004012
Licensee:	Nuclear Management Company, LLC
Facility:	Palisades Nuclear Plant
Location:	27780 Blue Star Memorial Highway Covert, MI 49043-9530
Dates:	October 1 through December 31, 2004
Inspectors:	J. Lennartz, Senior Resident Inspector M. Garza, Resident Inspector R. Alexander, Radiation Specialist, RIII M. Holmberg, Reactor Inspector, RIII C. Roque-Cruz, Reactor Inspector, RIII T. Bilik, Reactor Inspector, RIII R. Jickling, Emergency Preparedness Analyst, RIII R. Ng, Reactor Engineer, RIII
Approved by:	E. Duncan, Chief Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000255/2004012; 10/01/2004 - 12/31/2004; Palisades Nuclear Plant; Operator Performance During Non-Routine Evolutions and Events; Refueling and Other Outage Activities; Identification and Resolution of Problems; and Other (Temporary Instruction 2515/150).

This report covers a 3-month period of baseline resident inspections and announced baseline inspections in radiation protection, inservice inspection and emergency preparedness. The inspections were conducted by Region III inspectors and the resident inspectors. Four Green findings, two which had an associated Non-Cited Violation (NCV), were identified during this inspection period. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process (SDP)." Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance was self-revealed when condensate reject valve CV-0731 unexpectedly opened during maintenance activities on December 1, 2004, resulting in a low suction pressure to the main feedwater pumps. The primary cause of this finding was related to the cross-cutting area of human performance because licensee personnel failed to follow appropriate administrative procedure requirements when completing minor maintenance activities.

  This finding was more than minor because it was related to the human performance attribute of the Initiating Events cornerstone and adversely impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The finding was of very low safety significance because all mitigating systems were available during the transient. No violation of NRC requirements occurred. Corrective actions included evaluating all open work requests designated as minor maintenance to ensure that plant operations would not be impacted. (Section 1R14.1)

- Green. A finding of very low safety significance was self-revealed on August 31, 2004, when a fire occurred on the lower bearing of the condensate pump P-2B motor. The motor and pump were misaligned during reassembly following maintenance in July 2004 which was not identified when the pump was returned to service. Consequently, the fire was caused by heat that was generated around the bearing due to an overload condition caused by an excessive radial offset between the motor and pump.

  This finding was more than minor because it was related to the procedure quality and human performance attributes of the Initiating Events cornerstone and adversely impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. Control room operators commenced a rapid downpower in response to the fire and manually tripped the reactor so that the condensate pump motor could be secured. The finding was of very low safety significance because all mitigating systems were available during the event, and the fire was of short duration and was isolated to the motor. No violation of NRC requirements occurred. Planned corrective actions included the development of a written procedure for aligning vertical pumps and motors that specified a method for obtaining alignment data and associated acceptance criteria. (Section 4OA2.3)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance when the defined heavy load path inside containment was not followed on September 28, 2004, when a primary coolant pump motor was lifted and moved using the polar crane. Consequently, a portion of the motor passed over the refueling cavity during the move.

  This finding was more than minor because a portion of the heavy load traveled over the open reactor vessel that contained irradiated fuel and therefore could be reasonably viewed as a precursor to a significant event. Because this finding was not suitable for a significance determination process evaluation, in accordance with Inspection Manual Chapter 0612, Section 05.04.c, the finding was submitted for review by NRC management. This finding was of very low safety significance because: (1) the estimated likelihood of dropping the load was only about 1E-5 per crane operation based on a study in NUREG CR-4982 performed for spent fuel pool accidents; (2) the polar crane was in good working condition and had no known deficiencies that would have adversely impacted the crane's ability to lift the load; (3) the duration of the heavy load lift over the reactor cavity was short; and, (4) only a portion of the heavy load passed over the reactor cavity. One Non-Cited Violation of Technical Specification 5.4, "Procedures," was identified. Corrective actions included planned changes to the heavy load procedure and training of personnel involved with heavy load lifts to clearly define that the entire load, regardless of orientation, must be maintained within the heavy load path. (Section 1R20.2)

- Green. The inspectors identified a finding of very low safety significance when American Society of Mechanical Engineers Code requirements were not met for an ultrasonic examination procedure associated with the non-destructive examinations of the weld repairs to reactor vessel head penetration nozzles No. 29 and No. 30. Specifically, the licensee failed to incorporate the Code requirements related to the timing, acceptance criteria, and corrective actions for unsatisfactory calibration checks into the ultrasonic examination procedure used for examination of these repair welds. The cause of this finding was related to the cross-cutting area of human performance because the cause of this error was due to a lack of rigor in the review of procedures.

  This finding was more than minor because if left uncorrected, unacceptable weld flaws could be allowed to remain in service. Because this finding was not suitable for a significance determination process evaluation, in accordance with Inspection Manual Chapter 0612, Section 05.04.c, the finding was submitted for review by NRC management. The finding was of very low safety significance because these errors did not affect the quality of the ultrasonic examination data recorded. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified. As part of their immediate corrective actions, licensee personnel verified that the inadequate procedure had no actual impact on the quality of the weld examination. (Section 4OA5.3)

B. Licensee-Identified Violations

None.

REPORT DETAILS

A list of documents reviewed within each inspection area is included at the end of the report.

Summary of Plant Status

The plant was in Mode 6, "Refueling", for a scheduled refueling outage when the inspection period began. Plant heat-up commenced on November 7, 2004, after all the outage activities were completed, and the reactor was taken critical on November 15th. The plant entered Mode 1, "Power Operation", on November 16th following low power physics testing and the main generator was synchronized to the electrical grid on November 17th. Plant power was raised to full power on November 21st and the plant was maintained at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather (71111.01)

The inspectors completed four inspection samples regarding actions taken to prepare for the onset of adverse weather conditions as described below.

.1 Cold Weather Preparations

a. Inspection Scope

The inspectors verified that licensee personnel had completed their cold weather preparation in accordance with System Operating Procedure 23, Attachment 8, "Cold Weather Checklist," in December 2004. The inspectors verified that heat tracing for safety-related components was operable and that insulation on safety-related components located outside were in an acceptable material condition.

The inspectors reviewed selected condition reports related to cold weather problems. The inspectors verified that identified problems were entered into the corrective action program with the appropriate significance characterization, and planned and completed corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

.2 Emergent Adverse Weather Preparations

a. Inspection Scope

The inspectors reviewed the actions taken in response to a severe thunderstorm warning with forecasted high wind gusts that was received by control room personnel on October 30, 2004. The inspectors verified that the required actions were taken in accordance with Off Normal Procedure 12, "Acts of Nature."

b. Findings

No findings of significance were identified.

.3 Emergent Adverse Weather Preparations

a. Inspection Scope

The inspectors reviewed the actions taken by control room personnel on December 12, 2004, in response to a winter storm warning which included prolonged high winds. The winter storm warning was in effect from 1:00 p.m. on December 12th until 4:00 p.m. on December 13th. The inspectors reviewed control room logs, daily work activities and plant risk assessments to verify that the necessary actions for the winter storm warning were completed in accordance with Off Normal Procedure 12, "Acts of Nature."

b. Findings

No findings of significance were identified.

.4 Warm Weather Preparations

a. Inspection Scope

In April 2004, the inspectors verified that licensee personnel had completed their warm weather preparations as specified in Standard Operating Procedure 23, Attachment 10, "Warm Weather Checklist." The inspectors utilized this checklist to verify that the prescribed actions had been completed for safety-related equipment such as the emergency diesel generators and service water intake structure.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdowns (71111.04Q)

a. Inspection Scope

The inspectors completed partial equipment alignment walkdowns on the following safety-related and risk significant plant components which represented four inspection samples:

- equipment required by General Operating Procedure 14, Shutdown Operations, to maintain vital electrical auxiliaries available to minimize plant risk during refueling outage activities on October 29, 2004;

- equipment required by General Operating Procedure 14, Shutdown Operations, for maintaining primary coolant system inventory available to minimize plant risk during refueling outage activities on November 9, 2004;

- safety injection tanks on November 29, 2004, after the plant was returned to Mode 1, "Power Operation," following the refueling outage; and

- containment spray pump P-54C on December 22, 2004.

During the walkdowns, the inspectors verified that power was available, that accessible equipment and components were appropriately aligned, and that no discrepancies existed which would impact system availability.

The inspectors reviewed selected condition reports related to equipment alignment problems and verified that identified problems were entered into the corrective action program with the appropriate significance characterization, and that planned and completed corrective actions were appropriate.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Fire Area Walkdowns (71111.05Q)

a. Inspection Scope

The inspectors completed seven fire protection inspection samples by touring the following areas in which a fire could affect safety-related equipment:

- fire area 7, emergency diesel generator 1-1 day tank room
- fire area 11, safety-related battery number 1 room
- fire area 12, safety-related battery number 2 room
- fire area 21, electrical equipment room

- fire area 30, east mechanical equipment room
- fire area 31, west mechanical equipment room
- fire area 29, central mechanical equipment room

The inspectors verified that transient combustibles and ignition sources were appropriately controlled and that the installed fire protection equipment in the fire areas corresponded with the equipment which was referenced in the Updated Final Safety Analysis Report, Section 9.6, "Fire Protection." The inspectors assessed the material condition of fire suppression systems, manual fire fighting equipment, smoke detection systems and fire barriers. In addition, the inspectors reviewed documentation for completed surveillances to verify that fire protection equipment and fire barriers were tested as required to ensure availability.

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation (71111.05A)

a. Inspection Scope

The inspectors completed one inspection sample regarding annual fire drills by observing the unannounced fire drill on November 24, 2004. The inspectors assessed the fire brigade's readiness to respond to and mitigate fires. The inspectors verified that protective clothing was properly donned and that fire hoses were capable of reaching the fire. The inspectors verified that communications within the fire brigade were clear, efficient and effective, and that the fire scenario was overall appropriately simulated. The inspectors also verified that the licensee’s pre-planned drill scenario was followed and that the objectives were met.

The inspectors reviewed selected condition reports related to the annual fire drill and verified that identified problems were entered into the corrective action program with the appropriate significance characterization. Planned corrective actions were reviewed to verify they were appropriate for the circumstances.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06A)

a. Inspection Scope

The inspectors completed one inspection sample pertaining to flood protection measures for external flooding events.

The inspectors toured plant areas with safety-related equipment which were below flood levels susceptible to groundwater ingress. Utilizing Standard Operating Procedure 3, Checklist 3.4, "Plant Flood Door System Checklist," the inspectors verified that flood doors and floor plugs designed to protect areas with safety-related equipment from external flooding were functional. Plant areas that were checked included the component cooling water pump room, auxiliary feedwater pump room, emergency diesel generator room, and 2400-volt bus 1C switchgear room. The inspectors reviewed permanent maintenance procedure MSM-M 16, "Inspection of Watertight Barriers," and associated work orders, and Off Normal Procedure 12, "Acts of Nature." The inspectors verified that preventive maintenance activities had been completed on the watertight barriers as required and that adequate guidance for coping with external flooding existed.

Further, the inspectors reviewed condition reports to verify that corrective actions for previously identified flood protection problems were appropriate and had been properly implemented.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A)

a. Inspection Scope

The inspectors completed one inspection sample regarding heat sink performance.

The inspectors reviewed documentation for special test T-390, "Single Tube Testing of the Component Cooling Water Heat Exchanger," for component cooling water heat exchanger E-54A to verify that test acceptance criteria were satisfied. The inspectors observed portions of heat exchanger E-54A tube inspections, and observed the as-found and as-left condition of the tubes to verify that the heat exchanger's operability was not adversely affected.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Inservice Inspection Program

a. Inspection Scope

The inspectors conducted a review of the implementation of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. The inspectors selected examinations and components in order of risk priority as identified in Section 71111.08-03 of IP 71111.08, "Inservice Inspection Activities," based upon the ISI activities available for review during the on-site inspection period.

From September 19, 2004 through October 8, 2004, the inspectors conducted an onsite review of the following two types of nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI requirements and to verify that indications and defects (if any) were dispositioned in accordance with the ASME Code. Specifically, the inspectors observed;

- ultrasonic testing (UT) of two primary loop auxiliary piping welds (06-05 PCS-039 welds 1 and 2) and pressurizer spray line welds (02-05.1 PCS-4-PRS-1P1-1, nozzle to safe end; 02-03.1 PCS-4-PSS-1P1-20, elbow to safe end; 02-04.1 PCS-4-PSS-1P1-21, safe end to nozzle), and
- bare metal visual examination of the pressurizer penetrations (Section 4OA5.1).

The inspectors reviewed an examination from the previous outage with recordable indications that were accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code. Specifically, the inspectors reviewed indications identified in pipe-to-elbow weld CSW-005A weld No. 8 in the critical service water system, which were accepted for continued service.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage, to verify that the welding acceptance and preservice examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following two work activities;

- high pressure safety injection pump P-66A miniflow check valve; and
- E-50A steam sample for service water SX-0719 root.

The review discussed above was considered to be one inspection sample.

The inspectors reviewed a sample of licensee activities related to the Boric Acid Corrosion Control program. Specifically, the inspectors performed:

- observation of licensee walkdowns of systems inside containment to identify evidence of boric acid leakage and to verify that these examinations emphasized locations where boric acid leaks can cause degradation of safety significant components;

- review of two engineering evaluations performed for boric acid found on reactor coolant system piping and components to confirm that the applicable ASME Code requirements including minimum wall thickness were maintained;

- interviews with licensee staff involved in the boric acid program to verify that degraded or non-conforming conditions were properly identified in the licensee's corrective action system; and

- review of corrective actions performed for evidence of boric acid leaks to confirm that corrective actions were consistent with requirements of the ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI.

The review discussed above was considered to be one inspection sample.

From September 20, 2004, through October 8, 2004, and November 8, 2004, through November 12, 2004, the inspectors observed acquisition of steam generator (SG) tube eddy current testing (ET) data. The inspectors also reviewed the SG ET examination scope, expansion criteria, analysis procedures, and examination reports to confirm that;

- the examination scope, scope expansion and in-situ SG tube pressure testing screening criteria were consistent with the Electric Power Research Institute (EPRI) Guidelines and TS requirements

- the examination scope was sufficient to identify tube degradation based on site and industry operating experience. The inspectors completed this activity by confirming that the licensee’s SG ET examination scope was consistent with the EPRI Guidelines;

- the in-situ SG tube pressure testing screening criteria were properly applied;

- licensee tube repair criteria and process (plugging) was consistent with TS requirements;

- the numbers and sizes of flaws identified in degraded SG tubes were consistent with the previous outage operational assessment; and

- the ET probes and equipment used were qualified in accordance with the EPRI Guidelines for the expected types of tube degradation.

The review discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of the inspection procedure, but the sample was completed to the extent practical. The specific activities that were not available for review to complete this inspection sample and other procedure section samples not available for review are identified in the table below.

Inspection Procedure 71111.08 Section Number	Reason Activity was Unavailable For Inspection	Reduction in Inspection Procedure Samples
Section 02.02. Vessel Upper Head Penetration Inspection Activities.	Not applicable. This section is not required to be implemented until after completion of temporary instruction (TI) 2515/150.	This not applicable activity constituted a reduction by one from the total number of samples required by Section 71111.08-5 of inspection procedure 71111.08.
Section 02.04.a 3 and 4: associated with review of licensee in-situ pressure testing of steam generator tubes. Section 02.04.d: associated with review of new degradation mechanisms.	Not applicable. The licensee did not identify any tubes that required pressure testing and did not identify any new degradation mechanisms.	These unavailable and not applicable activities constituted a reduction by one from the total number of samples required by Section 71111.08-5 of inspection procedure 71111.08.

Inspection Procedure 71111.08 Section Number	Reason Activity was Unavailable For Inspection	Reduction in Inspection Procedure Samples
Section 02.04.j: If the licensee has identified loose parts or foreign material on the secondary side of the steam generator, confirm appropriate repairs or an evaluation of the potential effects of object migration and/or tube fretting damage.	The licensee did not perform an evaluation of the potential effects of object migration or tube fretting damage for foreign material left in SG B (e.g. a piece of flexitalic gasket (CAP044293)). This evaluation was not performed, because the licensee staff believed that this loose part was not free to move and would not cause tube fretting. The licensee staff stated that they had not been able to free this object from the sludge pile. Further, based upon review of ET data, the licensee's staff concluded that this object had been in this same location for more than one operating cycle.	
Section 02.04.h: associated with steam generator tube leakage greater than 3 gallons per day.	Not applicable. The licensee reported that SG tube leakage had not been observed.	
Section 02.04.k associated with review of one to five samples of ET data.	Not applicable. The licensee did not perform any on-site analysis of ET data and the inspectors did not identify any "serious questions" regarding the eddy current data.	

b. <u>Findings</u>

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

From September 20, 2004, through October 8, 2004, the inspectors performed an on-site review of ISI related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action program documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and review of licensee actions to incorporate lessons learned from industry issues related to the ISI Program. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspectors completed one inspection sample of licensed operator requalification training by observing one crew of licensed operators during simulator training on November 17, 2004. The inspectors observed the operators response to the simulated events which included a failed pressurizer pressure instrument, an inadvertent dilution event, a steam generator tube rupture and a failure of safety injection to automatically initiate on pressurizer low pressure. The inspectors verified that the operators were able to effectively implement applicable alarm response procedures, Off-Normal Procedure 23.2, "Steam Generator Tube Leak," and Emergency Operating Procedure 5, "Steam Generator Tube Rupture Recovery," to mitigate the events. The inspectors also observed the post-training critique to assess the licensee evaluators' and the crew's ability to self-identify performance problems.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13Q)

a. Inspection Scope

The inspectors completed four inspection samples regarding plant risk assessments for planned and emergent maintenance activities.

The inspectors reviewed Operator's Risk Reports and documented safety assessments to verify that plant risk assessments were completed as required by 10 CFR 50.65(a)(4) prior to commencing maintenance activities; reviewed the Operations Log and daily maintenance schedules to verify that equipment necessary to minimize plant risk was operable or available as required during planned and emergent maintenance activities; and conducted plant walkdowns to verify that equipment necessary to minimize risk was available for use during the following activities:

- planned maintenance activities for November 22 through 26, 2004, which included monthly surveillance testing for emergency diesel generator 1-2.

