U.S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No:	50-397/93-31
Docket No:	50-397
License No:	NPF-21
Licensee:	Washington Public Power Supply System P. O. Box 968 Richland, WA 99352
Facility Name:	Washington Nuclear Project No. 2 (WNP-2)
Inspection at:	WNP-2 site near Richland, Washington
Inspection Conducted:	August 3 - September 6, 1993
Inspectors:	R. C. Barr, Senior Resident Inspector D. L. Proulx, Resident Inspector D. E. Corporandy, Project Inspector (August 16-20) M. P. Payne, Reactor Inspector (August 23-27) K. E. Johnston, Project Inspector (August 30-Sept 3)

Approved by: P. H. Johnson, Chief, Reactor Projects Section 1 — Date Signed: 10/7/93

Summary:

Inspection on August 3 - September 6, 1993 (Report No. 50-397/93-31)

Areas Inspected: Routine, announced inspection by the resident and region-based inspectors of control room operations, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, employee concerns program, and procedural adherence. During this inspection, Temporary Instruction 2500/028 and Inspection Procedures 61726, 62703, 71707, 71710, 90712, 92700, 92701, 92702 and 93702 were used.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: One violation with two examples (Paragraphs 5.a and 6.d) was identified involving the failure to follow procedures. Five non-cited violations (Paragraphs 5.a, d, e, and f, and 6.a) were identified involving failure to adhere to procedures, to perform adequate post-maintenance testing, and to provide an adequate procedure.

Strengths:

- Operator response to the reactor scram and the unusual event was good (Paragraph 5.a).

- An engineer exhibited good attention to detail and awareness in finding a steam leak on one of the main steam lines (Paragraph 5.c).

Weaknesses:

- Inadequate post-maintenance testing (PMT) contributed to the reactor scram of August 3, 1993, and to an under-vessel thermocouple reading the incorrect area temperature. These weakness are particularly noteworthy because a NRC special team inspection, documented in Inspection Report No. 50-397/92-25, identified similar weaknesses in the WNP-2 testing program in 1992 (Paragraph 5).

- Errors in maintenance technician work practices resulted in the incorrect repair of a dual solenoid pneumatic pilot valve for MS-V-22, which in conjunction with inadequate PMT caused the reactor scram on August 3, 1993, a half-scram, and a half-isolation. Of particular concern are observed instances of I&C technicians not adhering to procedures, inadequate self-checking and not following shop practices (Paragraphs 5 and 6).

- The licensee's safety evaluations in two Licensee Event Reports (LERs), 50-397/92-08 and 50-397/92-20, were weak in that the evaluations did not thoroughly discuss the safety implications of the events. In addition, the licensee did not have a documented analysis to support the conclusions in LER 93-11 regarding the safety significance of improperly set load limits for refueling bridge hoists (Paragraph 8).

- One instance was observed wherein the nomenclature on three clearance tags in the plant did not match the nomenclature of the equipment to which they were attached (Paragraph 4.b(5)).

- The operating crew's response to a reactor vessel level indicator anomaly was weak (Paragraph 5.h).

DETAILS

1. Persons Contacted

V. Parrish, Assistant Managing Director for Operations
*J. Gearhart, Quality Assurance Director
*M. Flasch, Engineering Director
J. Swailes, Plant Manager
*G. Smith, Operations Division Manager
*R. Webring, Technical Services Manager
*M. Monopoli, Maintenance Division Manager
*R. Barbee, Systems Engineering Manager
*J. Albers, Radiation Protection Manager
*A. Hosler, Licensing Manager
*J. Sampson, Maintenance Production Manager
*J. Peters, Administrative Manager
*W. Shaeffer, Operations Manager
*J. Benjamin, Quality Assessments Manager
*B. Pesek, Projects Manager
*C. Fies, Licensing Engineer
*D. Schumann, Operating Events Analysis and Resolution Engineer
*K. Lewis, Licensing Engineer

The inspectors also interviewed various control room operators, shift supervisors and shift managers; maintenance, engineering, quality assurance, and management personnel.

*Attended the Exit Meeting on September 17, 1993.

2. Plant Status

At the start of the inspection period, the plant was in Mode 1 (power operation) at 100% power. On August 3, 1993, operators received a full reactor scram when a main steam isolation valve closed due to an apparent maintenance error (Paragraph 5). An Unusual Event (UE) was declared by the Shift Manager to provide for increased management awareness. The plant remained in Mode 3 (hot shutdown) until August 5, 1993, when an unisolable steam leak was discovered in a main steam line weld, prompting a plant cooldown to Mode 4 (Cold Shutdown). The plant remained in cold shutdown to repair the MSIV, leaking weld, and containment exhaust purge valves. The plant was restarted on August 13, 1993. During the plant heatup, operators noted a reactor vessel level anomaly (Paragraph 5.h). The plant achieved full power on August 16, 1993, and continued to operate at 100% power (except for temporary downpowers to 85% to support bypass valve testing and control rod exercises) until the end of the inspection period.

3. Previously Identified NRC Inspection Items (92701, 92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings:

a. (Closed) Violation (50-397/92-37-04): Scram Setpoints not Reduced by the "T" Factor.

Following the August 15, 1992, power oscillation event at WNP-2, the inspector found that the scram and rod block setpoints were not lowered by the "T" factor prior to exceeding 25% power as required by the Technical Specifications (TS). The licensee revised Plant Procedures Manual (PPM) 7.4.2.1, "Power Distribution Limits," and PPM 3.1.2, "Reactor Plant Cold Startup," to include specific signoffs to ensure the setpoint adjustments occur. In addition, all of the licensed operators and Station Nuclear Engineers have received training on these procedure changes. The inspector reviewed the procedure changes and training documentation, and concluded that the licensee's actions were satisfactory. This item is closed.

b. (Closed) Deviation (50-397/93-37-07): Commitment Not Met to Install Effective Stability Monitor.

Following the August 15, 1992, power oscillation event at WNP-2 the inspector found that the licensee had not met their commitment to install a stronger, faster, better method of monitoring the reactor for stability. The licensee installed the Advance Neutron Noise Analysis (ANNA) system in 1989 to monitor the stability based on on-line calculation of the decay ratio. However, because of the limited usage of ANNA, and the filters installed in the system after delivery, the ANNA was not an effective means of monitoring the reactor for stability. After this event, the ANNA system filters were removed and procedure PPM 3.1.2, "Reactor Plant Cold Startup," was changed to include dedicated ANNA watches when the plant is maneuvered through the power-to-flow areas vulnerable to instability. The inspector reviewed the licensee's corrective actions and witnessed a number of reactor plant startups, and concluded that the licensee's corrective actions were satisfactory. This item is closed.

c. (Closed) Violation (50-397/92-40-01): Operator Log and 10 CFR 50.72 Reporting Deficiencies:

This enforcement item concerned the failure of Operations Department personnel on two occasions to properly record or report plant events requiring notification under 10 CFR 50.72. The first event concerned an unplanned automatic isolation of the reactor core isolation cooling (RCIC) system which occurred during surveillance testing. This event was not reported within the time limits prescribed by 10 CFR 50.72, nor was it logged by the control room operators and Shift Manager in their respective logs, as required by procedure PPM 1.3.4, "Operating Data and Logs." WNP-2 Licensee Event Report (LER) 92-45 was also issued to address this event. The second event involved the failure to log a freon spill, an event which the licensee reported under 10 CFR 50.72, into the Control Room Operator's log and Shift Manager's log, as required by PPM 1.3.4.

