WASHINGTON PUBLIC POWER SUPPLY SYSTEM

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January 28, 1994
GO2-94-026
Docket No. 50-397

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Mail Station P1-37
Washington, D. C. 20555

Gentlemen:

Subject: WNP-2, OPERATING LICENSE NO. NPF-21
NRC INSPECTION REPORT 93-45
RESPONSE TO NOTICE OF VIOLATION

The Washington Public Power Supply System hereby replies to the Notice of Violation contained in your letter dated December 29, 1993. Our reply, pursuant to the provisions of Section 2.201, Title 10, Code of Federal Regulations, consists of this letter and Appendix A (attached).

Operations Management concurs with the conclusion in your inspection report cover letter concerning the need for continued strong management oversight to ensure proper procedure implementation. The examples you outlined in the report, along with observations made by our staff, demonstrate the need for continued improvements in the following areas:

- A more structured approach to problem resolutions and resisting the tendency to draw conclusions based on past experience.

- The need for all parties involved in the decision process to probe and question all aspects of a particular problem and not focus only on the individual's particular area of responsibility.

These areas of improvement have been one of the focuses of our benchmarking efforts over the past six months. In an attempt to determine how other utilities have been successful at fostering those attributes at their nuclear facilities. As a result of these efforts, we have implemented a number of initiatives to bring about improvements in the above areas. These include:

- Reorganization of responsibilities within the Control Room to push responsibilities down with the goal of placing the Shift Manager in an overview function.

- Accelerating our five year plan to increase the number of Senior Reactor Operators (SROs) to facilitate a rotation program into and out of the Control Room. Operations has established a group of positions to be filled from internal and external candidates who will be attending the next licensing class.

- Continue to clearly communicate management's expectations concerning procedural compliance and conservative decision process.

With these changes, we believe there have been some indications of improvement. However, we clearly recognize that this is a long term effort that we must continue to pursue.

Supply System management concurs with your other concern that we failed to identify and incorporate NRC Generic Letter 91-18 guidance into plant procedures in a timely manner. As discussed in our response to the Notice of Violation, the Operating Experience Review (OER) for the generic letter has been reopened. The original review did not meet our current expectations of clearly identifying and specifically addressing the applicability and resolution of each issue.

Technical management has reviewed the concerns identified in the inspection report regarding the system walkdowns by the system engineers and concurs with the observations. Our own assessment of walkdown effectiveness provides mixed results. Inconsistencies still exist in performing regular, in-depth system reviews and we have identified other examples where a more intrusive approach to system walkdowns could have identified equipment problems at an earlier stage.

Additional emphasis has been placed on performing system walkdowns and management expectations have been communicated down through first line supervision to the engineers. We have identified some positive results from this effort but realize that continued high priority is required in this area to avoid allowing other activities to dominate the system engineer's time. The Technical Division has worked with Work Control to establish a periodic walkdown with

Operations, Maintenance, Engineering, and the system engineer as part of the twelve week rolling system outage schedule. This process provides an opportunity for the system engineer, working with his counterparts, to identify problems needing correction during the upcoming system outage window and to prioritize those activities. This effort is just getting underway with approximately two months of experience. We believe this process can be a method of involvement by the system engineer to enhance the team concept of system management and are working to make it a success.

We are continuing to look for ways to be more effective in the application of our engineering resource in the plant. Plant management has been meeting with Engineering personnel to refine responsibilities for system engineering consistent with plant needs. We will continue to monitor this effort and make adjustments where necessary to further improve engineering support to the plant.

In Appendix A, the violation is addressed with an explanation of our position regarding validity, corrective action and date of full compliance.

Sincerely,

J. V. Parrish (Mail Drop 1023)
Assistant Managing Director, Operations

cc: KE Perkins - NRC RV
NS Reynolds - Winston & Strawn
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Appendix A

During an NRC inspection conducted on October 19 through November 29, 1993, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violations are listed below:

A. Technical Specification 6.8.1 states, in part, "Written procedures shall be established, implemented, and maintained covering the activities referenced below:

"a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

d. Surveillance and test activities of safety-related equipment."

Appendix A of Regulatory Guide 1.33 recommends procedures for abnormal, off-normal, or alarm conditions, stating in Paragraph 5 that, "...Each safety-related annunciator should have its own written procedure..."

1. WNP-2 Plant Procedures Manual (PPM) 1.5.1, Revision 18, "Technical Specification Surveillance Testing Program," Paragraph 8.5.2, states, "If that combination of authorized activities results in making the tested system or component INOPERABLE, the Shift Manager shall declare the equipment INOPERABLE at the time the component is actually removed from service."

   Contrary to this requirement, on October 20, 1993, the licensee performed PPM 7.4.3.7.5.9, in [sic] which the containment hydrogen/oxygen monitors were rendered inoperable, but did not enter the applicable action statement.

2. WNP-2 PPM 7.4.3.1.1.48, Revision 15, "Average Power Range Monitor (APRM) Channel F Channel Functional Test and Channel Check," Paragraph 7.5, states:

   "Step 5) With the power potentiometer, adjust the power indication upscale...until the local Upscale Neutron lamp comes on.

   Step 13) Examine the Process Computer alarm typer printout and verify that it printed (D551) and then shows a reset shortly afterwards."

   Contrary to this requirement, on November 8, 1993, PPM 7.4.3.1.1.48 was not implemented during the initial performance of Paragraph 7.5 when illumination of the Upscale Neutron Trip lamp was not obtained and the alarm typer printout of computer point D551 was not verified; however, the step was signed off as completed.

3. WNP-2 annunciator response procedure PPM 4.601.A3 Window 3-8, Revision 5, "Leak Det MSL Tunnel ΔT High," states, in part:

> "3. If leakage is indicated by redundant instrumentation, locate and isolate the leak."

Contrary to this requirement, on November 5, 1993, operators received the "Leak Det MSL ΔT High" annunciator and confirmed the temperature differential of 65°F on redundant instrumentation, but did not initiate action to locate and isolate the leak until November 10.

This is a Severity Level IV violation (Supplement I).

Validity of Violation

Example 1

The Supply System agrees with the validity of this example of the violation.

The original Technical Specification Surveillance Program, Administrative Procedure PPM 1.5.1, "TECHNICAL SPECIFICATION SURVEILLANCE TESTING PROGRAM," did not include the requirement to declare equipment inoperable that is incapable of performing its safety function as a result of a surveillance test. NRC Generic Letter 91-18 provided guidance to clarify this requirement. It was not plant operating practice to declare equipment inoperable during surveillance testing and the Supply System missed an opportunity to incorporate the Generic Letter guidance during the December 1991 Operational Events Review (OER) No. 91043A. However, this programmatic omission was subsequently identified during the Technical Specification Surveillance Improvement Project (TSSIP) review and the requirement was incorporated into Revision 18 to PPM 1.5.1 on September 9, 1993. The revision was issued on September 30, 1993. The TSSIP is in place to provide an in-depth technical review of the WNP-2 Technical Specification Surveillance Program and procedures, and was established and chartered to identify and correct deficiencies of this nature (as discussed in Licensing Event Report [LER] 93-010).

The procedure review documentation for Revision 18 to PPM 1.5.1 did not identify Paragraph 8.5.2, which states: "If the combination of authorized activities results in making the tested system or component INOPERABLE, the Shift Manager shall declare the equipment INOPERABLE at the time the component is actually removed from service," as a significant change to plant operating practice. Although not stated in the previous revisions of PPM 1.5.1, it was assumed that the guidance in NRC Generic Letter 91-18 had been incorporated into the existing surveillance program. Therefore, training on the procedure change was not recommended for Operations personnel prior to implementation. Although, training did

commence before the procedure was issued. Surveillance Program Procedure coordinators were trained one-on-one before the procedure was issued. In addition, seven training sessions were conducted on successive Fridays between September 19, 1993 and October 29, 1993. Two of the seven training sessions were held before the procedure was issued. However, the significance of Paragraph 8.5.2 was not realized or emphasized during the training.