- planned maintenance activities on November 30 through December 3, 2004, which included corrective maintenance for charging pump P-55A, online testing of main steam safety valves and high pressure safety injection pump P-66A surveillance testing.

- planned maintenance activities on December 6 through 10, 2004, which included component cooling water pump P-52C preventive maintenance, online testing of main steam safety valves and emergency diesel generator 1-1 surveillance testing.

- planned maintenance activities on December 12 through 17, 2004, which included preventive maintenance on service water pump P-7B and component cooling water pump P-52C, and surveillance testing on auxiliary feedwater pumps.

The inspectors verified that condition reports related to emergent maintenance issues were entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

The inspectors completed two inspection samples pertaining to operator performance during the non-routine evolutions described below.

.1 Entry Into Off Normal Procedure

a. Inspection Scope

On December 1, 2004, the inspectors observed the operators response to a lowering main feedwater pump suction pressure and reviewed condition report CAP045506, "Off Normal Procedure - 3 Loss of Feedwater Entered for Lowering Hotwell Level and Main Feedwater Pump Suction Pressure." The inspectors verified that: (1) the operators implemented the required actions in Off Normal Operating Procedure 3, "Loss of Feedwater," to mitigate the lowering suction pressure; (2) this issue was entered into the licensee's corrective action program with the appropriate significance characterization; and (3) the corrective actions were appropriate to address the cause.

b. Findings

Introduction

The inspectors determined that a finding of very low safety significance (Green) was self-revealed when the condensate reject valve CV-0731 unexpectedly opened during maintenance activities and required operator action to mitigate the ensuing transient. No violation of NRC requirements occurred.

Description

On December 1, 2004, maintenance personnel coordinated with the Control Room Supervisor to continue troubleshooting activities on condensate reject valve CV-0731 to address a problem with the valve failing to open at the correct condenser water level. Troubleshooting had previously been performed on November 17, 2004, utilizing the minor maintenance work process when the plant was at 5 percent power and not synchronized to the electrical grid. However, the previous maintenance did not correct the problem with the valve. Therefore, maintenance personnel wanted to continue the troubleshooting activities which were suspended on November 17th.

On December 1st, the plant was at full power and synchronized to the electrical grid when the troubleshooting activities recommenced. Neither the maintenance personnel nor the Control Room Supervisor questioned conducting this activity utilizing the minor maintenance process. Consequently, the work did not receive an appropriate level of planning, work was allowed without isolating the valve, no formal pre-job brief was conducted, and no contingency actions were identified.

After receiving permission from the Control Room Supervisor to commence the work, the maintenance technician did not read the appropriate pressure gauge on the controller. As a result, the technician failed to recognize that the adjustments made to the controller caused the output to change which subsequently fully opened the valve. The minor maintenance work order being utilized did not require CV-0731 to be isolated for the troubleshooting activities. Consequently, when the valve opened, the main condenser hotwell level dropped rapidly, which resulted in a lowering suction pressure to the main feedwater pumps.

Control room operators responded to the main feedwater pump low suction pressure alarm, noted the lowering hotwell level, and entered the off normal procedure for a loss of feedwater. Control room operators took manual control of the main feedwater pumps to reduce pump speed and conserve hotwell inventory; notified the maintenance technician to stop work; and responded to and locally isolated the condensate reject valve. Control room operator actions successfully mitigated the transient to preclude a main feedwater pump trip and resultant plant trip.

Analysis

The use of the minor maintenance work process to adjust the condensate reject valve with the plant at full power was a performance deficiency which warranted a significance evaluation. The inspectors determined that the finding was more than minor in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Disposition Screening," because it was related to the human performance attribute of the Initiating Events cornerstone and adversely impacted the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions since operator response was required to mitigate the lowering suction pressure to the main feedwater pumps to preclude a main feedwater pump trip and a resultant plant trip.

The finding was related to the cross-cutting area of Human Performance because maintenance personnel failed to follow applicable administrative procedures when conducting minor maintenance activities. Administrative Procedure 5.21, "Fix-It-Now Maintenance," Section 7.2, "Minor Maintenance," stated that for work to be considered minor maintenance, the work shall have no operational impacts. However, the adjustments made to the condensate reject valve were performed using the minor maintenance work process. Consequently, the work activities did not receive the appropriate level of planning, contingency actions were not addressed, and the work resulted in an operational impact which required operator action to mitigate.

Using IMC 0609, Appendix A, "SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones," the inspectors determined that Initiating Events was the only cornerstone affected. This finding was related to the transient initiators in the column for the Initiating Events cornerstone. However, because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions would not be available, the finding screened as Green and was considered to be of very low safety significance.

Enforcement

Because maintenance personnel were performing activities on a nonsafety-related system and the administrative procedure was not one required by 10 CFR 50, Appendix B, no violation of regulatory requirements occurred. This was considered a finding of very low safety significance (FIN 05000255/2004012-01). The licensee entered this issue into the corrective action program as condition report CAP045506, "ONP-3 Loss of Feedwater Entered For Lowering Hotwell Level and Main Feedwater Pump Suction Pressure." Corrective actions included evaluating all open work requests designated as minor maintenance to ensure that plant operations would not be impacted and establishing the expectation that approval from specific operations personnel was required prior to conducting any work activities not included in the daily schedule, such as minor maintenance.

.2 Response to Inadvertent Safety Injection During Surveillance Testing

a. Inspection Scope

On November 14, 2004, during preparation activities to perform technical specification surveillance test RO-12, "Containment High Pressure and Spray System Test," an inadvertent safety injection signal was generated. The inspectors observed control room operator response to the inadvertent safety injection signal and the subsequent system realignment. The inspectors verified that operators implemented the appropriate Emergency Operating Procedure to verify that the systems responded as designed, and that the appropriate System Operating Procedures were followed to realign the system as necessary. This issue was entered into the licensee's corrective action program as CAP045023, "Inadvertent Safety Injection Actuation During RO-12, Containment High Pressure Test."

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspections Scope

The inspectors completed one inspection sample regarding permanent plant modifications.

The inspectors reviewed the design change information and the 10 CFR 50.59 screening evaluation for modification MOD-2003-0021, "Investigation of Enhancements to Containment Drainage Paths," and walked down the as-built modification in containment. The inspectors verified that the design bases, licensing bases and performance capability of containment was not degraded through this modification; the modification was installed as designed; and the appropriate revisions were made to the affected plant procedures.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors completed four samples regarding post maintenance testing which included the following four activities:

- corrective maintenance to replace a cracked current transformer on the "X" phase of breaker 152-204 for service water pump P-7A;
- corrective maintenance to repair station battery charger number 2;
- corrective maintenance to replace charging line loop 1A check

valve CK-CVC2114; and

- corrective maintenance to repair safety injection tank T-82C outlet isolation valve MO-3049.

The inspectors observed portions of the post maintenance testing and reviewed documentation to verify that the tests were performed as prescribed by the work orders and test procedures, applicable testing prerequisites were met prior to the start of the tests; and the effect of testing on plant conditions was adequately addressed by the control room operators.

The inspectors reviewed documentation to verify that the test criteria and acceptance criteria were appropriate for the scope of work performed; reviewed test procedures to verify that the tests adequately verified system operability; and reviewed documented test data to verify that the data was complete, and that the equipment met the prescribed acceptance criteria.

Further, the inspectors reviewed condition reports to verify that post maintenance testing problems were entered into the corrective action program with the appropriate significance characterization. For select condition reports, the inspectors verified that the corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

The inspectors completed one inspection sample regarding refueling outage activities.

.1 Scheduled Refueling Outage

a. Inspection Scope

The inspectors observed and assessed licensee's performance in completing activities during a planned refueling outage that ended on November 17, 2004. The inspectors performed the following general activities periodically throughout the refueling outage:

- verified that plant equipment required to minimize plant risk was aligned in accordance with plant procedures;
- performed walkdowns of the containment building to observe ongoing activities;
- verified that equipment tagouts were adequate for activities that could affect shutdown risk; and
- reviewed selected condition reports to verify that identified problems were accurately characterized; entered into the corrective action program with the appropriate significance; and that corrective actions were appropriate.

The inspectors performed the following specific activities during the refueling outage:

- observed portions of refueling activities and performed an independent review of reactor core fuel loading documentation and videotapes to verify that the fuel assemblies were placed in the specified core locations;
- randomly performed partial walkdowns of the spent fuel pool cooling system to verify it was properly aligned and not impacted by ongoing outage work;
- observed control room operator performance during portions of the primary coolant system drain down to mid-loop;
- while the plant was in mid-loop, the inspectors: (1) conducted plant walkdowns to verify to the extent practical that plant equipment required by GOP-14, "Shutdown Cooling Operations," Attachment 14, "Reduced Inventory Checklist," was available and properly aligned to minimize plant risk; (2) verified that containment closure capability was in place for the mitigation of radioactive releases, including appropriate staging of personnel and equipment; (3) verified that at least two independent, continuous indications of primary coolant system temperature and level were available; and (4) verified that at least two additional means of adding inventory to the primary coolant system were available, in addition to the residual heat removal system;
- randomly verified that station electrical power, emergency diesel generators, decay heat removal and primary coolant system inventory control systems were aligned as required by GOP-14;
- reviewed primary coolant system temperature data on the plant computer and documented data in surveillance procedure PO-2, "Primary Coolant System Heatup/Cooldown Operations," to verify that Technical Specification heatup rate limits were adhered to during plant startup activities;
- reviewed documentation to verify that appropriate mode change checklists were appropriately completed during plant startup;
- performed containment walkdowns prior to plant restart to evaluate the licensee's process for maintaining containment cleanliness as required by Checklist 1.4, "Containment Closeout Walk-Through," and to verify that no material was left in containment that could adversely impact containment sump design attributes; and
- observed operator performance during portions of reactor startup, turbine valve testing, and main generator synchronization to the electrical grid.

b. Findings

No findings of significance were identified.

.2 Heavy Load Lift Inside Containment

a. Inspection Scope

The inspectors observed the heavy load lift of the primary coolant pump P-50C motor inside containment during the refueling outage on September 28, 2004. The motor was lifted with the containment polar crane and moved from the equipment hatch to the laydown area during preparation activities to replace the existing motor.

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) when the defined heavy load path inside containment was not followed when a primary coolant pump motor was lifted and moved using the containment polar crane. A Non-Cited Violation of Technical Specification 5.4, "Procedures," was associated with this finding.

Description

On September 28, 2004, the inspectors observed a primary coolant pump motor being moved from the containment equipment hatch to the laydown area in containment. The motor was considered a heavy load and was lifted using the containment polar crane. The inspectors noted that a portion of the motor passed over the reactor vessel when the load was moved past the refueling cavity and questioned licensee personnel regarding the heavy load path. Based on the inspectors observations, licensee personnel initiated condition report CAP044047, "Potential Encroachment of Heavy Load Path Restrictions in Containment," to evaluate the issue.

Licensee personnel subsequently determined that the heavy load was not positioned correctly relative to the load path. Specifically, the correct alignment for the primary coolant pump motor during transit was to have the longest dimension of the lifting rig configured parallel to the refueling cavity. A parallel configuration would have ensured that the widest point of the lift device was well within the defined heavy load path.

However, when the primary coolant pump motor was moved on September 28th, the load was rotated which resulted in the motor being perpendicular to the defined load path. Consequently, the motor was wider than the defined load path when oriented perpendicular to the load path and a portion of the motor passed over the open reactor vessel which was prohibited by permanent maintenance procedure FHS-M 24, "Movement of Heavy Loads in the Containment Building Area." This incorrect orientation was caused by licensee personnel involved with the heavy load lift for the primary coolant pump motor who believed that compliance with the load path was based on only the crane hook being within the load path and not the entire load.

Analysis

The inspectors determined that the failure to move the primary coolant pump motor within the defined heavy load path inside containment was a performance deficiency which warranted a significance evaluation. The Barrier Integrity cornerstone was impacted by this finding. The finding was more than minor because it could be reasonably viewed as a precursor to a significant event because a portion of the heavy load traveled over the reactor vessel that contained irradiated fuel and the reactor vessel head was removed for refueling activities. However, the finding was not suitable for a significance determination process evaluation. Therefore, in accordance with IMC 0612, Section 05.04.c, the finding was submitted for review by NRC management and was determined to be of very low safety significance (Green).

The inspectors consulted with the regional Senior Reactor Analyst and determined that the finding was not greater than very low safety significance because: (1) the estimated likelihood of dropping the load was about 1E-5 per crane operation based on a study in NUREG/CR-4982 performed for spent fuel pool accidents; (2) the polar crane was in good working condition and had no known deficiencies that would have jeopardized the crane's ability to lift the load; (3) the duration of the heavy load lift over the reactor cavity was short; and, (4) only a portion of the heavy load passed over the reactor cavity.

Enforcement

Technical Specification 5.4.1 required, in part, that the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, be established and implemented. Regulatory Guide 1.33, Section 9.0, "Procedures for Performing Maintenance," required, in part, that maintenance that can affect the performance of safety-related equipment be performed in accordance with written procedures appropriate to the circumstances. Permanent maintenance procedure FHS-M 24, Attachment 7, "Heavy Load Path for Primary Coolant Pump P-50A, B, C, and D Motor and Pump Assemblies and Subassemblies," defined the heavy load path for moving primary coolant pump motors inside containment which did not include the reactor cavity.

Contrary to this requirement, maintenance procedure FHS-M 24 was not appropriate to the circumstances. Specifically, the procedure did not clearly specify that the entire load was to remain within the boundaries of the defined heavy load path. As a result, on September 28, 2004, during a heavy load move for a primary coolant pump motor inside containment, although the crane hook remained within the boundaries of the heavy load path, the load was oriented perpendicular to the load path and was wider than the defined load path. Consequently, a portion of the motor was outside the boundaries of the defined heavy load path and passed over the reactor cavity and the open reactor vessel which contained irradiated fuel.

However, because this violation was associated with a finding of very low safety significance and because the finding was entered into the licensee's corrective action program, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000255/2004012-02). This issue was entered into the licensee's corrective action program as CAP044047. As an immediate corrective action, the Site Director and Shift Outage Director conducted training with each shift to ensure that each crane and rigging crew understood the requirement to maintain the load within the boundaries of the designated heavy load path. Other corrective actions included planned changes to the heavy load procedure and the training of personnel involved with heavy load lifts to clearly define that the entire load, regardless of orientation, must be maintained within the heavy load path.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors completed seven baseline inspection samples by reviewing the following surveillance testing activities that were conducted on safety-related plant equipment:

- Refueling Test 8C, "Engineered Safeguards System - Left Channel"
- Refueling Electrical 139-1, "Test Start Time of Emergency Diesel Generator 1-1"
- Refueling Test 130, "Functional Test of Bus 1D Undervoltage Relays"
- Refueling Test 92, "Inspection of ECCS (Emergency Core Cooling System) Train Containment Sump Suction Inlet"
- Refueling Operations 141, “Containment Sump Check Valves Inservice Test”
- Refueling Operations 22, "Control Rod Drop Times"
- Daily/Weekly Operations 1, Attachment 8, "Primary Coolant System Inventory"

The inspectors observed portions of the testing to verify that appropriate test procedures were utilized and reviewed documented test data to verify that testing acceptance criteria were satisfied.

In addition, the inspectors reviewed applicable portions of Technical Specifications, the Updated Final Safety Analysis Report, and design basis documents to verify that the surveillance tests adequately demonstrated that system components could perform required safety functions.

b. Findings

No findings of significance were identified.

1REP Equipment Availability, Reliability and Functional Capability (71111.EP)

.1 Quarterly Maintenance Effectiveness Reviews

a. Inspection Scope

The inspectors completed two inspection samples of maintenance effectiveness.

The inspectors reviewed the maintenance activities conducted on the spent fuel pool ventilation system and safety injection tank T-82C outlet isolation valve MO-3049; and, reviewed the licensee’s implementation of the maintenance rule requirements to verify that equipment failures were evaluated and appropriately dispositioned. The inspectors verified that the selected components were scoped into the maintenance rule and properly categorized as (a)(1) or (a)(2) in accordance with 10 CFR 50.65.

b. Findings

No findings of significance were identified.

.2 Operability Evaluations

a. Inspection Scope

The inspectors completed four inspection samples by reviewing operability assessments as documented in the associated condition reports for the following risk-significant plant equipment:

- reactor protection system;
- battery charger number 2;
- primary coolant pump P-50B seal; and
- service water intake structure.

The inspectors interviewed the cognizant engineers and reviewed the supporting documents to assess the adequacy of the operability assessments for the current plant mode or past operability as applicable. The inspectors reviewed the applicable sections of the Technical Specifications, Updated Final Safety Analysis Report, and design basis documents to verify that the operability assessments were technically adequate and that the components remained available, such that no unrecognized increase in plant risk had occurred.

The inspectors reviewed condition reports generated for equipment operability issues and verified that the problems were accurately described; that the issues were entered into the licensee's corrective action program with the appropriate significance characterization; and, that corrective actions were appropriate and implemented as scheduled.

b. Findings

No findings of significance were identified.

.3 Temporary Modification

a. Inspection Scope

The inspectors completed one inspection sample by reviewing temporary modification TM-2004-008, "Temporary Installation of Blank Plate on Duct Inlet Frame of VF-8, Fuel Handling Area Exhaust Prefilter." The modification was necessary for the degraded fuel handling area ventilation system and was installed to isolate leakby air flow that passed through damper D-977 to fuel handling area exhaust prefilter VF-8. The leakby flow was of concern because the flow bypassed the high efficiency particulate filter and charcoal bed filter which were required to be in service while moving fuel. The temporary modification enabled the fuel handling area ventilation system to successfully pass the surveillance test necessary to prove operabilty.

The inspectors reviewed the design documents, 10 CFR 50.59 safety screening, Updated Final Safety Analysis Report, and applicable technical specifications and their bases to verify that the temporary modification did not affect operability of the fuel handling area ventilation system and other interfacing systems. The inspectors conducted plant walkdowns to verify that the temporary modification was implemented as designed and reviewed post modification testing to verify that tests were performed satisfactorily.

b. Findings

No findings of safety significance were identified.