The inspectors reviewed the licensee's root cause assessment and proposed corrective actions, which included additional training for their licensed reactor operators and development of pertinent material for initial operator training classes. The inspectors determined the licensee's proposed corrective actions to be appropriate and noted that most of the corrective actions had been completed ahead of schedule. One of the corrective actions was to evaluate the licensee's administrative controls for reporting to the NRC. The licensee's evaluation recommended revising PPM 1.10.1, "Reportable Events and Occurrences Required by Regulatory Agencies," to reflect recent changes in 10 CFR 50.72 reporting requirements. Although the due date for the proposed revision of PPM 1.10.1 had not yet arrived at the time of the inspection, the inspectors viewed a draft copy of the revised PPM 1.10.1. Based on the licensee's completed and pending actions, Violation 397/92-40-01 and LER 92-45 are closed.

d. <u>(Closed) Violation (50-397/92-14-03): Failure to Control Foreign Material Around the Reactor Vessel During Refueling Activities</u>

This enforcement item concerned the licensee's failure to adequately control foreign material around the reactor pressure vessel (RPV) cavity during their 1992 refueling outage. Failure to properly log foreign materials and to secure or otherwise capture them resulted in the licensee's finding a roll of tape and a rag underwater in the refueling cavity on May 30, 1992.

In their response to the violation, the licensee acknowledged the validity of the violation and noted that "... the process for controlling the material accountability in the refueling cavity was changed for the 1992 maintenance and refueling outage, R7." The licensee determined the root cause of the violation to be less than adequate change management in ensuring that newly assigned personnel responsibilities were clearly defined and communicated to affected personnel. The inspectors verified that the licensee had modified procedure PPM 1.3.18, "Foreign Material Control Around the Spent Fuel Pool, the Reactor Cavity and the Dryer-Separator Pit," prior to the 1993 refueling outage to ensure that material control around the reactor cavity was maintained. The licensee also informed affected personnel of their responsibilities.

During the licensee's 1993 (R8) refueling outage, the resident inspectors observed improvement in the reduction of improperly controlled foreign material near the refueling cavity. In subsequent discussions with licensee management responsible for PPM 1.3.18, the inspectors also learned that the licensee was continuing to monitor the implementation of the revised PPM 1.3.18 and was in the process of making changes in response to lessons learned from R8. The inspectors noted that subsequent to this violation, NRC inspectors identified a similar violation, 50-397/93-19-01, during R8. Based on improvements in the licensee's program, overall performance, and the licensee's actions in response to the violation described by 50-397/93-19-01, Violation 50-397/92-14-03 is closed.

e. (Closed), Followup Item (50-397/93-24-06): Issues Concerning a Temporary Modification to the Containment Nitrogen System.

Earlier, the inspector performed a walkdown of the containment nitrogen system in conjunction with a review of LER 50-397/89-01. The inspectors had two concerns regarding a temporary modification to the high flow feature of the temperature-controlled automatic isolation valves in the nitrogen supply line for drywell inerting. The first concerned the control of drawings and the second concerned the control of locked valves. The inspectors had found that while a control room copy of the system drawing reflected the temporary modification, the microfilm copy of the same revision did not. In addition, the computer database, to which plant workers were directed to refer to ensure that a microfilm copy of a drawing was current prior to use, was not updated to reflect the installation of temporary modifications.

The inspector reviewed the licensee's procedure for temporary modifications, PPM 1.3.9, Revision 11. The inspector determined that the procedure contained sufficient instructions on the use of temporary modification tags to ensure that workers in the field would be made aware of a temporary modification not reflected in their drawings. The inspector had also noted that manual bypass valves in the low-flow portion of the containment nitrogen system were locked closed. The inspector understood that the valves were locked closed to prevent them from being inadvertently opened, allowing liquid nitrogen into portions of the system not designed for low temperatures.

The inspector questioned whether disabling the high-flow automatic isolation valves in the open position by the temporary modification required the manual valves in series to be locked closed. The inspector followed this finding up with plant technical engineering and the operations procedure group. The licensee determined that there was no regulatory requirement to lock these containment nitrogen valves open. Further, there were several closed manual valves in series in the high flow line upstream of piping sensitive to low temperatures. This item is closed.

4. Operational Safety Verification (71707)

a. Plant Tours

The inspectors toured the following plant areas:

- Reactor Building
- Control Room
- Diesel Generator Building
- Radwaste Building
- Service Water Buildings
- Technical Support Center
- Turbine Generator Building
- Yard Area and Perimeter

b. The inspectors observed the following items during the tours:

(1) Operating Logs and Records. The inspectors reviewed records against Technical Specification and administrative control procedure requirements.

(2) Monitoring Instrumentation. The inspectors observed process instruments for correlation between channels and for conformance with Technical Specification requirements.

(3) Shift Manning. The inspectors observed control room and shift manning for conformance with 10 CFR 50.54.(k), Technical Specifications, and administrative procedures. The inspectors also observed the attentiveness of the operators in the execution of their duties and the control room was observed to be free of distractions such as non-work related radios and reading materials.

(4) Equipment Lineups. The inspectors verified valves and electrical breakers to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation.

(5) Equipment Tagging. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and the equipment was in the condition specified.

On August 27, 1993, while walking down a safety-related clearance order, the inspector found that three tags in the plant did not match the nomenclature on the breaker cubicles. The tags were labeled for breakers SW-V-4A, SW-V-4B, SW-V-4C, while each of these breaker cubicles was labeled as "Spare." PPM 1.3.8, "Danger Tag Clearance Orders," requires the individual hanging the tags to ensure that the nomenclature on the tags exactly matches the labeling on the breaker cubicle.

Upon further investigation, the inspector found that SW-V-4A, B, and C had been converted from motor-operated valves to manually operated valves, which included removing all electrical sources and cabling to the motor operators. The licensee intended to convert the unused breakers for these valves to spares as part of these modifications. However, the breaker cubicles were relabeled as spares prior to completion of the work. Therefore, the cubicles were relabeled while the tags were still hanging, without the knowledge of the operators.

The inspector notified the Shift Manager, who took no action because he thought that the clearance order for these tags was being removed imminently. However, on August 31, the inspector noted that the discrepant tags were still in place. The inspector then discussed these observations with the Operations

Division manager. The Operations Division manager stated that it was his expectation that in order to avoid confusion, danger tags should match the component labeling exactly. It was also his expectation that the Shift Manager should have cleared the discrepant tags, and rehung them with the proper nomenclature. The inspector also noted that communications between Operations and Maintenance personnel appeared to require improvement. The Plant Manager acknowledged the inspector's comments.

(6) General Plant Equipment Conditions. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that would prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

(7) Fire Protection. The inspectors observed fire fighting equipment and controls for conformance with administrative procedures.

(8) Plant Chemistry. The inspectors reviewed chemical analyses and trend results for conformance with Technical Specifications and administrative control procedures.

(9) Radiation Protection Controls. The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors also observed compliance with Radiation Work Permits, proper wearing of protective equipment and personnel monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to the specified calibration frequency.

(10) Plant Housekeeping. The inspectors observed plant conditions and material/equipment storage to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination.

(11) Security. The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, that the search equipment at the access control points was operational, that the vital area portals were kept locked and alarmed, and that personnel allowed access to the protected area were badged and monitored and the monitoring equipment was functional.

c. Engineered Safety Features Walkdown

The inspectors walked down selected engineered safety features (and systems important to safety) to confirm that the systems were aligned in accordance with plant procedures. During the walkdown of

the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were also observed for adequacy. The inspectors also verified that certain system valves were in the required position by both local and remote position indication, as applicable.

The inspectors walked down accessible portions of the following systems on the indicated dates:

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3.	August 17, 26
Low Pressure Coolant Injection (LPCI) Trains "A", "B", and "C"	August 17, 24
Low Pressure Core Spray (LPCS)	August 24
High Pressure Core Spray (HPCS)	August 17, 24
Main Steam Leakage Control (MSLC)	August 17, 24
Reactor Core Isolation Cooling (RCIC)	August 24
Residual Heat Removal (RHR), Trains "A" and "B"	August 17, 24
Standby Service Water System	September 1
125V DC Electrical Distribution, Divisions 1 and 2	September 2
250V DC Electrical Distribution	September 2

No violations or deviations were identified.