Designated procedure reviewers and Plant Operating Committee (POC) members did not recognize that this change to the procedure represented a significant change to operating practice. During Operations training sessions conducted on October 8 and 15, 1993, it was identified that the requirement to declare equipment inoperable when performing surveillances was not general operating practice and had not been understood or communicated as such to on-shift Operations crews. The Supply System failed to resolve this issue prior to October 20, 1993, when the NRC Resident Inspector observed the performance of Surveillance Procedure PPM 7.4.3.7.5.9, "ACCIDENT MONITORING INSTRUMENTS CONTAINMENT HYDROGEN/OXYGEN ANALYZER - DIV II - CC."

During the performance of PPM 7.4.3.7.5.9, the NRC Resident Inspector discovered that the Hydrogen/Oxygen Analyzer had not been declared inoperable, which was contrary to Paragraph 8.5.2 of PPM 1.5.1. The Shift Manager and Control Room Supervisor on-shift when this violation was identified had attended a PPM 1.5.1, Revision 18 training session conducted on September 24, 1993. This was before the significance of Paragraph 8.5.2 was recognized by Operations management.

The root causes for this example of the violation were:

The failure of the designated procedure reviewers and POC members to recognize that PPM 1.5.1, Revision 18, Paragraph 8.5.2 was a change to operating practice.

The failure of the procedure change management process to identify and emphasize the significance of PPM 1.5.1, Revision 18, Paragraph 8.5.2.

The contributing causes for this example of the violation were:

The failure of the TSSIP coordinator to verify that PPM 1.5.1, Revision 18, Paragraph 8.5.2 was only a re-statement of existing requirements.

The failure to properly evaluate the equipment operability guidance of NRC Generic Letter 91-18.

Example 2

The Supply System agrees with the validity of this example of the violation.

On November 8, 1993, Instrument and Control (I&C) Technicians were performing the APRM (Average Power Range Monitoring) Upscale Neutron Trip setpoint check in accordance with Surveillance Procedure PPM 7.4.3.1.1.48, "APRM CHANNEL F RUN MODE - CFT/CC [Channel Functional Test/Channel Calibration]." While performing the procedure, the Technicians notified the Shift Manager that the Process Computer Alarm Typer did not print out the trip status of the APRM Upscale Trip (computer point D551) as required by the procedure. The APRM Upscale Neutron Trip compares actual reactor power to a trip setpoint (118% rated reactor power with the reactor mode switch in "Run" or 15% rated reactor power with the mode switch not in "Run") and initiates a Reactor Protection System (RPS) trip and APRM Upscale alarm when reactor power exceeds the setpoint. Operations personnel verified that the Upscale Neutron Trip computer point for the Alarm Typer was active, so the APRM Upscale Trip should have printed out. However, because of an assumed long-standing Alarm Typer buffer overflow problem, on-shift Operations personnel believed that the Alarm Typer simply missed the computer point trip status change. They were not aware that the Alarm Typer problem had been resolved by replacement with a new model. As a result, no action was taken by Operations personnel to actively pursue the cause of the Alarm Typer failure.

To verify the APRM Upscale Neutron Trip setpoint, PPM 7.4.3.1.1.48 requires the I&C Technicians to quickly adjust the simulated reactor power signal voltage to the trip point (9.60 VDC) and verify the trip by observing illumination of the Upscale Neutron Trip status lamp. This must be performed within the constraints of a six second "time constant" to prevent the APRM Flow Biased Upscale Thermal Trip from tripping the RPS before the Upscale Neutron Trip. The NRC Resident Inspector had been observing the performance of the procedure and witnessed the sequence of events. Because of the procedural requirements and the fact that the Alarm Typer had recently printed out other APRM trip alarms, the NRC Resident Inspector questioned whether the Upscale Neutron Trip had actually been actuated. As a result, the I&C Technicians reverified the "as-left" condition of the APRM Channel F status lamps and found that the Upscale Neutron Trip status lamp was not illuminated, but the Upscale Thermal Trip status lamp was illuminated. This status lamp condition indicated that the I&C Technicians may not have adjusted the power signal voltage quickly enough to actuate the Upscale Neutron Trip before the Upscale Thermal Trip. Based on this possibility, the suspect portion of the test was reperformed and the Alarm Typer printed out the APRM Upscale Trip as required.

After further discussions with the I&C Technicians, it was discovered that the Technician performing the trip verification had been wearing reading glasses that impaired his field vision. The Technician erroneously verified the illumination of the Upscale Neutron Trip status lamp when it was the Upscale Thermal Trip status lamp that actually illuminated (the two status lamps are next to each other). Consequently, the procedure steps for verification of the Upscale Neutron Trip test were initially signed off in error. If not for the NRC Resident Inspector's involvement, the procedure would have been signed off as complete without verifying the Upscale Neutron Trip since the Alarm Typer is not required acceptance criteria for the surveillance test.

The root cause for this example of the violation was the failure of the I&C Technician to practice "self-checking." A contributing cause was the failure of the Operations Shift Manager to aggressively verify initial problem assumptions.

The PPM 7.4.3.1.1.48 steps for verification of the Upscale Neutron Trip test were reperformed satisfactorily on November 8, 1993 and the Technical Specification Table 4.3.1.1-1.2.a, b, and c weekly surveillance requirements were not violated. However, the Supply System agrees with the finding of Inspection Report 93-45 that this violation had potential safety significance. Without the NRC Resident Inspector's prompting, WNP-2 would likely have operated in a condition prohibited by the Technical Specifications due to the surveillance test not having been completed.

Example 3

The Supply System agrees with the validity of this example of the violation.

At 0835 hours on November 5, 1993, the Main Control Room received the "LEAK DET [Leak Detection System] MSL [Main Steam Line] TUNNEL ΔT HIGH" alarm at a differential temperature of 64.5° F between the Steam Tunnel and the Reactor Building. The alarm cleared temporarily, but came in again at 0622 hours on November 6, 1993 and remained sealed in until November 10, 1993. The alarm is designed to alert Operations personnel that a MSL steam leak may exist inside the Steam Tunnel, which is within Secondary Containment. In this case, packing steam leaks in the Steam Tunnel on Instrumentation Root Valve PI-V-X18A2 and MSL Equalizing Valve MS-V-20 were sufficient to raise the differential temperature between the Steam Tunnel and the Reactor Building to the alarm point. On-shift Operations personnel did not take immediate action to locate and isolate the steam leaks, and Operations management was not made aware of the alarm condition. Action was delayed for five days because on-shift Operations crew personnel incorrectly assumed that the alarm was caused by low ambient temperatures in the Reactor Building due to heating steam not being in service.

The Steam Tunnel high ΔT alarm circuitry compares the Steam Tunnel temperature to the Reactor Building temperature to develop the differential temperature, but does not compensate for variations in Reactor Building ambient temperature. Thus, actuation of the alarm could indicate the presence of a steam leak inside the Steam Tunnel due to rising Steam Tunnel temperatures or could also indicate falling Reactor Building ambient temperatures. Because the weather had been relatively warm, Reactor Building heating steam had not been placed in service. However, outside temperatures had recently turned colder (20° to 30° F) and it was assumed that the Reactor Building was correspondingly colder. These conditions and assumptions led Operations crew personnel to the assumption that the Steam Tunnel high ΔT alarm was caused by low Reactor Building ambient temperatures. As a result, no trending of Reactor Building temperatures was performed.