.4 Operator Work-arounds

a. Inspection Scope

The inspectors completed three inspection samples regarding operator work-arounds.

The inspectors reviewed the two operator work-arounds that existed in November 2004, when the plant returned to power after the refueling outage. Specifically, operator work-arounds 03-01OWA, "Control Room Indicator Light Failure," and 03-03OWA, "Auxiliary Building Radio Coverage," were reviewed to verify that the functional capability of mitigating systems and the operators ability to implement off-normal and emergency operating procedures were not affected.

The inspectors assessed a third operator work-around which emerged when the normal level control valve, CV-0608, on the moisture separator drain tank T-5 failed and was isolated and bypassed on December 11, 2004. Consequently, if a plant transient were to occur with CV-0608 isolated, manual operator action would be required to ensure adequate level was maintained in T-5 to preclude a loss of heater drain pumps and a resultant loss of suction pressure to the main feedwater pumps. The inspectors reviewed the compensatory actions that were developed to verify that the operators ability to implement off-normal operating procedures during plant transients were not adversely affected.

The inspectors reviewed other operator burden items which were defined and tracked by licensee personnel as operations concerns, operator challenges and control room deficiencies; and reviewed Administrative Procedure 4.12, Attachment 3, "Operator Work-Around / Challenge Monthly Aggregate Impact Assessment," that was completed November 16, 2004, by operations personnel. The inspectors verified that the cumulative effect of operator work-arounds and other operator burden items would not adversely impact the reliability and availability of mitigating systems; would not significantly increase the potential to operate a mitigating system incorrectly; and, would not significantly impact the operators ability to respond in a correct and timely manner to plant transients.

Condition reports pertaining to operator work-arounds were reviewed to verify that the problems were accurately described and entered into the corrective action program with the appropriate significance characterization.

b. Findings

No findings of safety significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector reviewed Revisions 9 and 10 of the Palisades Nuclear Power Plant Site Emergency Plan and changes made to its emergency action levels that reverted the emergency action levels back to its last approved revision. These were reviewed to determine if any of the changes identified in these revisions reduced the plan's effectiveness, pending on-site inspection of the implementation of these changes.

b. Findings

No findings of significance were identified.

1EP6 Emergency Preparedness Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed a simulator training session for one crew of licensed operators on November 17, 2004, in which the Shift Manager was required to implement the emergency plan in response to simulated plant conditions. Licensee emergency preparedness personnel had pre-designated that the opportunities for the Shift Manager to classify the event and make required notifications would be evaluated and included in performance indicator data regarding drill and exercise performance.

The inspectors verified that the Shift Manager classified the emergency condition and completed the required notifications to state and local police authorities in an accurate and timely manner as required by the emergency plan implementing procedures. The inspectors verified that the emergency preparedness evaluator accurately assessed and documented the number of opportunities that was to be included in the performance indicator data.

In addition, the inspectors reviewed condition reports to verify that identified problems regarding emergency preparedness were entered in the licensee's corrective action program with the appropriate significance characterization.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following four radiologically significant work areas controlled as radiation areas, high radiation areas and/or airborne radioactivity areas in the plant and reviewed work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings and barricades were acceptable:

- Auxiliary Building;
- Upper Containment (including the reactor vessel head storage/inspection stand);
- Lower Containment (including the steam generator platforms and pressurizer inspection area); and
- Fuel Handling Building.

The inspectors reviewed the RWPs and work packages used to access these four areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down and surveyed these areas to verify that the prescribed RWP, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers (as necessary) were properly located.

The inspectors reviewed the RWPs for the reactor vessel head inspection and thermal sleeve removal activities which had the potential for creating an airborne radioactivity area. The inspectors reviewed the RWPs to verify barrier integrity and engineering control contingency plans were in place and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. These and other work activities/areas having a history of, or the potential for, airborne transuranic isotopes were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection.

The inspectors assessed the adequacy of the licensee's internal dose assessment process by reviewing personnel contamination event logs (and associated dose assessments) for the RO17 refueling outage. No personnel contamination events resulted in dose assignments of greater than 50 millirem committed effective dose equivalent during the refueling outage. However, the inspectors evaluated the licensee's internal dose assessment process by reviewing the assessment for a 23 millirem intake associated with work on the reactor vessel head.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following four jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Steam Generator Eddy Current Inspections;
- Removal of the Reactor Vessel Head Thermal Sleeves;
- Primary Coolant Pump 50C Motor Replacement and Other Maintenance; and
- Preparations for Diving Operations in the Reactor Cavity to Repair the Fuel Carriage Limit Switch.

The inspectors reviewed radiological job requirements for these activities including RWP requirements and work procedure requirements, and attended pre-job briefings.

Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors also verified the adequacy of radiological controls (including required radiation, contamination, and airborne surveys); radiation protection job coverage (including audio/visual surveillance for remote job coverage); and contamination controls.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. In particular, the reactor cavity diving activities and entries under the reactor vessel head (for inspections and thermal sleeve removal) involved areas with the potential for severe dose rate gradients which required the licensee to assess the necessity for providing multiple dosimeters and/or enhanced job controls.

These reviews represented three inspection samples.

b. <u>Findings</u>

No findings of significance were identified.

.3 <u>Radiation Worker Performance</u>

a. <u>Inspection Scope</u>

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

These reviews represented one inspection sample.

b. <u>Findings</u>

No findings of significance were identified.

.4 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed several corrective action reports related to access control issues identified during the Fall 2004 refueling outage. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

1. Initial problem identification, characterization, and tracking;
2. Disposition of operability/reportability issues;
3. Evaluation of safety significance/risk and priority for resolution;
4. Identification of repetitive problems;
5. Identification of contributing causes;
6. Identification and implementation of effective corrective actions;
7. Resolution of Non-Cited Violations tracked in the corrective action system; and
8. Implementation/consideration of risk significant operational experience feedback.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable (ALARA) Planning And Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed licensee procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following seven work activities of highest radiological exposure significance:

- Disassembly and Movement of Reactor Head to the Stand (RWP P04-5102);
- Reactor Head Reassembly and Refueling Close-Out Activities (RWP P04-5108);
- Removal/Installation of Incore Control Instrumentation Flanges (RWP P04-5111);
- Scaffold Work in Containment (RWP P04-5306);
- Inspection of the Reactor Vessel Closure Head (RWP P04-5510);
- Removal of the Reactor Vessel Head Thermal Sleeves (RWP P04-5515); and
- Pressurizer Tank T-72 Electric Heaters Maintenance (RWP P04-5601).

For these activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining if the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

The inspectors evaluated the interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups were to identify interface problems or missing program elements. Additionally, the inspectors evaluated the integration of ALARA requirements into work procedure and RWP documents to verify that the licensee's radiological job planning was effectively applied to the work activities in the field.

Finally, the inspectors evaluated if work activity planning included consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components/piping, job scheduling, and shielding and scaffolding installation and removal activities.

In the weeks following the completion of the refueling outage, the inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for several work activities related to the repair of two nozzles on the reactor vessel closure head. The licensee's initial reasons/evaluations for the inconsistencies between intended and actual work activity doses were reviewed.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors evaluated licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered. This included determining if adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles and not adjusted to account for failures to control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process

The licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. Radiation work permits were reviewed to determine if they covered too many work activities to allow work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work and via observations of daily Outage Control Center turnover meetings, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Control

a. Inspection Scope

As noted in Section 2OS1.2, the inspectors observed several work activities performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers. The inspectors evaluated the licensee's use of ALARA controls for these work activities using the following:

(1) The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

(2) Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays.

(3) The inspectors attended work briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included verification that the first-line job supervisor ensured that the work activity was conducted in a dose efficient manner by minimizing work crew size, ensuring that workers were properly trained, and that proper tools and equipment were available when the job started.

Finally, the inspectors reviewed exposures of individuals from selected work groups to evaluate if any significant exposure variations existed among workers and to determine whether these significant exposure variations were the result of worker job skill differences or whether certain workers received higher doses because of poor ALARA work practices.

These reviews represented four inspection samples.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

During observations of work activities described in Section 2OS1.2, the inspectors determined if workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used. Additionally, the inspectors assessed if workers utilized low dose waiting areas, and whether any procedure compliance issues existed. Also, the inspectors observed radiation worker performance to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Public Radiation Safety

4OA1 Performance Indicator Verification (71151)

The inspectors completed four inspection samples pertaining to performance indicator data verification as detailed in the below two sections.

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for performance indicators (PIs) listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the data. The inspectors interviewed engineering staff to determine whether the performance indicator data was collected and reported consistent with industry guidance contained in NEI [Nuclear Energy Institute] 99-02. The following PIs were reviewed:

- Reactor Coolant System (RCS) Specific Activity
- Safety System Unavailability - Residual Heat Removal System
- Unplanned Transients per 7000 Critical Hours

The inspectors reviewed a sample of operator logs, maintenance history, maintenance rule records and surveillance test records for residual heat removal system unavailability information from October 2003 to September 2004. The inspectors also verified the licensee's calculation of required hours and evaluated residual heat removal system unavailability against the performance indicator definitions.

Regarding unplanned power changes, the inspectors reviewed the monthly operating reports and operator logs for October 2003 to September 2004, to verify that the associated data gathered by licensee personnel and reported to NRC was accurate.

The inspectors reviewed the licensee's assessment of its performance indicator for RCS specific activity by reviewing Chemistry Department records and selected isotopic analyses (July 2003 through September 2004) to verify that the greatest Dose

Equivalent Iodine (DEI) value obtained during those months corresponded with the value reported to the NRC. The inspectors also reviewed selected DEI calculations to verify that the appropriate conversion factors were used in the assessment as required by Technical Specifications. Additionally, on December 15, 2004, the inspectors observed a chemistry technician obtain and analyze reactor coolant samples for DEI to verify adherence with licensee procedures for the collection and analysis of reactor coolant system samples.

b. Findings

No findings of safety significance were identified.

.2 Radiation Protection Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for performance indicators (PIs) and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PI was reviewed:

- RETS/ODCM Radiological Effluent Occurrence

Since no reportable occurrences were identified by the licensee for 4th Quarter 2003 through 3rd Quarter 2004, the inspectors compared the licensee's data and reviewed corrective action documents generated during the time period to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. Also, the inspectors evaluated the licensee's methods for determining offsite dose and selectively verified that liquid and gaseous effluent release data and associated offsite dose calculations performed since this indicator was last reviewed were accurate.

b. Findings

No findings of safety significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that condition reports were being generated and entered into the corrective action program with the appropriate significance characterization. For select condition reports, the inspectors verified that identified corrective actions were appropriate and had been implemented or were scheduled to be implemented in a timely manner commensurate with the significance of the identified problem.

b. Findings

No findings of safety significance were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors completed the semi-annual review of trends to verify that a more significant safety issue did not exist than would be apparent in a single condition report. The inspectors also verified that condition reports had been generated for potential trends which were noted by the inspectors through daily reviews of condition reports.

The inspectors reviewed the station trend reports for the second and third quarter of 2004, and condition reports for licensee identified potential trends. The inspectors verified that the trends had been evaluated and that appropriate corrective actions were planned or implemented as necessary.

b. Findings

No findings of significance were identified.

.3 Selected Issue Follow-up Inspection

a. Inspection Scope

The inspectors completed one inspection sample regarding selected problem identification and resolution evaluations.

The inspectors reviewed the root cause evaluation for a fire in the lower bearing on the motor for nonsafety-related condensate pump P-2B as documented in condition report CAP043294, "Reactor Trip Due to Fire On P-2B Condensate Pump."

The inspectors verified that: (1) the problem was accurately identified; (2) the root cause, apparent cause, and contributing causes were adequately justified; (3) extent of condition and generic implications were appropriately addressed; (4) previous occurrences were considered; and (5) corrective actions were appropriately focused to address the problem and implemented commensurate with the safety significance of the issue.

b. Findings

Introduction

The inspectors determined that one finding of very low significance (Green) was self-revealed on August 31, 2004, when a fire ignited in the lower bearing on the motor for condensate pump P-2B that subsequently required a manual reactor trip. No violation of regulatory requirements occurred.

Description

On August 31, 2004, site personnel reported to the control room that smoke was coming from the lower bearing on the motor for nonsafety-related condensate pump P-2B. Operators immediately initiated a rapid power reduction and called out the fire brigade. Operations personnel confirmed that there was a fire on condensate pump P-2B motor and the reactor was manually tripped so that the pump P-2B motor could be secured. The fire was rapidly extinguished by the fire brigade using portable fire extinguishers and the fire only affected the motor on P-2B.

Site personnel inspected the motor bearing and reviewed the work order that was used to reinstall the motor on July 30, 2004, following necessary repair activities. An analysis of the motor bearing concluded that the fire and bearing deterioration was caused by excessive forces applied to the motor and shaft bearing. During a review of the work order, site personnel noted that maintenance personnel incorrectly obtained the radial offset readings between the pump and motor shafts. Consequently, the motor and pump were misaligned during reassembly in July 2004 which was not recognized when the pump was returned to service. Therefore, site personnel concluded that the fire was caused by heat that was generated around the bearing due to an overload condition caused by an excessive radial offset between the motor and pump.

Site personnel concluded that the root cause for this issue was that the work order did not contain adequate guidance for obtaining alignment readings between the pump and motor; and therefore, aligning the components relied too heavily on craft skills. Several contributing causes were identified during the work to reinstall the motor in July 2004 which included: (1) the failure by maintenance personnel to reinstall two pump shaft vibration proximity probes as directed by the work order; and (2) post maintenance testing did not include steps to obtain thermography readings for the motor or coupling. Data obtained from the vibration probes and thermography may have identified the misalignment condition prior to the bearing fire. The inspectors did not identify any concerns with the identified causes.

Analysis

The inspectors determined that the misalignment between the pump and motor when P-2B was reassembled in July 2004 was a performance deficiency which warranted a significance determination.

The inspectors determined that the finding was more than minor in accordance with IMC 0612, Appendix B, "Issue Disposition Screening," since the finding was associated with the procedure quality and human performance attributes of the Initiating Events cornerstone and adversely impacted the cornerstone objective of limiting the likelihood of events that upset plant stability because operator action was required to commence a rapid downpower and manually trip the reactor to mitigate the event.

Using IMC 0609, Appendix A, "SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones," the inspectors determined that only the Initiating Events cornerstone was affected. The inspectors reviewed the transient initiators and the external event initiator categories in the Initiating Events column and discussed the issue with a regional Senior Reactor Analyst. The finding was determined to be of very low safety significance because: (1) the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation functions would not be available; (2) the fire was of short duration; and (3) the fire was isolated to the motor. Therefore, the finding screened out as Green.

Enforcement

Maintenance personnel were performing activities on a nonsafety-related system and the work order used was not a procedure required by 10 CFR Part 50, Appendix B. Therefore, no violation of regulatory requirements occurred. This was considered a finding of very low safety significance (FIN 05000255/2004012-03). The licensee entered this issue into the corrective action program as condition report CAP043294, "Condensate Pump P-2B Motor EMA-2205 Bearing Fire." Planned corrective actions included the development of a written procedure for aligning vertical pumps and motors that specified a method for obtaining alignment data and associated acceptance criteria

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report (LER) 50-255/2004-001: Reactor Protection System and Auxiliary Feedwater System Actuation

On August 31, 2004, control room operators manually tripped the reactor because of a fire in the lower bearing on the motor for nonsafety-related condensate pump P-2B. The auxiliary feedwater system started automatically to maintain steam generator water level. All other equipment actuated as designed following the plant trip. The licensee determined that the fire was a result of overheating at the lower motor bearing, which was caused by pump and motor misalignment following maintenance in July 2004.

The inspectors assessed the root cause evaluation for this event and determined that a finding of very low safety significance was self-revealed which was documented in Section 4OA2.3 of this report. Operator response to this event was assessed and documented in NRC Inspection Report 05000255/2004010 with no findings identified. The inspectors determined that the information provided in LER 50-255/2004-001 did not raise any new issues or change the conclusions reached. This event did not constitute a violation of NRC requirements. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

.1 A finding described in Section 1R14.1 of this report had, as a primary cause, a human performance deficiency. Maintenance personnel failed to follow administrative procedures which resulted in required operator response to mitigate a plant transient during maintenance activities inappropriately conducted as minor maintenance.

.2 A finding described in Section 4OA5.3 of this report had, as a primary cause, a human performance deficiency, in that a lack of rigor in the review of procedures resulted in an ultrasonic examination procedure not having ASME code required provisions for timing, acceptance criteria, and corrective actions for unsatisfactory calibration checks.

4OA5 Other

.1 Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (TI 2515/153)

a. Inspection Scope

The inspectors reviewed the licensee's 60-day response and an associated supplemental response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors." This bulletin addressed issues associated with potential post-accident debris blockage that may prevent operation of the containment emergency sumps during the recirculation mode. The NRC was tracking final resolution of this industry concern under Generic Safety Issue 191, "Assessment of Debris Accumulation on Pressurized Water Reactor Sump Performance."

The inspectors verified that the licensee's compensatory actions were either implemented or were scheduled to be implemented consistent with the responses. This was accomplished, as applicable, by reviewing training records, modification documents and procedures; conducting containment tours; and interviewing plant personnel. The inspectors observed containment sump inspections that were completed in accordance with surveillance procedure RT-92, "Inspection of Emergency Core Cooling System Containment Sump Suction Inlet," and reviewed the documented results.

The inspectors reviewed condition reports for identified problems pertaining to reactor sump performance to verify that the problems were entered into the licensee's corrective action program with the appropriate significance characterization. Associated corrective actions were reviewed to verify they were appropriate for the circumstances.

The inspectors review of the plant modification that was completed to enhance containment drainage paths and observation of the sump inspection surveillance test are documented as baseline inspection samples in sections 1R17 and 1R22, respectively, of this report. Temporary Instruction 2515/153 was not a part of the baseline inspection program and was therefore not considered a sample; however, the Temporary Instruction is considered complete.

b. Evaluation of Inspection Requirements

In accordance with the requirements of TI2515/153, the inspectors evaluated and answered the following questions:

1. For units that entered refueling outages after August 31, 2002, and subsequently returned to power: Was a containment walkdown to quantify potential debris sources conducted by the licensee during the refueling outage?