5. Event Followup (71707, 92701, 93702)

At 5:39 a.m., on August 3, 1993, with the reactor at 100% power and technicians conducting surveillance testing on the D main steam line radiation indicating switch (MS-RIS-610D), the reactor automatically scrammed on main steam isolation valve (MSIV) closure caused by high steam line flow. All safety systems functioned as designed with the exception of one main steam safety/relief valve (SRV). MS-RV-1B, with a lift setpoint of 1076 psig, did not open. At approximately 6:00 a.m., the Shift Manager (SM) declared an unusual event (UE) based on a situation that warranted increased awareness on the part of the plant operating staff.

The inspectors assessed the issues that emerged from the scram, the subsequent forced outage and the reactor restart. The inspectors

performed followup inspection on the following issues: closure of the B main steam isolation valve (MS-V-22B), the failure of SRV MS-RV-1B to open even though pressure exceeded its lift setpoint, water leakage of a control rod drive mechanism, high under-vessel temperature, a pinhole steam leak on MS-V-22A, a half-scram during average power range monitor (APRM) surveillance testing, a half-isolation during leak detection surveillance testing, and a reactor vessel level anomaly during startup. The following describe the inspectors' findings and observations.

a. B MSIV Closure

The licensee's analysis of post-reactor scram data identified that the B MSIV had shut during the performance of Technical Specification (TS) surveillance procedure PPM 7.4.3.1.7.12D, "Main Steam Line High Radiation Channel D - Channel Check," when the surveillance procedure directed the technician to trip the B reactor protection system (RPS). When the B MSIV closed, steam flow increased as expected in the A, C, and D main steam lines, exceeding the high steam flow MSIV closure setpoint. Closure of the B MSIV when the B train solenoid was deenergized indicated that the A train solenoid of the dual solenoid pilot-operated valve may have failed. This valve had been had been replaced during the R8 outage. The licensee initiated problem evaluation report (PER) 293-1032 to document the scram.

Troubleshooting following the scram verified the that the dual solenoid pilot-operated valve had malfunctioned. The licensee generated a maintenance work request (MWR) to repair the valve. Upon visual inspection, electricians found operating air to be leaking from the solenoid valve. The electricians replaced the valve with a refurbished valve from warehouse spares, and it was then satisfactorily retested.

Upon disassembly and examination of the failed A train solenoid of the pilot valve, licensee craftsmen and engineers concluded that the valve had malfunctioned because the valve repair performed on July 25, 1993, had interchanged matched repair parts with previously used parts. Specifically, the plug and plugnut assembly of the rebuild kit were matched components, but at least one of the components had been interchanged with parts removed from the valve. The co-mingling of the A train solenoid parts caused the valve not to direct air to the opening piston of the B MSIV operator, resulting in the B MSIV closing when the surveillance test de-energized the opposite train solenoid.

In discussions the with the craftsmen, the craft supervisor and a system engineer, licensee event evaluators found that the maintenance work request (MWR) had required installation of the entire rebuild kit. However, due to cramped working conditions and the rush to close containment at the end of R8, the craftsmen performing the repairs accidently co-mingled the used and new parts. The licensee's event evaluators also found that during the valve maintenance performed on July 25, 1993, after the valve had been repaired and reinstalled, a QC inspector identified that the valve had been rotated 180 degrees from its correct position. This

resulted in the valve's operating air "blowing by," because the incorrect orientation resulted in incorrect connection of the operating air lines. The valve was correctly positioned, which stopped the "blowing by." From discussions with the craftsmen that had performed the valve repairs, the licensee evaluators determined that the valve had been incorrectly oriented when the electricians first identified that operating air was "blowing by."

After the July 25 maintenance on the dual solenoid valve, the licensee also failed to identify that the plug nut assembly had been co-mingled because the post maintenance test (PMT) was inadequate. The PMT that was performed operated the B MSIV with both the A and B train solenoids energized. Therefore, the test could not identify a malfunction of only one of the two solenoids. The failure to perform an adequate post maintenance test is a violation of Criterion XI, "Test Control," of 10 CFR 50, Appendix B. However, because the licensee satisfied the criteria specified in Section VII.B(2) of the Enforcement Policy, this violation is not being cited (NCV, 50-397/93-31-01, Closed).

The licensee determined that the root causes of this event were that the technicians had not applied self-checking, job scoping had not been thorough, and post-maintenance testing had been inadequate.

As corrective actions to prevent event recurrence, the licensee counselled the technicians and the system engineer, plans to revise the PMT requirements and maintenance training for dual-solenoid ASCO valves, and plans to provide general training on post-maintenance testing to maintenance, system, and project engineers.

The inspectors responded to the event, observed operator actions associated with plant stabilization, and discussed the event with plant operators, maintenance technicians, system engineers and managers. The inspectors also attended selected licensee fact-finding meetings and reviewed the Licensee Event Report (LER).

The inspectors concluded that licensed operators took appropriate actions to mitigate the scram. The inspectors also concluded that the licensee's event evaluation was generally acceptable; however, the evaluation did not resolve the issue of the craftsmen finding the valve incorrectly oriented.

PPM 1.3.12, "Problem Evaluation Requests," Revision 17, defines a condition adverse to quality as "any deficiency identified on safety-related equipment that significantly degrades its performance or renders it inoperable." Because the dual solenoid pilot valve was incorrectly oriented, MS-V-22B was inoperable. Section 6.1 of this PPM states that "Any person who observes an actual problem or perceives a potential problem shall initiate a PER." Neither the QC inspector, the craftsmen, the craft supervisor nor the system engineer initiated a PER upon recognizing the incorrect orientation of the valve. Although the licensee's event evaluation team became aware on August 5, 1993, that a PER had not been initiated to address this concern and document its resolution, a PER was not

subsequently initiated. The failure to adhere to PPM 1.3.12 is a violation of Technical Specification 6.8.1.a (Violation, 50-397/93-31-02, Open). Although the licensee identified this violation, it is being cited because appropriate corrective actions were not taken.

b. Failure of MS-RV-1B to Actuate at Greater than Setpoint Pressure

As stated above, following the automatic reactor scram, reactor pressure increased to approximately 1091 psig, but MS-RV-1B did not lift at its pressure relief setpoint of 1076 psig. Licensee investigation of the failure of this valve to open found that the pressure switch, MS-PS-39E, had drifted out of tolerance. The licensee documented the failure of MS-RV-1B to lift in PER 293-1029.

The licensee recalibrated the pressure switch and retested the relief valve. The licensee verified that MS-PS-39E did not have a history of setpoint drift.

During the investigation of this event, the licensee found that the digital Heise gauge used to calibrate the relief valve pressure switches was out of calibration. The licensee documented this deficiency on PER 293-1058.

The licensee concluded that because the design of the pressure measuring instrument did not have the bourdon tube rigidly fixed to the back of the instrument near the instrument's connection point, the instrument's calibration could be affected during its connection if additional caution was not used. The licensee notified all craftsmen of the additional caution required when connecting this device, and will verify the instrument's calibration after each use.

The inspectors observed the calibration of one of the pressure switches, examined the Heise gauge that the licensee found out of calibration, and reviewed PERs 293-1029 and 293-1058. The inspectors concluded that the licensee's disposition and corrective actions for this event were appropriate.

c. Unisolable Steam Leak on A Main Steam Line Flow Element (MS-FE-5A)

At 5:15 a.m. on August 5, 1993, during the repair of MS-V-22B, a system engineer identified a pinhole steam leak on a socket weld in the instrument piping coming from A main steam line flow element (MS-FE-5A). Because this piping was unisolable from the reactor pressure boundary, the licensee took the reactor to cold shutdown and repaired the weld. The licensee documented the steam leak in PER 293-1050.

The licensee's investigation of the weld failure, which included removing the weld for destructive examination, concluded that the defect had resulted from inadequate fusion of the weld during the initial construction welding. The licensee visually inspected the socket welds of the other steam line flow elements and found no indication of leakage.