At 0230 hours on November 9, 1993, the "B" Seal Steam Evaporator was started to supply heating steam to the Reactor Building. At 0400 hours on November 10, 1993, the on-shift Operations Shift Manager noted in the Shift Managers Log that "Steam Tunnel ΔT has been slowly increasing for several days, even after heating steam was put in service. . . ." At this point, Operations personnel believed that a steam leak existed in the Steam Tunnel and initiated actions to locate and isolate the leak in accordance with PPM 4.601.A3, Window 3-8. By this time, the Steam Tunnel ΔT was 76° F, which was near the 80° F Containment Isolation Group 1 (Main Steam) trip point. At 1053 hours on November 10, 1993, packing steam leaks were identified on PI-V-X18A2 and MS-V-20. PI-V-X18A2 was backseated to stop its packing leak at 1300 hours on November 10, 1993 and MS-V-20 was sealed with Furmanite to stop its packing leak at 1500 hours on November 11, 1993. By 1200 hours on November 12, 1993, the Steam Tunnel ΔT had returned to the normal values of 51° to 53° F.

The root cause for this example of the violation was the failure of on-shift Operations personnel to exhibit a more "questioning attitude" and implement effective problem solving techniques to followup and verify initial assumptions (e.g., the failure to adequately trend and evaluate Reactor Building ambient temperatures).

During the five day period between November 5 and 10, 1993, when the Steam Tunnel leaks existed, the highest Steam Tunnel ΔT recorded was approximately 76° F and the highest ambient temperature recorded was approximately 136° F. The Isolation Group 1 trip points are 80° F for Steam Tunnel ΔT and 150° F for Steam Tunnel ambient temperature. Thus, no Group 1 half isolation trip occurred. Essential equipment located inside the Steam Tunnel is designed to operate in a harsh environment with temperatures to 340° F. However, the Steam Tunnel ambient temperature did not exceed the normally expected maximum temperature of 140° F (Final Safety Analysis Report [FSAR] Table 3.11-1). Therefore, the Steam Tunnel leak did not challenge Isolation Group 1, Secondary Containment, or the essential equipment located in the Steam Tunnel. Accordingly, the leaks did not reduce the plant's capability to mitigate the consequences of an accident and the Supply System believes this example of the violation to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

Example 1

1. Immediate corrective action was taken to provide on-shift Operations personnel with guidance to ensure compliance with Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

2. The TSSIP is actively working to identify and correct deficiencies in the WNP-2 Technical Specification Surveillance Program as demonstrated by the discovery of the failure to incorporate the operability guidance of NRC Generic Letter 91-18.

3. Operations Administrative Procedure PPM 1.3.1A, "DEPARTMENT POLICIES," has been revised to include the criteria for declaring equipment inoperable as specified in Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

4. Appropriate plant personnel have been trained on PPM 1.5.1, Revision 18.

5. A POC procedure review commitee has been established as part of the procedure change management process to perform an additional procedure review prior to general POC member review.

6. OER 91043A has been reopened to assure that the guidance included in NRC Generic Letter 91-18 is adequately addressed.

7. This violation and the part POC played in the problem were reviewed at a POC meeting held on January 28, 1994.

Example 2

1. The I&C Technician who committed the procedure verification error was counseled on the need to be more investigative when problems occur and to practice "self-checking" and teamwork.

2. The Shift Manager involved in this incident has been counseled to be more proactive in resolving problems and to follow through on initial assumptions to ensure they are correct. The Shift Manager involved is conducting briefings with Operations crew personnel on the lessons learned from this incident.

3. This incident was discussed with I&C Maintenance Shop personnel.

4. This incident has been made required reading for Operations Shift Managers, Control Room Supervisors, Shift Support Supervisors, and Shift Engineers.

5. APRM CFT/CC Surveillance Procedure PPMs 7.4.3.1.1.43 through 7.4.3.1.1.48 have been changed to incorporate Human Performance Enhancement System (HPES) recommended changes, such as clarifying trip indications.

6. A review of APRM surveillance procedures completed since July 1993 was performed to determine if similar problems with the Alarm Typer were evident. No similar problems were identified during the procedure review.

Example 3

1. The Shift Managers involved in this incident have been counseled by the Operations Manager.

2. The Operations Manager and Division Manager have met with Shift Managers to discuss the lessons learned from this incident.

3. The Shift Manager turnover process has been strengthened by requiring a more thorough turnover and panel walkdowns in the Main Control Room.

4. A Technical Evaluation Request (TER) has been initiated to re-analyze the Steam Tunnel High Energy Line Break (HELB) accident to allow Steam Tunnel access through the door (instead of the hatch) during Operating Conditions 1, 2, and 3. This would permit easier (and faster) access to the Steam Tunnel for inspections in response to alarm conditions.

5. PPM 4.601.A3, Window 3-8 has been changed to improve the guidance on how to discern whether a leak is present and to clarify management expectations for investigating potential leaks in the Steam Tunnel.

Corrective Action to be Taken

Example 1

1. Administrative Procedure PPM 1.2.2, "PLANT PROCEDURE PREPARATION," will be changed by February 28, 1994 to require that applicable surveillance procedures include statements of operability for components undergoing surveillance testing.

2. Performance expectations will be established for implementing procedure change management and the information will be disseminated to POC members and procedure coordinators by February 28, 1994.

Example 2

The above corrective steps taken are considered sufficient to preclude recurrence of a similar error.

Example 3

1. The Operations Manager is briefing Operations crews on the importance of a "questioning attitude," "attention to detail," and "self-checking," and will be completed by February 15, 1994.

2. Other Leak Detection (LD) System annunciator response procedures will be reviewed and revised as necessary by April 15, 1994 to assure consistency in actions for leak identification and isolation.

Date of Full Compliance

Example 1

Full regulatory compliance was achieved on November 19, 1993 when PPM 1.3.1A was revised to include the criteria for declaring equipment inoperable as specified in Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

Example 2

Full compliance was achieved on November 24, 1993 when the above corrective steps were completed.

Example 3

Full regulatory compliance was achieved on November 11, 1993 when the valve packing leaks were located and isolated.

B. Technical Specification 6.11.1 requires procedures for personnel radiation protection to be prepared consistent with the requirements of 10 CFR Part 20 and adhered to for all operations involving personnel radiation exposure.

PPM 1.11.11, Revision 4, "Entry Into, Conduct In, and Exit From Radiologically Controlled Areas," implements this TS and states in Paragraph 4.5, "Persons entering a radiologically controlled area shall adhere to all requirements specified by Health Physics personnel (i.e., RWP [radiation work permit] requirements, posted instructions, verbal instructions, etc.)."

PPM 11.2.7.3, Revision 8, "High Radiation Area Controls," requires in Paragraph 5.1 that personnel entering a posted high radiation area be signed in on a high radiation area RWP and provided with one or more of the following: (a) a radiation monitoring device that continuously indicates the dose rate in the area, (b) an alarming dosimeter, or (c) be accompanied by a qualified health physics technician with a radiation monitoring device.

Contrary to the above, on October 19, 1993, a licensee employee did not follow posted instructions, in that he reached into an area posted as a high radiation area, but had not signed in on a high radiation area RWP, was not issued a radiation monitoring device,

was not issued an alarming dosimeter, and was not accompanied by a qualified health physics technician with a radiation monitoring device.