Yes. Palisades plant entered a refueling outage on March 16, 2003, and licensee personnel conducted containment walkdowns to quantify potential debris sources. These walkdowns were conducted using NEI 02-01, Revision 1, "Condition Assessment Guidelines: Debris Sources Inside PWR (Pressurized Water Reactor) Containments," as guidance.

2. For units that are currently in a refueling outage, is a containment walkdown to quantify potential debris sources being conducted during the current refueling outage?

Yes. Palisades plant entered a refueling outage on September 19, 2004, and licensee personnel conducted containment walkdowns to gather additional data regarding potential debris sources.

3. For units that have not entered a refueling outage between September 1, 2002 and the present, will containment walkdown to quantify potential debris sources be conducted during the upcoming refueling outage?

Not applicable.

4. Did the walkdowns conducted check for gaps in the sumps' screened flowpath and for major obstructions in containment upstream of the sumps?

Yes. During the refueling outages in 2003 and 2004, licensee personnel completed Technical Specification Surveillance Test RT-92, "Inspection of ECCS (Emergency Core Cooling System) Train Containment Sump Suction Inlet," which checked for gaps in the sumps' screens as well as for cleanliness of the screens and sump.

The inspectors observed Technical Specification Surveillance Test RT-92 during the 2004 refueling outage and did not identify any significant gaps or tears in the sump screens. However, the inspectors noted that some biological growth (algae) remained on the screens after cleaning activities were completed. Through a review of past condition reports, the inspectors noted that condition report CAP035107, "Biological Growth Found on Containment Sump Screens and Containment Sump Floor," was initiated during the refueling outage in April 2003. A corrective action developed in response to CAP035107 was a work order which was written to thoroughly clean the sump screens and then spray them with an algae inhibitor during the 2004 refueling outage. The inspectors determined that the work was completed during the 2004 refueling outage but did not accomplish a thorough cleaning of the sump screens as evidenced by the biological growth that remained on the screens after the work order was completed. Licensee personnel generated condition report CAP044798, "Biological Growth Remains on Screens After Cleaning," to evaluate this issue.

Licensee personnel subsequently concluded that the algae would not adversely impact water flow through the sump screens and therefore the sump screens were considered operable. However, licensee personnel also determined that additional cleaning of the screens was needed as required by the surveillance procedure which directed that any material on the screens be removed which was below that which would hinder emergency core cooling system operation. Through documentation reviews, the inspectors verified that the additional cleaning was completed and noted that the algae was easily removed from the screens. The inspectors reviewed pictures taken of the screens after the second cleaning to verify that all the algae was removed.

In addition, licensee personnel completed containment walkdowns to verify that there were not any major obstructions in containment upstream of the sumps. Operations personnel conducted additional walkdowns as required by Checklist 1.4, "Containment Closeout Walk-Through," to verify that no loose material which could potentially plug the containment sump screens was left in containment after the refueling outage. The inspectors independently performed containment walkdowns prior to plant restart to evaluate the licensee’s process for maintaining containment cleanliness. No significant problems regarding loose material left in containment that could clog the emergency sump screens were identified.

5. Are any advanced preparations being made at the present time to expedite the performance of sump-related modifications, in case it is found to be necessary after performing the sump evaluation?

No. Through discussions with engineering personnel, the inspectors determined that no advanced preparations are being made at this time.

Assessment of Licensee Commitments

The inspectors reviewed the licensees 60-day response, dated August 5, 2003, to NRC Bulletin 2003-01 and the associated supplemental response, dated May 17, 2004, to verify that the seven documented commitments had been satisfactorily met. The inspectors concluded that the commitments had been completed as described with one exception.

Commitment 1 was to develop and implement training by January 31, 2004, on containment sump clogging. The training was to be administered to licensed operators, auxiliary operators, site emergency directors and assistant site emergency directors, including those in training. Through a review of training records, the inspectors identified one site emergency director and two assistant site emergency directors who had not received the training. Based on this issue, licensee personnel generated condition report CAP044891, "NRC Commitment Not Completely Captured," which was entered into the corrective action program to determine the extent of condition.

Licensee personnel identified one additional site emergency director who had not received the training. In this instance, the individual had entered the site emergency director qualification program after the stated commitment date of January 31, 2004; however, the training had not been incorporated into the qualification program and therefore the individual would not have received the training on sump clogging.

The inspectors concluded that this issue was of minor significance because no actual consequences occurred as a result of not receiving the training and because the training was considered an "enhancement" to qualifications for the site emergency director and assistant director positions. To address these issues, licensee personnel planned to provide training on sump clogging to the individuals who have not received the training and to incorporate the training into the qualification programs for the site emergency director and assistant director positions. Training on containment sump clogging had already been incorporated into the licensed operator and auxiliary operator training programs.

c. Findings

No findings of significance were identified.

.2 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (TI 2515/160)

a. Inspection Scope

On May 28, 2004, the NRC issued Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors." The purpose of this Bulletin was to: (1) Advise PWR licensees that current methods of inspecting Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections may need to be supplemented with additional measures to detect and adequately characterize flaws due to primary water stress corrosion cracking (PWSCC); (2) Request PWR addressees to provide the NRC with the information related to the materials from which the pressurizer penetrations and steam space piping connections at their facilities were fabricated; (3) Request PWR licensees to provide the NRC with the information related to the inspections that have been and those that will be performed to ensure that degradation of Alloy 82/182/600 materials used in the fabrication of pressurizer penetrations and steam space piping connections will be identified, adequately characterized, and repair.

The objective of TI 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors," was to support the NRC review of licensees' activities for inspecting pressurizer penetrations and steam space piping connections made from Alloy 82/182/600 materials and to determine whether the inspections of these components are implemented in accordance with the licensee responses to Bulletin 2004-01. In response to Bulletin 2004-01, the licensee committed to perform a bare metal visual inspection of 100 percent of all pressurizer heater sleeve locations, in a manner that permitted visual access to the bare metal 360 degrees around each heater sleeve penetration. In addition, the licensee committed to perform a bare metal visual inspection of all Alloy 82/182/600 primary system pressure boundary locations that normally operate at greater than or equal to 350 degrees Fahrenheit within the next two refueling outages. The inspectors performed a review, in accordance with a TI 2515/160, of the licensee's procedures, equipment, and personnel used for pressurizer penetration nozzles and steam space piping connections examinations to confirm that the licensee met commitments associated with Bulletin 2004-01. The results of the inspectors' review included documenting observations and conclusions in response to the questions identified in TI 2515/160.

b. Observations

Summary: Based upon a bare metal visual examination of the pressurizer, the licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

Evaluation of Inspection Requirements

In accordance with the requirements of TI 2515/160, inspectors evaluated and answered the following questions:

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee conducted a direct visual examination of the bare metal surface of the lower pressurizer head heater penetration nozzles and UT of pressurizer nozzles with knowledgeable staff members certified to Level II as VT-2 examiners in accordance with procedure NDT-A-02, "NDT Personnel Training, Qualification and Certification." This qualification and certification procedure referenced the industry standard ANSI/ANST CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?

   Yes. The inspectors observed the licensee inspector performing the bare metal inspection of the vessel head in accordance with procedure NDT-VT-09, "Bare Metal Visual Examination." The licensee considered this procedure to be demonstrated because examination personnel could resolve lower case alpha numeric characters 0.044 inch in height at the actual distance used during the direct visual examination. The inspectors observed the licensee inspector performing this visual quality check.

   Yes. The inspectors observed the licensee inspection staff performing the UT of the nozzle-to-safe end welds for the pressurizer power operated relief valve (PORV) and spray lines in accordance with procedure NDT-UT-30, "Manual Ultrasonic Examination of Dissimilar Metal Welds." This procedure was based upon the Performance Demonstration Initiative (PDI) generic procedure PDI-UT-10, “Generic Procedure for the Ultrasonic Examination of Dissimilar Metal Piping Welds,” and contained the same essential variables or variable ranges required by the generic PDI procedure.

3. For each of the examination methods used during the outage, was the examination able to identify, disposition, and resolve deficiencies and capable of identifying and characterizing boron deposits and capable of identifying leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations if it had existed. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations which were free of debris or deposits that could mask evidence of leakage in the areas examined. However, the inspectors identified that the procedure did not provide guidance for when and how to collect samples of deposits if any had been identified near pressurizer penetrations examined. Further, no guidance existed to identify what analysis would be performed to determine the source of deposits identified. Instead, the licensee staff was relying on the corrective action system process to make decisions on how to characterize deposits which may be identified on the pressurizer. Because the licensee did not identify any deposits indicative of leakage in the areas examined, the inspectors could not assess the licensee's plans to characterize leakage on pressurizer components. Inspectors noted that overall boric acid program and implementing procedures also lacked guidance in this area. The licensee staff identified that they would apply the Nuclear Management Corporate procedure CD 5.23, "Boric Acid Corrosion Program Standard," which identified a section that discussed information such as radiochemistry and concentration analysis that may be "helpful" in determining the timing, source and conditions about a leak. The licensee staff could not provide any examples where this procedure had been implemented for actual boric acid leakage at Palisades.

Yes. The inspectors observed the licensee inspection staff performing the UT of the pressurizer PORV and spray line safe end to nozzle welds in accordance with procedure NDT-UT-30, "Manual Ultrasonic Examination of Dissimilar Metal Welds." The licensee completed the required examination volume and identified no relevant indications. Because this procedure was based upon the PDI generic procedure PDI-UT-10, which had been demonstrated as effective in identification of cracks, the inspectors concluded that this procedure and examination would be effective at identification of cracking in the pressurizer penetration weldments examined.

4. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system and what if any, impediments were identified (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

<u>Pressurizer Heater Penetration Nozzle Visual Examinations</u>

The Palisades pressurizer lower head was originally covered with canned metal insulation filled with mineral wool. This had been removed and the pressurizer heater wires were removed to allow installation of staging directly below the lower pressurizer head. The staging platform provided sufficient access to perform the bare metal examination of the heater penetrations. The inspectors performed a direct visual inspection for portions of each of the 120 pressurizer heater penetration nozzles. Based on this examination, the lower pressurizer head and penetration nozzle area were clean and free of debris or deposits or other obstructions which would mask evidence of leakage.

Upper Pressurizer Head Penetration Visual Examinations

The upper pressurizer penetrations included four level instrument piping taps, an upper head temperature element, three safety relief valve penetrations, and a PORV penetration. The inspectors observed that the canned metal reflective insulation had been removed from the pressurizer at these penetration locations to allow a bare metal visual examination. The inspectors performed a direct visual inspection for portions of these pressurizer penetrations. Based on this examination, the area examined was clean and free of debris or deposits or other obstructions which could mask evidence of leakage.

Pressurizer Spray Line Weld Visual Examinations

The inspectors observed the licensee performing visual examinations of the pressurizer spray line Inconel welds after removal of temporary lead shielding. These welds had been ground smooth during preparation for the UT examinations which removed any potential boric acid deposits. The inspectors questioned the licensee staff on the effectiveness of these visual examinations. The licensee stated that they would not credit this visual examination and would instead do another bare metal visual examination of these welds next outage.

Ultrasonic Examinations of Pressurizer Penetration Piping

The licensee performed manual UT of pressurizer spray line and PORV line Inconel welds. The inspectors observed that the surface condition of these welds were prepared (ground flush), and no limitations existed for the UT of these welds.

Lower Temperature Elements

The inspectors reviewed the bare metal visual examination report for the visual examination of the pressurizer temperature elements (penetrations 57 and 58). The surface condition for these welds was as found and no limitations existed for the examination. The licensee did not identify evidence of boric acid leakage or degradation for these penetrations.

5. How was the Visual Examination Conducted and How Complete Was The Coverage (e.g., video camera or direct visual by examination personnel)?

The licensee was able to perform a direct visual examination for 360 degrees around each weldment or penetration. This examination included each of 120 pressurizer heater penetrations, and Inconel welds for the safety valves, level piping penetration, PORV line, and temperature element. The scope of the licencee's bare metal visual examinations did not include the pressurizer spray line Inconel welds as discussed above.

Surge Line Nozzle

The licensee did not remove insulation, nor conduct a bare metal inspection of the pressurizer surge line nozzle penetration. The licensee staff stated that they intended to perform an ultrasonic examination of surge line nozzle welds during the next refueling outage. Additionally, the pressurizer surge line nozzle was not within the scope of inspections discussed in NRC Bulletin 2004-01.

6. What material deficiencies were identified that required repair?

   None.

7. If volumetric or surface examinations were used for the augmented inspection examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of these examinations?

   Not applicable. No augmented volumetric or surface examinations were performed. The licensee performed UT examinations of pressurizer PORV and spray line Inconel weldments in accordance with their Inservice Inspection Program.

8. Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure retaining components in the pressurizer system?

   Not applicable. The licensee did not identify any indications of boric acid leaks from pressure retaining components in the pressurizer system.

c. Findings

No findings of significance were identified.

.3 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On February 11, 2003, the NRC issued Order EA-03-009 (ADAMS Accession Number ML030410402). This order required examination of the reactor pressure vessel head and associated vessel head penetration (VHP) nozzles to detect primary water stress corrosion cracking (PWSCC) of VHP nozzles and corrosion of the vessel head. The purpose of TI 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," was to implement an NRC review of the licensee's head and VHP nozzle inspection activities required by NRC Order EA-03-009. The inspectors performed a review in accordance with TI 2515/150 of the licensee's procedures, equipment, and personnel used for examinations of the reactor vessel closure head (RVCH) and VHP nozzles to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors' review included documentation of observations in response to the questions identified in TI 2515/150.

From September 20, 2004 through October 8, 2004, October 14, 2004 through October 15, 2004, and November 8, 2004, through November 11, 2004, the inspectors performed a review of the licensee's RVCH inspection activities completed in response to NRC Order EA-03-009. This review included:

- a direct visual examination of the head-to-nozzle interface for portions of 2 VHP nozzles that required repairs from inside containment;
- a direct visual examination of the surface condition of the outer surface of the RVCH from inside containment;
- observation of the licensee personnel conducting automated UT of 4 VHP nozzle locations from the on-site data acquisition trailer;
- interviews with nondestructive examination personnel performing non-destructive examinations of the RVCH and VHP nozzles from an on-site trailer;
- certification records of nondestructive examination personnel performing examinations of the RVCH and VHP nozzles;
- dye penetrant (PT), UT, ET, and visual examination procedures used for examinations of the RVCH and VHP nozzles;
- procedures used for identification and resolution of boric acid leakage from systems and components above the vessel head;
- the licensee's procedures and corrective actions implemented for boric acid leakage;
- photographs of PT examination indications for VHP nozzles No. 29 and No. 30 J-groove welds; and
- visual, UT, ET, and PT examination records for the RVCH and VHP nozzles.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009, using procedures, equipment, and personnel qualified for the detection of PWSCC in vessel VHP nozzles and detection of vessel head wastage.

From September 20, 2004, through September 30, 2004, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation to:

- verify that appropriate plant-specific information was used as input;
- confirm the basis for the head temperature used by licensee; and
- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

From November 17, 2004, through November 19, 2004, and November 30, 2004, through December 1, 2004, the inspectors performed a review of the licensee's repair activities for VHP nozzles No. 29 and No. 30. Specifically, the inspectors reviewed the licensee's weld procedures, certified mill test reports for the pressure boundary materials, process traveler steps, weld control records, nondestructive examination records and repair drawings to confirm that ASME Code Section III and Section XI requirements were met (as amended by a licensee's Code relief request). The scope of the inspectors' review did not include a detailed review of the modification package, safety evaluation or supporting design analysis for this repair.

b. Observations

Summary:

As of September 19, 2004, the Palisades vessel head was at 9.67 effective degradation years (EDY), which is in the moderate susceptibility ranking category as described in NRC Order EA-03-009. To meet the inspection requirements of Order EA-03-009, the licensee completed automated UT for each of the 53 VHP nozzles and head vent line penetration nozzles. The licensee did not identify any limitations in volumetric examination scope required by Order EA-03-009. Based upon this examination, the licensee identified evidence of leakage from the interference zone of VHP nozzles No. 29 and No. 30 and conducted a followup PT examination on the J-groove welds at these locations. During the PT examinations, indications were identified in the J-groove welds, which the licensee reported to the NRC as evidence of through-wall cracking. The licensee implemented repairs to these nozzles which included establishing a new pressure boundary (temper bead weld) and installation of Inconel Alloy 690 nozzle extensions. Because cracks were identified in the J-groove welds, the licensee followed the NRC Order EA-03-009 requirements for examination of vessel heads in the high susceptibility ranking category and expanded their original examination scope to include a visual examination of the bare metal head and penetration nozzle interfaces.

Overall, the inspectors concluded that the licensee had completed an examination of the reactor vessel head which was consistent with the requirements of NRC Order EA 03-009. The inspectors documented conclusions in response to 11 specific questions related to the quality of personnel, procedures, and equipment used to perform the vessel head examination. For some of the questions in this temporary instruction, the inspectors could not independently confirm the ability of some of the licensee's UT techniques to detect PWSCC. This condition reflected a lack of industry or vendor "qualified" techniques and did not represent a deviation from NRC Order EA-03-009, which did not specify qualification or demonstration standards for the UT techniques used. Additionally, the inability of the UT technique to identify PWSCC within the J-groove weld is consistent with the requirements of Order EA-03-009, which does not require examination of the J-groove welds when UT of the nozzle base material has been completed.

Evaluation of Inspection Requirements

1. For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly

describe the personnel training/qualification process used by the licensee for this activity.)