The inspector observed selected portions of the weld repair and reviewed PER 293-1050. The inspector concluded the licensee's corrective actions for this event were appropriate.

d. High Area Temperature Indication Under the Reactor Vessel

Approximately three weeks prior to the reactor scram, licensed operators recognized that one (CMS-TE-23) of several temperature sensors (thermocouples) that measure area temperature under the reactor vessel was indicating a significantly higher temperature than other sensors in the same general area. PER 293-1057 documented this deficiency. Licensee engineers concluded that the thermocouple reading high was in error. The licensee committed to determine the cause of the erroneous reading during the next cold shutdown.

Following the reactor scram and cooldown to repair the steam leak on MS-FE-5A, licensee engineers and craftsmen investigated the cause of the erroneous under-vessel area temperature. They found that during the R7 outage, technicians had incorrectly wired the thermocouples during maintenance associated with basic design change (BDC) 88-0038-3T. This BDC replaced the temperature indicators for CMS-TE-17 and CMS-TE-23 with CMS-TR-5, which provided light emitting diode (LED) readout and hard copy trending capability. As a result of the wiring error, temperature sensor CMS-TE-23 was actually reading primary shield wall area temperature rather than under-vessel temperature, and the corresponding under-vessel sensor was indicating primary shield wall temperature. Licensee craftsmen correctly wired the two thermocouples and verified correct temperature response of each.

The licensee determined that the root cause of the wiring error was inadequate post-maintenance testing and inadequate attention to detail by the craftsmen and QC verifier. The failure to perform an adequate post-maintenance test is a violation of Criterion XI, "Test Control," of 10 CFR 50, Appendix B. However, because the licensee satisfied the criteria specified in Section VII.B(2) of the Enforcement Policy, this violation of test control is not being cited (NCV, 50-397/93-31-03, Closed).

The inspectors verified that the post-maintenance indications of the thermocouples were in agreement with the other thermocouples in their respective areas and assessed the PER. The inspectors concluded that the licensee's corrective actions for this event were adequate. The inspectors considered the identification of the disparity between the temperature indications by the operators to be a good example of a questioning attitude and a positive change in performance.

e. Half-Scram During the Performance of Surveillance Testing

On August 10, 1993, during the performance of Technical Specification surveillance 2-TSS-PN-7.4.3.1.1.63, "APRM Channel B Calibration," an unanticipated half-scram was received from APRM

channel A. The Shift Manager had the Instrument and Control (I&C) technicians discontinue the surveillance. He also had the I&C technicians initiate PER 293-1069 to document the event.

The licensee's evaluation of the event found that the technician performing the surveillance, due to poor self-checking work practices, had failed to adhere to procedures in that he repositioned the Channel A APRM mode switch, which is located in the A APRM drawer, to the standby position instead of the Channel B APRM mode switch, which is located in the B APRM drawer. The failure to adhere to procedure requirements of surveillance 2-TSS-PN-7.4.3.1.1.63 is a violation of TS 6.8.1.a. However, because the licensee satisfied the criteria specified in Section VII.B(2) of the Enforcement Policy, this violation is not being cited (NCV, 50-397/93-31-04, Closed).

The licensee's evaluation concluded that the event had the following four causes: APRM-CH-A and APRM-CH-B are located in the same cabinet; the paper used to cover the meter and controls was too small (8 1/2" by 11"); the technicians made a self-checking error; and the surveillance was performed on graveyards.

The licensee implemented the following corrective actions: the technicians were counselled on performing self-checking; the surveillance procedure will be revised to require a more positive method of covering the mode switch; and I&C supervision will consider a different time period for performance of these types of surveillances.

In addition to reviewing the PER and the procedure, the inspectors discussed the event with the Plant Manager, the Shift Manager, the I&C Supervisor, and the Maintenance Production Manager. Even though the licensee's corrective actions appeared appropriate, the inspectors expressed concern to the aforementioned managers that for this event the Supply System appeared to place greater emphasis on very minor weaknesses in the surveillance procedure and less emphasis on the technician performance issues. These managers assured the inspector that when performance issues occurred the issues were appropriately emphasized.

f. Half-Isolation While Conducting Surveillance Testing

On August 27, 1993, during the performance of Technical Specification surveillance PPM 7.4.3.2.1.6, "Leak Detection," an unanticipated half-isolation was received. The Shift Manager had the I&C technicians discontinue the surveillance procedure. He also had the I&C technicians initiate PER 293-1128 to document the event.

The licensee's evaluation concluded that the cause of the event was procedure nonadherence due to inadequate self-checking. Specifically, section 7.9, step 2 required the I&C technician to insert three keys to bypass the isolation function; however, the technicians inserted only one key with the result that, when subsequent steps were performed, resulted in a half-isolation. The failure to adhere to procedure requirements of PPM 7.4.3.2.1.6 is a violation

of TS 6.8.1.a. However, because the licensee satisfied the criteria specified in Section VII.B(2) of the Enforcement Policy, this violation is not being cited (NCV, 50-397/93-31-05, Closed).

The licensee implemented the following corrective actions: the technicians were counselled on performing self-checking; the surveillance procedure will be revised to make key insertion the responsibility of Operations personnel, and a Fast Action Team was convened to determine why the I&C technicians' performance has declined.

In addition to reviewing the PER and the procedure, the inspectors discussed the event with the Plant Manager, the Shift Manager, the I&C Supervisor, and the Maintenance Production Manager, and expressed concern regarding the relatively high number of procedure adherence and attention to detail errors by I&C technicians. The licensee's corrective actions appeared appropriate.

g. Control Rod Drive Housing Flange Joint Leak

On August 3, 1993, during the under-vessel inspection performed following the reactor scram, and with reactor pressure at approximately 900 psig, the licensee identified that the housing flange for control rod drive mechanism (CRDM) 18-59 was leaking at approximately 10 drops per second. The licensee initiated PER 293-1077 to document this problem, and initiated MWR AP4907 to check the torque of the eight flange bolts and verify the source of the leakage.

Craftsmen and the system engineer verified the leak was from the housing flange joint of CRDM 18-59. The craftsmen determined the flange bolts' torque was acceptable.

After conferring with the vendor, license engineers determined that the most likely cause of the leakage was that one or more of the teflon-coated, stainless steel O-rings used to seal the main housing flange was defective, causing the leak. The engineers classified the leakage as non-pressure boundary, identified leakage. The leakage was quantified as 0.023 gallons per minute, which was substantially less than the TS limit of five gallons per minute.

As corrective action, the licensee initiated more frequent monitoring of reactor coolant leakage, and plans to remove and replace the three O-rings during the 1994 refueling (R9) outage.

The inspectors observed the leakage and agreed with the licensee's determination that the leakage was not pressure boundary leakage. The inspectors concluded the licensee's corrective actions were appropriate.

h. Reactor Vessel Water Level Anomaly During Restart

At approximately 11:00 p.m. on August 10, 1993, during the initial plant heatup from cold shutdown with the reactor adding heat, control room operators observed that the A reactor vessel level

indication began to diverge from the B and C reactor vessel level indications. By 12:45 a.m. on August 11, 1993, with reactor pressure at 20 psig, the A level indicator had increased to 13 inches greater than B and C. At 2:00 a.m., with reactor pressure at 56 psig, channel A had converged to within 2 inches of the other channels. As heatup continued and reactor pressure increased, the indicators came into full agreement. The Shift Manager initiated PER 293-1072 to document this event.

The licensee concluded that the cause of the level divergence was entrained gas bubbles in the Train A reference line piping. The bubbles began to compress as reactor pressure increased, causing the observed level to increase (due to decreasing level in the reference leg). The licensee concluded that the divergence of the A level indication decreased as condensation refilled the reference leg from the condensing pot and as the bubbles were displaced to horizontal portions of the instrument line. The licensee determined the operating crew responded to the event properly.

As corrective action, as previously discussed in the Supply System's response to NRC Bulletin 93-03, the licensee plans to implement a design change to the level indicating system during the next cold shutdown that will provide a constant volume flow to the reference legs of the level indication system. The licensee also clarified the expectations of the operating crew with respect to making timely conservative operability determinations.

Inspector followup of this event included review of the PER, review of the logs, procedures and charts, and discussions with the Shift Manager, the Operations Manager, and the Plant Manager.