This is a Severity Level IV violation (Supplement IV).

Validity of Violation

The Supply System agrees with the validity of this violation.

On October 19, 1993, the NRC Resident Inspector and an NRC Intern Inspector were performing a Residual Heat Removal (RHR) system walkdown in the "A" RHR Pump Room. An Equipment Operator (EO) was assisting in the walkdown and called the Health Physics (HP) Lead Technician for permission to briefly reach his hand and arm into a posted contaminated area to check the position of a valve. The EO was not aware that the contaminated zone was also a posted High Radiation Area. The EO did not see the High Radiation Area sign although it was conspicuously posted. Based on the information received during the telephone conversation, the HP Lead Technician directed the EO to wear gloves while reaching into the contaminated area.

The EO donned the gloves and a lab coat and reached into the High Radiation Area to perform the valve position check. The NRC Intern Inspector performing the RHR system walkdown observed the EO's actions and reported the incident to the HP Lead Technician when he discovered that the EO had not informed HP that the valve position check required reaching into a High Radiation Area. It was determined that the EO's actions violated HP Procedure PPM 11.2.7.3, Revision 8, "HIGH RADIATION AREA CONTROLS" and Administrative Procedure PPM 1.11.11, Revision 4, "ENTRY INTO, CONDUCT IN, AND EXIT FROM RADIOLOGICALLY CONTROLLED AREAS" because the EO technically entered a High Radiation Area without signing in on a High Radiation Area Radiation Work Permit (RWP), receiving a pre-job briefing, and wearing special dosimetry.

The root causes for this violation were:

Insufficient "attention to detail" and a failure to practice "self-checking" techniques in that the EO did not fully assess the radiological conditions before acting.

The failure of the HP Lead Technician to exhibit a more "questioning attitude" and solicit all pertinent information prior to authorizing special access controls for a radiologically controlled area.

The radiation dose rate of the area the EO reached into was later determined by HP to be 50 to 75 millirem per hour. Only the EO's hand and arm were exposed to this dose rate and the exposure time was brief. Thus, the EO's radiation exposure was minimal. Supply System

management recognizes that the generic implications of this violation had potential safety significance. However, the particular circumstances described in the violation are believed to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

1. The EO involved in this incident was counseled by the Operations Manager to be more aware of all radiation signs by paying more "attention to detail" and by practicing "self-checking" techniques.

2. The Operations Manager reemphasized awareness to all radiation signs and the importance of "attention to detail" and "self-checking" to Operations crew personnel.

3. At both turnover meetings and "all-hands" staff meetings, HP Management used this example to stress management expectations for thorough communications with a "questioning attitude" in accordance with impending administrative procedural changes.

4. Because the lack of a "questioning attitude" was found to be a generic problem, as opposed to and individual performance issue, an effective communications training session was included in the fourth quarter continuing training for Radiation Protection Technicans.

Corrective Action to be Taken

The above corrective steps taken are considered sufficient to preclude recurrence of a similar error.

Date of Full Compliance

Full compliance was achieved on December 20, 1993 when the above corrective steps were completed.

C. 10 CFR 50, Appendix B, Criterion V states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

PPM 10.2.53, Revision 7, "Seismic Requirements for Scaffolding, Ladders, Tool Gang Boxes, Hoists, and Metal Storage Cabinets," paragraph 7.2.g, states, "Scaffolding shall be erected in a manner such that no item (i.e., clamp, tube or any portion thereof [which] passes through an instrument rack) is closer than 2" to any sensing line, instrument rack or other Class-I item except structural members of equipment bases."

Paragraph 7.1.7 requires that Civil/Structural Engineering inspect or analyze each installation which does not conform to a previously analyzed configuration.

Contrary to the above, as of October 20, 1993, a scaffold existed on the 548-foot level of the reactor building in which scaffolding material was installed within two inches of a safety-related instrument sensing line, but this scaffolding did not conform to a previously analyzed configuration and had not been inspected or analyzed for this condition by civil engineering personnel.

Validity of Violation

The Supply System agrees with the validity of this violation.

The "tube and clamp" scaffold located at the East end of the Containment Exhaust/Supply Purge Valve Room (Reactor Building 548' elevation) cited in this violation was erected during a Plant Forced Outage on August 7, 1993 for Containment Exhaust Purge (CEP) valve work. Scaffold dismantling and removal work commenced prior to plant startup from the outage, but the work was temporarily interrupted with the scaffold only partially dismantled. When craft personnel returned to complete the scaffold dismantling and removal work, plant startup power ascension had already begun. The craft were informed that work could not continue because of ALARA concerns related to the increasing power ascension radiation dose rates.

When work was stopped, the upper deck of the two-tiered scaffold had been removed, except for one vertical four foot long "tube-loc" support brace. Since the upper deck horizontal support for this vertical brace had been removed, the tube leaned enough to come within two inches of the control air supply tubing for a safety-related CEP valve (CEP-V-2B). This condition violates the requirements of Maintenance Procedure PPM 10.2.53, Revision 7, "SEISMIC REQUIREMENTS FOR SCAFFOLDING, LADDERS, TOOL GANG BOXES, HOISTS, AND METAL STORAGE CABINETS," Section 7.1.2.g, which states that "[s]caffolding shall be erected in a manner such that no item (i.e., clamp, tube or any portion thereof [which] passes through an instrument rack) is closer than 2" to any sensing line, instrument rack, or other Class I item except structural members or equipment bases." On October 20, 1993, when the NRC Resident Inspector identified this violation, PPM 10.2.53 did not address scaffold qualification requirements during the period when scaffold is in the process of being erected or removed. The procedure only specified final, "erected," qualification requirements.

The root cause for this violation was that PPM 10.2.53 was inadequate in that it did not adequately address conditions for scaffold qualification.

CEP-V-2B is a two inch air operated Primary Containment isolation valve that is normally closed and fails closed on loss of control air. This valve is used to vent oxygen from the upper Containment Drywell during normal plant operation, in lieu of routinely using the thirty inch

exhaust purge valves (CEP-V-1A and CEP-V-2A). If, during a seismic event, the scaffold had caused a loss of control air to CEP-V-2B, the valve would perform its safety function and fail closed. The inability to vent oxygen from the drywell using CEP-V-2B would pose no immediate threat to the safe operation of the plant because CEP-V-1A and CEP-V-2A would still be available as an alternative method for venting oxygen. Therefore, the Supply System believes this violation to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

1. Immediate corrective action was taken to remove the deficient vertical "tube-loc" support brace from the Reactor Building 548' elevation scaffold to bring the scaffold into compliance with PPM 10.2.53. In addition, the scaffolds located within the Power Block were inspected and the partially dismantled scaffolds were verified to be in compliance with PPM 10.2.53.

2. PPM 10.2.53 has been changed to address scaffold qualification requirements when the scaffold is in the process of being erected or removed.

3. Appropriate craft personnel have been trained on the changes to PPM 10.2.53.

Corrective Action to be Taken

The above corrective steps taken are considered sufficient to preclude recurrence of a similar condition.

Date of Full Compliance

Full compliance was achieved on January 19, 1994 when the above corrective steps were completed.

ACCELERATED DISTRIBUTION DEMONSTRATION SYSTEM

REGULATORY INFORMATION DISTRIBUTION SYSTEM (RIDS)

ACCESSION NBR:9402030217 DOC.DATE: 94/01/28 NOTARIZED: NO DOCKET #
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SUBJECT: Responds to NRC 931229 ltr re violations noted in insp rept 50-397/93-45.Corrective actions:provided on-shift operations personnel w/guidance to ensure compliance w/Paragraph 8.5.2 of PPM 1.5.1,Rev 18.