Above Head Visual Examinations

Yes. The licensee conducted a direct visual examination of the top surface of the vessel head with knowledgeable staff members certified to Level II as VT-2 examiners in accordance with procedure NDT-A-02, "NDT Personnel Training, Qualification and Certification." In this qualification and certification procedure, the licensee referenced the industry standard ANSI/ASNT CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

Under Head Automated UT and ET Examinations

Yes. The licensee's vendor personnel that performed the automated UT and ET examinations were certified to level II or III in UT examination in accordance with vendor (Framatome Advanced Nuclear Products Inc. (FANP)) Procedures 54-ISI-30-01, "Written Practice for the Qualification and Certification of NDE Personnel;" 54-ISI-30-02, "Written Practice for the Qualification and Certification of NDE Personnel;" 54-ISI-24-28, "Written Practice for Personnel Qualification in Eddy Current Examination;" 54-ISI-21-31, "Written Practice for Personnel Qualification Ultrasonic Method;" and ISwT Nuclear Projects Operating Procedure 2.0-NDES-001. These licensee vendor procedures referenced the industry standard ANSI/ASNT CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel." Additionally, the licensee's vendor UT acquisition and analysis personnel had completed a minimum of 16 hours training on the automated UT techniques used.

Under Head PT Examinations

Yes. The licensee conducted a manual solvent removable PT examination of the VHP nozzle No. 29 and No. 30 J-groove weld locations with knowledgeable staff members certified to Level II in PT examination in accordance with procedure NDT-A-02, "NDT Personnel Training, Qualification and Certification." In this qualification and certification procedure, the licensee referenced the industry standard ANSI/ASNT CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?

Above Head Visual Examinations

Yes. The licensee performed the bare metal inspection of the vessel head in accordance with procedure NDT-VT-09, "Bare Metal Visual Examination." The licensee considered this procedure to be demonstrated because examination personnel could resolve lower case alpha numeric characters 0.044 inches in height at the actual distance used during the direct visual examination. The inspectors had previously observed licensee personnel performing visual examinations to this procedure during the bare metal examination of pressurizer components and had not identified any concerns.

Under Head Automated UT of the Control Rod Drive Mechanism (CRDM) Penetration Nozzles

Yes. For the CRDM nozzle penetrations, the licensee's vendor performed automated UT of VHP nozzles in accordance with FANP Procedure 54-ISI-100-13, "Remote Ultrasonic Examination of Reactor Head Penetrations." The vendor performed these examinations using a rotating probe head from the inside surface which was consistent with the probe configurations used during vendor mockup testing. The licensee's vendor had demonstrated an earlier version of this procedure on mockup VHP nozzles which contained cracks or simulated cracks as documented in EPRI MRP-89, "Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations." The inspectors reviewed the revisions to Procedure 54-ISI-100-13 implemented since the licensee's vendor had demonstrated this procedure in EPRI MRP-89, to ensure that any equipment configuration changes did not affect flaw detection capability. Additionally, the licensee's vendor had demonstrated the capability to detect a leakage path in the interference zone using this procedure on a mockup with a simulated leak path and at other nuclear power plants with leakage paths confirmed by visual examinations (e.g., the Oconee Units). Therefore, the inspectors considered this procedure demonstrated.

Under Head Automated UT of the In-Core Instrument (ICI) Penetration Nozzles

Unknown. For the ICI nozzle penetrations, the licensee's vendor performed automated UT in accordance with FANP Procedure 54-ISI-100-13, "Remote Ultrasonic Examination of Reactor Head Penetrations." The licensee performed these examinations from the inside and outside surfaces of the RPV nozzle. The UT performed by the licensee's vendor at the inside surface was conducted with a rotating head probe which contained a transducer configuration which was consistent with that used on vendor mockup tests in which real or closely simulated PWSCC flaws were used. However, the equipment used by the licensee to scan the ICI nozzles from the outside surface had not been demonstrated on mockups containing real or closely simulated PWSCCs. The licensee's vendor considered this procedure demonstrated based upon the ability to see electric discharge machined (EDM) notches or holes at the inside and outside surface of a calibration standard (reference FANP Procedure Qualification 54-PQ-100-7). The EDM process results in a uniform notch with a relatively wide air filled gap perpendicular to one surface that is readily detected by UT. In contrast, PWSCC gaps are very small (e.g., tight), are not uniform in nature and may not be perpendicular to the surface, which represents a more significant challenge for detection by UT. Therefore, the inspectors determined that detection of EDM flaws on the calibration standard would not conclusively demonstrate the capability of this equipment to detect PWSCC.

Under Head Automated UT of the Head Vent Nozzle

Unknown. The licensee conducted under head automated UT of the vessel head vent line nozzle penetration in accordance with FANP Procedure 54-ISI-137-04, "Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations." The licensee's vendor considered this procedure demonstrated based upon the ability to see EDM notches at the inside and outside surface of the UT calibration standard (reference 54-PQ-137-04, "Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations"). The EDM process results in a uniform notch with a relatively wide air filled gap perpendicular to one surface that is readily detected by UT examination. In contrast, PWSCC gaps are very small, are not uniform in nature and may not be perpendicular to the surface, which represents a more significant challenge for detection by UT. Therefore, the inspectors determined that detection of EDM flaws on the calibration standard would not conclusively demonstrate the capability of this equipment to detect PWSCC.

J-Groove Welds

No. For the UT of CRDM and ICI nozzle penetration J-groove weld regions, the UT technique performed was not designed to detect PWSCC contained entirely within the J-groove welds. Thus, the inspectors concluded that the procedure was not demonstrated in this region. Because the licensee completed a UT of the nozzle base material areas as defined in Order EA-03-009, the inspectors concluded that the licensee met the examination requirements of Order EA-03-009, which did not require inspections of the J-groove weld regions in this case.

Yes. The licensee conducted a manual solvent removable PT examination of J-groove welds at penetration nozzles No. 29 and No. 30, in accordance with procedure NDT-PT-01, "Liquid Penetrant Examination," which was consistent with the ASME Code, Section V requirements. Based upon meeting code requirements and industry experiences where solvent removable PT examinations have detected PWSCC, the inspectors concluded this procedure and method were demonstrated.

Yes. The licensee conducted under head automated ET examination of the vessel head vent line J-groove nozzle weld face in accordance with FANP Procedure 54-ISI-460-01, "Multi-Frequency Eddy Current Examination of Nozzle Welds and Regions." The licensee's vendor concluded that this procedure was demonstrated based upon the ability to see cracking during mockup testing using a mockup with stress corrosion cracks (reference Framatome document 54-PQ-460-01-00 and EPRI document, "Demonstration of Framatome Eddy Current Examination for the RVHP Attachment Weld"). Because the licensee's vendor identified nearly 100 percent of the flaws on a mockup using this procedure, the inspectors concluded that this procedure was demonstrated as capable of identifying PWSCC.

3. For each of the examination methods used during the outage, was the examination able to identify, disposition, and resolve deficiencies and capable of identifying the PWSCC and/or head corrosion phenomena described in Order EA-03-009?

Above Head Visual Examinations

Yes. The licensee was able to obtain a bare metal visual examination at each of the 53 VHP nozzles and the head vent line nozzle penetration, with no obstructions or interferences. Therefore, the inspectors concluded that the inspection performed was capable of detecting evidence of leakage at the VHP nozzle penetrations cause by PWSCC or corrosion of the vessel head caused by boric acid.

Under Head Automated UT of the CRDM Penetration Nozzles

Yes. For the CRDM nozzle penetrations, the VHP nozzle base metal material was scanned using UT equipment, techniques and procedures that were consistent with those demonstrated as effective in detection of PWSCC (see Question 2 above). For these examinations, a rotating head type UT probe was used to acquire data from the inside surface of VHP nozzles (with thermal sleeves removed). This rotating probe contained multiple time of flight diffraction (TOFD) transducer configurations and shear wave transducers which were designed to optimize detection of both circumferential and axial oriented flaws. Additionally, the UT probes were configured to detect evidence of leakage/corrosion in the interference zone behind the VHP nozzle based on patterns in the UT backwall response. The licensee did not identify any limitations to these examinations. Therefore, the inspectors concluded that this examination would have detected PWSCC in the CRDM penetration nozzle base material if it had been present.

Under Head Automated UT of the ICI Penetration Nozzles

Unknown. For the ICI nozzles, the VHP nozzle base material was scanned using UT equipment, techniques and procedures which were consistent with those used on mockup tests. The licensee's vendor scanned the inside diameter of the ICI nozzles using a rotating probe similar to that used on the CRDM nozzles. For the volume of base metal scanned by this probe, the inspectors concluded that the UT would be effective at detection of PWSCC. However, due to the unique ICI nozzle configuration (transition taper at the inside surface), the licensee had to supplement the examination area with UT conducted from the outside surface of these nozzles to get the UT coverage required by NRC Order EA-03-009. The licensee conducted UT of the outside surface using TOFD UT transducers mounted to a mechanical scanning device. The TOFD transducers on this probe were designed to maximize a UT signal from axial and circumferentially oriented indications. However, the vendor's mockup used for demonstration of the outside surface scanning technique did not contain flaws representative of PWSCC cracking (see Question 2 above). Therefore, the inspectors could not independently confirm that this examination would be effective at detection of PWSCC.

Under Head Vent Line Penetration Automated UT

Unknown. The licensee used a rotating probe with pulse-echo type shear and longitudinal wave transducers to acquire data from the inside surface of the head vent line penetration. However, the vendor's mockup used for demonstration of this UT technique did not contain flaws representative of PWSCC cracking (see Question 2 above). Therefore, the inspectors could not independently confirm that this examination would be effective at detection of PWSCC.

J-Groove Welds

No. The licensee's UT of CRDM and ICI nozzle penetrations was not designed to detect PWSCC contained entirely within the J-groove welds, and therefore would not be effective at identification of PWSCC flaws located in this region.

Yes. The licensee used a manual solvent removable PT examination of J-groove welds at No. 29 and No. 30, with a procedure which was in accordance with ASME Code requirements and which was successful at detecting PWSCC.

Yes. The licensee conducted under head ET examination of the vessel head vent line nozzle J-groove weld. For this examination, the licensee's vendor used an array of ET probes mounted to a scanner that was rotated around the face of the J-groove weld. The inspectors confirmed that the essential variables identified on the examination technique specification sheet matched those used in the mockup demonstration. Therefore, the inspectors concluded that this examination would have been effective at detecting PWSCC in the head vent line J-groove weld.

4. What was the physical condition of the reactor head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

Above Head Visual Examinations

The inspectors conducted an examination of the bare metal reactor vessel head with the insulation removed and did not identify obstructions or debris, that would affect the licensee's visual examination of the nozzle-to-head interface regions. The only limitation recorded by the licensee during the visual examination, was associated with an insulation support ring mounted to the head. The licensee estimated that this insulation support ring obscured about two percent of the head outer surface. The licensee concluded that 98 percent of the head surface was inspected, which met the 95 percent minimum examination coverage required by NRC Order EA-03-009.

5. Could small boron deposits, as described in Bulletin 2001-01, be identified and characterized?

Above Head Visual Examinations

Yes. Based upon the lack of obstructions and complete access for the bare metal visual examination, the inspectors concluded that the licensee could have identified boric acid deposits or corrosion of the head during the visual examination. The licensee documented in the visual examination record that no evidence of leakage or corrosion existed on the reactor vessel head.

6. What material deficiencies (i.e., cracks, corrosion, etc) were identified that require repair?

On October 11, 2004, the licensee's contractor identified discontinuities in the backwall signal for penetrations No. 29 and No. 30, which were characterized as a "leak path" in the UT records. As a result of these indications, the licensee initiated PT examinations on these J-groove welds.

On October 14, 2004, the licensee performed a manual solvent removable PT examination of the CRDM penetration nozzle No. 29 J-groove weld due to indications of leakage identified by UT. The licensee identified a rounded indication at the interface of the J-groove weld and cladding of penetration nozzle No. 29. The licensee elected to remove (by grinding) a small amount of metal at this location and re-exam this area using PT. The re-examination revealed a 1/4-inch long axial crack running perpendicular to the fusion line (CAP 044679).

On October 15, 2004, the licensee performed a manual solvent removable PT examination of the CRDM nozzle penetration No. 30 J-groove weld due to indications of leakage identified by the UT. The licensee identified two rounded indications 0.9 and 0.6 inches in from the toe of the J-groove weld. The licensee elected to remove (by grinding) a small amount of metal at these locations and re-exam this area using PT. The re-examination revealed a 1-inch long circumferential crack running adjacent to the fusion line of the J-groove weld (CAP 044679).

On October 17, 2004, the licensee notified the NRC (Event No. 41128) that on October 16, 2004, following minor excavation of the J-groove weld surface of nozzles No. 29 and No. 30, through-wall flaws were identified. The risk impact of past plant operation with these flaws will be determined by the licensee when the Licensee Event Report for this condition is submitted to the NRC. The NRC inspection process will include a review of this Licensee Event Report to assess the regulatory and risk significance of this condition.

The licensee implemented repairs to penetration nozzles No. 29 and No. 30 in accordance with MOD-2004-010, "Reactor Vessel Head Penetration Repair Project." In this modification, the licensee removed the original nozzle to a point above the existing J-groove weld, established a new temperbead weld repair (pressure boundary weld) on the inside diameter of the head bore and installed a new Inconel Alloy 690 nozzle extension piece below the weld. On August 2, 2004, the licensee requested NRC approval for relief from applicable ASME

Code requirements to support this repair process, and on November 8, 2004, the NRC granted this relief request. A more detailed discussion of the licensee's repair process is identified in the NRC relief request approval letter dated November 8, 2004. Based upon review of the licensee's welding records, certified material test reports, and nondestructive examination records, the inspectors confirmed that the welded repair completed, was consistent with ASME Code, Section III and Section XI requirements as amended by the licensee's approved Code relief request. However, the inspectors identified that UT procedure used to examine the J-groove welds did not contain applicable requirements from the ASME Code, Section V, and is discussed in the Findings portion of this inspection report section.

7. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

The licensee cut and permanently removed portions of thermal sleeves in each head nozzle (not including the head vent nozzle) to facilitate the UT conducted from the inside surface of each nozzle. Removal of these thermal sleeves allowed the licensee to obtain the extent of UT coverage required by Order EA-03-009.

During the UT, the licensee identified shallow circumferentially oriented grooves (scoring) on the inside diameter of each of the 45 CRDM nozzles as discussed in question No. 9. This area of scoring was generally located just below the J-groove weld elevation, but was in the area of interest for the extent of UT required by Order EA-03-009. The licensee's vendor acquired data from additional UT transducers on their inspection probe to ensure that the nozzle areas near this scoring were completely examined. The licensee fabricated a mockup to allow their vendor to demonstrate the ability to depth size grooves on this mockup (reference report, "Reactor Vessel Head Penetration NDE Inspection Field Report For NMC Palisades RFO-17"). The depths and circumferential extent of the grooves in the CRDM nozzles as measured by this UT examination were used by the licensee in evaluating the structural significance (see question No. 9).

8. What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations, (e.g. thermal hydraulic modeling, instrument uncertainties), etc.?

NRC Order EA-03-009 required licensees to calculate the susceptibility category of the reactor head to PWSCC-related degradation. The susceptibility category in EDY established the basis for the head inspections scope. The licensee documented the EDY for the Palisades reactor head in EA-JRP-02-001, "Reactor Head Effective Degradation Years Calculation." In this calculation, the licensee used the formula required by NRC Order EA-03-009 and determined the EDY for the vessel head. As of September 19, 2004, the Palisades vessel head was at 9.67 EDY which placed it in the moderate susceptibility category. The inspectors also reviewed the results of visual examination records from the previous outage examinations and confirmed that no leakage (indicative of PWSCC) of VHPs had been identified.

NRC Order EA-03-009, required the licensee to have used best estimate values in the calculation used to determine the susceptibility category for the vessel head. The licensee determined that the current operating head temperature was 586.4 degrees Fahrenheit in EA-C-PAL-01-03348-01, "Upper Head Fluid Temperature For Palisades Reactor (Westinghouse Calculation CN-WFE-02-5)." In this calculation, the head temperature was derived based upon the assumption that core bypass flow and core exit temperature mixing was perfect in the head region and therefore, the head temperature was assumed to be the same as hot leg temperature. This calculation included the licensee’s power uprate and this head temperature was applied in the EDY calculation (EA-JRP-02-001) beginning with operating cycle number 9. However, the inspectors questioned the licensee staff as to the basis for the hot leg temperatures (assumed to be representative of vessel head temperature) used in EA-JRP-02-001 for operating cycles 1 through 8. The cognizant licensee engineer did not know the basis for these head temperatures. Further, the inspectors identified that for operating cycle 7, the hot leg temperature as determined from data recorded by the process computer for 100 percent reactor power on June 15, 1988, and June 16, 1988, was four degrees above the head temperature used in calculation EA-JRP-02-001 for cycle 7. Therefore, the inspectors could not confirm that the licensee had used appropriate plant specific information to determine the operating head temperatures in all cases. Because of the small amount of temperature differences involved and the margin available (2.3 EDY to the high susceptibility bin), the inspectors judged that this error would not impact the current susceptibility ranking of the Palisades vessel head. Additionally, based upon finding cracking in the J-groove welds at nozzles No. 29 and No. 30, the Palisades vessel head was required to be placed in the high susceptibility ranking bin independent of the head EDY.

Enforcement: On September 30, 2004, while performing TI 2515/150, the inspectors identified a minor violation of NRC Order EA-03-009 for the licensee’s failure to use best estimate values for the reactor head temperature calculation EA-JRP-02-001, "Reactor Head Effective Degradation Years Calculation."

NRC Order EA-03-009, Section IV.A, required in part that, the licensee perform a calculation of effective degradation years for the end of each operating cycle. This calculation shall be performed with best estimate values for each parameter at the end of each operating cycle and T_{headj} = 100 percent power head temperature during the time period j.

Contrary to this requirement, the inspectors identified that in calculation EA-JRP-02-001, "Reactor Head Effective Degradation Years Calculation," the licensee failed to use best estimate values for the reactor head temperature (T_{headj}). Specifically, this calculation used a non-conservative, non-best estimate head temperature for operating cycle No. 7 which was 4 degrees below applicable temperature data measured from the process computer for cycle

No. 7. This violation had existed since the licensee issued Revision 0 of this calculation in 2003. The inspectors compared this performance deficiency to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612 "Power Reactor Inspections Reports," to determine whether the finding was minor. Following that review, the inspectors determined that this issue was similar to example 3.l associated with a non-significant dimensional error. Therefore, because the licensee entered this issue into the corrective action program (CAP 043867) the inspectors concluded that this issue was a violation of NRC Order EA-03-009 of minor significance.