The inspectors noted in their review of procedures that PPM 3.2.1, "Plant Shutdown," which was not applicable during this phase of plant operation, states that "... any evidence of notching or degassing will be evaluated to determine instrument operability. Notching or degassing which renders an affected instrument inoperable is defined as an unexplained level change of greater than 6" lasting greater than 2 minutes or as determined by the shift manager, and requires the affected instruments be declared inoperable with the appropriate Technical Specification actions taken." Also, licensee procedure PPM 7.0.0, "Shift and Daily Instrument Checks," establishes a channel check acceptance criterion for these level indicators of "less than 10 inches of each other." The channel check is required only once per shift.

When the channel check was performed early on midshift, channel A, which had a 6" difference from the other channels, had met the Supply System's criterion for degassing (i.e., greater than 6" for greater than 2 minutes). Therefore, an operability determination would have been appropriate, even though PPM 3.1.2, "Startup From Cold Shutdown" did not require the operability determination. Additionally, closer monitoring of the indicators against the channel check criteria would have been appropriate, since it was apparent the instrument was drifting and the instruments had

previously experienced notching. In addition, for a brief time the A level indication was greater than the 10 inch requirement and the Shift Manager took no action other than monitoring level, even though he stated he was aware the anomaly was occurring.

To the inspector, it appeared that the untimely operability determination resulted from the crew's focusing on difficulties that were being experienced with the withdrawal of a control rod and not adequately addressing this important operating issue. The inspector concluded that the operating crew's questioning attitude should have been heightened because, until this time, the Supply System had only experienced degassing during reactor depressurization. The inspector concluded that although there was no violation of requirements, the operating crew's performance during the level anomaly was weak.

In the discussions with the aforementioned managers, the inspectors expressed concern regarding the operating crew's response to the event because the operators did not make a timely operability determination. As a result of these discussions, the Operations Division Manager clarified his expectations of the operating crews with respect to level deviations in an Interoffice Memorandum dated August 11, 1993.

One cited violation and four non-cited violations were identified.

6. Surveillance Testing (61726)

The inspectors reviewed surveillance tests required to be performed by the Technical Specifications (TS) on a sampling basis to verify that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

The inspectors observed portions of the following surveillance tests on the dates shown:

Procedure	Description	Dates Performed
7.4.3.3.1.58	HPCS Suction Transfer on Low Condensate Storage Tank (CST) Level	August 16
7.4.3.7.5.3	Suppression Pool Level and Suppression Chamber Pressure Channel Checks (CC) and Channel Functional Test (CFT)	August 19
7.4.3.1.1.70	Local Power Range Monitors (LPRM) Calibration and Gain Adjustments	August 24-25

7.4.3.6.1.1A	Control Rod Block Monitor CC	August 25
7.4.1.3.1.2	Control Rod Exercises	August 27
7.4.7.9.1	Turbine Bypass Valve Testing	August 27

a. LPRM Gain Calibration and Setpoint Check

The LPRM gain calibration and setpoint check surveillance was observed and evaluated against TS requirements. The inspector noted that PPM 7.4.3.1.1.70 had recently been revised to improve the quality of the procedure by providing more detail in the procedure steps. The procedure validation verification was performed by walking through, but not performing, the procedure at the work area on June 23, 1993. The inspector found several instances where the technicians had difficulty performing the procedure, including the following observations:

- The surveillance test was secured on August 24, 1993, after 7 of the 8 LPRM pages in Section 7.7 were completed. On August 25, different technicians resumed the surveillance. They recommenced the surveillance in Section 7.7, step 1, to complete the last LPRM page. The technicians completed step 9, rotating the dial to cause an LPRM DOWNSCALE TRIP. When the technicians went to record the downscale trip voltage in step 11, they recognized that it was necessary to install a digital voltmeter. However, Section 7.7 had not specified that a multimeter was required. Subsequently, the technicians recognized that other Sections of the procedure specified that a multimeter be installed. It appeared to the inspector that this problem resulted from the technicians entering a partially completed procedure before adequately familiarizing themselves with earlier requirements of the procedure.

  PPM 1.2.3, Section 5.3.4.b requires that prerequisites and the status of system configuration shall be confirmed, and the Shift Manager's authorization obtained, prior to restart of the procedure. The inspector determined that the technicians did not completely review the procedure to ensure that all instrumentation was installed prior to resuming the test as required by PPM 1.2.3, Section 5.3.4.b. Based on discussion with the I&C Supervisor, the inspector concluded that performance of the procedure required a significant amount of time. However, the procedure did not provide instructions for resuming the test after it was secured, and relied on the technicians to review up to 30 pages of procedure steps to ensure all requirements had been met.

- PPM 7.4.3.1.1.70, Section 7.7, step 6 required the technician to rotate the adjustment control knob to obtain a mid-scale reading. When the technicians rotated the adjustment knob the meter did not respond. The technicians investigated and realized that they had inadvertently missed step 2, which stated in part, "Select a LPRM card using the LPRM front panel meter

select switches." After the technicians selected the proper channel on the meter face a mid-scale reading was obtained.

The inspector noted that PPM 1.2.3, Section 5.3.4.a required that procedures be followed step-by-step unless otherwise stated. PPM 7.4.3.1.1.70, Section 4.2 states that steps of this procedure are not required to be performed in sequence. However, to get the desired response in Section 7.7, the procedure had to be performed in the sequence written. Therefore, the inspector concluded that the procedure was misleading in that certain parts of the procedure had to be performed in a step-by-step manner and the procedure did not require this. Also, the technicians realized that they had missed a step of the procedure when they did not get the desired response.

- PPM 7.4.3.1.1.70, Section 7.7, step 4 states, "... verify the local LPRM bypass lamp is illuminated". The top portion of the panel has a bypass lamp for each card, and the meter face has a bypass lamp. When the inspector questioned the technicians, it was not clear to them what lamp should be illuminated. The technicians proceeded with the procedure after verifying that only the panel lamp was illuminated.

- The inspector noted that Shop Practices Manual (SPM) 8.1, Section 5.2.d of the Electrical Enclosure requires that the technicians take a piece of paper and cover the unit that is not to be tested. The inspector noted this shop practice was being followed on August 24; however, it was not followed by the technicians on August 25.

The inspector concluded that the problems observed during the conduct of the above surveillance tests resulted from an inadequate pre-job brief of the technicians, lack of a questioning attitude, insufficient procedure familiarity by the technicians, and an inadequate procedure. The procedure did not provide instructions on how to resume testing after it was secured, and was misleading by allowing steps to be performed in any order when they needed to be performed in the sequence written. The failure to provide the technicians with a surveillance procedure appropriate to the circumstances is a violation of Criterion V, "Procedures," of 10 CFR 50, Appendix B. The inspector discussed these observations with licensee management, who stated that an appropriate procedure revision would be provided before the next performance of this surveillance test. However, because the licensee satisfied the criteria specified in Section VII.B(1) of the Enforcement Policy, including a commitment to take appropriate corrective action, this Severity Level V violation was not cited (NCV, 50-397/93-31-06, Closed).

b. <u>Control Rod Block Monitoring</u>

The control rod block monitoring Channel A CFT surveillance was observed and evaluated against TS requirements. This met the requirement of Inspection Procedure 61726. The surveillance was

conducted in a formal and deliberate manner and in accordance with licensee and TS requirements.

c. Control Rod Exercises

While witnessing PPM 7.4.1.3.1.2, the inspector noted that operators received a "Rod Withdrawal Block" annunciator that did not immediately clear. The individual performing this surveillance was a trainee operating the plant under instruction (UI). Rather than referring to the annunciator response procedure, the qualified operator directed the UI operator to deselect, then reselect the control rod in question, and the alarm cleared. The operator then told the UI that he would explain the logic of these actions later. The inspector was concerned that the UI was not receiving the full benefit of the training experience in that he did not fully understand the actions he was directed to take. The inspector discussed this observation with the Operations Division Manager, who agreed with the inspector's conclusions. The Operations Division Manager stated that he would reiterate management's expectations for proper conduct of practical training within the Operations Division.

d. High Pressure Core Spray (HPCS) System Transfer on CST Low Level

The inspector observed licensee instrument and control (I&C) technicians perform Technical Specifications Surveillance Procedure 7.4.3.3.1.58, "HPCS System Transfer on CST Low Level." The licensee's technicians did not follow a step in their procedure, which instructed them to fill the HPCS line to the top of the vent line above the upper vent valve. Furthermore, the technicians did not contact the control room for preapproval by the Shift Manager to deviate from the procedure as required in procedure PPM 1.2.3, "Use of Controlled Procedures." The technicians appeared technically knowledgeable in that they recognized the need to fill the line with water above the upper vent valve in order to avoid air pockets in the line, and did fill the line sufficiently to prevent air pockets. Since the water in the line was potentially contaminated, the procedure as written presented the possibility of spilling potentially contaminated water. Prior to the exit meeting, the licensee took prompt corrective action to instruct the technicians involved and to correct the procedure. This failure to follow surveillance procedures is a violation of TS 6.8.1 (Violation, 50-397/93-31-07, Open).