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WASHINGTON PUBLIC POWER SUPPLY SYSTEM

P.O. Box 968 • 3000 George Washington Way • Richland, Washington 99352

January 28, 1994
GO2-94-026
Docket No. 50-397

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
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Washington, D. C. 20555

Gentlemen:

Subject: **WNP-2, OPERATING LICENSE NO. NPF-21**
NRC INSPECTION REPORT 93-45
RESPONSE TO NOTICE OF VIOLATION

The Washington Public Power Supply System hereby replies to the Notice of Violation contained in your letter dated December 29, 1993. Our reply, pursuant to the provisions of Section 2.201, Title 10, Code of Federal Regulations, consists of this letter and Appendix A (attached).

Operations Management concurs with the conclusion in your inspection report cover letter concerning the need for continued strong management oversight to ensure proper procedure implementation. The examples you outlined in the report, along with observations made by our staff, demonstrate the need for continued improvements in the following areas:

- A more structured approach to problem resolutions and resisting the tendency to draw conclusions based on past experience.

- The need for all parties involved in the decision process to probe and question all aspects of a particular problem and not focus only on the individual's particular area of responsibility.

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These areas of improvement have been one of the focuses of our benchmarking efforts over the past six months. In an attempt to determine how other utilities have been successful at fostering those attributes at their nuclear facilities. As a result of these efforts, we have implemented a number of initiatives to bring about improvements in the above areas. These include:

- Reorganization of responsibilities within the Control Room to push responsibilities down with the goal of placing the Shift Manager in an overview function.

- Accelerating our five year plan to increase the number of Senior Reactor Operators (SROs) to facilitate a rotation program into and out of the Control Room. Operations has established a group of positions to be filled from internal and external candidates who will be attending the next licensing class.

- Continue to clearly communicate management's expectations concerning procedural compliance and conservative decision process.

With these changes, we believe there have been some indications of improvement. However, we clearly recognize that this is a long term effort that we must continue to pursue.

Supply System management concurs with your other concern that we failed to identify and incorporate NRC Generic Letter 91-18 guidance into plant procedures in a timely manner. As discussed in our response to the Notice of Violation, the Operating Experience Review (OER) for the generic letter has been reopened. The original review did not meet our current expectations of clearly identifying and specifically addressing the applicability and resolution of each issue.

Technical management has reviewed the concerns identified in the inspection report regarding the system walkdowns by the system engineers and concurs with the observations. Our own assessment of walkdown effectiveness provides mixed results. Inconsistencies still exist in performing regular, in-depth system reviews and we have identified other examples where a more intrusive approach to system walkdowns could have identified equipment problems at an earlier stage.

Additional emphasis has been placed on performing system walkdowns and management expectations have been communicated down through first line supervision to the engineers. We have identified some positive results from this effort but realize that continued high priority is required in this area to avoid allowing other activities to dominate the system engineer's time. The Technical Division has worked with Work Control to establish a periodic walkdown with

Operations, Maintenance, Engineering, and the system engineer as part of the twelve week rolling system outage schedule. This process provides an opportunity for the system engineer, working with his counterparts, to identify problems needing correction during the upcoming system outage window and to prioritize those activities. This effort is just getting underway with approximately two months of experience. We believe this process can be a method of involvement by the system engineer to enhance the team concept of system management and are working to make it a success.

We are continuing to look for ways to be more effective in the application of our engineering resource in the plant. Plant management has been meeting with Engineering personnel to refine responsibilities for system engineering consistent with plant needs. We will continue to monitor this effort and make adjustments where necessary to further improve engineering support to the plant.

In Appendix A, the violation is addressed with an explanation of our position regarding validity, corrective action and date of full compliance.

Sincerely,

J. V. Parrish (Mail Drop 1023)
Assistant Managing Director, Operations

cc: KE Perkins - NRC RV
NS Reynolds - Winston & Strawn
JW Clifford - NRR
DL Williams - BPA/399
NRC Site Inspector - 927N

Appendix A

During an NRC inspection conducted on October 19 through November 29, 1993, violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C, the violations are listed below:

A. Technical Specification 6.8.1 states, in part, "Written procedures shall be established, implemented, and maintained covering the activities referenced below:

"a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978.

d. Surveillance and test activities of safety-related equipment."

Appendix A of Regulatory Guide 1.33 recommends procedures for abnormal, off-normal, or alarm conditions, stating in Paragraph 5 that, "...Each safety-related annunciator should have its own written procedure..."

1. WNP-2 Plant Procedures Manual (PPM) 1.5.1, Revision 18, "Technical Specification Surveillance Testing Program," Paragraph 8.5.2, states, "If that combination of authorized activities results in making the tested system or component INOPERABLE, the Shift Manager shall declare the equipment INOPERABLE at the time the component is actually removed from service."

Contrary to this requirement, on October 20, 1993, the licensee performed PPM 7.4.3.7.5.9, in [sic] which the containment hydrogen/oxygen monitors were rendered inoperable, but did not enter the applicable action statement.

2. WNP-2 PPM 7.4.3.1.1.48, Revision 15, "Average Power Range Monitor (APRM) Channel F Channel Functional Test and Channel Check," Paragraph 7.5, states:

"Step 5) With the power potentiometer, adjust the power indication upscale...until the local Upscale Neutron lamp comes on.

Step 13) Examine the Process Computer alarm typer printout and verify that it printed (D551) and then shows a reset shortly afterwards."

Contrary to this requirement, on November 8, 1993, PPM 7.4.3.1.1.48 was not implemented during the initial performance of Paragraph 7.5 when illumination of the Upscale Neutron Trip lamp was not obtained and the alarm typer printout of computer point D551 was not verified; however, the step was signed off as completed.

3. WNP-2 annunciator response procedure PPM 4.601.A3 Window 3-8, Revision 5, "Leak Det MSL Tunnel ΔT High," states, in part:

> "3. If leakage is indicated by redundant instrumentation, locate and isolate the leak."

Contrary to this requirement, on November 5, 1993, operators received the "Leak Det MSL ΔT High" annunciator and confirmed the temperature differential of 65°F on redundant instrumentation, but did not initiate action to locate and isolate the leak until November 10.

This is a Severity Level IV violation (Supplement I).

Validity of Violation

Example 1

The Supply System agrees with the validity of this example of the violation.

The original Technical Specification Surveillance Program, Administrative Procedure PPM 1.5.1, "TECHNICAL SPECIFICATION SURVEILLANCE TESTING PROGRAM," did not include the requirement to declare equipment inoperable that is incapable of performing its safety function as a result of a surveillance test. NRC Generic Letter 91-18 provided guidance to clarify this requirement. It was not plant operating practice to declare equipment inoperable during surveillance testing and the Supply System missed an opportunity to incorporate the Generic Letter guidance during the December 1991 Operational Events Review (OER) No. 91043A. However, this programmatic omission was subsequently identified during the Technical Specification Surveillance Improvement Project (TSSIP) review and the requirement was incorporated into Revision 18 to PPM 1.5.1 on September 9, 1993. The revision was issued on September 30, 1993. The TSSIP is in place to provide an in-depth technical review of the WNP-2 Technical Specification Surveillance Program and procedures, and was established and chartered to identify and correct deficiencies of this nature (as discussed in Licensing Event Report [LER] 93-010).