The inspectors also identified that the licensee had not established a method to maintain control of the Excel spread sheet calculation file (program) used to determine the EDY for each cycle in calculation EA-JRP-02-001. The inspectors independently confirmed that the spread sheet calculation had produced the correct EDY values from the previous calculation revision.

<u>Enforcement</u>: On September 30, 2004, while performing TI 2515/150, the inspectors identified a minor violation of 10 CFR Part 50, Appendix B, Criterion III for the licensee's failure to check or verify the accuracy of calculations contained in an uncontrolled computer based Excel spread sheet which was used in support of EA-JRP-02-001, "Reactor Head Effective Degradation Years Calculation."

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires in part measures to verify and check design processes.

Contrary to this requirement, the inspectors identified that in calculation EA-JRP-02-001, "Reactor Head Effective Degradation Years Calculation," the licensee failed to verify and check the design process to ensure that the electronic file/program (Excel spread sheet) had not been not altered or changed between calculation revisions. This violation had existed since the licensee issued Revision 1 to this calculation in 2004. The inspectors compared this performance deficiency to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612, "Power Reactor Inspections Reports," to determine whether the finding was minor. Following that review, the inspectors considered this issue similar to example 1.a. associated with a record keeping issue of low significance. Therefore, because the licensee entered this issue into the corrective action program (CAP 043867) the inspectors concluded that this was a violation of 10 CFR Part 50, Appendix B, Criterion III, of minor significance.

9. During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?.

The licensee identified through-wall cracks in the J-groove welds of nozzles No. 29 and No. 30 (see question number 6). Because the licensee's repair process leaves a portion of the cracked J-groove weld in-service, the licensee performed a flaw evaluation. In this evaluation, No. 32-5044161-00, "CRDM Nozzle IDTB J-Groove Weld Flaw Evaluation," the licensee demonstrated that a postulated flaw left in the J-groove weld would not propagate to an unacceptable size within the reactor head base material. The inspectors did not perform a detailed review of this flaw analysis, because the flaws were in the J-groove weld and the flaw evaluation guidance of Appendix D of TI 2515/150 was not applicable. Additionally, by letter dated August 2, 2004, the licensee submitted to the NRC, a request for relief from ASME Code requirements to support repairs to nozzles No. 29 and No 30. This relief request included flaw evaluation No. 32-5044161-00, which demonstrated that a flaw present in the J-groove weld remnant would continue to satisfy ASME, Section XI Code criteria for fracture toughness (IWB-3612) for 27 years of operation. Because this flaw evaluation was reviewed by the NRR staff as a basis to for the licensee relief request approved by the NRC on November 8, 2004, the inspectors concluded that the disposition of J-groove weld flaws was acceptable.

During the UT, the licensee identified shallow circumferentially oriented grooves (depth of deepest groove recorded was 0.090 inches) on the inside diameter of each of the 45 CRDM penetration nozzles (nozzle wall thickness was a nominal 0.38 inches). The licensee determined that this scoring was caused by a grinder used in partial removal of the thermal sleeves completed in 1970. The licensee identified that this area of scoring could serve as a crack initiating site and performed EA-A600-2004-02, "Evaluation of Machining Grooves Observed in CRDM Nozzles." In this evaluation, the licensee performed a linear elastic fracture mechanics evaluation which included plant operating and residual weld stresses. The licensee demonstrated that if axial or circumferential cracks were assumed to propagated as PWSCC from the most limiting groove/nozzle combination, the remaining service life (e.g., time to reach 75 percent wall depth) was 2.2 years. This service life was sufficient to demonstrate integrity of the nozzles until reexamination during the next refueling outage. However, the inspectors identified that the licensee had used a RVCH temperature of 585 degrees Fahrenheit, vice 586.4 degrees Fahrenheit (best estimate value) in the flaw growth analysis used to demonstrate continued integrity of the nozzles affected by these grooves. The licensee documented this design input error in CAP045190 and estimated that the use of a lower head temperature (585 degrees Fahrenheit) would underestimate the crack growth rate by 3.5 percent, which would not impact the overall conclusion that these nozzles would retain structural integrity for at least one cycle of plant operation. The inspector concluded that the licensee’s flaw evaluation approach and acceptance criteria were conservative and consistent with the guidance of Appendix D of Temporary Instruction TI-2515/150.

<u>Enforcement</u>: On September 30, 2004, while performing TI 2515/150, the inspectors identified a minor violation of 10 CFR Part 50, Appendix B, Criterion III, for the licensee’s failure to use an appropriate design input value for reactor head temperature in calculation EA-A600-2004-02, "Evaluation of Machining Grooves Observed in CRDM Nozzles."

Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires in part, measures to verify and check design processes.

Contrary to this requirement, the inspectors identified that in calculation EA-A600-2004-02, "Evaluation of Machining Grooves Observed in CRDM Nozzles," the licensee failed to verify and check the design process to ensure that an appropriate design input value for reactor head temperature was used. This violation had existed since the licensee issued this calculation in 2004. The inspectors compared this performance deficiency to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612 "Power Reactor Inspections Reports," to determine whether the finding was minor. Following that review, the inspectors considered this issue similar to example 1.a. associated with a record keeping issue of low significance. Therefore, because the licensee entered this issue into the corrective action program (CAP045190) the inspectors concluded that this was a violation of 10 CFR Part 50, Appendix B, Criterion III, of minor significance.

10. Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the vessel head?

    Yes. The licensee performed inspections of components within containment to identify leakage which included areas above the vessel head. The licensee conducted these inspections with the plant in Mode 3 at the beginning of the outage in accordance with WI-PCS - 6, "NSSS Walk Down," and at the end of the outage in accordance with procedure RT-71A-2, "Primary Coolant System, Class 1 Reactor Vessel Visual Examination." The licensee’s engineering evaluations of components potentially degraded by boric acid were controlled by procedure EM-09-13, "Inservice Inspection Pressure Testing Program/Boric Acid Corrosion Control Program."

11. Did the licensee perform appropriate follow-on examinations for boric acid leaks from pressure retaining components above the vessel head?

    Yes. The licensee completed an engineering evaluation for boric acid leakage identified at an In-Core Instrumentation Flange on the Reactor Vessel Head in 2004. This evaluation appropriately identified the components which could be affected by boric acid including the reactor head. However, the corresponding corrective actions documented in CAP 042994 and associated work order No. 24422191 did not document actions to inspect the reactor head to assess the extent of condition or determine if the head was affected. The licensee staff stated that this was a documentation error and that the head had not been affected. The NRC had previously confirmed that no evidence of boric acid leakage remained on the Unit 1 head following the last refueling outage bare metal head examination (reference NRC Inspection Report 50-255/2003-02). Additionally, the licensee did not identify any boric acid deposits or corrosion of the vessel head during the current outage visual head examination.

c. Findings

Introduction

The inspectors identified a Green finding and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” that was associated with the inadequate non-destructive examinations of the weld repairs to reactor vessel head penetration nozzles No. 29 and No. 30.

Description

The licensee performed weld repairs to reactor vessel head penetration nozzles No. 29 and No. 30 in accordance with the repair design described in MOD-2004-010, "Reactor Vessel Head Penetration Repair Project." In this modification, the licensee removed the original nozzle to a point above the existing J-groove weld, established a new temperbead weld repair (pressure boundary weld) on the inside diameter of the head bore, and installed a new Inconel Alloy 690 nozzle extension piece below the weld. The licensee examined and accepted the new repair welds based upon UT and PT examinations. However, the inspectors identified that the licensee had failed to incorporate several Code requirements associated with equipment calibration into Procedure 54-ISI-178-04, "Ultrasonic Examination of Control Rod Drive Mechanism (CRDM) Nozzle Temperbead Weld Repair," used to examine the repair welds on nozzles No. 29 and No. 30.

Procedure 54-ISI-178-04 allowed UT equipment calibration checks at 12-hour intervals, contrary to the ASME Code, Section V, Article V, Paragraph T-542.4.7 requirement to perform calibration checks at 4-hour intervals during the examination. Consequently, the licensee’s vendor performed calibration checks which ranged from 5 to 7 hours apart, which exceeded the maximum time allowed by the Code. Because the final calibration check was satisfactory, the licensee concluded that this error did not affect the quality of the UT data recorded.

Procedure 54-ISI-178-04 also lacked the ASME Code, Section V, Article V, Paragraph T-542.5.1 calibration check acceptance criteria to verify that a point on the distance amplitude correction curve had not moved by more than 5 percent of the full range sweep reading for the UT equipment. To address this issue, the licensee’s vendor provided information to the inspectors that demonstrated that the 5 percent of full sweep range criteria was bounded by the 10 percent single point sweep check criteria, which had been used in the procedure. Therefore, the licensee concluded that this deficiency did not invalidate the UT data recorded.

Procedure 54-ISI-178-04 also lacked the ASME Code Section V, Article V, Paragraph T-542.5.1 and Paragraph T-542.5.2 requirements to void UT data collected if the calibration checks failed and to reperform the UT. The licensee’s vendor lead level III UT analyst stated that he would not have voided the UT data and reexamined these welds if the UT calibration check had failed under certain conditions. This postulated action would have been contrary to the Code requirements, but was consistent with the procedure, which left it up to the analyst to decide on corrective actions for failed calibration checks. Because the final calibration check was satisfactory, the licensee’s vendor did not take any actions contrary to the Code requirements and thus, the quality of the UT data recorded was not affected.

Analysis

The licensee's performance deficiency associated with this finding was the failure to incorporate the Code requirements related to the timing, acceptance criteria and corrective actions for unsatisfactory calibration checks into the UT procedure used for examination of repair welds at reactor vessel head penetration nozzles No. 28 and No. 29. The inspectors compared this performance deficiency to the findings identified in Appendix E, "Examples of Minor Issues," of IMC 0612, "Power Reactor Inspections Reports," to determine whether the finding was minor. Following that review, the inspectors concluded that none of the examples listed in Appendix E of IMC 0612 accurately represented this example. As a result, the inspectors compared this performance deficiency to the questions contained in Section 3, "Minor Questions," of Appendix B of IMC 0612. Following that review, the inspectors concluded that this finding was greater than minor, because if left uncorrected, it could have resulted in allowing unacceptable weld flaws to remain in-service which was a more significant safety concern. Specifically, the licensee intended to use Procedure 54-ISI-178-04 again at Palisades during the next outage and the vendor will likely use this procedure again at other reactor plant sites which have implemented the FANP temperbead repair method and the lack of Code requirements for UT calibration could result in acceptance of weld examinations which do not meet Code. A non-Code UT may not effectively detect weld flaws, which could result in plant operation with degraded nozzle welds. The cause of this finding was related to the cross-cutting area of human performance because the cause of the error was due to a lack of rigor in the review of procedures.

This finding affected the Barrier Integrity cornerstone. The inspectors determined that the finding could not be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," because the SDP for the Barrier Integrity Cornerstone only applied to degraded systems/components, not to deficiencies in the procedures that were designed to detect component degradation. Therefore, this finding was reviewed by NRC management in accordance with IMC 0612, Section 05.04c, who determined that this finding was of very low safety significance (Green) because these procedural deficiencies did not actually degrade the quality of the weld examinations on nozzles No. 28 and No. 29.

Enforcement

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," required in part, that procedures shall have appropriate quantitative or qualitative acceptance criteria for determining that important activities affecting quality have been satisfactorily accomplished.

The ASME Code, Section V, Article V, Paragraph T-542.4.7, required in part, that a calibration check on at least one of the basis reflectors in the basic calibration block shall be made every 4 hours during the examination.

The ASME Code, Section V, Article V, Paragraph T-542.5.1, required in part, that if a point on the distance amplitude correction curve has moved on the sweep line by more than 10 percent of the sweep reading or 5 percent of the full sweep, whichever is greater, correct the sweep range calibration. If reflectors are recorded on the data sheets, those data sheets shall be voided and a new calibration shall be recorded. All recorded indications since the last valid calibration or calibration check shall be reexamined with the corrected calibration and their values shall be changed on the data sheets.

The ASME Code, Section V, Article V, Paragraph T-542.5.2, required in part, that if any point of the distance amplitude correction curve has increased more than 20 percent or 2 decibels of its amplitude, all recorded indications since the last valid calibration or calibration check shall be reexamined with corrected calibration and their values shall be changed on the data sheets.

Contrary to these requirements, on December 1, 2004, the inspectors identified that procedure 54-ISI-178-04, "Ultrasonic Examination of Control Rod Drive Mechanism (CRDM) Nozzle Temperbead Weld Repair," did not contain appropriate acceptance criteria associated with the UT equipment calibration checks. Specifically, this procedure did not contain the requirement to perform a calibration check every 4 hours, nor did it contain the requirement to check if the point on the distance amplitude correction curve had moved by more than 5 percent of the full sweep, nor did it contain the requirement to void data sheets and reexamine the component if the calibration check failed to meet these requirements. This violation had existed since at least November 2, 2004, when this procedure was used to examine reactor vessel head penetration nozzle No. 28 and No. 29 repair welds. However, because this violation was associated with a finding of very low safety significance and because the issue was entered into the licensee’s corrective action program (CAP04549 and CAP045386), it is being treated as a NCV, consistent with Section VI.A.1 of the Enforcement Policy (NCV 05000255/2004012-04). As part of their immediate corrective actions, licensee personnel verified that the inadequate procedure had no actual impact on the quality of the weld examination. The licensee had not yet developed long-term corrective actions for this finding at the conclusion of this inspection.

.4 <u>Reactor Pressure Vessel Lower Head Penetration Nozzles</u> (TI 2515/152)

a. <u>Inspection Scope</u>

The Palisades Nuclear Plant reactor pressure vessel lower head does not have penetration nozzles. Therefore, TI 2515/152 which requires NRC review of licensee examinations of lower head penetration nozzles does not apply and therefore this TI will not be performed at Palisades.

b. <u>Findings</u>

No findings of significance were identified.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to members of licensee management on December 29, 2004. Licensee personnel acknowledged the findings presented. The inspectors asked licensee personnel whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

- Occupational Radiation Safety - refueling outage radiological access control and ALARA programs inspection with Mr. P. Harden on October 1, 2004.

- Temporary Instruction 2515/150, Temporary Instruction 2515/160 and the ISI procedure (IP 7111108) with Mr. D. Malone and other licensee staff members on October 8, 2004, November 12, 2004, and December 1, 2004.

- Occupational Radiation Safety - radiological access control and ALARA programs inspection with Mr. D. J. Malone on December 17, 2004.

- Emergency Preparedness inspection with Mr. T. Blake on December 30, 2004.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
D. Malone, Site Vice President
P. Harden, Site Director
M. Acker, ASME and Valve Programs Supervisor
J. Beer, Technical Supervisor, Chemistry and Radiation Protection
T. Blake, Emergency Preparedness Supervisor
M. Carlson, Engineering Director
W. Doolittle, Supervisor/Shipper, Chemistry and Radiation Protection
T. Fouty, Inservice Inspection
G. Hettel, Plant Manager
L. Lahti, Licensing Manager
K. Smith, Operations Manager
D. Williams, Manager, Chemistry and Radiation Protection

Nuclear Regulatory Commission
J. Stang, Project Manager, NRR
S. Klementowicz, Senior Health Physicist, NRR

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000255/2004012-01	FIN	Condensate Reject Valve Failed Full Open During Maintenance Activities Resulted in Operator Action to Mitigate Transient (Section 1R14.1)
05000255/2004012-02	NCV	Heavy Load Lift of Primary Coolant Pump Outside of Required Path (Section 1R20.2)
05000255/2004012-03	FIN	Condensate Pump Motor Bearing Fire Resulted in Manual Reactor Trip (Section 4OA2.3)
05000255/2004012-04	NCV	Lack of Code UT Calibration Requirements in Procedure for Examination of Nozzle Repair Welds (Section 4OA5.3)

Closed

05000255/2004001-01	LER	Reactor Protection System and Auxiliary Feedwater System Actuation (Section 4OA3.1)
05000255/2004012-01	FIN	Condensate Reject Valve Failed Full Open During Maintenance Activities Resulted in Operator Action to Mitigate Transient (Section 1R14.1)

05000255/2004012-02	NCV	Heavy Load Lift of Primary Coolant Pump Outside of Required Path (Section 1R20.2)
05000255/2004012-03	FIN	Condensate Pump Motor Bearing Fire Resulted in Manual Reactor Trip (Section 4OA2.3)
05000255/2004012-04	NCV	Lack of Code UT Calibration Requirements in Procedure for Examination of Nozzle Repair Welds (Section 4OA5.3)

<u>Discussed</u>

None.