Two violations were identified.

7. Plant Maintenance (62703)

During the inspection period, the inspectors observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required QA/QC involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspectors verified that reportability for these maintenance activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
AP4367, Fabricate and Install Seismic Supports for Control Rod Drive (CRD) to RPV Level Instrument Purge	August 17-18
AP4368, Fabricate and Install Valves for CRD to RPV Level Purge	August 17-18
PER/PID-293/1119, Troubleshoot and Repair MSLC Heaters	August 19
AP4553, Troubleshoot/Repair RCIC-P-3	August 23-24
AP3604, Replace Relay MS-RLY-TK-120	August 23

a. The inspector observed portions of the MSLC heater current characteristics troubleshooting (PER/PID 293-119) on August 26. The troubleshooting plan was intended to study current characteristics over time to determine why the current values were outside the acceptance range for surveillance procedure PPM 7.4.6.1.4.1A. The troubleshooting concluded that the clamp-on ammeter was out of calibration. The surveillance procedure was satisfactorily re-performed using another clamp-on ammeter. The troubleshooting was conducted in a formal manner.

b. The maintenance associated with RCIC-P-3 (the system keep-full pump) was initiated because the discharge pressure had decayed over a period of time from approximately 80 psig to just under 70 psig. The control room annunciator for low discharge pressure for RCIC-P-3 had a setpoint of 67 $\pm$ 2 psig. This alarm was coming in intermittently prior to repair of the pump.

The MWR associated with RCIC-P-3 included taking a set of data while varying the discharge throttle valve's position to develop a set of pump head curves to compare with the vendor manual. This initial set of data indicated that the total developed head at each of the points was well below the vendor-provided curves. The system engineer determined that the initial action for the pump would be to adjust the clearance of the pump impeller. The adjustment was partially successful because the discharge pressure of RCIC-P-3 was increased to about 71.5 psig. The system engineer determined that the minor improvement in discharge pressure appeared to be adequate to keep the pump's discharge pressure above the alarm setpoint.

After completion of the impeller adjustment, the licensee took another set of data for the pump head curves to compare with vendor-supplied curves. The licensee determined that only minor improvement had been made, and that the pump still appeared to be degraded.

The inspector reviewed the data developed by the licensee and found that the calculations for pump head, which were in feet of water,

contained minor discrepancies. Pump head in feet of water was calculated by dividing the pressure by the density. The licensee entered data for flow rate, pump discharge pressure, and water temperature. However, when calculating pump head, the licensee was inconsistent in determining which pressure gage to use for the calculation. In addition, the licensee recorded a water temperature of 131 degrees, but calculated pump head using the density of water at 70 degrees. These errors resulted in an approximate error of 4 feet of water compared to the actual pump head. These apparent discrepancies were minor in nature and did not effect the system engineer's judgement on the condition of RCIC-P-3. However, these problems appeared to indicate that more thorough technical reviews were needed when Technical personnel reduce data. Licensee management acknowledged the inspector's comments.

No violations or deviations were identified.

8. Licensee Event Report (LER) Followup (90712, 92700)

a. The inspector reviewed the following LERs associated with operating events. Based on the information provided in the report it was concluded that reporting requirements had been met, root causes had been identified, and corrective actions were appropriate. The inspectors closed the following LERs based on in-office review:

LER NUMBER	DESCRIPTION
93-12	Main Turbine Bypass Valves Not Operable Per Technical Specification Requirements
93-19	Engineered Safety Features Isolation and Actuations Due to a 500 KV Load Break Disconnect Failure

b. The inspectors reviewed the following LERs by on-site followup of the details contained therein:

(1) (Closed) LER 50-397/92-45, Unplanned Automatic ESF Isolation of Reactor Core Isolation Cooling Due to Surveillance Procedure Deficiency and Training Inadequacy

LER 92-45 was associated with one of the events described in Violation 50-397/92-40-01, which is discussed in detail in paragraph 3.a of this report. This LER is closed based on the inspectors' observations, as discussed in paragraph 3.a.

(2) (Open) LER 50-397/92-20, "Flow Element for Low Pressure Core Spray (LPCS) Minimum Flow Control Not Properly Installed"

On May 5, 1992, the licensee determined that a flow element in the LPCS system, LPCS-FE-002, had not been installed properly. The improper installation had allowed air to be entrained in the sensing lines during LPCS pump operation, giving an erroneously high flow reading which could have resulted in the

premature closing or the failure to open of the minimum flow valve. The sensing lines for flow element LPCS-FE-002 provide inputs for flow switch LPCS-FIS-4, which is designed to actuate to close the minimum flow valve. Table 3.3.3-2 of the WNP-2 Technical Specifications (TS) specified the setpoint for the minimum flow valve to be ≥770 gpm, with an allowable value of ≤900 gpm. The licensee reported this in LER 50-397/92-20 as a condition prohibited by the plant's TS.

Between December 1991 and April 1992, the licensee noted several instances in which LPCS-FIS-4 read on-scale while the system was shut down. This offset could have caused the minimum flow valve to close when LPCS flow was less than 770 gpm. The licensee discovered in their review that the instrument sensing lines were connected to the top of the pipe, not the side as specified by the vendor manual for LPCS-FIS-4. The error had been made during plant construction.

The inspector documented his initial review of this LER in Inspection Report No. 50-397/93-24. As discussed in that inspection report, the licensee notified the inspector that on April 18, 1992, LPCS-FIS-4 had been found reading 800 gpm while the pump was in standby. This had not been addressed in the LER.

On September 3, 1993, during on-site follow-up inspection, the inspector was informed by the licensee that on May 28, 1992, during testing of LPCS system valves, the minimum flow valve did not open following starting of the pump. After attempting to open the minimum flow valve, which would close automatically after each attempt, operators stopped the pump. The plant computer indicated that LPCS-FIS-4 was reading approximately 900 gpm during the event. The licensee speculated that air entrained in the instrument sensing line provided an erroneous flow indication. This event would indicate that the LPCS pump was not operable at the time of the test and may not have been operable for several months. Although this event occurred one week before LER 92-20 was submitted to the NRC, it was not discussed in the LER or subsequently reported.

The inspector expressed concern regarding the adequacy and completeness of the LER with the licensee at an exit meeting on September 3, 1993. The Plant Manager committed to re-evaluate the adequacy of the LER 92-20. This LER will remain open pending completion of the licensee's additional evaluation.

(3) <u>(Open) LER 50-397/92-08, Revision 1, Standby Gas Treatment System Flow Limiter Could Result in Fan Trip</u>

The inspector reviewed LER 50-397/92-08, Revision 1, which concerned the operability of the standby gas treatment system (SGTS) under certain conditions. The inspector was unable to determine from the LER the conditions in which the SGTS would have been prevented from performing its safety functions.

At the exit meeting on September 3, 1993, the Plant Manager committed to review the LER and assess the necessity of a second Revision.