The procedure review documentation for Revision 18 to PPM 1.5.1 did not identify Paragraph 8.5.2, which states: "If the combination of authorized activities results in making the tested system or component INOPERABLE, the Shift Manager shall declare the equipment INOPERABLE at the time the component is actually removed from service," as a significant change to plant operating practice. Although not stated in the previous revisions of PPM 1.5.1, it was assumed that the guidance in NRC Generic Letter 91-18 had been incorporated into the existing surveillance program. Therefore, training on the procedure change was not recommended for Operations personnel prior to implementation. Although, training did

commence before the procedure was issued. Surveillance Program Procedure coordinators were trained one-on-one before the procedure was issued. In addition, seven training sessions were conducted on successive Fridays between September 19, 1993 and October 29, 1993. Two of the seven training sessions were held before the procedure was issued. However, the significance of Paragraph 8.5.2 was not realized or emphasized during the training.

Designated procedure reviewers and Plant Operating Committee (POC) members did not recognize that this change to the procedure represented a significant change to operating practice. During Operations training sessions conducted on October 8 and 15, 1993, it was identified that the requirement to declare equipment inoperable when performing surveillances was not general operating practice and had not been understood or communicated as such to on-shift Operations crews. The Supply System failed to resolve this issue prior to October 20, 1993, when the NRC Resident Inspector observed the performance of Surveillance Procedure PPM 7.4.3.7.5.9, "ACCIDENT MONITORING INSTRUMENTS CONTAINMENT HYDROGEN/OXYGEN ANALYZER - DIV II - CC."

During the performance of PPM 7.4.3.7.5.9, the NRC Resident Inspector discovered that the Hydrogen/Oxygen Analyzer had not been declared inoperable, which was contrary to Paragraph 8.5.2 of PPM 1.5.1. The Shift Manager and Control Room Supervisor on-shift when this violation was identified had attended a PPM 1.5.1, Revision 18 training session conducted on September 24, 1993. This was before the significance of Paragraph 8.5.2 was recognized by Operations management.

The root causes for this example of the violation were:

The failure of the designated procedure reviewers and POC members to recognize that PPM 1.5.1, Revision 18, Paragraph 8.5.2 was a change to operating practice.

The failure of the procedure change management process to identify and emphasize the significance of PPM 1.5.1, Revision 18, Paragraph 8.5.2.

The contributing causes for this example of the violation were:

The failure of the TSSIP coordinator to verify that PPM 1.5.1, Revision 18, Paragraph 8.5.2 was only a re-statement of existing requirements.

The failure to properly evaluate the equipment operability guidance of NRC Generic Letter 91-18.

Example 2

The Supply System agrees with the validity of this example of the violation.

On November 8, 1993, Instrument and Control (I&C) Technicians were performing the APRM (Average Power Range Monitoring) Upscale Neutron Trip setpoint check in accordance with Surveillance Procedure PPM 7.4.3.1.1.48, "APRM CHANNEL F RUN MODE - CFT/CC [Channel Functional Test/Channel Calibration]." While performing the procedure, the Technicians notified the Shift Manager that the Process Computer Alarm Typer did not print out the trip status of the APRM Upscale Trip (computer point D551) as required by the procedure. The APRM Upscale Neutron Trip compares actual reactor power to a trip setpoint (118% rated reactor power with the reactor mode switch in "Run" or 15% rated reactor power with the mode switch not in "Run") and initiates a Reactor Protection System (RPS) trip and APRM Upscale alarm when reactor power exceeds the setpoint. Operations personnel verified that the Upscale Neutron Trip computer point for the Alarm Typer was active, so the APRM Upscale Trip should have printed out. However, because of an assumed long-standing Alarm Typer buffer overflow problem, on-shift Operations personnel believed that the Alarm Typer simply missed the computer point trip status change. They were not aware that the Alarm Typer problem had been resolved by replacement with a new model. As a result, no action was taken by Operations personnel to actively pursue the cause of the Alarm Typer failure.

To verify the APRM Upscale Neutron Trip setpoint, PPM 7.4.3.1.1.48 requires the I&C Technicians to quickly adjust the simulated reactor power signal voltage to the trip point (9.60 VDC) and verify the trip by observing illumination of the Upscale Neutron Trip status lamp. This must be performed within the constraints of a six second "time constant" to prevent the APRM Flow Biased Upscale Thermal Trip from tripping the RPS before the Upscale Neutron Trip. The NRC Resident Inspector had been observing the performance of the procedure and witnessed the sequence of events. Because of the procedural requirements and the fact that the Alarm Typer had recently printed out other APRM trip alarms, the NRC Resident Inspector questioned whether the Upscale Neutron Trip had actually been actuated. As a result, the I&C Technicians reverified the "as-left" condition of the APRM Channel F status lamps and found that the Upscale Neutron Trip status lamp was not illuminated, but the Upscale Thermal Trip status lamp was illuminated. This status lamp condition indicated that the I&C Technicians may not have adjusted the power signal voltage quickly enough to actuate the Upscale Neutron Trip before the Upscale Thermal Trip. Based on this possibility, the suspect portion of the test was reperformed and the Alarm Typer printed out the APRM Upscale Trip as required.

After further discussions with the I&C Technicians, it was discovered that the Technician performing the trip verification had been wearing reading glasses that impaired his field vision. The Technician erroneously verified the illumination of the Upscale Neutron Trip status lamp when it was the Upscale Thermal Trip status lamp that actually illuminated (the two status lamps are next to each other). Consequently, the procedure steps for verification of the Upscale Neutron Trip test were initially signed off in error. If not for the NRC Resident Inspector's involvement, the procedure would have been signed off as complete without verifying the Upscale Neutron Trip since the Alarm Typer is not required acceptance criteria for the surveillance test.

The root cause for this example of the violation was the failure of the I&C Technician to practice "self-checking." A contributing cause was the failure of the Operations Shift Manager to aggressively verify initial problem assumptions.

The PPM 7.4.3.1.1.48 steps for verification of the Upscale Neutron Trip test were reperformed satisfactorily on November 8, 1993 and the Technical Specification Table 4.3.1.1-1.2.a, b, and c weekly surveillance requirements were not violated. However, the Supply System agrees with the finding of Inspection Report 93-45 that this violation had potential safety significance. Without the NRC Resident Inspector's prompting, WNP-2 would likely have operated in a condition prohibited by the Technical Specifications due to the surveillance test not having been completed.

Example 3

The Supply System agrees with the validity of this example of the violation.

At 0835 hours on November 5, 1993, the Main Control Room received the "LEAK DET [Leak Detection System] MSL [Main Steam Line] TUNNEL ΔT HIGH" alarm at a differential temperature of 64.5° F between the Steam Tunnel and the Reactor Building. The alarm cleared temporarily, but came in again at 0622 hours on November 6, 1993 and remained sealed in until November 10, 1993. The alarm is designed to alert Operations personnel that a MSL steam leak may exist inside the Steam Tunnel, which is within Secondary Containment. In this case, packing steam leaks in the Steam Tunnel on Instrumentation Root Valve PI-V-X18A2 and MSL Equalizing Valve MS-V-20 were sufficient to raise the differential temperature between the Steam Tunnel and the Reactor Building to the alarm point. On-shift Operations personnel did not take immediate action to locate and isolate the steam leaks, and Operations management was not made aware of the alarm condition. Action was delayed for five days because on-shift Operations crew personnel incorrectly assumed that the alarm was caused by low ambient temperatures in the Reactor Building due to heating steam not being in service.