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of documents on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather

Plant Procedures

SOP - 23, Attachment 10; Warm Weather Checklist, Checklist 1; Revision 18
SOP - 23, Attachment 8; Cold Weather Checklist, Checklist 1; Revision 19
SOP - 22, Emergency Diesel Generators; Revision 36
SOP - 24; Ventilation and Air Condition System; Revision 38
ONP - 12; Acts of Nature; Revision 19

Condition Reports Reviewed to Assess Corrective Actions

CAP039606; PI-1345 Found Reading Abnormally High
CAP041046; Intake Structure Ventilation Supply Unit Failed on Full Recirc
CAP039613; Minimum/Maximum Temperature Requirements for Screenhouse
CAP045706; Breaker Caution Tagged "Open" per the Cold Weather Checklist Found "Closed"
CAP045699; Cold Weather Concern on Level Transmitters
CAP045519; Degraded Condition of Feedwater Purity HVAC System

1R04 Equipment Alignment

Plant Procedures

GOP-14, Attachment 16; Shutdown Operation Equipment Sheets; Revision 21
GOP-14, Attachment 7; PCS Inventory Control Requirements; Revision 21
GOP-14, Attachment 6; Maintenance of Vital Auxiliaries - Electric; Revision 21
SOP-3, Attachment 17; Engineered Safeguards System Checklist (Heatup); Revision 62
SOP-4, Attachment 2; Test Start Containment Spray Pump P-54B; Revision 22
SOP-4, Attachment 3; Test Start Containment Spray Pump P-54C; Revision 22

Miscellaneous Documents

System Diagram -204; Safety Injection, Containment Spray and Shutdown Cooling System

1R05 Fire Protection

Plant Procedures

FPSP-SI-1; Data Sheet for Alarm Bells and Ionization Smoke Detectors for Fire Areas 29, 30, 31, 10; Revision 4
FPSP-RP-11; Fire Barrier Penetration Seal/Conduit Seal Inspection Form for Fire Areas 29, 30, 31, 3, 6, 10; Revision 5
FP-PE-3; Check Sheet for Fire Extinguishers for Fire Areas 29, 30, 31
FPSP-MO-2; Fire Hose Reel Station on and Fire Hose Rack Station Checkoff Sheet for Fire Areas 30, 31; Revision 1
ONP25.1; Off-Normal Procedure - Fire Which Threatens Safety-Related Equipment Fire Areas 10; Revision 4
FPSP-RO-9; Fire Sprinkler System Inspection; Revision 0
FPSP-SO-2; Inspection and Testing of Palisades Plant Fire Doors Fire Areas 10; Revision 1
FPSP-WP-1; Safety-Related Fire Door Data Sheet Fire Areas 6, 10; Revision 2

Miscellaneous

Palisades Nuclear Plant Fire Hazards Analysis for Fire Areas 7, 11, 12, 21, 29, 30, 31; Revision 5
EA-PSSA-00-001; Palisades Plant Post Fire Safe Shutdown Summary Report; Revision 2
Fire Hazards Analysis Report; Revision 5

Plant Procedures

ONP-25.1; Fire Which Affects Safety-Related Equipment; Revision 14

Condition Reports Reviewed to Assess Significance Characterization of Identified Problems

CAP043195, Combustibles Brought Into Containment Without Transient Material Variance Requests

1R06 Flood Protection

MSM-M - 16, Attachment 18; Door/Hatch Inspection Sheet
Work Order 24324240; Annual Inspection of Watertight Barriers; April 6, 2004

Condition Reports Reviewed to Assess Corrective Actions

CAP040403; Door-256 Fails Annual Watertight Barrier Inspection
CAP040405; Door 58 Fails Annual Watertight Barrier Inspection
CAP020329; Expansion Joint Inspection Fails to Identify Known Deficiency

1R07 Heat Sink Performance

T-390; Single Tube Testing of Component Cooling Water Heat Exchanger

Condition Reports Reviewed to Assess Corrective Actions

CAP044400; Sulfate Reducing Bacteria Identified in VHX-2 (Containment Air Cooler)
CAP044399; Sulfate Reducing Bacteria Identified in E-54A (Component Cooling Water Heat Exchanger
CAP044414; Data Collection Anomalies During Special Test T-390

1R08 Inservice Inspection Activities (IP 71111.08)

Procedures

NDT-UT-30; Manual Ultrasonic Examination of Dissimilar Piping Welds; Revision 3
NDT-UT-33; Ultrasonic Examination of Austenitic Welds; Revision 2
NDT-UT-32; Ultrasonic Examination of Ferritic Pipe Welds; Revision 2

Documents Related to Code Pressure Boundary Welding

PNP Weld Inspection Checklist for E-50A Steam Sample SX-0719 Root; WO 24321145; April 3, 2003
PNP Weld Inspection Checklist for HPSI Pump P-66A Miniflow Check Valve; WO 24212745; April 12, 2003
Proc. No. GT-1-1; Welding Procedure Specification (WPS); Revision 8; January 12, 1993
Proc No. GT-8-8; Welding Procedure Specification (WPS); Revision 6; January 15, 1990
PQR for Gas Tungsten Arc (GTAW); Revision 8, PQ No: GT-1-1; April 29, 1985
PQR for Gas Tungsten Arc (GTAW); Revision 6, PQ No: GT-8-8; September 30, 1981

Documents Associated with Two Types of Nondestructive Testing

P-4-39035; UT Calibration Data Sheet; September 29, 2004
P-4-39025; UT Calibration Data Sheet; September 28, 2004
P-4-38036; UT Examination Data Sheet, System: Primary Coolant System (PCS-039 Weld 1); September 29, 2004
P-4-38037; UT Examination Data Sheet, System: Primary Coolant System (PCS-039 Weld 2); September 29, 2004
P-4-39025; UT Examination Data Sheet, System: Pressurizer (PZR-009 Weld 1); September 28, 2004
P-4-38016; UT Examination Data Sheet, System: Pressurizer (PZR-015 Weld 20); September 28, 2004

Corrective Action Program Documents With Engineering Evaluations

CAP042980; Dry Boric Acid Build-up on Pipe Cap on Bottom Safety Injection Tank T-82C; August 14, 2004
CAP042994; In-Core Instrumentation Flange Leak on Reactor Vessel Head; August 14, 2004

Corrective Action Program Documents

CAP038461; Boric Acid on HPSI P-66A Casing Vent Valves; November 5, 2003
CAP039324; Informational PCS Leak Rate Following QO-34 Indicates >0.1 GPM Leakage; January 6, 2004
CAP039863; Dry Boric Acid Accumulation at Outlet Fitting to MV-ES3413; February 6, 2004
CAP040052; MV-SFP 137 Packing Leakage (P-51B Discharge to P-82 Suction); February 18, 2004
CAP040575; Boric Acid Precipitation Found on Pipe Cap Downstream of MV-ES3348; March 15, 2004
CAP041053; CV-3037, HPSI Pump, P-66A, to HPSI Train # 1 Isolation Valve, Has Dried Boric Acid; April 12, 2004
CAP042841; Boric Acid Built Up on MO-2160 SIRW to Charging Pumps Isolation; August 5, 2004
CAP042911; Dry Boric Acid on Floor Under MV-PC-1175 Pressurizer Spray Isolation; August 11, 2004
CAP042972; Dry Boric Acid Residue Found on CV-1902 and CV-1903; August 13, 2004
CAP043613; Boric Acid Found on MV-ES-3003 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043620; Boric Acid Found on MV-PC-1043A During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043623; Boric Acid Found on MV-PC-1032B During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043625; Boric Acid Found on MV-CVC-2008 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043626; Boric Acid on Valve MV-ES-3157; September 19, 2004
CAP043627; Boric Acid Found on MV-PC-1132A During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043630; Boric Acid Found on MO-3015 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043631; Boric Acid on MO-3016; September 19, 2004
CAP043635; Boric Acid Found on MO-3049 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043636; Boric Acid Found on MO-3081 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043641; Boric Acid Found on CV-2202 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043643; Boric Acid Found on CV-2115 During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043646; Boric Acid Found on Tilt Cap During 045090 Start of Outage Mode 3 Walkdown; September 19, 2004
CAP043655; Boric Acid Not Cleaned Up From Valve Work in August 2004; September 19, 2004
CAP043658; Insulation of Boric Acid on Insulation Jacket for Feed Flow Venture; September 19, 2004
CAP043661; Boric Acid on #1 ICI Flange; September 19, 2004
CAP043669; Boric Acid Leaks on CVCS Valves; September 19, 2004
CAP043673; Evidence of a Boric Acid Leak Found on Valve; September 19, 2004

CAP045003; SG Eddy Current Analysis Possible Loose Parts; November 3, 2004
CAP044460; SG E-50 Administrative Repair by Plugging; October 9, 2004
CAP044433; SG E-50A/B ET Ding >5 Volts; October 8, 2004
CAP044434; Data Management Issues Identified in SG Ding >5 Volt; October 8, 2004
CAP044310; SG E-50A ET Bobbin Inspection in C-2 Category Expansion; October 5, 2004
CAP044212; SG E-50A/B ET Bobbin Inspection in C-2 Category Expansion; October 2, 2004
CAP044215; SG E-50A ET Inspection Identified Axial Indications in Non Expanded Tubes; October 2, 2004
CAP044148; SG ET Inspection Indicates Tube Plugging for Wear; September 30, 2004
CAP044293; Foreign Material Found in Secondary Side of SG E-50B; October 4, 2004
CAP044322; Foreign Material Found in SG E-50A; October 5, 2004
CE011496; Foreign Material Found in Secondary Side of SG E-50B; October 15, 2004

Corrective Action Documents As A Result of NRC Inspection

CAP043856; ASME Section XI Repair/Replacement Plan Documentation Error; September 24, 2004
CAP043829; Weld Thickness Note Stated on PQRs; September 23, 2004

Drawings

Westinghouse 1B81393; Revision 0
Westinghouse 1B81394; Revision 0
Westinghouse 1B81292; Revision 0
Westinghouse 1B81301; Revision 0

Other Documents

Westinghouse Document - MRS-TRC-1521 Use of Appendix H Qualified Techniques at Palisades Unit 1 For the Fall 2004 S/G Inspection; Revision 0
ACTS No. PAL-01-04; Bobbin 48 IPS; September 23, 2004
ACTS No. PAL-02-04; Bobbin 40 IPS; September 23, 2004
ACTS No. PAL-03-04; Bobbin 24 IPS; September 23, 2004
ACTS No. PAL-04-04; 3 Coil +Point 1200RPM; September 23, 2004
ACTS No. PAL-05-04; 3 Coil +Point 900RPM; September 23, 2004
ACTS No. PAL-06-04; 3 Coil +Point 420RPM; September 23, 2004
ACTS No. PAL-07-04; 3 Coil +Point 900RPM; September 23, 2004
ACTS No. PAL-08-04; 3 Coil Mag Bias +Point 900RPM; September 23, 2004
ACTS No. PAL-09-04; U-bend +Point 900RPM; September 23, 2004
ACTS No. PAL-10-04; U-bend +Point 420RPM; September 23, 2004
ACTS No. PAL-11-04; U-bend Mag Bias +Point 900RPM; September 23, 2004
ACTS No. PAL-12-04; U-bend High Frequency +Point 900RPM; September 23, 2004

Letter to T. Rexius, Consumers Power Co. from D.P Siska Combustion Engineering; Evaluation of Loose Wire Found on Secondary Face of the Tubesheet at the Palisades Nuclear Plant; March 11, 1996
Completed Attachment 9 Sheets from EM-09-05; Steam Generator E-50A/B Tube

Plugging 2004; October 6 - 9, 2004
EM-09-05; Steam Generator Program; Revision 11
EM-09-013; Inservice Inspection Pressure Testing Program/Boric Acid Corrosion Control Program; September 9, 2004
Technical Specifications, Section 5.5.7 Inservice Testing and Section 5.5.8 Steam Generator Tube Surveillance Program; Amendment No. 189
Steam Generator Degradation Assessment 2004 Refueling Outage; September 25, 2004
Steam Generator Degradation Assessment 2003 Refueling Outage; March 16, 2003
Steam Generator Tube Integrity Assessment 2003 Refueling Outage; April 1, 2003
Steam Generator Eddy Current Data Analysis Techniques; September 2, 2004

1R11 Licensed Operator Requalification

Simulator Performance Exam

SPE-25; PCS Dilution/SGTR; Revision 4

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

Miscellaneous Documents

Operators Risk Reports for November 22-26; November 29 - December 3; December 6-10; and December 12-17
Control Room log entries for November 22-26; November 29 - December 3; December 6-10; and December 12-17
Administrative Procedure 4.02, Attachment 4, Documented Safety Assessment; November 22-26; November 29 - December 3; December 6-10; and December 12-17

1R14 Operator Performance During Non-Routine Evolutions and Events

Plant Procedures

SOP-3, Attachment 4; SIAS Reset Criteria and Repositioning SIAS Equipment; Revision 62
Emergency Operating Procedure Supplement 5; Checklist for Safeguards Equipment Following SIAS; Revision 62
AP-5.21; Fix-It-Now Maintenance; Revision 2
ONP-3; Loss of Main Feedwater; Revision 19

Condition Reports Reviewed to Assess Significance Characterization for Identified Problems

CAP045023; Inadvertent SI Actuation During RO-12, Containment High Pressure Test

1R17 Permanent Plant Modifications

SDR-04-0360; 50.59 Screen for MOD-2003-0021

Condition Reports Reviewed to Assess Corrective Actions

CAP044800; Modification to Containment Air Room Blowout Panel Appears to be Incorrect
CAP044799; Modification to Door 48 (CWRT Room) May Not Be Complete
CAP045011; Procedure Change Request Not Initiated For Modification Implementation

1R19 Post Maintenance Testing

Work Orders

24422408; Replace Cracked Current Transformer, Breaker 152-204; November 5, 2004
24422200; Safety Injection Tank T-82C Outlet Isolation; November 15, 2004
24422506; Charging Line Loop 1A Check Valve; November 18, 2004
24422685; Battery Charger #2

Condition Reports Reviewed to Assess Corrective Actions

CAP040167; PMT Failed on F-4C Spray Nozzle
CAP040169; PMT Failed on F-4B Spray Nozzle
CAP041832; Needed PMT Step Added to WO 24420187
CAP043685; Radiography of CK-CVC2114 Indicates that Valve is Open
CAP044235; Battery Charger No. 2 (ED-16) Failure
CAP044296; Battery Charger No. 2 (ED-16) Not Operating Properly

1R20 Refueling and Outage Activities

Plant Procedures

GOP-14; Shutdown Cooling Operations; Revision 21
GOP-4; Mode 2 to Mode 1; Revision 15
SOP-1C; Primary Coolant System Heatup; Revision 0
PO-2; PCS Heatup and Cooldown Operations; Revision 0
ONP-17; Loss of Shutdown Cooling; Revision 32
RT-191; Low Power Physics Testing; Revision 3
GOP-2; Mode 5 To Mode 3; Revision 26
SOP-3, Attachment 12; Checklist 3.3; Containment Integrity Checklist; Revision 62
SOP-1A, Attachment 5; 250# Heatup Checklist Containment Building; Revision 2
SOP-1A, Attachment 8; Discussion Items For The Containment Cleanliness Debris Inspection; Revision 2
SOP-1A, Attachment 6; Checklist 1.4, Containment Closeout Walk-Through; Revision 2
FHS-M 24; Movement of Heavy Loads In the Containment Building Area; Revision 18
T-94; Visual Verification of Core Loading; Revision 12
ONP-23.3; Loss of Refueling Water Accident; Revision 5
SOP-27; Fuel Pool System; Revision 46
SOP-34; PPC Urgent Alarms; Revision 17
SFPO-3; Removal From Service SFP Cooling System for Maintenance; Revision 8
GOP-3; Mode 3 $525EF to Mode 2; Revision 18

SOP-8; Main Turbine and Generator System, Attachment 2, System Testing; Revision 67

Condition Reports Reviewed to Assess Significance Characterization and Corrective Actions

CAP044047; Potential Encroachment of Heavy Load Path Restrictions in Containment
CAP043821; FPSP-RE-13 Scheduled After Removal of Reactor Head
CAP043612; CRDM-36 Control Rod Drive Mechanism Seal Indicates Degraded
CAP044007; Steam Generator Snubber SNB-57 Failed Functional Testing
CAP043929; SIRW Recirc Valve CV-3056 Does Not Meet RO-119 Acceptance Criteria
CAP045236; Potential Water Hammer on Safety Injection T-82B
CAP044331; MV-CW732 Found to Have Broken Gate
CAP043843; Problems with Communications for Hatch Closure During Reduced Inventory
CAP045287; Control Rod Deviation Greater Than 8 inches for Control Rod 40
CAP045275; VT-2 Results of RT-71A
CAP045273; VT-2 Results of RT-71B
CAP045314; Generator Breaker 25F7 Did Not Close on Generator Synchronization to the Grid
CAP044390; Containment Air Cooler Fan V-2A Failure to Start On DBA Sequencer
CAP043973; Apparent Negative Trend in Maintenance FME Events

1R22 Surveillance Testing

Completed Surveillance Test Procedures

RT-130; Functional Test of Bus 1D Undervoltage Relays; Revision 4; October 7, 2004
RT-8C; Engineered Safeguards - Left Channel; Revision 18; October 1, 2004
RO-22; Control Rod Drop Times; November 15, 2004
RE-139-1; Test Start Time of Emergency Diesel Generator 1-1; September 30, 2004
DWO-1; Attachment 8; PCS Inventory Form; November 23, 2004
RT-92; Inspection of ECCS Train Containment Sump Suction Inlet; October 31, 2004
RO-141; Containment Sump Check Valves Inservice Test; Revision 1

Condition Reports Reviewed to Assess Characterization of Identified Problems

CAP044197; NRC Question Related to Actuation of Emergency Diesel Generator During RT-8C
CAP044912; Testing of CK-ES3181 per RO-141 Indicated an Increase in Free Rotation Torque
CAP045601; Control Rod Drop Time For Rod 26 Longer Than Expected

1REP Equipment Availability and Functional Capability

Maintenance Effectiveness

Maintenance Rule Scoping Document and Maintenance Rule Performance Indicators for Heating, Ventilation & Air Conditioning

Condition Reports Reviewed to Assess Maintenance Rule Evaluations and Corrective Actions

CAP043993; C Safety Injection Tank Outlet Failed to Close During Surveillance RO-105
CAP042920; Safety Injection Tank T-82C Outlet MO-3049 Would Not Close
CAP044008; MO-3049, SIT T-82C Outlet Isolation Exceeds MR Performance Criteria
CAP034558; MO-3049, SIT T-82C Outlet Did Not Close on Initial Attempt
CAP041689; Maintenance Rule Goal Setting For Traveling Screens F-4B and F-4C
CAP039952; F-4B Has a Broken Shear Pin in the Drive Sprocket
CAP040824; Traveling Screen F-4B Shear Pin Found Broken
CAP038846; Grinding Noise From Traveling Screen F-4C
RCE000345; Unexpected EK-0737 Charging Pumps Seal Cooling Low Pressure Alarm

Operability Evaluations

CAP045303; B Primary Coolant Pump Has a Slight Leak at Upper Vapor Seal; November 17, 2004
CAP041048; Intake Structure Damage Found During Divers Inspection; October 13, 2004
CAP044235; Battery Charger #2 (ED-16) Failure
CAP044421; Areva Cycle 18 Setpoint Verification Will Be Non-Conforming