Background

The SGTS was designed to limit the release of airborne radioactive contaminants from the reactor building to atmosphere following a design basis accident. The SGTS is composed of two full-capacity filter trains designed to provide a reactor building pressure of 0.25" water gage (w.g.) lower than atmospheric pressure under design basis conditions. Each filter train has two full-capacity fans, powered from separate vital 480V buses.

The SGTS was designed to automatically initiate on high drywell pressure, reactor vessel low water level, and high radiation level in the reactor building exhaust plenum. System flow is controlled by fan inlet flow dampers. The fan inlet flow dampers are automatically controlled to maintain building pressure negative with respect to atmosphere and have a limited maximum flow to protect the filter trains and the fan motor. The original maximum flow setpoint was 4457 cubic feet per minute (cfm) as indicated by a flow annubar in the fan discharge piping.

In 1989 the licensee recognized that the SGTS would not be able to maintain -0.25" w.g. under all design basis atmospheric conditions with system flow limited to 4457 cfm. The licensee changed the flow limiter setpoint to 5600 cfm. The issue was discussed by the licensee in LERs 89-40 and 89-40, Revision 1 (dated June 19, 1990).

As documented in Inspection Report No. 50-397/91-42, dated January 3, 1992, the inspector determined that the licensee had not performed an adequate design change evaluation to support the flow limiter setpoint change. While the design change considered the increased flow effects on the system filters and ducting, it did not fully consider the load impact of the increased flow on the fan motors. Specifically, the licensee did not consider the impacts of degraded voltage, instrument inaccuracies, and cold building temperatures. The failure to consider these issues in the licensee's design change process was the subject of a Notice of Violation.

During the licensee's initial consideration of these factors, they determined that the margin between the peak fan motor current and the thermal overload setpoint would be substantially reduced, but that the thermal overload setpoint would not be exceeded. However, upon subsequent review, considering factors that had not been previously included, the licensee determined that a flow limiter setpoint of 5600 cfm could cause the fan motor thermal overloads to trip under certain conditions. The new information apparently considered

concerned instrument reference calibration conditions and instrument loop uncertainties. This conclusion was reported in LER 92-08 and LER 92-08, Revision 1 (dated June 11, 1993).

Review of LER 92-08, Revision 1

The Abstract for LER 92-08 stated that the SGTS fan motors thermal overloads could trip, preventing the system from performing its safety function "...under highly unlikely design conditions." While this statement was repeated several times throughout the LER, the inspector could not determine from the LER the specific conditions in which the licensee concluded the SGTS would not have performed its function.

The calculation of peak fan motor current was an example of the information included in the LER.

- On page 3 of the LER the licensee concluded that the current draw on the fan motor corresponding to the worst case demand flow rate and low voltage conditions was 38 amps. The original thermal overload trip point was 36.5 amps.

- The LER stated that as part of the corrective actions, the flow limiter setpoint was reduced to 5380 cfm and the thermal overload trip point was raised to 45 amps.

- On page 5 of the LER, the licensee concluded that with the new flow limiter setpoint, the peak current draw on the fan would be 39 amps. The inspector questioned why the peak current draw would be greater under what would appear to be more favorable conditions.

- On page 6 of the LER, the licensee concluded that the current draw corresponding to worst case low voltage conditions and average building air temperature conditions would be 38 amps. The inspector questioned why this value was the same as the value provided on page 3, since worse case conditions would appear to be colder building temperatures.

The LER indicated that the worst case conditions would be dependent on temperature conditions, degraded voltage, and instrument inaccuracies, but did not provide specific values, the relative probability of their occurrence, or whether these conditions had previously existed. Without this information, it was not possible for the inspector to verify the licensee's conclusions in the LER that the safety significance was "negligible." The licensee was unable to provide supporting documentation for these conclusions during the week the inspector was onsite. This LER will remain open while the licensee reviews the LER and assesses the necessity for a revision.

(4) <u>(Open) LER 50-397/93-11, Revisions 0 and 1, Surveillance Requirements for Refueling Platform Inadequately Implemented Due to Analysis Deficiencies and Surveillance Requirement Misinterpretations</u>

On March 10, 1993, the licensee determined that surveillance testing had not been adequate to demonstrate the operability of hoists associated with the refueling platform. The licensee had discovered that instrument uncertainties had not been adequately considered in setting cutoffs and interlocks. In addition, the licensee determined that they had misinterpreted the testing requirements for the slack cable cutoff. LER 93-11, Revision 0, was submitted on April 9, 1993 to address these issues.

On April 9, 1993, a Shift Technical Advisor (STA) discovered that the overload cutoffs on two refueling bridge hoists were not being set in accordance with the TS 4.9.6.b, and that the TS appeared to be in error. On May 5, 1993, the licensee submitted a revision to LER 93-11 to include this issue.

The inspector reviewed the LERs and found the discussion of root cause and corrective action to be acceptable. However, the inspector found that the licensee did not have a documented analysis to support their assertion in the "Safety Significance" section of the LER that the incorrect setpoints "...were not of sufficient magnitude to appreciably affect the likelihood of damage to reactor vessel internal components, fuel bundles, or the refueling platform hoists." The setpoints of concern were the following:

- The main hoist "overload cutoff", designed to prevent damage to either the fuel bundles or reactor internals by stopping the hoist travel when a force greater than 1250 pounds is applied to the hoist. This cutoff could have been set as high as 1441 pounds.

- The TS required the main hoist "hoist loaded interlock", designed to provide a rod block to prevent control rod withdrawal when a fuel bundle is being lifted, to be set at 485 $\pm$ 50 pounds. This interlock could have been set as high as 670 pounds. The licensee had not performed a calculation to determine whether this interlock may have been defeated if the weight of the fuel element and the lower mast segment were less than 670 pounds.

- The TS required the main hoist "hoist loaded redundant interlock," designed to prevent upward movement of the refuel mast if the grapple is not closed and the hoist is loaded, to be set at 550 $\pm$ 50 pounds. This interlock could have been set as high as 736 pounds. The licensee had not considered whether this interlock may have been defeated if the weight of the fuel element and the lower mast segment was less then 736 pounds.

The inspector expressed concern at the exit meeting on September 3, 1993, about the adequacy and completeness of this LER. The Plant Manager committed to assess these findings and determine the necessity for an analysis. This LER remains open.

(5) (Closed) LER 50-397/93-18, "Spent Fuel Pool Makeup Not Adequate to Mitigate Accident Conditions"

LER 93-18, submitted by the licensee on May 28, 1993, addressed the licensee's discovery that WNP-2 did not have the ability to remotely supply service water (SW) makeup to the spent fuel pool (SFP) following a design basis event as stated in the WNP-2 Final Safety Analysis Report (FSAR). Remote makeup to the SFP was to be supplied from either of two SW trains by two remote-manual, motor-operated isolation valves, SW-V-75A and B. However, two manual valves downstream of the motor-operated valves had been maintained closed by operating procedures since plant startup.

The licensee concluded that it would be preferable to leave the manual valves closed to provide a double isolation barrier between the SFP (a radioactive system) and the SW system, which communicates with the environment. To support this conclusion, they determined that during the worst case LOCA environment, an operator could expect to receive less than 5 Rem opening one of these manual valves. In addition, the licensee concluded that a LOCA concurrent with a loss of fuel pool makeup capability was extremely low.

The inspector walked down the valves and determined that they were adequately labeled and accessible without the use of ladders. In addition, the inspector discussed the valves and their locations with a control room supervisor (CRS). The inspector concurred that the probability of a concurrent LOCA and loss of fuel pool makeup capability was low. Additionally, the inspector concluded that there was sufficient time to detect a loss of fuel pool level and plan appropriate actions necessary to open one of the manual valves to prevent significant SFP inventory reduction. This item is closed.