The Steam Tunnel high ΔT alarm circuitry compares the Steam Tunnel temperature to the Reactor Building temperature to develop the differential temperature, but does not compensate for variations in Reactor Building ambient temperature. Thus, actuation of the alarm could indicate the presence of a steam leak inside the Steam Tunnel due to rising Steam Tunnel temperatures or could also indicate falling Reactor Building ambient temperatures. Because the weather had been relatively warm, Reactor Building heating steam had not been placed in service. However, outside temperatures had recently turned colder (20° to 30° F) and it was assumed that the Reactor Building was correspondingly colder. These conditions and assumptions led Operations crew personnel to the assumption that the Steam Tunnel high ΔT alarm was caused by low Reactor Building ambient temperatures. As a result, no trending of Reactor Building temperatures was performed.

At 0230 hours on November 9, 1993, the "B" Seal Steam Evaporator was started to supply heating steam to the Reactor Building. At 0400 hours on November 10, 1993, the on-shift Operations Shift Manager noted in the Shift Managers Log that "Steam Tunnel ΔT has been slowly increasing for several days, even after heating steam was put in service. . . ." At this point, Operations personnel believed that a steam leak existed in the Steam Tunnel and initiated actions to locate and isolate the leak in accordance with PPM 4.601.A3, Window 3-8. By this time, the Steam Tunnel ΔT was 76° F, which was near the 80° F Containment Isolation Group 1 (Main Steam) trip point. At 1053 hours on November 10, 1993, packing steam leaks were identified on PI-V-X18A2 and MS-V-20. PI-V-X18A2 was backseated to stop its packing leak at 1300 hours on November 10, 1993 and MS-V-20 was sealed with Furmanite to stop its packing leak at 1500 hours on November 11, 1993. By 1200 hours on November 12, 1993, the Steam Tunnel ΔT had returned to the normal values of 51° to 53° F.

The root cause for this example of the violation was the failure of on-shift Operations personnel to exhibit a more "questioning attitude" and implement effective problem solving techniques to followup and verify initial assumptions (e.g., the failure to adequately trend and evaluate Reactor Building ambient temperatures).

During the five day period between November 5 and 10, 1993, when the Steam Tunnel leaks existed, the highest Steam Tunnel ΔT recorded was approximately 76° F and the highest ambient temperature recorded was approximately 136° F. The Isolation Group 1 trip points are 80° F for Steam Tunnel ΔT and 150° F for Steam Tunnel ambient temperature. Thus, no Group 1 half isolation trip occurred. Essential equipment located inside the Steam Tunnel is designed to operate in a harsh environment with temperatures to 340° F. However, the Steam Tunnel ambient temperature did not exceed the normally expected maximum temperature of 140° F (Final Safety Analysis Report [FSAR] Table 3.11-1). Therefore, the Steam Tunnel leak did not challenge Isolation Group 1, Secondary Containment, or the essential equipment located in the Steam Tunnel. Accordingly, the leaks did not reduce the plant's capability to mitigate the consequences of an accident and the Supply System believes this example of the violation to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

Example 1

1. Immediate corrective action was taken to provide on-shift Operations personnel with guidance to ensure compliance with Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

2. The TSSIP is actively working to identify and correct deficiencies in the WNP-2 Technical Specification Surveillance Program as demonstrated by the discovery of the failure to incorporate the operability guidance of NRC Generic Letter 91-18.

3. Operations Administrative Procedure PPM 1.3.1A, "DEPARTMENT POLICIES," has been revised to include the criteria for declaring equipment inoperable as specified in Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

4. Appropriate plant personnel have been trained on PPM 1.5.1, Revision 18.

5. A POC procedure review commitee has been established as part of the procedure change management process to perform an additional procedure review prior to general POC member review.

6. OER 91043A has been reopened to assure that the guidance included in NRC Generic Letter 91-18 is adequately addressed.

7. This violation and the part POC played in the problem were reviewed at a POC meeting held on January 28, 1994.

Example 2

1. The I&C Technician who committed the procedure verification error was counseled on the need to be more investigative when problems occur and to practice "self-checking" and teamwork.

2. The Shift Manager involved in this incident has been counseled to be more proactive in resolving problems and to follow through on initial assumptions to ensure they are correct. The Shift Manager involved is conducting briefings with Operations crew personnel on the lessons learned from this incident.

3. This incident was discussed with I&C Maintenance Shop personnel.

4. This incident has been made required reading for Operations Shift Managers, Control Room Supervisors, Shift Support Supervisors, and Shift Engineers.

5. APRM CFT/CC Surveillance Procedure PPMs 7.4.3.1.1.43 through 7.4.3.1.1.48 have been changed to incorporate Human Performance Enhancement System (HPES) recommended changes, such as clarifying trip indications.

6. A review of APRM surveillance procedures completed since July 1993 was performed to determine if similar problems with the Alarm Typer were evident. No similar problems were identified during the procedure review.

Example 3

1. The Shift Managers involved in this incident have been counseled by the Operations Manager.

2. The Operations Manager and Division Manager have met with Shift Managers to discuss the lessons learned from this incident.

3. The Shift Manager turnover process has been strengthened by requiring a more thorough turnover and panel walkdowns in the Main Control Room.

4. A Technical Evaluation Request (TER) has been initiated to re-analyze the Steam Tunnel High Energy Line Break (HELB) accident to allow Steam Tunnel access through the door (instead of the hatch) during Operating Conditions 1, 2, and 3. This would permit easier (and faster) access to the Steam Tunnel for inspections in response to alarm conditions.

5. PPM 4.601.A3, Window 3-8 has been changed to improve the guidance on how to discern whether a leak is present and to clarify management expectations for investigating potential leaks in the Steam Tunnel.

Corrective Action to be Taken

Example 1

1. Administrative Procedure PPM 1.2.2, "PLANT PROCEDURE PREPARATION," will be changed by February 28, 1994 to require that applicable surveillance procedures include statements of operability for components undergoing surveillance testing.

2. Performance expectations will be established for implementing procedure change management and the information will be disseminated to POC members and procedure coordinators by February 28, 1994.

Example 2

The above corrective steps taken are considered sufficient to preclude recurrence of a similar error.

Example 3

1. The Operations Manager is briefing Operations crews on the importance of a "questioning attitude," "attention to detail," and "self-checking," and will be completed by February 15, 1994.

2. Other Leak Detection (LD) System annunciator response procedures will be reviewed and revised as necessary by April 15, 1994 to assure consistency in actions for leak identification and isolation.

Date of Full Compliance

Example 1

Full regulatory compliance was achieved on November 19, 1993 when PPM 1.3.1A was revised to include the criteria for declaring equipment inoperable as specified in Paragraph 8.5.2 of PPM 1.5.1, Revision 18.

Example 2

Full compliance was achieved on November 24, 1993 when the above corrective steps were completed.

Example 3

Full regulatory compliance was achieved on November 11, 1993 when the valve packing leaks were located and isolated.

B. Technical Specification 6.11.1 requires procedures for personnel radiation protection to be prepared consistent with the requirements of 10 CFR Part 20 and adhered to for all operations involving personnel radiation exposure.

PPM 1.11.11, Revision 4, "Entry Into, Conduct In, and Exit From Radiologically Controlled Areas," implements this TS and states in Paragraph 4.5, "Persons entering a radiologically controlled area shall adhere to all requirements specified by Health Physics personnel (i.e., RWP [radiation work permit] requirements, posted instructions, verbal instructions, etc.)."

PPM 11.2.7.3, Revision 8, "High Radiation Area Controls," requires in Paragraph 5.1 that personnel entering a posted high radiation area be signed in on a high radiation area RWP and provided with one or more of the following: (a) a radiation monitoring device that continuously indicates the dose rate in the area, (b) an alarming dosimeter, or (c) be accompanied by a qualified health physics technician with a radiation monitoring device.