Temporary Plant Modifications

Procedure FP-E-MOD-03; Temporary Modifications; Revision 0
Procedure RT-85C; Fuel Handling Area Ventilation System Filter Testing; Revision 7
Temporary Modification TM-2004-008; Temporary Installation of Blank Plate on Duct
Work Order 24421427; D-977 Damper Leaks Excessively and Will Not Be Replaced; May 12, 2004

Condition Reports Reviewed to Assess Significance Characterization of Identified Problems

CAP043433; Aborted RT-85C Due to Malfunction of Test Equipment; Sept. 9, 2004
CAP043460; Leakage Past Charcoal Filter VF-66 in Excess of TSST RT-85C Allowable Limits; September 10, 2004

Operator Work-arounds

PPAC X-OPS589; Assessment of Operator Work-Arounds; November 16, 2004
Data base for operations concerns, operator challenges, control room deficiencies; November 18, 2004
Item 04-133; Equipment and System Operational Guidance/Recommendation; SOP-10, Heater Extraction Drain System; Continued Plant Operation with T-5 Normal Level Control CV-0608 Bypassed and/or Isolated per SOP-10, Section 8.2.1; December 16, 2004

Condition Reports Reviewed to Assess Significance Characterization of Identified Problems

CAP045624; Received EK-0146, FW PPS LOW SUCTION PRESS CHANNEL TRIP C-24A Unexpectedly

CAP045690; Initial Attempts to Isolate CV-0608 T-5 Level Control Not Successful

1EP4 Emergency Action Level and Emergency Plan Changes

Palisades Nuclear Plant Site Emergency Plan; Revisions 4, 8, 9 and 10

1EP6 Emergency Preparedness Drill Evaluation

Emergency Plan Implementing Procedures

EI-1; Emergency Classifications and Actions; Revision 44
EI-3; Communications and Notifications; Revision 20

2OS1 Access Control to Radiologically Significant Areas

CAP 043127; Incorrect Procedure Revision Used for Locked High Radiation Area Key Logs; August 23, 2004
CAP 043923; Airborne Radioactivity Caused by Unplugging a HEPA Ventilation Unit; September 25, 2004
CAP 043944; Unexpected High Dose Rates Noted During Radiography in Containment; September 26, 2004
CAP 043980; Worker in Containment Without High Noise or Remote Dosimeter; September 27, 2004
CAP 043901; S/G Jumper Not Signed in on RWP; September 25, 2004
CAP 043923; Airborne Radioactivity Caused By Unplugging a HEPA Ventilation Unit; September 25, 2004
CAP 044358; S/G Flashing Lights Turned Off; October 6, 2004
CAP 044674; Radiological Stay Times Not Calculated in Accordance With HP 2.29; October 16, 2004
CAP 044900; Radiological Air Sampling Either Not Performed Per the RWP or Misplaced; October 28, 2004
CAP 045108; Improper Control of Radioactive Material Movements on 649' Containment; November 8, 2004
CAP 045175/RCE000369; Apparent Trend in Failing to Meet Posting Requirements of 10 CFR 20.1902; November 11, 2004
CAP 045230; Work Performed in North Storage Not in Accordance with Required RP Controls; November 13, 2004
Personnel Primary Dose Assessment Record (Internal Dose Assessment for Worker under RWP P04-5008); December 14, 2004
IOP.02.05; Underwater Construction Corporation: Contaminated Water Diving Procedure; Revision 2
Radiological Survey Sheet - Reactor Cavity Tilt Pit; September 30, 2004 (1445 Hours)
RWP P04-5102; Disassemble and Move Reactor Head to Stand; Revisions 0 - 1
RWP P04-5108; Reactor Head Reassembly and Refueling Close-Out Activities; Revision 0
RWP P04-5111; Remove/Install Incore Control Instrumentation Flanges; Revision 0
RWP P04-5120; Reactor Cavity Diving Operations; Revision 0
RWP P04-5306; Scaffold Work in Containment; Revisions 0 - 2
RWP P04-5510; Inspection of the Reactor Vessel Closure Head (RVCH); Revision 1

RWP P04-5515; Removal of the Thermal Sleeves; Revision 3
RWP P04-5601; Pressurizer Tank T-72 Electric Heaters; Revision 0
WI-RSD-H-012; Palisades Nuclear Plant Work Instruction: Control of Diving Operations in Radiologically Controlled Areas; Revision 3

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning And Controls

ALARA In-Progress Review: RWP P04-5520; Revisions 0, 1, and 5
RWP P04-5517; ALARA Pre-Job Review: Machining Activities to Support Repair to Nozzle Numbers 29 and 30; Revision 0
RWP P04-5518; ALARA Pre-Job Review: Welding Support Activities for CRD Nozzle Repairs on Nozzle Numbers 29 and 30; Revision 0
RWP P04-5519; ALARA Pre-Job Review: Water Jet Remediation Inside Penetration Numbers 29 and 30; Revision 0
RWP P04-5520; Inspection of the Reactor Closure Head; Revisions 0 - 5
RWP P04-5520; ALARA Pre-Job Review: Inspection of the Reactor Closure Head Revision 0
RWP Scope Addition Form: RWP P04-5520; Revisions 2, 3, and 4
AP 7.02; ALARA Program; Revision 13
C & RP Department Outage RWP Dose Tracking Spreadsheet (Estimates versus Actuals); September 30, 2004
HP 11.1; Processing Radiation Work Permits and ALARA Reviews; Revision 18
HP 11.1, Att. 3; Evaluation of Airborne Radioactive Material Controls and Use of Respiratory Protection - RWP P04-5102; May 22, 2004
HP 11.1, Att. 3; Evaluation of Airborne Radioactive Material Controls and Use of Respiratory Protection - RWP P04-5108; June 11, 2004
HP 11.1, Att. 3; Evaluation of Airborne Radioactive Material Controls and Use of Respiratory Protection - RWP P04-5111; June 12, 2004
HP 11.1, Att. 3; Evaluation of Airborne Radioactive Material Controls and Use of Respiratory Protection - RWP P04-5510; April 26, 2004
HP 11.1, Att. 3; Evaluation of Airborne Radioactive Material Controls and Use of Respiratory Protection - RWP P04-5515 (TEDE 1 & 2); August 25, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5102; September 8, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5108; September 8, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5306; September 7, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5111; September 1, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5510; August 30, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5515; September 2, 2004
HP 11.1, Att. 4; ALARA Pre-Job Review - RWP P04-5601; September 19, 2004
HP 11.1, Att. 8; ALARA In-Progress Review - RWP P04-5102; September 25, 2004
Palisades Nuclear Plant Individual Dose Status Report: Framatone - Reactor Head Project; September 30, 2004
Palisades Nuclear Plant Individual Dose Status Report: Westinghouse - Primary Coolant Pumps; September 30, 2004
Palisades Nuclear Plant Individual Dose Status Report: Westinghouse - Steam Generator Services; September 30, 2004
Palisades Nuclear Plant Shift Electronic Logs: Outage Control Center - Chemistry and Radiation Protection; September 14 - 30, 2004

4OA1 Performance Indicator Verification

CH 1.15; Radiochemistry Program; Revision 0
Chemistry Spreadsheet of Daily PCS Sample Dose Equivalent Iodine Data; July 2, 2003 through September 27, 2004
DWC-2; PCS Radiochemical Analysis; Revision 20
Gamma Isotopic Spectroscopy Report for PCS Sample DWC-2; December 15, 2004
NRC Indicator RETS/ODCM Radiological Effluent Occurrence (PR-01) Memo; January 8, April 7, July 2, and October 5, 2004
NEI 99-02, Rev 2; "Regulatory Assessment Performance Indicator Guideline;"
Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants NUMARC 93-01 Rev. 2
Palisades' NRC PI Data for IE03; Unplanned Power Changes per 7000 Critical Hours; for 4th quarter 2003 to 3rd quarter 2004
Hours critical report for 2003 and 2004
Operator logs in 2003 and 2004

Miscellaneous Documents

Procedure 3.09, Attachment 7; NRC Performance Indicator, Safety System Unavailability, Residual Heat Removal System (MS-04); Revision 10
NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 2
ESS System PI Data; 4th Qtr. 2003, 1st Qtr. 2004, 2nd Qtr. 2004 and 3rd Qtr. 2004

4OA2 Identification and Resolution of Problems

Corrective Action Program Documents

RCE000360; Condensate Pump P-2B Motor EMA-2205 Bearing Fire
CAP043294; Reactor Trip Due to Fire On P-2B Condensate Pump

Miscellaneous Documents

WO24422006; Condensate Pump P-2B EMA-2205; August 5, 2004
WO24422001; EMA-2205; July 30, 2004
WO24422071; Condensate Pump P-2B; September 30, 2004

4OA3 Event Follow-up

Licensee Event Report 05000255/2004-001; Reactor Protection System and Auxiliary Feedwater System Actuation; October 13, 2004

4OA5 Other

Supplement to 60-Day Response to Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors;" Palisades Nuclear Power Plant; May 17, 2004

60-Day Response to Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors;" Palisades Nuclear Power Plant; August 5, 2003
EOP Supplement 43; Refill of SIRW Post-RAS; Revision 0
ONP-23; Primary Coolant Leak; Revision 23

Condition Reports Reviewed to Assess Significance Characterization and Corrective Actions

CAP044891; NRC Commitment Not Completely Captured
CAP044672; Grout Missing From Containment Sump Support Columns
CAP044798; Biological Growth Remains on Containment Sump Screens After Cleaning
CAP044670; Frayed Screen Mesh Edges Observed on Containment Sump Screen
CAP044852; Potential for Preconditioning of Technical Specification Test RT-92
CAP044679; Primary Water Stress Corrosion Crack Identified on Reactor Head; October 16, 2004
CAP045052; Unqualified NDE Materials Used During Repair of Reactor Head; November 5, 2004
CAP044537; Discontinuities Exist in the UT Signal for Penetrations 29 and 30; October 11, 2004
CAP 2004-2649; Position Tool Tolerance; October 26, 2004
CAP 2004-2682; Out of Tolerance Machining of Replacement Nozzle 30; October 29, 2004
CAP 2004-2697; Out of Tolerance Machining of Nozzle 29 Bore; October 29, 2004

Pressurizer Penetration Nozzles and Steam Space Piping Connections in U. S. Pressurized Water Reactors (TI 2515/160)

Other Documents

NDT-A-02; NDT Personnel Training, Qualification and Certification; Revision 19

Procedures

NDT-VT-09; Bare Metal Visual Examination; Revision 2

Personnel Qualifications and Certification Records

D. Catherman, VT Level II; June 12, 2003
B. Lenius, UT Level III; June 8, 2004

Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

Certified Mill Test Reports

Special Metals Welding Products Company, Certified Material Test Report No. 139707 (weld filler material ERNiCrFe-7); June 2, 2004
Valinox Nucleaire, Certified Material Test Report (SB167, UNS N06690 tubing); January 12, 2004

Combustion Engineering, Inc., Materials Certification Reports (Reactor Head Plate Material SA-302 Grade B); March 25, 1968

Drawings

FANP No. 5038702; Palisades CRDM Nozzle ID Temper Bead Weld Repair; Revision 3
FANP No. 5039299; Palisades CRDM Replacement Nozzle; Revision 1

Personnel Qualifications and Certification Records

J. Breza, UT Level II; January 29, 2004
H. Diaz, UT Level III; July 21, 2004
B. Flesner, UT Level II; January 19, 2004
K. Graybill, UT Level II; July 13, 2004
M. Hacker, UT Level III; July 29, 2004
T. Ribaric, UT Level III; August 22, 2003
J. Touhalisky, UT Level II; January 7, 2004
B. Lenius, PT Level II; May 22, 2003
G. French, PT Level II; March 1, 2003
D. Zentner, PT Level II; May 27, 2003.
M. Olafson, VT Level II; September 30, 2002
S. James, VT Level II; August 26, 2003

Nondestructive Examination Reports

Liquid Penetrant Examination Report, Reactor Head Penetration No. 30 J-groove Weld; October 15, 2004
Liquid Penetrant Examination Report, Reactor Head Penetration No. 29 J-groove Weld; October 15, 2004
Bare Metal Visual Examination Report, Reactor Vessel Head; October 14, 2000
Reactor Vessel Head Penetration NDE Inspection Field Report For NMC Palisades RFO-17; October 27, 2004
Liquid Penetrant Examination Report, CRDM Nozzle Replacement Penetration No. 29; November 3, 2004

Non-Destructive Examination Procedures

NDT-VT-09; Bare Metal Visual Examination; Revision 2
54-ISI-460-01; Multi-Frequency Eddy Current Examination of Nozzle Welds and Regions; Revision 1
NDT-PT-01; Liquid Penetrant Examination; Revision 14
54-ISI-100-13; Remote Ultrasonic Examination of Reactor Head Penetrations; Revision 13
54-ISI-137-04; Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations; Revision 4
54-ISI-244-08; Liquid Penetrant Examination of Reactor Vessel Head Penetrations; Revision 8
54-ISI-178-04; Ultrasonic Examination of Control Rod Drive Mechanism (CRDM) Nozzle Temperbead Weld Repair; October 28, 2004

Other Documents

Procedure Qualification Framatome Document No. 54-PQ-460-01-00; May 3, 2003
Demonstration of Framatome Eddy Current Examination for the RVHP Attachment Weld; October 22, 2003
NDT-A-02; NDT Personnel Training, Qualification and Certification; Revision 19
EA-A600-2004-02; Evaluation of Machining Grooves Observed in CRDM Nozzles; Revision 0
Framatome ANP 54-ISI-30-01; Written Practice for the Qualification and Certification of NDE Personnel; Revision 1
Framatome ANP 54-ISI-30-02; Written Practice for Personnel Qualification in Ultrasonic Examination; Revision 2
Framatome ANP 54-ISI-24-28; Written Practice for Personnel Qualification in Eddy Current Examination; Revision 28
Framatome ANP 54-ISI-21-31; Written Practice for Personnel Qualification Ultrasonic Method; Revision 31
ISWT 2.0-NDES-001; Nondestructive Examination Personnel Qualification and Certification; Revision 3, Change 2
FANP Procedure Qualification 54-PQ-100-07; September 20, 2004
FANP Procedure Qualification 54-PQ-137-04; September 21, 2004
EPRI MRP 89 Materials Reliability Program: Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations; September 2003
EA-JRP-02-001; Reactor Head Effective Degradation Years Calculation; Revision 1
EA-C-PAL-01-03348-01; Upper Head Fluid Temperature For Palisades Reactor; Revision 0 and Revision 2
CD 5.23; Boric Acid Corrosion Program Standard; Revision 0
Work Order No. 24211866, Pen #29,30; Perform Rx Vessel Closure Head Nozzle Repairs; October 24, 2004
Completed Document FANP 50-5040022-00; Process Traveler Ambient IDTB Repair of CRDM Nozzles; October 27, 2004 through November 4, 2004
WI-PCS-—6; NSSS Walkdown; Revision 0
RT-71A-2; Primary Coolant System, Class 1 Reactor Vessel Visual Examination; Revision 3
EM-09-13; Inservice Inspection Pressure Testing Program/Boric Acid Corrosion Control Program; Revision 7
Completed Process Traveler No. 50-5040022-00, For Palisades ID Temper Bead Repair for CRDM Nozzle; October 26, 2004 through November 4, 2004
FANP 51-5016360-00; PQR-7183 Mechanical Testing Requirements; January 17, 2002
FANP 51-5052985-00; UT Data Evaluation for Repair Location 29 and 30; October 23, 2004

Repair Weld Non-Destructive Examination Reports

30-NDE-760-00; Liquid Penetrant Examination Report, CRDM Nozzle Replacement Penetration No. 30; November 3, 2004
29-NDE-760-00; Liquid Penetrant Examination Report, CRDM Nozzle Replacement Penetration No. 29; November 3, 2004
30-NDE-690-00; RPVH Penetration Weld Repair UT Data Sheet, RVH Penetration No. 30; November 2, 2004

29-NDE-690-00; RPVH Penetration Weld Repair UT Data Sheet, RVH Penetration No. 29; November 2, 2004

Weld Control Records

Nozzle No. 29; Temperbead Weld Control Record; October 31, 2004
Nozzle No. 30; Temperbead Weld Control Record; October 31, 2004
Nozzle No. 29; Operator Work Sheets; Pages 1 - 11; not dated
Nozzle No. 30; Operator Work Sheets; Pages 1 - 11; not dated

Weld Procedures (New Pressure Boundary Weld Nozzle No. 29 and No. 30)

FANP Weld Procedure Specification 55-WP3/43/F/F43TBSCa3-01; Revision 1
FANP Temper Bead Weld Repair, 55-SPP05-12; Revision 12

Weld Procedure Qualification Records

FANP Procedure Qualification Record No. PQ7164-03; May 23, 2003
FANP Procedure Qualification Record No. PQ7183-03; May 8, 2003

LIST OF ACRONYMS USED

ADAMS	Agency-Wide Document and Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASNT	American Society for Nondestructive Testing
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CRDM	Control Rod Drive Mechanism
DEI	Dose Equivalent Iodine
ECCS	Emergency Core Cooling System
EDM	Electric Discharge Machined
EDY	Effective Degradation Years
EPRI	Electric Power Research Institute
ET	Eddy Current
FANP	Framatome Advanced Nuclear Products, Inc.
GDC	General Design Criteria
ICI	Incore Instrument
IMC	Inspection Manual Chapter
IR	Inspection Report
ISI	Inservice Inspection
NCV	Non-Cited Violation
NMC	Nuclear Management Company
PARS	Publicly Available Records
PDI	Performance Demonstration Initiative
PI	Performance Indicator
PNP	Palisades Nuclear Power Plant
PORV	Power Operated Relief Valve
PT	Dye Penetrant
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RGEM	Radioactive Gaseous Effluent Monitoring
RP	Radiation Protection
RVCH	Reactor Vessel Closure Head
RWP	Radiation Work Permit
SDP	Significance Determination Process
SG	Steam Generator
TI	Temporary Instruction
TOFD	Time Of Flight Diffraction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Examination
VHP	Vessel Head Penetration