(6) (Closed) LER 50-397/93-09, Revisions 0, 1, and 2, "Existence of Noncondensible Gases in the Reference Leg of Reactor Pressure Vessel Instrumentation"

LER 93-09, Revisions 0, 1, and 2 discussed the licensee's conclusion that noncondensible gases in the reference legs of reactor pressure vessel instrumentation caused level instrument anomalies during RPV pressure reductions. This issue, including the licensee's review of root cause analysis, corrective actions, and safety consequences, has been reviewed by the NRC in several discussions with licensee management. Reviews of this issue were documented in Inspection Report Nos. 50-397/92-43 and 50-397/93-18. The inspector reviewed the LERs

and concluded that they acceptably presented the issue as previously discussed. This item is closed.

No violations or deviations were identified.

9. Employee Concerns Program (2500/028)

The inspector determined information regarding the employee concerns program, and recorded details of the program in Appendix A to this inspection report, in accordance with NRC Temporary Instruction 2500/28.

The licensee's program is provided to obtain and resolve employee and contractor concerns and allegations in an anonymous fashion. The program is called Direct Line, and consists of a published telephone number which is routed directly to the Assistant Managing Director for Operations. He discusses the caller's concern, investigates or directs investigation of the concern, and responds back to the caller if requested. This program is applicable to both quality and non-quality-related problems, and is used to resolve these concerns.

No violations or deviations were identified.

10. Exit Meeting

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on September 17, 1993. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

The licensee did not identify as proprietary any of the information reviewed by or discussed with the inspectors during the inspection.

Appendix A: Summary of Information Regarding the Employee Concerns Program (Refer to Paragraph 9)

Attachment A

EMPLOYEE CONCERNS PROGRAMS

PLANT NAME: WNP-2 LICENSEE: Washington Public Power Supply System
DOCKET #: 50-397

NOTE: Please circle yes or no if applicable and add comments in the space provided.

A. PROGRAM:

1. Does the licensee have an employee concerns program?

Yes The program is called "Direct-Line"

2. Has NRC inspected the program? Report # _____

The resident inspectors have been generally aware of the program. However, no specific inspection has been documented since the program was initiated in 1990 (a different form of employee concerns program existed prior to that time).

B. SCOPE: (Circle all that apply)

1. Is it for:

a. Technical? Yes

b. Administrative? Yes

c. Personnel issues? No

According to the licensee, personnel issues are supposed to be handled through their appeal process. However, the inspector noted that a number of issues raised through the licensee's "Direct-Line" concerned personnel issues (e.g., complaints of cigarette smoking).

2. Does it cover safety as well as non-safety issues? Yes

3. Is it designed for:

a. Nuclear safety? Yes

b. Personal safety? Yes

c. Personnel issues - including union grievances? No

4. Does the program apply to all licensee employees? Yes

5. Contractors? Yes

6. Does the licensee require its contractors and their subs to have a similar program?

   No — As noted in Item B.5, the regular program covers contractor employees. A mandatory part of standard licensee contracts reminds contractors and their subcontractors involved in providing services or components for a nuclear plant of their obligations under 10 CFR 50.7 and Section 211 of the Energy Reorganization Act of 1974.

7. Does the licensee conduct an exit interview upon terminating employees asking if they have any safety concerns?

   Yes — Currently the exit interview is offered as an option to the licensee's employees when they leave the company. A draft of proposed changes to the licensee's employee concerns program calls for the exit interview to be mandatory for exiting Supply System employees and optional to exiting contract employees.

C. INDEPENDENCE:

1. What is the title of the person in charge?

   The Direct-Line Program is administered personally by the Assistant Managing Director for Operations (AMDO), the utility's senior nuclear officer.

2. Who do they report to?

   Managing Director (the utility's chief executive officer)

3. Are they independent of line management?

   Not entirely. Plant management reports to the AMDO. Engineering and QA report directly to the Managing Director.

4. Does the ECP use third party consultants?

   Third party consultants are used when deemed necessary by the AMDO.

5. How is a concern about a manager or vice president followed up?

   Concerns about a manager can be taken to the AMDO. Concerns about the AMDO can be taken directly to the Managing Director.

D. RESOURCES:

1. What is the size of staff devoted to this program?

   No one is solely devoted to this program. Resources are dedicated as necessary.

2. What are ECP staff qualifications (technical training, interviewing training, investigator training, other)?

   There are no specific qualifications. Typically, the AMDO would assign followup on a concern to a seasoned employee — in most cases a manager — who could be expected to be independent, able to maintain confidences, and knowledgeable in the area of concern.

   Some of the licensee's managers and supervisors have attended training sessions on how to deal with employee concerns. The licensee's legal counsel has given some training to Supply System managers and supervisors on how to handle employee concerns.

E. REFERRALS:

1. Who has followup on concerns (ECP staff, line management, other)?

   The AMDO is ultimately responsible for followup on concerns. As mentioned in D.2, the AMDO may assign individual concerns to another person for investigation.

F. CONFIDENTIALITY:

1. Are the reports confidential? Yes

2. Who is the identity of the alleger made known to (senior management, ECP staff, line management, other)?

   Other The identity of the alleger is divulged only to those with a need to know.

3. Can employees be:

   a. Anonymous? Yes

   b. Report by phone? Yes

      The phone number is posted and is included on the back cover of the licensee's phone book (copy included as Attachment B).

G. FEEDBACK:

1. Is feedback given to the alleger upon completion of the followup?

   Yes Feedback can be either written or verbal if the identity of the alleger is known. If the identity of the alleger is unknown, actions taken in response to the alleger's concern may be posted or published (e.g., in a Supply System newsletter).

2. Does program reward good ideas?

   No A different licensee program rewards good ideas.

3. Who, or at what level, makes the final decision of resolution?

   Assistant Managing Director for Operations

4. Are the resolutions of anonymous concerns disseminated?

   The resolutions may be disseminated. See answer to G.1.

5. Are resolutions of valid concerns publicized (newsletter, bulletin board, all hands meeting, other)?

   They may be, but in a manner which maintains the alleger's confidentially, as appropriate (see answer to G.1).

H. EFFECTIVENESS:

1. How does the licensee measure the effectiveness of the program?

   No formal measurement.

2. Are concerns:

   a. Trended? No

      Not formally, however, they may be tracked informally if a particular area were shown to have a lot of concerns, there might be some additional focus in that area.

   b. Used? Yes

3. In the last three years how many concerns were raised? 16
   Closed? 15 What percentage were substantiated? 0

   The inspector reviewed each of the 16 concerns with the AMDO and determined that only one concerned safety. The inspector noted that the safety concern was investigated, and it was documented that no evidence was found to substantiate the safety concern.

4. How are followup techniques used to measure effectiveness (random survey, interviews, other)?

   No specific techniques to measure effectiveness. However, each concern is entered onto a special form which requires completion of the "closeout" section before closing the concern.

5. How frequently are internal audits of the ECP conducted and by whom?

   No specific frequency. An audit was performed by the licensee's QA department in 1992.

I. ADMINISTRATION/TRAINING:

1. Is ECP prescribed by a procedure?

   No However, the ECP is described in the licensee's General Information Handbook (No. GIH 9.5.1, Rev. 0, dated 6/3/92).

2. How are employees, as well as contractors, made aware of this program (training, newsletter, bulletin board, other)?

   Contractors who perform work onsite and employees are made aware of the ECP through training (e.g., general employee training), bulletin boards, and through a notice on the back of every Supply System phone book.

ADDITIONAL COMMENTS: (Including characteristics which make the program especially effective or ineffective.)

1. According to the licensee, the Supply System tries hard to convey to its employees an "open door" policy for employee communication with all levels of management.

2. In most cases, licensee employees with knowledge of a plant problem would identify the problem by initiating a "Problem Evaluation Request" (PER). This process would ensure that the problem is communicated to Plant Management for action. The PER process is prescribed by licensee administrative procedure 1.3.12. Approximately 1500 PERs per year are generated at WNP-2.

The person completing this form please provide the following information to the Regional Office Allegations Coordinator and fax it to Richard Rosano at 301-504-3431.

NAME: TITLE: PHONE #:

David Corporandy/Project Inspector/510-975-0319 DATE COMPLETED: 8/20/93
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