Contrary to the above, on October 19, 1993, a licensee employee did not follow posted instructions, in that he reached into an area posted as a high radiation area, but had not signed in on a high radiation area RWP, was not issued a radiation monitoring device,

was not issued an alarming dosimeter, and was not accompanied by a qualified health physics technician with a radiation monitoring device.

This is a Severity Level IV violation (Supplement IV).

Validity of Violation

The Supply System agrees with the validity of this violation.

On October 19, 1993, the NRC Resident Inspector and an NRC Intern Inspector were performing a Residual Heat Removal (RHR) system walkdown in the "A" RHR Pump Room. An Equipment Operator (EO) was assisting in the walkdown and called the Health Physics (HP) Lead Technician for permission to briefly reach his hand and arm into a posted contaminated area to check the position of a valve. The EO was not aware that the contaminated zone was also a posted High Radiation Area. The EO did not see the High Radiation Area sign although it was conspicuously posted. Based on the information received during the telephone conversation, the HP Lead Technician directed the EO to wear gloves while reaching into the contaminated area.

The EO donned the gloves and a lab coat and reached into the High Radiation Area to perform the valve position check. The NRC Intern Inspector performing the RHR system walkdown observed the EO's actions and reported the incident to the HP Lead Technician when he discovered that the EO had not informed HP that the valve position check required reaching into a High Radiation Area. It was determined that the EO's actions violated HP Procedure PPM 11.2.7.3, Revision 8, "HIGH RADIATION AREA CONTROLS" and Administrative Procedure PPM 1.11.11, Revision 4, "ENTRY INTO, CONDUCT IN, AND EXIT FROM RADIOLOGICALLY CONTROLLED AREAS" because the EO technically entered a High Radiation Area without signing in on a High Radiation Area Radiation Work Permit (RWP), receiving a pre-job briefing, and wearing special dosimetry.

The root causes for this violation were:

Insufficient "attention to detail" and a failure to practice "self-checking" techniques in that the EO did not fully assess the radiological conditions before acting.

The failure of the HP Lead Technician to exhibit a more "questioning attitude" and solicit all pertinent information prior to authorizing special access controls for a radiologically controlled area.

The radiation dose rate of the area the EO reached into was later determined by HP to be 50 to 75 millirem per hour. Only the EO's hand and arm were exposed to this dose rate and the exposure time was brief. Thus, the EO's radiation exposure was minimal. Supply System

management recognizes that the generic implications of this violation had potential safety significance. However, the particular circumstances described in the violation are believed to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

1. The EO involved in this incident was counseled by the Operations Manager to be more aware of all radiation signs by paying more "attention to detail" and by practicing "self-checking" techniques.

2. The Operations Manager reemphasized awareness to all radiation signs and the importance of "attention to detail" and "self-checking" to Operations crew personnel.

3. At both turnover meetings and "all-hands" staff meetings, HP Management used this example to stress management expectations for thorough communications with a "questioning attitude" in accordance with impending administrative procedural changes.

4. Because the lack of a "questioning attitude" was found to be a generic problem, as opposed to and individual performance issue, an effective communications training session was included in the fourth quarter continuing training for Radiation Protection Technicans.

Corrective Action to be Taken

The above corrective steps taken are considered sufficient to preclude recurrence of a similar error.

Date of Full Compliance

Full compliance was achieved on December 20, 1993 when the above corrective steps were completed.

C. 10 CFR 50, Appendix B, Criterion V states, in part, "Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings."

PPM 10.2.53, Revision 7, "Seismic Requirements for Scaffolding, Ladders, Tool Gang Boxes, Hoists, and Metal Storage Cabinets," paragraph 7.2.g, states, "Scaffolding shall be erected in a manner such that no item (i.e., clamp, tube or any portion thereof [which] passes through an instrument rack) is closer than 2" to any sensing line, instrument rack or other Class-I item except structural members of equipment bases."

Paragraph 7.1.7 requires that Civil/Structural Engineering inspect or analyze each installation which does not conform to a previously analyzed configuration.

Contrary to the above, as of October 20, 1993, a scaffold existed on the 548-foot level of the reactor building in which scaffolding material was installed within two inches of a safety-related instrument sensing line, but this scaffolding did not conform to a previously analyzed configuration and had not been inspected or analyzed for this condition by civil engineering personnel.

Validity of Violation

The Supply System agrees with the validity of this violation.

The "tube and clamp" scaffold located at the East end of the Containment Exhaust/Supply Purge Valve Room (Reactor Building 548' elevation) cited in this violation was erected during a Plant Forced Outage on August 7, 1993 for Containment Exhaust Purge (CEP) valve work. Scaffold dismantling and removal work commenced prior to plant startup from the outage, but the work was temporarily interrupted with the scaffold only partially dismantled. When craft personnel returned to complete the scaffold dismantling and removal work, plant startup power ascension had already begun. The craft were informed that work could not continue because of ALARA concerns related to the increasing power ascension radiation dose rates.

When work was stopped, the upper deck of the two-tiered scaffold had been removed, except for one vertical four foot long "tube-loc" support brace. Since the upper deck horizontal support for this vertical brace had been removed, the tube leaned enough to come within two inches of the control air supply tubing for a safety-related CEP valve (CEP-V-2B). This condition violates the requirements of Maintenance Procedure PPM 10.2.53, Revision 7, "SEISMIC REQUIREMENTS FOR SCAFFOLDING, LADDERS, TOOL GANG BOXES, HOISTS, AND METAL STORAGE CABINETS," Section 7.1.2.g, which states that "[s]caffolding shall be erected in a manner such that no item (i.e., clamp, tube or any portion thereof [which] passes through an instrument rack) is closer than 2" to any sensing line, instrument rack, or other Class I item except structural members or equipment bases." On October 20, 1993, when the NRC Resident Inspector identified this violation, PPM 10.2.53 did not address scaffold qualification requirements during the period when scaffold is in the process of being erected or removed. The procedure only specified final, "erected," qualification requirements.

The root cause for this violation was that PPM 10.2.53 was inadequate in that it did not adequately address conditions for scaffold qualification.

CEP-V-2B is a two inch air operated Primary Containment isolation valve that is normally closed and fails closed on loss of control air. This valve is used to vent oxygen from the upper Containment Drywell during normal plant operation, in lieu of routinely using the thirty inch

exhaust purge valves (CEP-V-1A and CEP-V-2A). If, during a seismic event, the scaffold had caused a loss of control air to CEP-V-2B, the valve would perform its safety function and fail closed. The inability to vent oxygen from the drywell using CEP-V-2B would pose no immediate threat to the safe operation of the plant because CEP-V-1A and CEP-V-2A would still be available as an alternative method for venting oxygen. Therefore, the Supply System believes this violation to be of no safety significance, which is consistent with the findings of Inspection Report 93-45.

Corrective Steps Taken/Results Achieved

1. Immediate corrective action was taken to remove the deficient vertical "tube-loc" support brace from the Reactor Building 548' elevation scaffold to bring the scaffold into compliance with PPM 10.2.53. In addition, the scaffolds located within the Power Block were inspected and the partially dismantled scaffolds were verified to be in compliance with PPM 10.2.53.

2. PPM 10.2.53 has been changed to address scaffold qualification requirements when the scaffold is in the process of being erected or removed.

3. Appropriate craft personnel have been trained on the changes to PPM 10.2.53.

Corrective Action to be Taken

The above corrective steps taken are considered sufficient to preclude recurrence of a similar condition.

Date of Full Compliance

Full compliance was achieved on January 19, 1994 when the above corrective steps were completed.